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Contracting and Investment: A Cross-Industry Assessment

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1. OVERVIEW

- Neither the economics literature on long-term contracting nor the experience of the six industries we examine in this paper provide support for the view that long-term contracts with end-users are essential to assuring orderly investment in industries that resemble electric power generation.

- Both economic theory and industry experience suggest that long term contracts are essential to assuring orderly relationships between buyers and sellers when one or both parties must make investments specific to the relationship—for example when an aircraft component manufacturer invests in the specialized design or equipment needed to become a supplier of a part that is only purchased by a single customer for use on a single airplane model. In this situation, after investing, a supplier without a long-term contract is potentially vulnerable to a “hold up” by a customer insisting on prices that are sufficient to cover the supplier’s short-run costs but which deny it an adequate return on its sunk investments.

- The industries we examine in this paper illustrate the general prevalence of long-term contracting between suppliers and customers in circumstances where relationship-specific investments and the potential for hold-up are significant. For example, long-term contracting is used between mine-mouth power plants and their coal mine suppliers; between airplane and automotive manufacturers, on the one hand, and their respective suppliers, on the other; and between natural gas producers and interstate pipelines.

- But long-term contracts are not a common feature in industries in which relationship-specific investments between suppliers and end-users are relatively insignificant, as is generally the case for industries that produce a relatively homogeneous product that is equally (or very nearly equally) as valuable to any number of alternative users. Refiners do not need long-term contracts with consumers, nor do commercial airlines or hotels. These industries demonstrate that high fixed costs and lack of storability alone do not create a requirement for long-term contracts

- It is our view that the only reason long-term contracts may be necessary in power is when access to competitive markets is restricted by limitations—physical or regulatory—to transmission facilities or lack of competition among potential buyers.

- Instead of adopting or maintaining a wholesale power markets regime that relies primarily on long-term contracting to provide sufficient capital investment, regulators should consider other potential policy responses, such as (1) creating demand response capability through the use of advanced technology so that an adequate amount of load can respond to peak price signals and thus allow a more freely priced wholesale market, and/or (2) creating competitive capacity markets, that enable access to essential facilities yet minimize the need to transfer investment risk from producers to consumers and that preserve much of the flexibility inherent in a spot-market electricity sales mechanism.

1.1. INTRODUCTION

Since the 1990s the electric power industry in many parts of the United States has been transformed by extensive changes in regulation. There was an initial surge of investment in new "merchant" power plants that rely on market earnings rather than regulated rates to recover their costs and earn profits, followed by a predictable decline of new investment when forecasted reserve margins were high. Now forecasted reserve margins in many markets estimate a need for new capacity in the future. The challenge before the industry is how to spur new investment to meet these needs. Some have argued that regulated utilities should build the new generation, recovering the costs in regulated rates. Others believe that generators and utilities will need to enter into long-term contracts in order for new generation to be built. Supporters of these proposals believe that ultimately the end-use customer must bear the investment risk. In some regions, new "capacity markets" have been created to provide a longer-term price signal for non-regulated entities to build new generation without customers bearing the investment risk.

Although the electric power industry may be in some ways unique, we believe that examining other industries that face similar investment issues can provide valuable insights about the role long-term contracts may play in facilitating investment. This paper will address the arguments for and against long-term contracting by examining the need for long-term contracts, or lack thereof, between producers and end-use customers in several industries. The paper is organized into five major sections:

Section 1 provides an introduction and overview of the paper and summarizes our main results.

Section 2 provides a brief history of trends of electricity regulation and electric power plant construction in the United States.

Section 3 provides a non-technical survey of the economics literature on long-term contracting and its relationship to investment decisions.

Section 4 surveys contracting practices in sectors of six industries (hotel development, aircraft and airlines, automotive and automotive components manufacturing, petroleum refining, natural gas, and coal mining) all of which, as with electric power generation, require large and lumpy capital investments. Some of these industries and sectors exhibit fundamental conditions affecting the investment process that closely resemble those facing potential investors in new generation assets, while others differ in key respects.

Section 5 summarizes the lessons about contracting practices and capital investment that can be learned from the industry case studies presented in the previous section and explores the implications of these lessons for the electric power industry.

1.2. SUMMARY OF KEY FINDINGS

Designing a market structure for electric power markets that provides appropriate incentives for investment in new generating capacity must take into account key economic and technical characteristics affecting electricity supply and demand. Important characteristics affecting the supply of and demand for electricity include:

- Electricity is difficult to store, requiring that nearly all electricity must be produced at the moment it is used.
- Power plants, once built are locked in their locations, and while they can transmit their output over long distances where transmission capacity is sufficient, in many markets firm transmission reservations may be expensive or impossible to obtain.
- Generation is highly capital intensive and is built with the expectation of earning back the investment over many years.
- On a commercial scale, new generation capacity takes years to build. Available capacity to supply electricity is therefore essentially fixed in the short run.
- Because of regulatory rate structures, short-run demand for electricity has historically been little affected by short-term price variations. In most industries, a supply shortfall leads to high prices, which in turn curtails the quantity demanded to balance supply and demand. For historical reasons, few U.S. consumers are charged energy prices that could moderate demand during peak times.
- Long-run demand forecasts are uncertain.

In a prior era, the interplay of these characteristics posed few risks to the parties responsible for investing in new generating capacity. Regulated investor owned utilities (IOUs) undertook the bulk of such investments and were effectively guaranteed a return on their investments, as regulators allowed IOUs to charge their customers electricity rates incorporating an "allowed rate of return" to the utility on its investments in its generation assets. By this mechanism, end-use customers, and not IOUs, bore most of the risks associated with investments in new capacity. In many regions, today's regulatory and market regimes for electric power, by contrast, no longer force end-use customers to bear generation investment risk and, indeed, generally preclude regulated utilities from building new generation capacity. It is an open question, though, whether the market and regulatory structures and institutions that have evolved in recent years provide potential investors with a sufficient risk-adjusted rate of return to justify the new investments in generating capacity that will be needed to meet future demands for electricity. Some observers believe that an institutional structure in which most new investments in generation capacity are predicated on the security provided by a long-term contract with a credit-worthy entity—in practice, using the IOU as a vehicle to the end-use customer—will ultimately be required to provide unregulated investors with sufficient incentives to add capacity. Other observers disagree, pointing to other market or institutional reforms as more appropriate responses to any perceived failure of current structures to provide potential investors with adequate incentives to invest.

Neither the economics literature on long-term contracting nor the experience of the six industries we examine in this paper provide support for the view that long-term contracts with end-users are essential to assuring orderly investment in industries that resemble electric power generation. Both economic theory and industry experience suggest that long term contracts are essential to assuring orderly relationships between buyers and sellers when one or both parties must make investments specific to the relationship—for example when an aircraft component manufacturer invests in the specialized design or equipment needed to become a supplier of a part that is only purchased by a single customer for use on a single airplane model. In this situation, after investing, a supplier without a long-term contract is potentially vulnerable to a “hold up” by a customer insisting on prices that are sufficient to cover the supplier’s short-run costs but which deny it an adequate return on its sunk investments. The industries we examine in this paper illustrate the general prevalence of long-term contracting between suppliers and customers in circumstances where relationship-specific investments and the potential for hold-up are significant. For example, long-term contracting is used between mine-mouth power plants and their coal mine suppliers; between airplane and automotive manufacturers, on the one hand, and their respective suppliers, on the other; and between natural gas producers and interstate pipelines. But long-term contracts are not a common feature in industries in which relationship-specific investments between suppliers and end-users are relatively insignificant, as is generally the case for industries that produce a relatively homogeneous product that is equally (or very nearly equally) as valuable to any number of alternative users.

Many of the industries we examine fall into this category, as does (generally) electric power generation, and many share with the electric power industry some or nearly all of the key characteristics we identify as important characteristics of supply, demand, and investment decisions in the electric power industry. Such industries typically engage in little or no long-term contracting with end users. We find, for example, that despite facing uncertain long-run demand, commercial airplane manufacturers and automobile manufacturers are willing to invest in new models and factories requiring capital investments in the billions of dollars with either very limited (airplanes) or no (automobiles) advance financial commitments from their end-use customers, instead basing their decisions solely on their judgments about projected trends in end-user demand and about which models might appeal to such customers. Similarly, billions of dollars have been invested in expanding oil refineries, despite uncertainties about demand for refined petroleum products the prices for which are generally determined in spot market transactions.

Two industries in which capacity expansions occur regularly in the absence of long-term contracts with end users resemble power generation even more closely, namely, airlines and hotels. When an airline purchases a plane to increase its capacity, it does so despite long-run demand uncertainty in an industry in which the output the airline sells to users (airplane seats on particular flights) cannot be stored. In the case of hotels, the parallels with power plants are even fuller; not only are hotels a sector for which long-run demand is uncertain and in which output cannot be stored, but, like a new power plant investments, an investment in a new hotel takes some time to come on line, is a durable asset, and cannot be easily moved once made. The only economically significant way in which these industries differ from the power generation sector is that for both airlines and hotels prices to end users can be far more readily adjusted in response to short-term fluctuations in demand than has historically been the case in electric power markets.

An appropriate policy response to the perceived shortcomings of the current structure of electric power markets in eliciting sufficient investment in new generation capacity needs to address the limits the current structure places on the use of real-time pricing as a mechanism to ration consumer use during times of peak demand. An appropriate response also needs to take into account other shortcomings inherent in the current regulatory system, notably the inability of market regulators in many jurisdictions to commit credibly to implement a policy regime that would allow wholesale spot market electricity prices to rise to levels during peak-demand periods sufficient to justify undertaking generation investments predicated on offering power and earning market returns primarily during such periods. Encouraging long-term contracting that effectively transfers investment risks from generators to consumers is one policy response that can mitigate some of the limitations of the current market and regulatory structure governing sales of electric power create for potential investors in new generation capacity, but it is neither the only or the most appropriate such response. Instead, regulators should consider other potential policy responses, such as (1) creating demand response capability through the use of advanced technology so that an adequate amount of load can respond to peak price signals and thus allow a more freely priced wholesale market, and/or (2) creating competitive capacity markets (that allow needed generation and demand response resources to compete to meet the regions' reliability requirements) while minimizing the need to transfer of investment risk from producers to consumers and preserving much of the flexibility (and efficiency) inherent in a spot-market electricity sales mechanism to identify the lowest cost producers of power and to award short-term supply responsibilities to them.

2. SOME HISTORY OF UTILITY CONSTRUCTION

It did not take long after Thomas Edison built the first commercial electric system in New York City in 1882 for industry and government to realize that the electricity industry required some form of regulation. Historically, electric generating, transmission, and distribution equipment was costly. In order to make investment attractive, the electric company would have to charge rates above its short-run costs over time to earn a return on and of its investment. This need immediately raises two problems: with prices above marginal costs, a second electric company might enter the market, leading to destructive competition that could not sustain orderly investment as load grows. At the other extreme, if no competitor appears (perhaps fearing precisely just such a price war), the electric company would be a monopoly and could charge excessive prices. Neither extreme is desirable. The form most frequently adopted was the franchise investor-owned utility, or IOU.[1] In return for the exclusive right to provide electricity

[1] Public power companies, e.g., municipal and cooperative utilities, also generally follow the model of a defined service territory and cost of service rates.

(and, often, natural gas) in a geographic area, the IOU would be limited to charging rates set by a public regulatory body. These rates would be “just and reasonable,” granting an “allowed rate of return” to the IOU for its invested capital and recovery of prudently incurred costs.

For most of its history, this IOU model of regulation included sufficient incentives to encourage investment as well as the balances to limit over-investment. Regulators provided a strong regulatory guarantee that its utilities would be allowed to charge rates sufficiently high to earn a relatively attractive rate of return on invested capital, creating profits for the IOUs’ shareholders. Consequently, IOUs were typically willing to provide the capital needed to expand its power system, including adding new generation as required. Indeed, the challenge in some cases was to *limit* the amount of investment. Regulators typically required utilities to demonstrate the need and reasonableness of major new investments, and they might disallow recovery of costs from assets that were not “used and useful.” Thus, through a sometimes complex web of incentives and checks, regulators led utilities to make investments in power plants and other assets.

Through the 1980s and 1990s, several events raised questions in many regulators’ minds about the successfulness of the IOU monopoly model. The U.S. Congress, seeking to expand the role of renewable energy and co-generation, passed the Public Utility Regulatory Policies Act (PURPA), requiring IOUs to allow qualifying facilities to interconnect to their transmission systems and to buy their power at state-mandated prices and the Fuel Use Act, which prohibited utilities from building the very gas-fired generation that PURPA was encouraging. As a result of the Fuel Use Act, some IOUs (as well as public power utilities) undertook expensive generation projects—most notably, nuclear plants—that suffered enormous cost overruns. Although some of these costs were disallowed by regulators, resulting in the bankruptcy of several utilities, consumers bore most of these cost overruns. Some consumer advocates also charged that IOUs “gold plated” their system to increase profits, and there was a lack of public confidence that regulators were as effective as a competitive market would be in cutting allegedly excessive costs and wasteful investments from utility operations.

Consequently, by 1995 there were sweeping regulatory reforms in many parts of the country. In a series of orders, the Federal Energy Regulatory Commission (FERC), which oversees the transmission system throughout most of the continental United States, required that transmission owners provide open access to any generator. Many states, particularly in the northeast and mid-Atlantic regions, encouraged their IOUs to divest generation or move it to a non-regulated affiliate. To coordinate the operation of the diversely owned generation, the FERC required the creation of independent transmission companies, many of which also operate day-ahead power exchanges to coordinate the commercial activity, as well as the electrical operations.

What was largely assumed in this regulatory restructuring, however, was that market signals would suffice to induce generating companies to build generation resources when and where they were needed. Any attempt to build a successful market structure for electric power must, however, take into account certain physical and economic characteristics of electricity. :

- Electricity is currently difficult and expensive to store, so nearly all electricity must be produced at the moment it is used. Consequently, generation capacity needed to meet peak demand may sit idle for much of the year.

- A power plant is locked into its location. Although there are many locations where power plants *could* be built in most markets, once the investment has been made, it cannot easily or cheaply be reversed.

- The electrical output of a station may be transmitted over long distances if there is sufficient transmission capacity, but in many markets firm transmission reservations may be expensive or impossible to obtain.

- Traditional central-station new generating capacity is a durable asset that takes years to build. Therefore, the available supply of capacity is essentially fixed in any given month. Moreover, a single such generator may, depending on the transmission infrastructure, add substantially more capacity than is needed to meet incremental needs, taking several years to absorb the capacity addition and, in the interim, creating a surplus with adverse price impacts to the investor.

- Because of regulatory rate structures, short-run demand for electricity has historically been little affected by short-term price variations. In most industries, a supply shortfall leads to high prices, which in turn curtails the quantity demanded to balance supply and demand. For historical reasons, few U.S. consumers are currently charged energy prices that could moderate demand during peak times. If there is a generation insufficiency, system operators may need to curtail some customers involuntarily—the "rolling blackouts" in California during 2000 and 2001 being perhaps the most famous example.[2] Because short-term demand is so highly inelastic, regulatory concerns regarding the exercise of market power often impose rules that limit pricing to levels that reflect marginal cost and do not reflect the scarcity value of electricity.

- Long-run demand forecasts are uncertain.

In a power system where regulated utilities can no longer force end-use customers to bear generation investment risk—and indeed are precluded from building new, regulated generation—how does the market attract enough investment to provide enough resources to meet future demand? In particular, we take up the question of whether it is necessary for there to be long-term contracts with a credit-worthy entity—in practice, the utility as a vehicle to the end-use customer—to bring about sufficient investment, or whether there are analogs in other industries that would lead us to believe that long-term contracts are not a requirement.

2 Most service interruptions, however, are not caused by generation insufficiency. The most common problems are caused by localized failures of the distribution system, such as when an ice storm takes out power lines. The most publicized large-scale blackouts, such as the one that afflicted New York, Ontario, and other parts of the Northeast and Midwest, were the result of cascading transmission line failures, not a shortfall of available generation.

The answer to this question has pressing policy implications. One of the primary benefits of regulatory restructuring would be lost if utilities must ink long-term deals with every new resource needed for system adequacy, namely the shifting of risk for making the correct decisions about where, when, and what to build.

3. LONG-TERM CONTRACTS: SOME INSIGHTS FROM THE ECONOMICS LITERATURE

Most everyday consumer purchases and many business transactions take place without the necessity of long-term contracts. Instead they are made in spot market transactions or using a short-term contracting instrument such as a purchase order. The flexibility of such arrangements creates benefits for the parties and for the efficient allocation of resources. The ability to recontract allows buyers to reward quickly those sellers that deliver products offering superior value and likewise allows innovative sellers to quickly build their businesses. Prices revealed in spot markets also provide appropriate signals for the allocation of resources in both the short and long run. Market pricing allocates products among customers to those that value the products most highly, and, absent market imperfections such as externalities, market pricing provides appropriate signals for the efficient use of resources and result in profits or losses that signal to investors the identity of products for which investment in additional productive capacity is required and those for which capacity is currently abundant. Liquid spot markets also readily allow for forward contracting, and the ability to buy and sell these forward contracts can attract financial intermediaries willing to invest and assume risk from both buyers and sellers.

But many economic transactions are not mediated in spot markets. Rather we see a mix of longer-term arrangements, including long-term contracting and vertical integration. Why? This broad area has been the subject of much fruitful research in the economics literature.[3]

The basic insight is that while frequent recontracting and reliance on spot markets generally serves both buyers and sellers well, these mechanisms do not work well in circumstances where either buyer or seller has to make idiosyncratic, relationship-specific investments to meet the other party’s requirements. In such situations, long-term contracts (or, in some circumstances, full vertical integration) are required to avert potential “hold up” problems in which one party acts opportunistically to take advantage of the fact that its counterparty is locked in to the arrangement because it has made sunk investments that have little or no value outside the relationship. For example, a firm that sinks investment dollars into designing and tooling parts that are specifically tailored to the needs of a single customer could later find itself vulnerable to customer demands that it cut prices to levels below those that would provide it with a market return on its investments. Faced with a choice of losing the customer’s business and earning zero return on its investment or giving in to customer demands for prices that, while low, still provided it with

3 A good discussion of these issues can be found in Oliver Hart’s essay on “incomplete contracts” found in the *New Palgrave Dictionary of Economics*.

some margin above variable costs, the supplier might be forced to opt for the latter. To head off such a possibility, the potential supplier in such a situation looks for a long-term contract that, over its lifetime, provides the supplier with an expected income stream sufficient to cover the net investment required to fulfill its supply obligations.

Long-term contracts are thus most essential where the relationship between buyer and seller involves asset specificity—where one party or the other must make investments that have a much smaller value outside the relationship than inside it. Various situations can give rise to asset specificity, but the essence of whether relationships call for specific assets can usually be assessed by looking at 1) how readily the assets in question can be deployed in new productive opportunities and 2) the readiness with which the products produced by the assets can be sold to alternative purchasers. Where assets can, at low cost, be shifted to other productive uses, buyers cannot hold up suppliers because the supplier can credibly respond to a request for price cuts with a threat to cease production or to redeploy its productive assets into some other use. Similarly, a buyer of a relatively homogeneous product that is equally (or very nearly equally) as valuable to any number of alternative users cannot make extraordinary demands on its supplier because the supplier can credibly respond by redirecting its output to these other potential buyers at the same or very nearly the same price its original customer was willing to pay. This situation ought to characterize most transactions in electricity markets as the product is relatively homogeneous and can readily be transferred from one potential buyer to another, subject to the availability of suitable capacity in the transmission network (and that other buyers can be reached at reasonable cost via transmission). Thus, in the absence of transmission constraints, there is no inherent reason why electricity should not be tradable via short-term contracts or on a spot basis, and potential investors in electricity generation ought not to face significant hold-up problems from customers.

Increasing the degree of risk and uncertainty by itself does not diminish the important advantages afforded by short-term contracting in situations where transactions do not require significant transaction-specific investments.[4] Signing long-term contracts with customers to deliver a specified level of output at set prices before committing to an investment can reduce the investor's risk, but at the expense of increasing customer risk, since customers entering into long-term contracts give up the flexibility to purchase from other suppliers on the open market should the prices or quality of the goods supplied by alternative suppliers ultimately prove to be superior to those of its contracting partner. Potential customers will want to be compensated in the form of lower expected prices for assuming this risk. Unless the potential customer for some reason has a lower cost of bearing risk than does the supplier, long-term contracts with customers thus do not offer any particular advantages as a means for mitigating investment risks.

4 Uncertainty, however, does have important implications for contract and relationship design where asset specificity is important – for example, where business relationships between buyers and sellers are locked-in by virtue of relationship-specific investments, increasing the degree of uncertainty may be associated with increasingly complex long-term contracts both to deal with reasonably foreseeable contingencies and to lay out conflict resolution mechanisms to deal with unforeseen contingencies.

It is true, however, that a firm with a long-term output contract already in place with a credit-worthy counterparty does face lower risks than a firm without such a contract and should be able t to take on more debt than a firm without a contract for its output.[5] In particular, the relatively certain cash flows that a firm planning to sell its output thorough long-term contract can offer investors makes such projects suitable for higher leverage, thus increasing equity returns, while those projects without long-term output contracts may have to be financed with a higher percentage of equity financing and will have lower equity returns. Thus, while it is asset specificity, and not inherent riskiness, that we expect to drive the decision whether supplier-customer relationships will take place through long-term contracts or through spot markets, we expect to see a greater reliance on debt instruments to finance projects where long-term output contracts are in place and a relatively greater reliance on equity financing for projects that lack long-term contracts in place.

4. LONG-TERM CONTRACTS AND INVESTMENT DECISIONS: EXPERIENCE IN SELECTED INDUSTRIES

In this section, we examine several industries in which parties make large investments, identifying those investment opportunities for which long-term contracts are normally a precondition for investment and those where such contracts are not the norm. The discussion presented in the previous section suggests that we should find long-term contracting primarily in circumstances where relationship-specific investments are important. With a few notable exceptions, that is indeed what we find.

4.1. HOTELS

Hotel development represents an investment sector in which long-term contracting with end users does not occur (and indeed is fundamentally infeasible) and yet in which considerable investment takes place. Hotel room-nights, like airplane seats and electrical generation are perishable goods and must be consumed when they are produced.

Long-term contracts play a prominent role in some types of real estate development where investments specific to the relationship between landlord and tenant (or spillover relationships between tenants) are important. For example, a successful development of a shopping center generally requires obtaining a long-term commitment from a suitable anchor tenant, and the developer and the anchor

Lessons Learned Hotels

- Diverse buyers can—and must—be served without long-term contracts.
- Location-specific investments serving a competitive customer base succeed on the fundamental economics of the investment, as well as prudent management.

5 Assuming that the price of the commodity is uncertain.

tenant will generally work together in project planning on elements such as architectural styles, parking, signage, and landscaping. The choice of the anchor tenant will then influence the mix of other stores that can or cannot be suitably collocated in the shopping center.[6] But in other real estate development sectors, where relationship-specific investments between landlord and tenant or across tenants are minimal or nonexistent and where potential tenants are numerous and essentially interchangeable, long-term contracts are not the norm and do not play a significant role in project economics. Notable examples of sectors where development takes place in the absence of long-term contracts include apartment complexes and, especially, hotels. Rather than on any assurances provided by long-term leases, the cash flow projections underlying investment decisions in these types of projects must rely on market projections based on economic factors such as current vacancy rates for similar properties in the local market, and projections of future growth of demand in the area and of the rate in at which other potential competitors can be expected to enter the market.

Two aspects of the buyers of hotel services, however, make reliance on long-term contracts not only unnecessary, but infeasible: the diversity of buyers and the sporadic demand of each buyer. Except in very unusual situations, a hotel has thousands of potential buyers for its rooms on any given night. No one customer can, by withholding its custom, have a material effect on the profitability of the hotel. The hotel is not dependent on any one customer. Indeed, to the contrary, the sporadic nature of individual consumer demand renders long-term contracts between end users and hotel owners infeasible. While corporate customers may enter into preferred provider arrangements with individual hotels or hotel chains, the demand guarantees provided by such commitments are weak and the contracts are frequently renegotiated. But like facilities that generate electricity, hotels, once built, are tied to their site, making a financial commitment to building a hotel a substantial sunk cost. Because long-term contracts with end users are infeasible, the operating costs of hotels cannot be adjusted quickly, and the demand for hotel rooms is tied to trends affecting national and local economic conditions, hotel properties can realize extraordinarily volatile returns. As the authors of a recent journal article note:

> Hotels, even high profile city centre locations with well-established brand names, have never easily fulfilled stereotypical real estate investment criteria. They are highly leveraged operationally due to their staffing and supply and maintenance needs. ... [M]any factors such as terrorism and natural disasters are unpredictable and often impact hugely upon travel and thus hotel occupancy. While hotels can raise rates quickly in an upturn, in particular to corporate and premium individual clientele, tenants (or 'guests') can terminate or renegotiate their arrangements virtually overnight, certainly quicker than a typical hotel can adjust its high operational cost base. The volatility of hotel income

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6 Richard B. Peiser and Anne B. Frej, *Professional Real Estate Development: The ULI Guide to the Business,* 2nd Edition, Washington, D.C: ULI—the Urban Land Institute, 2003, p. 340.

> streams, even for trophy properties, is something many real estate fund managers have difficulty coming to grips with.[7]

Despite this volatility, new hotels are built, sometimes by firms that intend to operate them, sometimes by real estate investors planning to contract with a management company to oversee and run hotel operations, and sometimes by partnerships between these classes of investors. The sums involved can be quite large, with some especially large projects, like major casino hotels, costing billions of dollars to develop.

4.2. AIRCRAFT AND AIRLINES

This section examines the role of long-term contracts in the modern aviation sector. We examine the entire value-chain of the sector: from aircraft parts, to aircraft development, to airline operations. We find, as expected, that long-term contracts between producers and purchasers play little or no role in those parts of the aviation sector where relationship-specific investments are non-existent or small, namely airline operations and in commercial aircraft sales and development. By contrast, the relationships between commercial aircraft manufacturers and their component suppliers, which involve significant relationship-specific investment by both parties, are typically governed by long-term contracts. We also take a short excursion into military aircraft development, a sector in which investments specific to the relationship between the defense contractor and a single customer, the U.S. government, would ordinarily seem to call for long-term contracting, but which proves to be the exception that proves the rule: rather than relying on long-term contracts, defense contractors and the U.S. government instead resort to alternative financing methods because the government is unable to enter into the sort of long-term contracts that would typically be needed.

4.2.1. Airlines

Airlines, like electricity generators and hotel operators, produce and sell a relatively homogeneous product (airline seats on a particular flight) that is not storable and must be consumed when it is produced. Like electric power, the airline production process requires the use of very expensive capital equipment, as new commercial aircraft (as discussed in the next section, can command prices in the tens or hundreds of millions of dollars. Demand for air transport originates from a wide and diffuse customer base, and neither the airline nor its

Lessons Learned From Airlines

- Long-term contracts with individual customers may not be possible, even when substantial investments are required to meet market demand.
- Innovative combinations of ownership and leasing strategies can structure variable risk/reward balance that limits the exposure of capital asset owners to customer switching.
  - A separation between direct customer service providers and asset ownership is essential to this flexibility..

7 Daniel Larkin and Carmelo Lam, “Hotels—The Fifth Food Group?,” *Journal of Retail & Leisure Property*, vol. 6, no. i (2007), p. 23.

customers needs to make any large relationship-specific investment to facilitate transactions between them.

Given these demand characteristics, long-term contracts for seats between airlines and end users would serve no strong economic purpose; indeed, given the episodic nature of demand for airline seats, it is hard to imagine that many customers would be in a position to sign such contracts. While corporate customers may negotiate discounted rates with preferred carriers in return for meeting an overall volume or market share commitment, these are relatively weak commitments and are usually are renegotiated annually.

Airline firms contemplating investing in new equipment for entry or expansion must do so, therefore, without any contractual guarantees that demand will ultimately be sufficient to warrant the expansion. This uncertainty, however, poses no barrier to airlines in acquiring additional aircraft. Airlines can readily purchase aircraft suitable to their needs through any number of financial mechanisms, including purchases financed through retained earnings or equity capital, unsecured borrowing (if the airline is creditworthy), term loans with banks or other financial counterparties secured by the value of the aircraft, or Equipment Trust Certificates (ETCs, a long-term lease/purchase agreement between the airline and outside investors secured by the aircraft.) [8] Or, if they do not wish to take on the risks of ownership, airlines can contract to use aircraft owned by established leasing companies, such as the market leading firms International Lease Finance Corporation (ILFC) and GE Capital Aviation Services (GECAS).[9] These firms offer airlines aircraft operating leases that typically feature relatively short terms (between one and seven years, with five years representing an average length) and that allow the airline to return the aircraft to the lessor at relatively short notice without major penalty.[10]

A robust market for aircraft leasing and the wide availability of other financing instruments secured by the value of the aircraft themselves allow even firms with relatively little equity capital to enter the industry or expand their operations. Fundamentally, the general availability of leased capital and goods and of secured financing is made possible by conditions the same conditions, discussed in the section on commercial aircraft, that explain the absence of long-term contracts between aircraft manufacturers and airline customers, namely, that airplane models are standardized designs not built specifically to suit the needs of any particular airline.

Coupled with the fact that an airplane can readily be redeployed between almost any two airlines operating the same type of equipment no matter where the two airlines operate, standardization has facilitated a rich secondary market for used airplanes. In this respect, the airline industry differs from the electric generating industry, in which capital investment is effectively tied to a particular place—although with adequate transmission, the *output* of a generator can migrate to

8 Peter Morrell, *Airline Finance*, 3rd Edition, (Aldershot, England: Ashgate Publishing, 2005), pp. 92-98.

9 Ibid, pp. 104-106.

10 Ibid., p. 200.

other markets, even if the equipment itself cannot. In this example, though, we can analogize airlines to competitive load-serving entities (LSEs) in the electricity markets. Airlines may choose to serve customers through owned or leased assets, just as an LSE may choose to own or contract with a generator. Aircraft leasing firms are analogous, then, to independent power producers who take the risk that the *overall* market conditions will be favorable but do not need to commit to serving any particular LSEs when they make the needed capital investments.

4.2.2. Commercial aircraft

Developing new large passenger aircraft is a very expensive proposition. Merrill Lynch, for example, estimates that the two most recent large airliner projects each cost $10 billion or more to develop—the A380 superjumbo airliner costing Airbus and its partners $14 billion to develop and the Boeing 787 requiring $10 billion in development costs.[11]. Airplane manufacturers and their risk-sharing partners invest very large sums of money in product development with only very limited contractual commitments from customers and with no guarantee that they will ever see a profit on their investment. Long-term contracting is commonplace, however, in the relationships between airplane manufactures and the firms that supply them with components and systems. This difference in contracting institutions between the downstream market for aircraft output and the upstream markets for aircraft components is consistent with the differences in asset specificity that characterize producing for the two markets. While there is a relatively low degree of asset specificity associated with investing in producing an airplane design suitable to the needs of a wide variety of customers, producing components tailored to the needs of a single customer for a single model naturally requires numerous investments that are highly specific to a single customer relationship.

Because the development costs associated with a new aircraft program are so large (in the billions and even tens of billions of dollars), they typically require the manufacturer to sell hundreds of aircraft, potentially over a decade or more, to recoup the investment.[12] As a result, aircraft manufacturers such as Boeing and Airbus spend a great deal of effort to understand both current customer needs and to predict trends in air travel and how such trends will likely affect aircraft demand decades into the future. Airplane

Lessons Learned from Commercial Aircraft

- Contracts with end-use customers are not necessary for even high fixed costs investments if financial intermediaries are available.
- With many potential buyers, commercial aircraft designers depend on sound business judgment rather than long-term contracts to recover multi-billion dollar capital investments.
- Even the largest capital expenditures can be financed without contracts provided the investment serves a broad-based market need.

11 Merrill Lynch, “Prepare for Takeoff … Commercial Aerospace Primer” March 16, 2007, p. 60.

12 Airbus has stated, for example, that it expects to recover its initial investment in the A380 program once 250 aircraft have been sold. Merrill Lynch Primer, p. 62.

manufactures invest considerable sums in pre-commercial research and development, which they fund out of their own capital sources without any contributions from potential customers.

Airplane manufacturers require substantial customer interest reflected in an initial book of orders before committing funds to launch an aircraft design into the costly final development phase Early in this decade, for example, Boeing floated a proposed design for a new aircraft model, dubbed the sonic cruiser that would take advantage of new engine and airframe technologies to transport 250 passengers at nearly the speed of sound while achieving the same fuel consumption levels that characterized the previous generation of aircraft. When the concept attracted minimal interest from airlines, Boeing abandoned the project in favor of the 787, an aircraft of roughly the same capacity as the proposed sonic cruiser using many of the same technologies to improve fuel consumption while maintaining maximum speeds at levels similar to other commercial aircraft. The new design attracted enough interest, and enough launch orders, to justify a decision to launch the program in 2004, and the airplane should enter service sometime next year.

Launch orders, however, are typically not sufficient in scale or duration, nor do they involve enough of a financial commitment, to provide any guarantee that the product program will ever recover its investment costs. Launch orders merely represent an initial order commitment sufficient to establish a minimum economical production rate for the first year or two of the program.[13] The sums initially committed by launch customers is comparatively modest in comparison to the total costs of developing an airplane—typically a deposit of 2 percent to 5 percent of the final cost of the airplane—perhaps enough to cover some of the variable cost of assembling materials for the airplane, but not enough to make much of a dent in offsetting development costs.[14]

In committing to bring a product through development and into production, the airplane manufacturer is thus effectively betting that beyond this initial period it will continue to attract new product orders sufficient to keep the program operating at an economical rate. There are no guarantees that this will be true, and if the airplane manufacturer guesses wrong, it may never recover its initial investment. Boeing and Airbus, for example, have effectively placed bets on very different futures for international air travel—Airbus having developed the A380 superjumbo aircraft based on a view that over the next decades there will be major demand for very large aircraft to connect dense routes between international hub airports, while Boeing's investment in the 787 is based on a view that the major growth in long distance air travel will be in less dense point-to-point routes originating from or ending at secondary air travel markets.

13 Merrill Lynch Primer, p. 61.

14 For example, Airbus officially launched the A380 program upon receipt of an order for the fiftieth airplane. Even if each of these initial orders had been secured by a full 5 percent deposit against the approximately $300 million list price of the aircraft (and most customers, and launch customers in particular, purchase airplanes at a discount to list price), these deposits would have amounted to only $750 million in total, compared to the approximately $14 billion development cost of the aircraft.

Manufacturers are able to place these bets without the security of long-term contracts because customer hold-up is not a serious issue. Where once the market for certain jet aircraft was dominated by a very few large international carriers and a single carrier could serve as a launch customer for a new product (as Pan Am was for both the Boeing 707 and Boeing 747), and exercise some considerable influence over the product's design, today's aircraft are typically launched with the input of numerous airline and leasing company customers. While certain components and features of an airliner are customized to the ultimate customer's specifications—the customer can often choose between engines supplied by competing manufacturers and can customize interiors to its specification—the major investments in airframe development are not specific to any transaction or any particular customer. The risks associated with these investments are general marketplace risks that airplane manufacturers assume themselves or offset in ways other than by transferring risk to customers through restrictive long-term contracts.

4.2.3. Aircraft component suppliers

While hold-up is not a serious concern for aircraft manufacturers in dealing with final customers, such is not the case in the relationships between aircraft manufactures and their suppliers. While an airplane manufacturer typically markets an airplane of common design to numerous largely undifferentiated potential buyers, aircraft component suppliers must typically customize their products to the needs of a particular manufacturer's designs. These suppliers have long included firms that provide specialized systems such as engines, avionics, and landing gear and now increasingly include firms providing major structural elements of the airframe as well. (Boeing is reported to have outsourced roughly two-thirds of the production of the 787; while responsible for final assembly of the aircraft, the only major part of the aircraft actually built by Boeing itself is the vertical fin.[15])

Increasingly, these suppliers are asked to finance the development of the aircraft through risk-sharing agreements, in which they, rather than the airplane manufacturer, agree to fund development and tooling costs in hope of recouping their investment in product payments over the life of the product. The supplier may be guaranteed some minimum order quantity by the manufacturer, but this will not likely be sufficient to guarantee that it can recoup is initial investment. Alternatively, a supplier may agree to pricing that varies with the level of aircraft sales achieved by the manufacturer.[16] (Through such mechanisms, for example, suppliers are estimated to have

Lessons Learned Aircraft Components

- When investments are specific to a single customer, long-term contracts are needed to allocate risk and reward between the parties up front.

15 Merrill Lynch Primer, p. 68.

16 Merrill Lynch Primer, p. 125.

provided roughly half of the Boeing 787's $10 billion development cost.[17]) These agreements are part of long-term contract awards that typically single sourced and meant to cover the entire production lifetime of the aircraft design.[18] These long-term agreements, which guard against hold-up, are an important feature in eliciting supplier firms to make the investments necessary to meet the needs of their airplane manufacturer customers.

4.2.4. The defense procurement process

Developing new military aircraft can require capital expenditures that are even larger than those required to develop civilian airliners; for example, development costs for the F-35 strike fighter program—yet to start production—now amount to roughly $45 billion.[19] Yet the aerospace firms that undertake these programs typically do so without the benefit of significant long-term purchase commitments from their customer, the United States Department of Defense (DoD), The absence of long-term contracting for military aircraft, and for defense procurement in general, is surprising, as almost the entire investment in a new military aircraft or weapons system is specific to the relationship with the DoD and is potentially subject to the types of "hold-up" problems that typically provide the impetus for long-term contracting. As detailed below, institutional features peculiar to contracting with the federal government make it extremely difficult for the federal government to execute long-term contracts. As a result, the defense procurement process supplements short-term contracting with other contractual and institutional mechanisms designed to avert hold-up problems. Defense contracting provides a unique example illustrating the kinds of alternative mechanisms that are needed to avert hold-up problems where relationship-investments are significant yet long-term contracting is largely infeasible.

An essential feature of the defense procurement process—and of government contracting in general—is that the annual Congressional Appropriations process makes it extremely difficult to negotiate binding long-term contracts for government procurements. One Congress cannot commit a subsequent Congress to appropriate the funds needed to fulfill a long-term purchase commitment. As a result, the government typically purchases military aircraft or other weapons systems through a series of annual fixed-price procurement contracts.[20]

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17 David Greising and Julie Johnsson, "Behind Boeing's 787 Delays," *The Chicago Tribune*, December 8, 2007. (www.chicagotribune.com/services/newspaper/printedition/saturday/chisat_boeing_1208dec08,0,528945.story.)

18 Merrill Lynch Primer, p. 63

19 Stephen Manning, "Lockheed Fighter Jet Program Vulnerable," The Washington Post, December 3, 2006. (http://www.washingtonpost.com/wp-dyn/content/article/2006/12/03/AR2006120300527_pf.html).

20 Although the time required to produce the "batch" of weapons contracted for in one year will typically stretch into subsequent years. William Rogerson, "Economic Incentives and the Defense Procurement Process." *Journal of Economic Perspectives* (Fall 1994), p. x.

A potential contractor would be very unlikely to invest in the extraordinarily large costs developing a new military aircraft if its only guaranteed reward were a single year's procurement contract, even where such contracts are accompanied by an uncertain promise of subsequent annual contracts. The investment problem is solved, instead, by compensating firms for most development expenses directly though weapons development contracts.[21] Rogerson (1994), for example, reports that in 1993 more than half (58 percent) of all defense related research and development was funded by the Federal government though such weapons-specific development contracts. In addition, the Department of Defense undertakes some research and development in its own laboratories and contracts with universities and other non-profits to undertake additional research. The DoD also finances defense contractors to undertake a certain amount of "independent R&D" not tied to specific weapons development programs. Finally, private defense contractors supplement this independent R&D funding with some self-financed independent R&D, although such privately sponsored and funded R&D accounts for a relatively small fraction of defense R&D—only 6 percent of total defense-related R&D spending in 1993, for example.[22]

Lessons Learned From Defense Procurement

- If long-term contracts cannot be used, highly specific investments require direct reimbursement from the beneficiary.
- Uncertainty in cost recovery of capital drives investment towards lower capital investment, even if the marginal costs of output are higher.

In addition to providing contractors with development contracts and allowing them to benefit from the fruits of other government financed research, the DoD procurement process is designed in other ways to minimize hold-up problems. Major investments in product-specific tooling are financed by the government, which retains ownership of the tooling. Both in development and production contracts, contract officers are directed by DoD policy to negotiate fair pricing terms that include a profit element.[23] Nonetheless, there is some concern that hold-up has lead contractors to underinvest and to favor relatively labor intensive production processes in situations where more capital intensive methods might result in lower costs. The reason for this bias is that contracting officers are almost certain to allow contractors to recover labor costs, while capital cost recovery is a far more uncertain prospect. While negotiated prices are supposed to cover depreciation and to provide a return on invested capital, there is some

21 Under a weapons-development contract, the government pays all or most of the supplier's costs of developing a new weapons system on a "pay as you go" basis. They are analogous to "construction in progress" guarantees by regulators on large energy infrastructure investments.

22 Rogerson, p. 68.

23 Rogerson, p. 72.

evidence suggesting that defense contractors underinvest in capital equipment because prices in fact typically fail to do so.[24]

To avert this and other "hold up" biases and thereby to allow contractors to achieve lower prices by making investments predicated on producing weapons systems in relatively large batches, DoD is sometimes permitted to undertake longer-term procurement contracts for up to a maximum of five years. However, such contracts, which are allowed only for mature programs with a stable design, are exceptional, and can require specific Congressional authorization.

In general, defense contracting is the "exception that proves the rule" that long-term contracts typically go hand-in-hand with relationship-specific investments. In a more typical situation, long-term contracts serve to mitigate the hold-up problem because both parties understand that the contract is binding and that an aggrieved party will use the court system to enforce the contract should one party attempt opportunistically to break the contract. But because one Congress cannot bind its successors to appropriate funds, it is difficult for the federal government to negotiate truly binding long-term contracts. As a result, the federal government has had to develop alternative instruments and institutional constraints to avert hold-up problems, including direct funding of weapons development and designing and adopting contracting guidelines that commit the government to provide a return on contractors' investments. But even these institutions may be imperfect, resulting in some degree of underinvestment.

4.3. AUTO MANUFACTURING/AUTO COMPONENTS MANUFACTURING

Contracting practices in the motor vehicle industry are much the same as they are in the commercial aircraft industry, and for similar reasons. Long-term contracts (covering product lifetimes) are common between suppliers of customized components and automobile manufacturers, but automakers do not rely and cannot rely on long-term contracts with customers to mitigate market risks. Instead, auto manufacturers must assume the fixed costs of building and outfitting factories and developing products long before they take dealer orders for new products.

4.3.1. Motor vehicle manufacturing

As with aircraft, vehicle manufacturers invest large amounts of money to bring new vehicles into production without the benefit of long-term contracts with customers. The investment costs associated with developing a new vehicle and bringing it into production are large, on the order of $1 billion per new vehicle program. New factories are equally

Lessons Learned Auto Manufacturing

- Long-term contracts with individual customers may not be possible, even when substantial investments are required to meet market demand.
- Diverse customer demand and highly competitive retail markets allow market-based, rather than contract-based, capital investment.

24 Rogerson, p. 81.

costly— for example, Toyota reportedly spent nearly $1.3 billion to build and equip its new pickup truck assembly plant near San Antonio, and Nissan reportedly spent $1.4 billion to open its latest plant in Mississippi.[25] Yet when these investments were made, neither Toyota nor Nissan had a single firm order from any of its customers or dealers for the products these plants were designed to produce. Unlike the aircraft industry, auto manufacturers do not even have any identified "launch customers" paying deposits and making at least preliminary purchase commitments that can cover at least an initial year or so of production. Rather, vehicles are typically sold a few at a time through dealer orders, with payment passing from the dealer to the manufacturer only when vehicle title passes from manufacturer to dealer after the vehicle leaves the factory.[26]

Manufacturers thus assume almost the entire economic risk associated with the investment in a new vehicle program.[27] The vehicle may be a spectacular success, anticipating consumer wishes and capturing a large share of consumer demand (as for example, the first generation Ford Taurus) or a compete failure (like the Edsel), and the auto manufacturer will earn virtually all the rewards or take the entire loss associated with the vehicle program. Manufactures are willing to make these investments without the benefit of long-term vehicle purchase commitments because the potential rewards of success are great and because there are no particular customer issues likely to give rise to hold-up problems. Vehicles are generally sold one at a time (or at most, hundreds or a few thousand at a time to large fleet purchasers), and while option packages allow vehicles to be customized to a certain extent to fit customer needs, there are no important relationship-specific investments associated with any particular customer necessitating long-term contracts.

4.3.2. Automotive component supply agreements

Contracting practices between motor vehicle manufacturers and automotive component suppliers bear a great resemblance to those between aircraft manufacturers and aircraft component suppliers. In both cases, the standard contract for components engineered by the supplier to meet specifications for a particular vehicle (airplane) program is one that extends over the lifetime

25 Lindsay Chappell, "Stretched by Growth, Toyota Evolves to Plan B," and "Nissan Team Pushes a Hemispheric Approach," *Automotive News*, May 14, 2007.

26 While manufacturers do not enter into long term contracts with their dealers obligating the dealers to purchase set quantities of any vehicle, the franchise agreement that governs the overall relationship between the manufacture and its dealers is a long-term agreement; since the 1950s, the standard term for such agreements has been five years. (Jamie LaReau, "GM Blazes a Trail for Dealer-Factory Relations," *Automotive News*, September 25, 2006.) The length of these agreements mitigates hold-up concerns that could occur given the need for dealers to make considerable relationship-specific investments in areas such as signage and manufacturer-specific and model-specific service equipment and training.

27 Although as with commercial aircraft, suppliers may bear some of the risk to the extent they are asked to bear development costs that cannot be fully recovered through component piece cost payments unless the vehicle program achieves a target sales volumes.

of the vehicle (airplane) program.[28] Occasionally, the vehicle manufacturer contracts with more than one component supplier, but most specialized components are purchased through sole-sourced contracts. A common feature of many component contracts is a schedule of year-to-year price decreases that are intended to allow the auto manufacture to capture supplier productivity gains attributable to learning by doing.

Lessons Learned Auto Components

- A dominant purchaser can structure highly favorable contracts with dependent suppliers.
- This model may not be sustainable, stifling investment in innovation and driving some suppliers into bankruptcy.

As with airplane component manufacturers, the existence of a long-term contract provides incentives for a component supplier to undertake the relationship-specific investment required to produce components customized to a particular manufacturer. This willingness, however, has been recently tested by some of the contracting practices recently employed by US-based car manufacturers to squeeze price reductions out of existing suppliers in ways that potentially undermine these incentives. General Motors, for example, has included in its contracts language requiring its suppliers to match lower prices quoted by another potential supplier within 30 days or risk losing its sales to GM. Ford has reportedly asked suppliers to allow it to show supplier drawings to potential competitors.[29] While practices such as these have, in the short-run, lowered the prices at which US-based automakers have been able to obtain components, it is not clear how sustainable they will be in the long-run, as suppliers become increasingly less willing to share their most advanced technologies with U.S.-based automakers and to make relationship-specific investments to serve these customers.

4.4. PETROLEUM REFINING

Petroleum refiners do not have long-term contracts with end-use customers. Gasoline, diesel, jet fuel, and other liquid fuels are largely fungible in a given region, and consumers have not found value in long-term purchase agreements as a way of mitigating pricing risk. Instead, large buyers and sellers of refined products use financial instruments to hedge trading positions as needed given the well developed market for petroleum and the significant liquidity available in the market. While they do not enter into long-term contracts with end users, refiners do, however, sometimes enter into long-term contracts with crude oil suppliers. These arrangements are typically utilized in cases where the refiner must undertake costly capital investments to refine a particular grade of crude oil into a marketable slate of petroleum products.

28 Examples of such contracts (with pricing terms redacted) are occasionally attached to supplier's SEC filings. See, for example, the various documents styled "Lifetime Program Contract between General Motors Corporation North American Operations ('Buyer') and American Axle & Manufacturing, Inc. ('Seller')" attached as exhibits to American Axles form S-1, filed 7/14/1998.

29 International Labour Organization Sectoral Activities Programme, "Automotive Industry Trends Affecting Component Suppliers," 2005, pp. 74-75.

Since the discovery of oil at Spindletop in 1901 and the early years of petroleum refining, large refinery projects have been needed to bring crude oil-based products to market. As is the case with coal sold to power producers, the grades and composition of crude oil differ from region to region, and downstream processors must adopt production technology that allows them to exploit the properties of the crude oil they purchase, as different grades of crude oil may require different levels of processing and treatment to produce fuels meeting required specifications. Historically, the oil industry dealt with the potential for hold up this situation creates largely through vertical integration between refinery operations and upstream crude oil supply. As processes became standardized, markets developed, and technology advanced, flexibility in refiners' ability to process differing crude slates has since allowed the decoupling of refinery assets from crude oil supply in most markets.

Lessons Learned From Refining

- Robust spot market with many buyers and financial participants allow new capacity to be added without long-term contracts with customers.
    - Markets for physical delivery are necessary to support merchant investment; financial markets linked to these physical-delivery markets allow efficient risk management around those investments.
    - Direct customer participation in energy markets supports market liquidity and transparent price formation.
    - Robust markets span large geographies and allow free trade.
- Equity/debt leverage of new projects tracks project risk.
    - Reducing risk in energy markets allows greater project leverage.

Since the end of the Second World War, demand for transportation fuel has risen dramatically and has created a continual need for increased refining capacity in the U.S. and around the world. Consolidation in the industry and more stringent air quality and fuel formulation standards have led to a decline in the total number of U.S. refineries since the 1950s as older outmoded facilities were shut-down, but companies have continued to invest in incremental capacity at existing refineries to expand fuel and products production. According to the U.S. Department of Energy, the recent trend of increases refinery investment began in 1997, capital spending by major oil companies surged to $12.1 billion in 2001, and continues to rise. Much of that spending was driven by mergers-and-acquisitions-related refinery purchases and refinery optimization, but the industry has also continued to make incremental improvements to existing facilities to expand refinery output. Even though the total number of refineries fell, overall output over the past decade has risen by the equivalent of a new medium-sized refinery every year.[30] In addition, the recent announcement by Motiva, Shell's equal joint venture with Saudi Refining, to build a 325,000 barrel per day expansion of the Port Arthur, TX refinery at a cost of $7 billion represents the largest and most advanced refinery expansion in decades.[31]

30 "U.S. refiners stretch to meet demand," MSNBC, 24 Nov 2004.

31 " "Shell to begin Port Arthur refinery expansion," Reuters, 21 Sep 2007.

In general, oil refineries are built using a combination of equity and project debt financing by owner-operators and/or supply partners, with significant equity financing based on cost of capital. Historically there have been few speculative players in the refining sector. Refinery owners initially were upstream crude oil producers looking to bring product to the market and thus monetize their upstream crude oil assets. While the majority of refineries today are still owned, either in whole or in part, by large upstream crude oil producers, the refinery sector now also includes many independent refiners possessing specialized skills in commercializing and standardizing refining technology, cost control, and supply trading. This decoupling of refinery assets from crude oil supply reflects the mature state of crude oil and refined petroleum markets and the industry as a whole. The decoupling of refinery and crude oil assets has become possible because many commonly used refinery feedstocks are now traded using standard spot or supply assurance contracts and are essentially commodity in nature. Refineries built to rely on such feedstocks, like power plants relying on grades of coal available from numerous suppliers, do not need to pursue long-term contracts with their suppliers.

There are, however, exceptions to the spot market contracting model for feedstocks, and those exceptions are often driven by asset specificity. Increased development and production of non-standard and hard-to-process crude grades (e.g., heavy and sulfur-rich “sour” grades) has created problems of asset specificity because many refineries are not equipped to make effective use of such feedstocks without undertaking substantial investment. For example, the output from heavy crude oil projects or from Athabasca Oil Sands projects and other non-standard input feedstocks can only be processed by refineries with significant upgrading capacity. Costly investments in hydrocracking and coking units are required to process and take advantage of these disadvantaged crude oils, and refineries must make specific equipment investments to enable them to convert feeds to output products. Such investments are largely relationship specific and are potentially prone to hold-up. Long-term contracting between suppliers of crude oil of non-standard grades and their refiner customers has emerged as a way to deal with the asset specificity problems inherent in such customized refinery upgrades. These agreements offer both sides potential gains; the crude oil producer is able to bring its unfungible crude oil asset to market and the refiner gains secure access to crude oil priced at enough of a cost discount to standard grades to justify the investments it must make to handle the particular non-standard grade it has contracted to process.

The 1998 long-term supply arrangement between Premcor and Petroleos Mexicanos to supply low-cost heavy sour crude to the Premcor Port Arthur, TX refinery provides an excellent example of a long-term contract facilitating investments to upgrade an existing refinery. The Port Arthur refinery upgrade project required $1 billion in investment for the installation of coking, hydrocracking and sulfur removal capability and the expansion of the existing crude unit to approximately 250,000 barrels per day.[32] While Premcor funded the refinery upgrade, Petroleos Mexicanos agreed to contract terms for purchases of Mexican crude at a significant discount to the benchmark West Texas Intermediate (WTI) crude, so as to permit Premcor to lock in

32 “Too much of a good thing,” *Oilweek Magazine*, February 2005.

favorable refining margins once the upgraded capital was installed and online. Furthermore, a significant termination fee remained in place throughout the life of the arrangement to ensure that long-term supply of heavy sour crude oil remained available for purchase by Premcor. This long-term contracting arrangement enabled both parties to create value that would not have been possible in the spot market; Petroleos Mexicanos was able to market its disadvantaged, hard-to-process crude oil asset on a long-term basis while Premcor was able to justify a $1 billion capital investment by locking in a favorable rate of return through advantaged supply pricing and associated refining margins. While this example is an exception to the rule for most refineries, it is an example where long-term contracting can create value in the refining industry.

While the need to match refinery capabilities to crude oil feedstocks sometimes leads to the existence of relationship-specific assets in dealings between refineries and their upstream suppliers, there are essentially no relationship-specific assets involved in the relationships between refiners and their downstream customers. Output products are commodity in nature and are generally sold on spot markets. Consumers drive product demand and refineries produce based on forecasted demand and the level of available storage. As such, the notion that there is a need for long-term downstream contracting to support the construction of multi-billion dollar assets does not hold in the oil and gas industry. Crude oil and refined petroleum products are traded daily in established and liquid spot and futures markets, allowing producers and consumers to hedge risks using financial instruments bought and sold by financial intermediaries.

Thus, the oil refining sector is one in which investors routinely make investments in the billion-dollar range without the benefit of long-term contracts with their downstream customers. This result is not surprising given the commodity nature of refined petroleum products. Investors may, however, undertake long-term contracts with upstream suppliers as part of the investment process when upgrading a refinery. Such contracts are commonly used when a refiner contemplates a relationship-specific investment to permit it to use a non-standard feedstock, but are not required when the refiner is making investments predicated on the use of commodity feedstocks.

4.5. Natural Gas Industry

Adding new capacity in any of the major sectors of the natural gas industry—exploration, production, processing, transportation, or distribution—requires a great deal of capital investment. Long-term contracts are a regular feature associated with some types of gas investments, but not others. For example, in parts of the world with well-developed gas transportation and distribution infrastructure, natural gas drilling in the exploration and production phases is generally underwritten by equity financing without the benefit of long-term contracts with end users; by contrast, developers of the long-distance natural gas pipelines that bring gas from the fields to demand centers typically will assemble long-term commitments with potential users accounting for a large fraction of expected pipeline capacity before they undertake any large investments. These differences reflect differences in the importance of relationship-specific elements within the investment process and the potential for hold-up risks that follow when such elements are present.

4.5.1. Exploration and Production

Exploration and production investments offer the highest risks and the highest returns available within the oil and gas value chain. Uncertainties about the geological region being drilled and the technical challenges inherent in producing hydrocarbons from a given geological structure create real risks of failure. Key unknowns include whether or not gas can be successfully extracted from the well and how much gas may be available, among others. Gas exploration and production requires significant upfront capital, commonly funded largely by equity contributions, to invest in lease rights, equipment, and land surveys, and a smaller amount of capital to operating the gas production fields once found.

Lessons Learned From E&P

- Risk profile of the investment drives the debt/equity leverage.
- Access to regulated common carriers, or access to competing carriers, coupled with developed wholesale commodity markets, allows substantial investments without long-term contracts with either carriers or customers
    - o Contracts are used when a pipeline owner can extract rents from the producer.
    - o Contracts are also used when few customers exist for the output.

Yet despite the size and risk of these investments, long-term contracts with end users typically do not underpin the exploration and production investments made in natural gas fields located within well-developed national or regional gas markets. The only long-term contractual arrangements typically associated with such investments are equity partnership agreements, the length of which can vary widely.

In well-developed gas markets served by extensive pipeline networks, long term contracts between producers and end users are not required to fund new production investments for the same fundamental reasons that new investment in petroleum refining can take place without long-term contracts: natural gas, like gasoline or another refined petroleum products of a particular grade, is essentially a commodity product. As a result, end users do not have to undertake any relationship-specific investments to use a particular producer's gas, and gas producers do not need to undertake any relationship-specific investments to serve any particular end user.[33] Consistent with its status as a commodity

33 Natural gas as delivered to end users consists of fairly pure methane gas. While raw natural gas can vary considerably in chemical composition and quality from one producer to another, raw natural gas is routinely treated at natural gas processing plants to remove heavier hydrocarbons and to reduce contaminants such as water vapor, carbon dioxide, nitrogen, and various sulfur-containing compounds to trace levels. All treated gas introduced into a particular pipeline system must meet the pipeline's quality specifications for caloric value and maximum allowable quantities of contaminants. Investments by upstream producers in processing plant capacity are not specific to any particular end-use customer, and from the end user perspective, any one producer's delivered natural gas is interchangeable with any other producer's gas.

product in well-developed natural gas markets, natural gas is usually sold to end users at prices tied to spot prices at a relevant hub in the natural gas transmission system.

Within otherwise well developed natural gas markets, the few exceptions to this general rule generally arise in situations in which a producer lacks access to pipeline infrastructure or a large local gas market and is thus cut off from access to users in larger national or regional gas markets. Such a producer, typically located in a remote area, might find a customer for its gas by entering into a supply arrangement with a large industrial user such as a gas-fired power plant or a chemical plant. In such circumstances, which resemble the circumstances surrounding the development of mine-mouth power plants, both parties essentially require a long-term supply contract to safeguard their interests, given that both are making large investments predicated on the continued existence of the gas supply arrangement. Such arrangements are the exception rather than the rule in the U.S. market, but as we will later discuss in the context of liquefied natural gas (LNG) projects, have played an important role in many arrangements to develop remote-sourced natural gas resources elsewhere in the world.

4.5.2. Natural Gas Pipelines

Interstate natural gas pipelines play a major role in the United States gas distribution system; while the natural gas pipeline system consists of gathering lines, intrastate and interstate transmission lines, processing plants, market hubs, and underground storage facilities, interstate pipelines play a central role in moving large quantities of gas comparatively large distances from production-rich areas to areas where the gas can find high value uses. Pipelines are the most common and economical mode of transport for natural gas and in the United States, interstate gas transportation is regulated by the Federal Energy Regulatory Commission (FERC). FERC determines the rate-setting methods for interstate pipeline companies, sets rules for business practices, and has the sole responsibility for authorizing the siting, construction, and operations of interstate pipelines, among other energy facilities.

Lessons Learned From Pipelines

- Pipelines are nearly always built with long-term contracts with customers
  - Historically loads were the primary contracting parties, reflecting relatively weak locational gas markets and regulatory requirements.
  - More recently, following deregulation and as more remote gas fields are developed, producers typically contract capacity to take gas to market.
  - Strong regulatory oversight is applied to prevent 'hold up' of captive customers by pipelines.

Interstate pipelines are an important part of the natural gas midstream, referring to those activities that bridge the upstream exploration and production assets (natural gas wells) with downstream end users of natural gas. Midstream activities include processing and treating gas for impurities, separating out natural gas liquids, and transporting pipeline-quality natural gas to demand centers. In the U.S., key natural gas origination points include gas basins in the Gulf of Mexico, Texas, Louisiana, Oklahoma and New Mexico. Large pipelines from these basins serve hubs in Houston, Chicago, and elsewhere, and other pipelines running from these hubs serve large demand centers across the country. In general, pipeline companies have relatively stable cash flows, steady underlying demand, and limited exposure to commodity prices because they do not own the natural gas they transport; they only ship gas from one point to another and carry little or no underlying commodity risk.[34] Pricing for natural gas pipelines is based on FERC regulated tariff structures, which establish maximum pipeline tariffs based on full recovery and an allowed rate of return on equity. The FERC-approved tariff for each pipeline lists the rates for each service, including applicable surcharges, along with descriptions and rules for each rate schedule. Tariffs are based largely on capacity rather than on volume shipped, with transporters generally reserving capacity under long-term contracts.[35]

Contractual terms in the natural gas pipeline industry often are long-term take-or-pay arrangements and are largely a product of the revenue model inherent in this regulated infrastructure business. Given the tariff and cost recovery structure under FERC, earnings and cash flows depend on facility cost, capacity contracts, and the ability to re-contract capacity at the desirable rates given market competitiveness and rate boundaries set by FERC regulations. Competition comes in the form of discounted rates to key customers. Hence, investments in new pipeline expansions have historically been underpinned by secure base level contracts for long-term capacity contracted with either gas suppliers or large gas users or gas marketing organizations that ensure sufficient capacity rate-payers exist to justify the expansion. Pipeline companies will often propose a new segment of transportation pipeline, propose a tariff in conjunction with FERC, and then test the market to see if interest exists for capacity purchases on the line. If so, the line is financed and built based on firm capacity contracts; if the market displays little interest, the pipeline is often postponed or the plans are abandoned.

Today, most new projects are secured by, and essentially financed through, long-term contracts with upstream natural gas producers. Deregulation of downstream markets for gas has created a business environment in which downstream natural gas utilities are unwilling to sign binding long-term capacity commitments with particular pipelines; likewise, major industrial users are unwilling to sign the twenty-year contracts typically required by pipeline companies before they will add capacity, as few such firms can be reasonably confident of their needs for gas over such a long period and as secondary markets for pipeline capacity are illiquid. Resource owners, however, can be reasonably sure that they will still be producing gas (and will need some means to transport it) over long periods, and are still willing to sign long-term contracts. This pattern also accords with asset specificity; gas producers and pipelines are more likely to be locked in to relationships with one another than are gas customers and pipelines; gas customers may have potential access to gas obtained via more than one interstate pipeline or may have fuel switching capabilities or business strategies that allow them to do without gas entirely, while the economics of developing natural gas field are tightly tied to finding some way to move that gas to market and

34 Natural Gas Pipelines: An Investor Guide to MLPs, Merrill Lynch. 21 November 2006. p. 55.

35 Ibid., p. 56.

the economics of developing a pipeline are tied to keeping the pipeline's capacity nearly fully committed. The typical current structure for financing new pipeline construction thus consists of a set of long-term contracts for reserved capacity between gas producers and the pipeline owner at rates that afford the pipeline developer with a reasonably sure, if unspectacular, return on its investment. Supply exhaustion risks and market risks relating to demand in downstream natural gas markets are retained by the producers.

The $4.4 billion Rockies Express pipeline project currently being built by Kinder-Morgan and Sempra Energy illustrates the centrality of long-term commitments between gas producers and pipeline developers in building new natural gas pipeline capacity. When completed, the 1,678-mile pipeline will have a capacity to transport approximately 1.8 billion cubic feet per day (Bcf) of natural gas from gas production fields in the Rockies to markets in the upper Midwest and Northeast.[36] The pipeline is the largest interstate pipeline built in the U.S. in decades and as Scott Parker, President of Kinder Morgan Natural Gas, clearly points out in his characterization of this and other Kinder Morgan pipeline projects that the structure of these deals rely on long-term commitments that limit the owner's risk.

> We're pretty risk averse. We're not commodity driven. I told you before we do things on a fixed-fee basis. We'll take risks. We've taken a risk in conjunction with this [the Rockies Express pipeline] project. But they're measured risks, risks that we understand. We are not going to build things and hope the shippers show up. We didn't build the Rockies Express pipeline without commitments [and] we won't build the Mid-Continent Pipeline without commitments [either].[37]

Binding commitments from creditworthy shipping customers have been secured for virtually all of the capacity on the Kinder Morgan Rockies Express pipeline, which illustrates the way interstate pipelines are built in the United States—through the use of clear and firm long-term contracts with suppliers.

Because of asset specificity, long-term contracting is critical to financing and building large multi-billion dollar capital investments for large natural gas pipelines in the United States. In this respect pipelines differ from the petroleum refining industry, where long-term contracts with downstream entities are not required before investment funds are committed, and where long-term contracts with upstream suppliers are used only in cases where the economics of the refinery upgrade are explicitly predicated on favorable pricing for the specific grade of crude oil the refinery is being adapted to use. The key reasons underlying the different contracting institutions behind refining and pipeline investments are probably found in the differences between the two sectors in asset specificity and the potential for hold-up problems.

36 Morningstar, "Rockies Express Pipeline Completes Successful Open Season for Northeast Expansion Project," 12 Dec 2007.

37 Rosenberg, Martin. "Building Kinder Morgan's Pipe: Scott Parker Gets It Done." EnergyBiz Magazine. July/August 2006.

Even in an unregulated market, an interstate pipeline and its suppliers could face very serious hold-up problems in the absence of long-term capacity contracts, because supplier or customer commitments to a particular pipeline create relationship-specific assets. Gas producers and gas consumers contemplating major investments cannot purchase pipeline transportation capacity in liquid spot markets; rather their prospects for business success are effectively tied to the availability of capacity in one of the few, or even only, pipeline serving their area. Likewise, pipeline owners cannot sell their capacity in liquid markets; the prospects for their businesses are tied to the continued willingness of particular gas producers and major gas consumers to continue to purchase their pipeline services. This situation is very different from the standard refinery business model, in which all parties—refiners, crude oil suppliers, and consumers of refined products—have access to alternative sources of supply or demand in relatively liquid markets. Note, however, that consistent with the refinery model, deregulation of markets for natural gas has eroded the prevalence of long-term contracting in downstream gas markets; while gas producers still sign very long-term capacity agreements with pipelines for interstate gas transport; end users prefer not to sign such contracts either for interstate pipeline capacity or for gas derived from a particular production source, reflecting the usual absence of relationship-specific investments between any single gas user and any particular producer or any particular interstate pipeline. Instead, gas produced by any one supplier (or transported on a particular pipeline) can often be replaced by gas produced by any other supplier capable of arranging transport to the customer or to a place in the transmission and distribution system where the customer is prepared to accept delivery.

The relationship between a gas producer and a gas pipeline thus also exhibits fundamental differences from the typical relationships between gas producers and their end-users. The relationship between pipeline owners and producers involves a great deal of relationship specific investment on both sides, with hold-up problems a very potential threat on both sides of the relationship in the absence of long-term contracts between the parties. By contrast, hold-up is unlikely to be a problem in relationships between end users and gas producers because facilitating trade between producers and end users does not require either party to undertake any investments that would leave it vulnerable to a potential hold-up by the other. For these reasons, long-term contracts play a crucial role in the relationships between producers and pipelines and virtually no role in the relationships between producers and end users.

There are obvious parallels between the producer/end user and producer/pipeline relationships in the natural gas industry and the generator/end user and generator/transmission-assets owner relationships in the electric power industry, and the gas industry experience with contracting in these areas may offer lessons for the evolution of similar relationships in electric power markets. If the gas industry provides any guidance, then long-term contracts between end-users and generators would not seem to be required to elicit new investment in generating assets. When gas prices are expected to remain high, gas producers have no trouble justifying and financing the addition of new production capacity, as they can be reasonably sure that their gas will find willing buyers in what is essentially a commodity market for natural gas. The commodity nature of electric power delivered to the transmission grid—the ready substitutability of one end user for another from the power producer's side of the market and of one generator for another from the end user's perspective—should also allow a potential producer to finance an investment in a new generating asset without the assurance provided by long-term contracts with end users, provided the expected market prices for power are sufficient to justify the investment. In the absence of relationship-specific investments, both generators and end users should be able to rely on short-term contracting and spot market arrangements to mediate purchase and supply relationships and to utilize contracts with financial intermediaries to mitigate pricing risks. By contrast, potential investors in new generating capacity are potentially vulnerable to potential hold up by the transmission providers they require to reach end users and, likewise, potential investors in new transmission projects could find themselves vulnerable to hold-up from the generators they intend to serve. In this sector of the electric power industry, long-term contracts or other instruments and institutions designed to obviate hold-up are clearly required to facilitate investment.

4.5.3. Liquid Natural Gas Industry

Although oil remains the largest component of primary energy worldwide, natural gas is the world's cleanest fossil fuel and is increasingly used around the world for electric power production, home heating, and chemicals manufacturing. In 2006, world natural gas production totaled 2930 billion cubic meters (103.4 trillion cubic feet).[38] As is the case with most fossil fuels, there is a regional disconnect between where natural gas reserves are located and where fuel demand resides. Unlike crude oil, which is produced around the world and transported to demand centers via either tanker ship or pipeline relatively easily, natural gas is, given its gaseous form under atmospheric conditions, most easily and economically transported only by pipeline, and thus it is most often used in the local region where it is found and extracted. Natural gas has thus generally been a local or regional commodity rather than a global commodity. As a result, the supply availability and market prices for natural gas differ across regions, i.e. the market for gas in the U.S. differs significantly from that in Europe or that in the Middle East. Many gas resources, however, are found far from market; some of the largest and richest gas deposits are located in countries or regions where there is little or no developed local demand for gas, making them unmarketable using pipeline transportation and therefore almost devoid of market value with out an alternative transportation method. Historically, these "stranded gas assets" went undeveloped because they could not be economically developed for a local market.

Lessons Learned From LNG

- With immature, illiquid markets, tight contracting across the links of the value chain is critical to funding large infrastructure investments.
    - o High-risk, large investments with assets tied to specific projects require contracts or vertical integration.
- As markets mature, with greater competition for LNG cargos, greater flexibility in financing has resulted.
    - o Financial intermediaries play a key role in creating a market with shorter contract durations, delivery point flexibility, and other value-creating optionality.

38 Oil and Gas Journal LNG Observer, volume 4 issue 3, 1 Jul 2007.

Liquefied Natural Gas (LNG) is a technology that allows gas to be transported great distances using seagoing vessels, providing potential market value to stranded gas assets and bringing much needed gas supplies to demand centers. Four components are required for an LNG project to deliver gas to market: (1) a sizeable natural gas reserve that is physically far from market, (2) a liquefaction plant to cool the gas, (3) specialized ships to carry the super-cooled gas from the liquefaction plant to another locale, and (4) a regasification terminal to offload the gas into the distribution pipeline to sell it into the distant market. The heart of an LNG project is the liquefaction plant, which is the single largest investment in the chain. It performs the critical function of cooling the gas to -163ºC, whereupon natural gas becomes a liquid at atmospheric pressure. Specialized thermal LNG tanker ships function as a floating pipeline to ferry the liquefied gas to its destination and the regasification terminal is a fixed offloading facility that warms gas to standard temperature and pressure for insertion into the natural gas pipeline system. LNG development projects are multi-billion dollar capital projects that involve multiple financial partners, financial financing vehicles, and significant inter-party coordination to be successful.

Evolution of the LNG industry:

The LNG industry has evolved significantly over time. Traditionally, LNG projects were structured as a long-term, risk-mitigating way to monetize important but geographically isolated gas assets by identifying buyers in need of significant long-term volumes of natural gas and getting the gas to them through long-term contractual or ownership arrangements. As LNG has grown greatly in importance as a means of transporting gas, however, the industry has begun to mature and projects have increasingly used more flexible financing and pricing structures. Between 1975 and 2005, LNG's share of international natural gas flows grew from just 10 percent[39] to almost 24 percent of total volumes. With this growth has come an evolving market, better defined pricing mechanisms, and increasing diversity in supply sources and demand regions. There have been changes in the structure and nature of relationships between development and trade partners, moving from a business where success depended on long-term contracts to one where, more and more, long-term contracts are not required to build, finance, and market LNG projects successfully.

Traditionally, LNG projects were only undertaken by matching a large buyer with a long-term need for natural gas with a supplier in possession of an excellent, but geographically stranded gas reserve. These projects were expensive and faced substantial risks and challenges, given the slow pace of development, the scale and scope of the necessary facilities, and the price volatility inherent in the energy industry.[40] Traditionally, one key condition necessary to ensure the successful development of an LNG project was long-term commitment from buyers:

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39 Cedigaz. World LNG Outlook. G Maisonnier. Paris: 1999.

40 Tusiani, Michael D. and Gordon Shearer. LNG: A Nontechnical Guide. PennWell Corporation. 1 Aug 2007, p. 15.

> While every LNG facility may have varying degrees of its capacity reserved for short-term or spot trading, the capital costs required in order to build a facility usually dictate that a downstream buyer or buyers, who will contract for the majority of the plant's output, must be secured.[41]

In the early years, long-term relationships between participants were central to project economics. Speculative development was not a viable option for participants or financiers since project economics depended on uninterrupted delivery of gas volumes, underpinning the importance of long-term fixed supply contracts. Almost all supply and purchase agreements (SPAs) were long-term (typically 20-25 years), had take-or-pay provisions, had no destination flexibility as to where deliveries could be made, prices that were often indexed to the price of the next best alternative fuel for the region being supplied, which was often crude oil, and only updated every few years leaving few opportunities for price re-openings during the life of the contract.[42] LNG trade consisted of a series of point-to-point trades between well defined buyers, such as large electric utilities with gas-fired generators, and resource owners, with all facilities dedicated to a particular trade route. The key concerns motivating these arrangements were security of supply and a lack of market liquidity in gas shipments or clear price transparency between regions. These factors limited the ability to create short-term or spot contracts for excess volume.[43] An outstanding example of this traditional LNG project structure is the North West Shelf Australia LNG project, which was formed in the 1980s and which delivered its first cargo in 1989. The project participants are a consortium of upstream and downstream partners and the project was underpinned with long-term, 25-year gas supply contacts with key gas buyers, mostly in Asia. Here, both seller and buyers made asset-specific investments and entered into long-term contracts to consummate the capital project relationship: Japanese electric utilities built fuel-specific power plants and the LNG upstream partners spent billions of dollars to build and operate the LNG facilities in the oceans northwest of Australia needed to supply their fuel needs, with all parties agreeing to fixed-price purchase and sale arrangements.

Contracting arrangements in the LNG industry have evolved and matured beyond the type seen in the North West Shelf Australia project as new developments have led to changes in the structure of LNG markets. Japan, the United States and Europe were early participants in the LNG industry because these regions had an ever-growing need for natural gas and LNG provided a potentially economic source of natural gas. As the cost per unit of processing and transporting LNG has declined through technology innovation and operational experience, efficiencies have allowed more LNG to become available in the market. In addition, more LNG regasification terminals have been built in buyer countries, creating more flexibility in the LNG transportation system. Above all, however, two key evolutionary market developments have had a profound

41 Ibid., p. 16.

42 Robert Pirog, "Liquefied Natural Gas (LNG): Markets in Transition for U.S. Supply and Price." Congressional Research Service.

43 Tusiani, Michael D. and Gordon Shearer, LNG: A Nontechnical Guide. PennWell Corporation. 1 Aug 2007, pp. 200-202.

impact on the industry and helped change the nature of contracting between parties: the creation of established pricing points for spot-market transactions and the emergence of clear ongoing regional needs for imported natural gas in the U.S. and in Europe. Traditionally, pricing risk for LNG was managed using price escalation clauses in the LNG SPA that were revisited infrequently (every 5+ years) during the course of the contract, with gas prices often indexed to established pricing points for oil, such as WTI or Brent crude oil prices.[44] However in the last 20 years, the Henry Hub (HH) in the U.S. and National Balancing Point (NBP) in Europe have become clearly defined trading points for natural gas, with futures contracts pegged to these locales used to establish spot pricing. The advent of established gas price points that can be referenced worldwide allows for transparent prices for LNG across trading regions and has opened the possibility of competitive spot trades. Established liquid futures markets for natural gas at these delivery points allow buyers and sellers to manage risk using financial instruments, increasing competitiveness of markets and reducing the utility and attractiveness of long-term contracts as a means for managing risk.

The emergence of supply shortages in two of the largest gas markets, the U.S. and Europe, is another key development. Both regions have historically had enough natural gas to serve local demand, but as drilled natural gas resources have declined over the last 20 years while demand for natural gas has increased, both regions have been forced to import natural gas to meet demand. The U.S. and Europe have both become marginal gas buyers in the world gas market, beginning to serve as “LNG sinks,” where sellers know that they can offload cargoes in spot trades, subject to the availability of regasification terminal capacity. Today, someone contemplating developing a new LNG project now knows that there will be a buyer for spot LNG cargos at some price, unlike in earlier days when no capacity to offload unscheduled cargoes was available and the terms of LNG deliveries were virtually all fixed by contract.

LNG Today

Changing market conditions and the establishment of transparent pricing are leading to a change in the LNG model: a shift from the floating-pipeline model to a model of an integrated network of highly flexible trading arrangements. Flexible arrangements are clearly growing in importance in world LNG trade; in 2005, short-term LNG trades accounted for almost 14 percent of LNG traded worldwide, compared to less than 5 percent in 1998.[45] Underpinning this change is the evolution of contracts within the LNG industry. While most LNG projects once involved long-term contract arrangements between parties, customers are now requesting, and receiving, more liberalized contract terms than the SPAs signed in the 1980s. Take or pay provisions are now often only applied to a portion of total purchases, giving purchasers more flexibility to expand or contract purchases based on demand, and producers are being allowed more destination flexibility, giving

44 Robert Pirog. “Liquefied Natural Gas (LNG): Markets in Transition for U.S. Supply and Price.” Congressional Research Service, p. 3.

45 Tusiani, Michael D. and Gordon Shearer. LNG: A Nontechnical Guide. PennWell Corporation. 1 Aug 2007, p. 214.

them the opportunity to redirect a portion of LNG cargoes to take advantage of regional differences in natural gas prices. Finally, contract duration is evolving as well. Asset owners are increasingly relying on coverage strategies that rely on portfolios of supply contracts with varying durations. Today, some supply is contracted using medium-to-long-term contacts, some supply is contracted using short-term contracts, and some supply is reserved for opportunistic spot transactions.[46]

Thus, the LNG sector is one in which investors have traditionally made investments in multi-billion dollar assets which were underpinned by long-term contracts between buyers and suppliers to ensure acceptable rates of return in an illiquid market. This is not surprising given the asset-specific nature of LNG investments and the need to establish a clear supply chain between buyer and supplier at great cost and financial risk. However the LNG industry has developed significantly over the last 30 years to where increased worldwide demand for natural gas, the proliferation of LNG supply points, regasification points, and shipping assets, the establishment of market mechanisms for spot pricing, and the greater use of financial instruments for risk mitigation in the natural gas market have begun to change the structure of relationships in the industry. As such, long-term contracts are increasingly being modified in favor of more innovative supply arrangements given greater liquidity in the market. These changes create new and innovative financing options, allowing a different set of investors and partnerships to emerge and shorter-term trading to ensue. As market liquidity develops, financial intermediaries are increasingly working along-side suppliers and buyers in project development. Hence, one can argue that the LNG market is deepening, making long-term contracts optional rather than necessary for large-scale facility development. 25-year contracts are still commonly used given the asset-specific nature of the capital investments, but their duration is tending toward shorter-term arrangements with more flexible terms and, increasingly such long-term contracts have not been required to finance new LNG projects or project components.

4.6. COAL MINES AND COAL-FIRED POWER PLANTS

Some of the strongest published evidence that long-term contracting is associated with relationship-specific investments has been provided by studies of the electric power industry. These studies look not at the relationships between power plant owners and their customers but rather at the relationship between power plant owners and their fuel suppliers. A paper published in 1985 by Paul Joskow in the *American Economic Review* identifies three specific circumstances that cause investments in coal plants or coal mines to have a relationship-specific character that can give rise to potential hold up problems. It then tests to see whether the presence of these circumstances is, in fact, associated with longer contract terms.

46 A producer's ability to move product from one market to another can be subject to the availability of spare regasification capacity for unscheduled cargoes, which may not always be available in locations and situations that would otherwise support high priced spot trades; e.g., during periods of peak LNG demand. For this reason, LNG producers cannot yet build a business model relying entirely on a spot sales model and must rely, at least in part, on sales made through scheduled deliveries mediated by contracts.

The first of these circumstances arises when power plants are built at the mine mouth—a classic example of what Oliver Williamson terms "site specificity" in which buyer and supplier have chosen to locate "cheek by jowl" to realize inventory and transportation cost savings.[47] These locations are typically remote from any economic transport of coal—either *from* the mine or *to* the generator. With the power plant essentially wholly dependent on the adjacent mine for all of its coal needs and, conversely, the mine dependent on the power plant to utilize all or a substantial fraction of its output, there is clearly the potential for hold-up on either side of the contract. One would therefore expect to see contracts between mine and mine-mouth power plants to exhibit markedly longer durations than those between mines and distant power plants.

Lessons Learned From Coal

- Parties with few market alternatives need long-term contracts to protect the value of their investment.
    - Open access to transmission decreases bilateral reliance of generators and utilities, lessening the need for contracts. Retail electric competition further decreases the reliance.
- Assets built to meet a particular market niche seek long-term contracts to protect that investment.
    - Robust markets for the full range of products—including ancillary services, renewable energy, and environmental attributes—removes unpriced elements from purchases and sales, allowing more market-based trading.

The second are relationships which exhibit characteristics of what Williamson terms "physical asset specificity" where one or both parties make investments in physical assets that embody design characteristics specific to the transaction and that have lower values in alternative uses. Physical asset specificity can arise in the relationship between suppler and power plant because coal is not a homogeneous commodity and power plants are typically designed and built to work optimally with a particular type or grade of coal. If the particular type of coal that a power plant is designed to use is economically available from numerous actual or potential suppliers, then the value of the investment in the power plant is not tied to the existence of an ongoing supply relationship with any particular mine, and the power plant investment does not exhibit physical asset specificity. Such is generally the case, Joskow notes, for power plants designed to use coal produced in the eastern United States. Eastern coal tends to be of relatively uniform quality and is available from numerous relatively small underground mines, allowing new capacity to be introduced in relatively small increments, and is well connected to potential customers by a relatively large number of transportation alternatives. Eastern coal was also fairly widely traded in spot markets, with about 18 percent of power plant purchases of eastern coal conducted in spot transactions in 1982.

[47] Oliver E. Williamson, "Credible Commitments: Using Hostages to Support Exchange," *American Economic Review*, Vol. 73, No. 4 (Sep., 1983), pp. 519 - 540.

Physical asset specificity is, however, more likely to be a problem for power plants dedicated to using western coal. Western coal, by contrast to that produced in the east, tends to vary in quality from mine to mine, tends to be produced in very large mines requiring "lumpy" investment to add capacity, and, particularly in the seventies and early eighties, could only be transported to potential customers by a very limited number of transportation alternatives.[48] Because product of a particular quality grade might be available from only one or a very few mines, a power plant owner's decision at the design stage to use a particular grade of coal largely locked in its choice of coal supplier. Furthermore, the limited alternatives available for rail transport of much western coal encouraged power plants needing an assured source of western coal to make sure that their rail transportation arrangements were guarded from hold-up by long-term contracts. Thus, only 2 percent of western coal purchases by power plants were made on spot markets in 1982.[49]

Coal mine owners, too, may face hold up problems from their customers because of what Williamson terms "dedicated asset specificity". When a coal mine owner makes significant investments to expand capacity that are predicated on a single customer's continued willingness to buy that mine's output, it is effectively creating a dedicated asset that is source of a potential hold up problem. If the customer fails to purchase its expected quantities of coal, the mine owner may find its capacity utilization falling to unacceptably low levels and fail to earn sufficient returns on its investment. As a result, we would expect to see long term contracts between mines and large customers than between mines and smaller customers.

Joskow then tested these expectations by performing statistical tests on a sample of 277 contracts between power plant operators and coal companies Joskow then examined the terms of a relatively large sample of contracts between power plants and coal companies. His expectations were that he (1) would generally observe longer contracts for mine-mouth plants than for other power plants; (2) that contracts for western coal would generally exhibit the longest contract duration terms and eastern coal contracts the shortest duration terms, with contracts for midwestern coal contracts generally exhibiting durations falling between these extremes and (3) that coal contracts involving larger annual supply commitments would exhibit longer duration terms than contracts for smaller commitments. His statistical models provided evidence strongly consistent with all of these hypotheses. For example, Joskow's statistical results suggest, all else equal, that mine-mouth contracts are 14 to 16 years longer in duration than contracts for other coal plants; that western coal contracts have an average duration of 5 to 11 years longer than eastern coal contracts; and that contracts for larger quantities of coal are associated with longer contract terms.

48 Burlington Northern (now BNSF) was the only railroad with access to the west's largest coal region, Wyoming's Powder River basin, until 1984, when the Chicago and North Western railroad (acquired by Union Pacific in 1995) began service to the region.

49 Coal produced in the US Midwest fell between the extremes of eastern coal and western coal in dimensions of quality variation, mine size, and availability of transportation alternatives. About 8 percent of Midwestern coal supplied to power plants in 1982 was purchased in spot market transactions.

In sum, Joskow's 1985 paper provides empirical confirmation, drawn from the experience of the power plant industry, that systematic relationships exist between contract length and measures of the importance of relationship-specific assets. It is notable that generally shorter term contracts prevail where factors associated with the likelihood of hold-up problems are not present and that a relatively large volume of coal was, in fact, traded in spot markets in the eastern US, where the product is relatively homogeneous in quality, where transportation alternatives were relatively plentiful, and where supply capacity could reasonably easily be added in modest increments.

5. LESSONS AND CONCLUSIONS FOR POWER PLANT INVESTMENT

The industry examples discussed in the previous sections illustrate that long-term contracts between firms and downstream customers are generally the exception rather than the rule. In the usual case where downstream output markets are characterized by numerous relatively undifferentiated buyers, relationship-specific investments are negligible and "hold-up" risks are not a problem. Risks of investment are assumed by the investor or shared with its suppliers, not shared with customers via long-term contracts. Investments take place with no guarantee of success, on the expectation that if the product is successful in the marketplace, the quantities the firm will be able to sell and the prices it will receive will be more than sufficient to recover investment costs. Long-term contracts are more common in markets for intermediate inputs, where relationship-specific investments are important, as is the case for automotive and aviation components, or for the contractual relationships between some coal-fired power plants and their coal suppliers.

It is also possible for contractual norms to change over time as markets develop, products become standardized, and buyers become more numerous and less differentiated. The LNG industry is an illustration of this transition. In its earlier days, investments in either side of the transaction were largely relationship specific, as remote source natural gas producers did not have ready access to alternative customers through established gas markets and customers similarly had no ready access to alternative sources of supply. Investments on either side of the transaction were inherently relationship specific, and very long-term supply agreements were the predominant contracting form in these early days. Now, however, as international trade in LNG has grown and markets have matured, producers increasingly are able to sell gas into large and reasonably undifferentiated US and European markets, and the economics of new LNG export projects are no longer dependent on lining up long-term contracts with particular end-user customers.

Where does electric power output fit in this framework? Are relationship-specific investments important and is it likely that the output of a particular new plan will have a higher value to one or a few particular purchasers than it will for others? While it is certainly true that transmission constraints introduce some geographic differentiation into electric power markets—added output at a particular generating plant may be more or less valuable in meeting the peak load needs of a particular customer—within the broad geographical area a power plant can serve effectively buyers are usually numerous and the product is essentially a standardized commodity. Markets for electric power output thus seem closer to the model of a market characterized by numerous undifferentiated buyers than they do for markets characterized by few and specialized buyers. Hold-up should not be a problem, and long-term contracts with output customers should not be necessary to elicit investment. Why then, has there been a perceived under-investment in building new power plants in some areas?

We believe the lack of investment can be traced to several factors, the most notable of which involve regulatory failures. Any entity making investments in the electric power generation, regardless of the structure of its contracts with customers or suppliers and regardless of how it has chosen to finance its investments is implicitly locked in to a relationship with market regulators. The rules regulators have chosen to set—and the freedom they have been granted to make and remake those rules—have given rise to their own set of hold-up problems.

One piece of this regulatory failure is that in some instances and parts of the country, regulators have failed to create rules that are sufficient to blunt the ability of downstream IOUs from using their control of the distribution network to limit competition for retail customers from new upstream generators. In these circumstances, prospective new investors in electric power generation do face a hold-up problem with the downstream distributor of electricity that regulation has failed to eliminate. In some parts of U.S., for example, merchant generators have frequently charged that the host utility has unduly discriminated against them through such means as excessive transmission interconnection costs, unreasonable denial of transmission capacity for export to other regions, and dispatch rules that are preferential to the utility's own generation. In such circumstances, a classical hold-up problem exists, and we would not expect to see investment in new power plants taking place in the absence of long-term contracts between generators and downstream power distributors.

More generally, though, even regulatory regimes that have dealt reasonably effectively with the potential for hold-up by downstream firms still do not mitigate a relationship-specific investment problem unique to regulated industries—the potential for hold-up created by the behavior and incentives of the regulator itself. The returns earned on any investment in electric power generation are ultimately subject to the pricing and access rules adopted by the regulatory authorities and discretion of the regulator in administering or modifying those rules. Investing in electric power generation puts an investor at the mercy of the regulator—and a regulator does not (and really cannot) sign a long-term contract or other binding commitment with a generator that prevents it from changing pricing or access rules at some point during the useful economic life of a generating asset. A regulator is free to adopt pricing or other rules that make the business case for investing in electric power generation appear attractive, only to behave opportunistically and change these rules later to serve the short-term interests of other parties or the regulator itself. [50] Potential investors that are aware of this possibility are not likely to invest unless they can be reasonably sure that they will have access to income streams that are reasonably secure against regulatory expropriation.

The recent history of the electric power industry suggests that the problem of regulatory hold-up is far from an academic problem. An investor that hopes to recoup its investments over time through spot market pricing of generation output in competitive markets needs to be assured that it will be allowed to command very high prices for its output during periods of tight demand. In competitive power markets that lack any capacity payments, much of capital cost recovery for even base load generators and all cost recovery for peaking generators must be funded through high peak load prices—prices well above the short-run marginal cost of those peakers. Imagine, for example, a situation in which maintaining sufficient reserve capacity requires having available additional plants that might only operate for a few hours per year (and, in some years, no hours at all). If the regulator wants investors to build such plants and the only rewards the regulator allows such investors to earn are from sales of power output, then it must allow average rates over the few hours per year the plant will operate to rise to levels that fully cover the annual interest and depreciation cost of such a plant. Cap prices at any lower level, and prospective investors cannot recover their costs and will not invest. For example, a new peaking plant today must have a prospect of earning about $100 per kW per year of installed capacity (depending on development costs, which vary by location). If such a plant is only likely to operate 50 hours each year on average, prices would have to reach $2000/MWh in each of those hours. When ISO New England first started its competitive spot markets, the market design did not include any price or bid caps, and investment interest was high. About two years later, however, the market design was changed to include a $1000/MWh bid cap to limit the exercise of market power—but also effectively guaranteeing that prices could not go high enough, often enough, to support new investment through energy prices alone. Moreover, investors who had already sunk capital into New England generation had had the rules changed underneath their investments in a way that dramatically reduced their earnings. Indeed, this was a contributing factor to the bankruptcy of several of the large IPPs in the early 2000's.

When utilities operated as regulated, vertically integrated entities, this problem was solved by an implicit long-term contract between the regulators and the utilities. The utilities would build enough generation to maintain reliability, and the fixed costs of these resources—including recovery of capital costs—would be passed through in customer rates. When generation is built by independent power producers, owners cannot directly pass on their costs in retail tariffs, however, and so must rely on some other mechanism. Three such mechanisms exist, in principle:

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50 This general phenomenon, in which the inability of a party to commit credibly not to behave opportunistically at a later date can produce suboptimal outcomes, is known in the economics literature as the "time consistency" or "dynamic consistency" problem. The seminal paper in this literature, Finn Kydland and Edward Prescott's paper "Rules Rather than Discretion: The Inconsistency of Optimal Plans", *Journal of Political Economy*, 85, 473-490 (1977) was prominently cited by the Royal Swedish Academy of Sciences in awarding its authors the Nobel Prize in Economics in 2004.

1. Long-term contracts with credit-worthy entities. As we observed in many other industries, when there is a high degree of asset-specificity and a low degree of market robustness, the typical solution to the investment problem is for buyers and sellers to enter into long-term contracts. These contracts necessarily transfer risk from sellers to buyers, though, and may leave customers at substantial risk that the decisions as to location or technology made by the power plant developers turn out badly over time. These "stranded costs" have cost electricity consumers billions of dollars over the past two decades and were one of the primary spurs to restructure the power markets. Moreover, since it is not the retail customers that enter into these contracts, but rather intermediary retailers or other financial entities, there is a substantial risk to these intermediaries that customers will migrate away from a contract that creates full cost recovery to generators if they have alternative options that allow them to pay spot energy prices that (for reasons discussed above) do not include full recovery. Consequently, unless all entities in a market are required to hold long-term contracts, the mismatch between spot and contract prices will drive the market towards insufficient contracting to maintain traditional reliability standards.

2. Robust spot market prices and real demand response. As noted above, price caps set too low either lead to revenue insufficiency or resource inadequacy. If no price caps existed, prices would reach the level needed to make new investment in generation worthwhile. There are several challenges to this model, however, foremost among them being regulatory commitment. Since one regulatory commission cannot bind future commissions, this potential for changing the rules of the market after investment has been sunk is a serious risk that can impede efficient investment in an "energy only" market if investors believe there is a probability of regulatory "hold-up". Regulatory commitment is strengthened if a true demand response is available in short-term markets, in part because demand response acts as a check on the potential market power of generation owners and thus disciplines market prices. This response can occur with new technology in smart meters, in home information devices, "SmartGrid" technology, and automation.

3. Competitive capacity markets. Several competitive wholesale market operators have instituted a forward "capacity market," which is a middle ground between a long-term contract and a spot market. Modern versions of these markets, such as those implemented in the Mid-Atlantic and New England regions, make binding commitments three or more years forward with generation owners, guaranteeing payment in return for a commitment to be available. These payments are guaranteed through the market operators' FERC tariffs, under the "filed rate doctrine," therefore making them sufficiently firm to secure financing. The commitments, however, are for much less than the economic lifetime of each unit; this balances the stranded risk cost with the regulatory uncertainty that the capacity market design could change. Since the commitment is directly with the grid operator, rather than an individual marketer or load-serving entity, the cost of the capacity can be allocated equitably among all consumers, avoiding the free-rider problem that a bilateral contracting world can allow.

Although these capacity markets have no direct analog in any of the other industries we have examined in this paper, they are similar to payments that the U.S. government makes to defense suppliers and pharmaceutical manufacturers to maintain productive capability needed for potential homeland security risks, such as spare parts for key defense systems or production capacity for aircraft and exotic medications. These economic relationships, however, are less complex than the electricity markets, since the government will also be the direct buyer of the product, whereas in electricity markets, there are agency and free-rider problems created by the more complex value chain.

Based on our survey of other industries with similar characteristics—namely, in those requiring substantial investments in productive assets that are, to varying degrees, specific to the task—we note that there are several key factors that determine whether investment can be made without long-term contracts: primarily access to a robust market with many competing buyers, and secondarily a stable regulatory framework. If the electricity market is to follow the examples of the majority of capital-intensive industries in this country, therefore, regulators should seek to guide the development of robust market structures that create open, non-discriminatory access between generators and end-use customers, coupled with regulatory stability created from restraint in re-visiting market designs over-often with the goal of exacting short-run benefits for consumers, without fuller consideration of the long-run viability of the ability of the industry to attract the capital it will require to address pressing concerns of renewable energy and greenhouse gases. Success in the first step—creating robustly competitive retail markets for electricity and the associated increase in price transparency and demand response—will pave the way for greater competitiveness, and regulatory confidence in, wholesale energy competition.