

LONG-TERM NATURAL GAS CONTRACTS: DEAD, DYING, OR MERELY RESTING?

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I. INTRODUCTION

The last several years have been marked by considerable discourse within the natural gas industry about the decrease—over the course of the last two decades—in the length of natural gas contracts and the claimed adverse consequences associated with that decrease.¹ While there has certainly been discussion on the subject, the literature appears to be sparse; most of the literature in fact antedates the movement toward shorter contract terms. Nor does there seem to have been any examination of why contract terms appear to have shortened, the advantages and disadvantages of shortened terms, and whether action can or should be taken to alter the *status quo*. It is also fair to say that the current conversation has only focused on portions of the issue and has failed to make a comprehensive review of the subject.

This article addresses: (1) the apparent trend over the last twenty years from relatively long-term contracts for natural gas supply and natural gas transportation to relatively short-term contracts and examines the apparent causes of that change; (2) whether the trend has proven to be desirable or undesirable; (3) whether missteps of public policy have caused or accelerated the trend; and (4) if so, what can or should be done to chart a proper course. It discusses both natural gas supply contracts and natural gas transportation contracts, and the different considerations involved with each. The discussion focuses principally on the impact of the trend on natural gas consumers.

The article also addresses the implications of the trend toward shorter contract terms for the two largest potential sources of new natural gas for the United States in this era of constrained supply—an Alaska natural gas transportation system and additional liquefied natural gas import terminals. Much of the current discussion concerning long-term contracts has focused upon whether today's trend toward short-term contracts will impede the construction of infrastructure to bring Alaska natural gas to market and to bring liquefied natural gas to North American markets.

The trend toward shorter contract terms appears to have a number of causes. They can be grouped as either market-related or regulatory-related, although the

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1. See generally Ken Costello, *Are Regulators in For The Long Haul: An Economic Perspective on Long-Term Contracting for Gas Pipeline Service?*, 143 FORTNIGHTLY MAGAZINE – PUBLIC UTILITIES REPORT, July 2005, at 45, 50. Rather surprisingly, there has not been significant literature on the issue, although it has been the subject of much discussion in industry trade groups such as the National Association of Regulatory Utility Commissioners and the Interstate Oil and Gas Compact Commission.

relative magnitude of each is impossible to discern. Plainly, the market changes of the last twenty years (which were, as will be discussed below, largely caused by federal regulatory initiatives) have had a major impact on contract terms. The creation of competitive markets in natural gas and somewhat competitive markets in transportation has inexorably led to shorter contract terms.

From the purchaser's perspective, there is today, in the simplest terms, increased confidence that natural gas supply and transportation capacity can be obtained in the relatively near term, thus undercutting the perceived need for, and benefits of, long-term contracts and the certainty they provide. From the broader economic perspective, the market forces that have been unleashed in the last two decades have caused significant changes in industry structure. In the formative years of the American natural gas industry, the assets of gas producers and of pipeline operators—each involving enormous levels of investment—were essentially committed to particular customers and particular geographic markets. These assets would diminish greatly in value if not linked in some fashion to particular customers and markets. For many years, long-term contracts provided the assurance of revenue streams that were necessary to finance this infrastructure.

With the growth of competitive gas markets, creating multiple purchasers and multiple sellers and a variety of natural gas products, sellers of natural gas and of transmission service have been confronted with vastly expanded geographic markets. This change has dramatically reduced the risk of being captive to particular customers. Similarly, from the customer perspective, a whole array of new sellers of gas and transmission has become available, diminishing the risk of a "recalcitrant" or monopoly seller. Thus, from both ends of the value chain, the market forces unleashed by federal restructuring initiatives have diminished the value of long-term contracts significantly.

Regulatory uncertainties have certainly contributed to the market trend toward shorter contract terms. These include the asymmetry in risk-reward often caused by state prudence reviews and the uncertainties associated with state retail choice programs. Although the changes wrought in contract terms by market forces are beyond control, these regulatory uncertainties that militate toward shorter contract terms certainly are within the control of regulators.

Long-term contracts, for either natural gas or for transportation service, have benefits for consumers. They also carry risks. The risks of long-term contracts were addressed head-on in the 1980s when long-term natural gas purchase contracts containing take-or-pay clauses created huge tumult in the industry. These events, and perhaps others, make clear that, if regulators should decide that long-term contracts are beneficial to consumers, they must also acknowledge and plan for the risks associated with them. As the discussion that follows will show, if regulators conclude that long-term contracts will benefit their consumers, they must be rigorous in their analysis of the benefits and the risks of encouraging them.

II. EVOLUTION OF NATURAL GAS SUPPLY AND TRANSPORTATION CONTRACTS

A. *Those Were The Days: The Contractual Paradigm In The First Half-Century of the Industry*

The gas industry began in the United States as early as 1816. It was not, however, a “natural gas” industry. Rather, it was a manufactured gas industry created initially for lighting and heating end uses.² The business was essentially local, with integrated utilities producing gas at city manufactured gas plants and then distributing it within their service territories.³ The integrated national pipeline system that we know today did not exist. In this era, contracts for the sale and transportation of natural gas were largely unnecessary, as the entire value chain existed within the local utility.⁴

In the first quarter of the twentieth century, this pattern began to change as a result of the discovery of large volumes of natural gas in the mid-continent region and the introduction of steel pipe suitable for long-distance transmission, at high pressure, of natural gas to market areas.⁵ Thus began the evolution of the industry that we know today. In the early decades of the movement away from locally manufactured gas, large natural gas utilities created affiliates to construct and operate long-line natural gas transmission systems.⁶ Oil companies that produced natural gas also often created these long-line pipelines.⁷ Indeed, it appears that during this early period of the industry either natural gas producers or natural gas distribution utilities (or the two together) controlled most of the long-line interstate natural gas pipelines.⁸

In the prewar growth era of the natural gas system, the model, therefore, was vertical integration. This structure follows what economists would predict given the circumstances. Natural gas pipeline facilities (at least originally) were often “transaction-specific” assets—*i.e.*, essentially dedicated to the natural gas fields from which they transported natural gas and/or the particular natural gas utilities to which they transported it. The assets, once constructed, had little value except with respect to serving the upstream or downstream markets to which they were attached. The investments necessary to construct such facilities

2. See generally, ARLO R. TUSSING & BOB TIPPEE, *THE NATURAL GAS INDUSTRY* 59-65 (PennWell Publ'g Co., 2d ed. 1995).

3. *Id.* at 65.

4. During the nineteenth century, manufactured gas was in a number of instances supplemented by natural gas. In these instances the natural gas was produced in relatively close proximity to market centers and transported only relatively short distances to market. Additionally, these supplies were often short-lived, as the technology for efficiently producing natural gas that we today take for granted was entirely unknown.

5. TUSSING & TIPPEE, *supra* note 2, at 89-92.

6. Examples of this phenomenon include the creation by Peoples Gas Light & Coke Company in Chicago of Natural Gas Pipeline Company of America and the creation by Michigan Consolidated Gas Company in Detroit of Michigan-Wisconsin Pipe Line Company.

7. Jeff D. Makhholm, *The Theory of Relationship-Specific Investments, Long-term Contracts and Gas Pipeline Development in the United States* 7 (Apr. 6, 2006) (unpublished manuscript on file with the Nat'l Econ. Research Associates, Inc.), available at http://www.nera.com/Publication.asp?p_ID=2766.

8. *Id.* (citing C.E. Troxell, *Long Distance Natural Gas Pipe Lines*, 12 J. LAND AND PUB. UTIL. ECON. 347 (Nov. 1936)).

would not be undertaken absent assured revenue streams from one or both of these sets of upstream or downstream parties.

Stated alternatively, the value of such pipeline assets (and, by extension, upstream natural gas production facilities) is much smaller in transactions not linked either to the particular producers or the particular natural gas utilities served. Given that the economic success of such a greenfield venture turns heavily upon one or both of the other sets of parties, economists predict that such a venture will tend to be owned by one or the other, or both.⁹ Vertical integration makes particular sense with long-lived pipeline assets that are commercially linked to long-lived producing assets and long-lived distribution assets where there is no regulatory oversight of the pipeline asset. The essential economic challenge for all three levels—producer, pipeline, and natural gas utility—is sometimes referred to as the prospect of “hold up.” At each level, a viable enterprise requires large investment that is essentially dedicated to one or the other (or both) groups. Once the assets have been placed in service, the owner is at risk that the other essential party will hold it up financially, putting the value of the asset and the vitality of the enterprise at risk. Vertical integration is a logical and natural solution to this risk. In the initial phases of the growth of the natural gas industry, vertical integration was the prevailing model for the transmission assets linking production and markets.

In 1938, Congress enacted the Natural Gas Act¹⁰ to regulate the long-line interstate natural gas pipelines that had sprung up in the two preceding decades.¹¹ From the advent of the Act, and for half a century thereafter, the governing paradigm was that interstate pipelines engaged in bundled sales at federally regulated prices,¹² which were made almost exclusively to local natural gas utilities.¹³ Bundled sales to local natural gas utilities were made on a long-term basis, typically for twenty years. To the commercial eye, these transactions

9. Makhholm, *supra* note 7, at 7.

10. 15 U.S.C. §§ 717-717(u) (2000).

11. *Id.* § 717(f)(c). For purposes of the discussion that follows, it is important to note that the Natural Gas Act, as amended over the subsequent years, contains section 7(c), which requires that any person seeking to construct or operate a pipeline engaged in the interstate transmission of natural gas obtain a certificate of public convenience and necessity from the Federal Power Commission. An applicant is required to demonstrate to the Commission that its construction, operation, and contractual arrangements are in the public convenience and necessity. Congress enacted the Natural Gas Act to fill the jurisdictional gap created by a series of Supreme Court decisions holding that the states could not regulate interstate natural gas pipelines. *See generally* Public Utilities Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927); Missouri v. Kan. Gas Co., 265 U.S. 298 (1924); Pennsylvania v. W. Va., 262 U.S. 553 (1923).

12. TUSSING & TIPPEE, *supra* note 2, at 133. In a bundled sale, both the natural gas and the transportation to market are bundled together at one stated price, which was regulated under the Natural Gas Act.

13. Two other forms of transaction made up the balance of interstate pipelines' business activities. *First*, pipelines acted solely as transporters of natural gas, usually for other pipelines and often involving an upstream pipeline bringing distant gas supply to a downstream pipeline system; *second*, some pipelines made “direct sales” of bundled transportation and natural gas to industrial end-users attached to their systems. Such sales, because they were not “sales for resale” under section 1 of the Act, were not subject to Federal Power Commission jurisdiction. Nevertheless, the transportation embedded within the bundled transaction remained subject to federal jurisdiction. 15 U.S.C. § 717(b) (2000). *See also* Panhandle East. Pipe Line Co. v. Federal Power Comm'n, 324 U.S. 635, 646-48 (1945) (explaining that the FPC, while it lacked authority to fix rates for direct industrial sales, could take those rates into consideration when fixing the rates for interstate wholesale sales which subject to its jurisdiction).

were somewhat unusual. The contract itself—covering a term of twenty years, with a value measured in the hundreds of millions of dollars or more—was spartan in its terms, usually including little more than parties, term, maximum daily contract quantity, perhaps a maximum annual contract quantity, and delivery points involved. Most importantly, the contract incorporated by reference the pipeline's tariff as approved by the Federal Power Commission (later Federal Energy Regulatory Commission), wherein the price for the service and the other detailed terms of service were established under either section 4 or section 5 of the act.¹⁴ To support these downstream sale-for-resale contracts, which were the core of the pipeline's business, the pipeline also was party to gas-purchase contracts with hundreds, if not thousands, of natural gas producers. More often than not, these contracts also mirrored the sale-for-resale contracts with a twenty-year term, although sometimes the purchase contract would be for a term of the life of the natural gas reserves.

Subsequent to 1954 and prior to enactment of the Natural Gas Policy Act of 1978 (NGPA),¹⁵ the Federal Power Commission, in addition to regulating the prices for bundled natural gas sales by pipelines, also established the wellhead prices for natural gas sold in interstate commerce.¹⁶ As a result, pipelines were sandwiched between upstream and downstream long-term contracts, with federal price regulation at both ends. The pipeline served the essential roles of both transmission provider and merchant of natural gas. During this era, interstate pipelines accounted for the significant majority of all merchant activity in the natural gas industry.

During the decades when pipeline merchant activity (*i.e.*, bundled sales) was the paradigm—with matching twenty-year contracts at each end of the pipeline—the conventional wisdom was that long-term contracts were essential for the financing of the pipeline. Moreover, during this era—also marked by the post-World War II build-out of the interstate pipeline grid—the Federal Power Commission, in considering a certificate application to construct or expand a pipeline, typically required an applicant to demonstrate *both* adequate upstream supplies of natural gas under long-term contracts and a full complement of downstream purchase agreements with long-term commitments.

During these years from 1938 to 1978, the core of the interstate pipeline network that we know today was constructed. In significant measure, the growth of the network resulted from the postwar economic expansion and the abundance of inexpensive natural gas supplies. There was also a significant diminution in the pattern of vertical integration that was the hallmark of the initial round of pipeline construction in the 1920s and 1930s.¹⁷ The governing federal regulation imposed in the 1930s may well have been a significant cause of this

14. 15 U.S.C. §§ 717c-717d.

15. Natural Gas Policy Act, 15 U.S.C. §§ 3301-3432 (2000).

16. See generally *Phillips Petroleum Co. v. Wis.*, 347 U.S. 672 (1954) (the Supreme Court concluded that the Natural Gas Act required the Federal Power Commission to regulate the prices charged by producers of natural gas in interstate commerce).

17. Makhholm, *supra* note 7, at 14. Eighty percent of natural gas pipeline mileage in 1935 was controlled by holding companies, while by 1952 only eighteen percent of pipeline mileage was controlled by holding companies.

disaggregation. The Public Utility Holding Company Act of 1935¹⁸ somewhat deterred vertical integration. Additionally, the Natural Gas Act of 1938 placed interstate pipelines under a regime of comprehensive regulation. The regulatory scheme administered by the Federal Power Commission gave both natural gas producers and natural gas utilities a degree of certainty that, in the first instance, their product could get to market on fair terms and, in the second instance, that supply would be available to meet consumer needs. The risk of “hold up” was significantly reduced for the parties at each end of the pipeline, and the pressure for vertical integration was greatly reduced. Instead, federally regulated, long-term contracts for sales of gas to pipelines and federally regulated contracts for sales of gas to utilities became the governing model during the period from the 1930s to the 1970s.

Makholm reports that during this period the insurance industry played a critical role in financing this infrastructure expansion, with life insurance companies and trustees holding nearly all of the pipeline bonds around 1950.¹⁹ He further states that the then-existing regulatory scheme provided the bedrock for their investment in this growing and somewhat new industry.²⁰

From today’s vantage point, particularly for those in the industry who lived through the turmoil of the 1980s and 1990s, it is easy to visualize this business model with a fair degree of nostalgia, perhaps even longing. Long-term contracts characterized both ends of the pipeline. The challenge for pipeline operators and financiers was two-fold but simple and straightforward: line up adequate supplies of price-controlled natural gas (all of which could be easily sold) and assure that the many willing customers (mostly utilities) were creditworthy (which was almost always the case given state cost-of-service regulation). The significant challenge was acquiring gas supply, which became increasingly difficult in the 1960s and 1970s as a result of the long-term effects of federal wellhead price regulation. Given that interstate pipelines performed the merchant function, the challenge for natural gas utilities was predicting growth in demand and peak-day sendout.

Many today view this industry paradigm of both upstream and downstream long-term contracts, perhaps largely because it was the *status quo*, as the natural order. From today’s perspective, however, it may simply have been a way-station paradigm between a largely vertically integrated industry and today’s much more competitive industry.²¹

B. A Rumor of War: Restructuring of the Natural Gas Industry

A significant worldwide trend of the 1980s was the effort led by, among others, U.S. President Ronald Reagan and British Prime Minister Margaret Thatcher, to overhaul the role of government as it relates to economic activity.

18. Public Utility Holding Company Act of 1935, 15 U.S.C. §§ 79-79(z)(6), *repealed* by Energy Policy Act of 2005, Pub. L. No. 109-58, § 1263, 119 Stat. 594 (2005).

19. Makholm, *supra* note 7, at 20.

20. *Id.* at 21-22.

21. Similarly, from today’s vantage point, with the turmoil of the 1980’s and 1990’s now behind us, one might conclude that the regulatory pattern of those years was ultimately unstable and destined for a complete revamping.

In Britain Thatcher led an effort to dismantle large portions of the post-World War II social welfare state, symbolized by state industries. In the United States, President Reagan sought, on many fronts, to extricate government from control of industry and, where possible, to maximize the role of market forces. Although Thatcher and Reagan are often viewed as the most visible proponents of this movement, in fact this trend had already begun in the 1970s. Airline, telecommunications, trucking, railroads, and financial services were already moving toward deregulation prior to the Thatcher-Reagan era. Indeed, Congress enacted the most significant package of energy legislation in forty years toward the end of the Carter Administration, including the Natural Gas Policy Act (NGPA),²² the Public Utility Regulatory Policies Act,²³ and the Powerplant and Industrial Fuel Use Act.²⁴

These forces began to take hold at the Federal Energy Regulatory Commission²⁵ in the mid 1980s. Congress had already passed the NGPA, which provided that natural gas would, at least prospectively, be subject to congressionally mandated price ceilings (rather than Federal Power Commission-mandated cost-of-service ceilings), which, in a few categories, were removed over time.²⁶ This legislation was intended to cure the massive shortages of the 1960s and 1970s that had been produced by federal cost-of-service regulation of natural gas prices at the wellhead.²⁷ To a certain extent the NGPA was an attempt to cure the fundamental instability of the regulatory regime of the prior twenty-five years. Although the NGPA was essentially solomonic in its treatment of natural gas wellhead prices,²⁸ the Supreme Court recognized the overall intention of Congress in passing the act, which was that “the supply, the demand, and [the] price of . . . gas be determined by market forces.”²⁹

With this backdrop, FERC, in 1984 issued Order No. 380, eliminating pipeline gas-cost minimum bills.³⁰ For the first time, pipelines serving the same geographic area were required to compete at the margin for sales of gas on the basis of their gas costs. In the competitive—often urban—markets, pipelines began, essentially for the first time, to feel competitive pressures. Order No. 380 was in essence the opening salvo in an assault on the existing regulatory and market regime.

22. Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432 (2000).

23. Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601-45 (2000).

24. Powerplant and Industrial Fuel Use of 1978, 42 U.S.C. §§ 8301-8484 (2000).

25. Successor in 1977 to the Federal Power Commission.

26. See also Richard J. Pierce Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 ENERGY L.J. 1, 8 (1988). The NGPA represented a blend of the new order and the old. It maintained price ceilings for old gas. It raised price ceilings for new gas while imposing Congressional rather than FPC-determined prices, and over time it entirely deregulated a few categories of natural gas.

27. The NGPA provided that existing production would remain subject to federal price regulation. 15 U.S.C. §§ 3301-3432.

28. See generally, Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601-45.

29. *Transcontinental Gas Pipe Line Corp. v. State Oil and Gas Bd.*, 474 U.S. 409, 422 (1986).

30. Order No. 380, *Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provision*, 49 Fed. Reg. 22,778 (1984) (codified at 18 C.F.R. pt. 154), *aff'd*, *Wis. Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986).

1. The First Wave of Unbundling

The next year, responding in part to the NGPA and in part to an appellate court ruling that an experimental transportation program violated the anti-discrimination provisions of the Natural Gas Act,³¹ the FERC issued its watershed Order No. 436.³² Order No. 436 established a voluntary transportation program for interstate pipelines. Pipelines accepting a “blanket certificate” were permitted to offer transportation service to any customer without obtaining advance, case-specific FERC approval to do so, as had previously been required. In return, pipelines were required to provide such service to all persons requesting it.

The importance of the Order No. 436 program was that for the first time pipelines were *permitted* (but not required) to unbundle transportation service from bundled sales service but, if they did so, were required to do so on a widespread, nondiscriminatory basis. This transportation service was fundamentally different from prior pipeline transportation services, which had usually been performed for other pipelines, with each separately certificated pursuant to section 7(c) of the Act.³³ As was recognized by the FERC itself, pipelines were extremely reluctant to undertake unbundled transportation that competed with their own sales services.

When Congress imposed regulation on the natural gas pipeline industry in 1938, it opted for a scheme that was based entirely upon voluntary contracts. This essential point cannot be overlooked. The key component of interstate pipeline service is the service agreement between the pipeline and the customer. That agreement is approved by the FERC (or previously the FPC), and it does incorporate the tariff approved by the FERC, but the act of entering into the contract itself is volitional and discretionary on the part of the pipeline. The Natural Gas Act provides only a very narrow range of circumstances in which a pipeline is required to enter into a contract not of its own choosing, and the authority of the FERC to order such action under other provisions of the Natural Gas Act (*e.g.*, the provisions barring undue discrimination) is murky.

This pattern of regulation is entirely different from the schemes previously adopted by Congress in a number of other contexts. The predominant model in a number of other industries was common carriage. Under the common carriage model, the utility is required to provide service for all those desiring it. This model was adopted in the United States for railroads, oil pipelines, and airlines, among others. Under the common carrier model, if there is inadequate capacity to serve all customers, service is provided on a *pro rata* basis.

In the years leading up to Order No. 436, a debate had been waged before both the FERC and Congress with regard to this fundamental aspect of the interstate pipeline business. Many, particularly industrial consumers of natural

31. *Maryland People's Counsel v. FERC*, 761 F.2d 768 (D.C. Cir. 1985); *Maryland People's Counsel v. FERC*, 761 F.2d 780 (D.C. Cir. 1985).

32. Order No. 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1982-1985] F.E.R.C. STATS. & REGS. ¶ 30,665 (1985), 50 Fed. Reg. 42,408 (1985), *vacated and remanded*, *Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

33. 15 U.S.C. § 717f (2000).

gas, had argued that interstate pipelines should be made common carriers. Similar arguments were made before the FERC, although its statutory authority to follow such a pass was less than clear. A key, and often overlooked, aspect of Order No. 436 is that it reached a result not significantly different from common carriage, but by making the Order No. 436 blanket certificate voluntary, it retained the fundamental regulatory regime embodied by Congress in the Natural Gas Act.

Order No. 436 very quickly brought massive changes to both the pipeline system and energy markets in general.³⁴ One pipeline, Columbia Gas Transmission, promptly sought to opt into the voluntary blanket-certificate program, and, in fairly short order, all other pipelines in the nation joined the revolution.³⁵ Within several years the vast bulk of pipeline services being provided were under blanket transportation certificates. These services were provided under relatively short-term transportation contracts under Order No. 436 blanket certificates, in contrast to the early 1980s, when the vast bulk of services provided by interstate pipelines were bundled sales services under long-term contracts. The changes brought about by Order No. 436 are amply illustrated by the fact that the roughly 80% to 20% sales/transportation split in throughput of the early 1980s was entirely reversed by the late 1980s.

Order No. 436, while permitting the revamping of the pipelines' downstream contracts with customers, took no action with regard to the pipelines' upstream gas supply contracts. As a result, the late 1980s were largely marked at the FERC by efforts to address the take-or-pay problems that had been visited upon pipelines by the reversal of the sales/transportation ratio mentioned above.

The take-or-pay "crisis," as it was often described, is instructive when considering the issues surrounding the decrease in the term of contracts. The pipelines' take-or-pay contracts with their producers were more often than not twenty-year contracts requiring that the pipelines take or pay for 75-100% of the contract quantity. These long-term contracts were entered into to support pipelines' bundled merchant sales service. The pipelines' take-or-pay contracts were essentially contracts that had been entered into under one regulatory regime that became uneconomic under another.³⁶ Although many still quarrel about the details, in the aftermath, the FERC was required to set up a transitional mechanism to address these take-or-pay costs.³⁷ When all was said and done,

34. See also Tussing & Tippee, *supra* note 2, at 204-10.

35. At the time, observers believed that that pipeline, which had experienced myriad regulatory difficulties, hoped to gain a competitive advantage by opening its system to transportation. Its action, however, quickly led to a domino effect as one pipeline after another opted for open access in order to compete with an open-access pipeline serving the same market. Ultimately, all interstate pipelines had joined the new regulatory regime in the several years following Order No. 436.

36. See also Tussing & Tippee, *supra* note 2, at 212-14.

37. See also Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1986-1990] F.E.R.C. STATS. & REGS. ¶ 30,761 (1987), 52 Fed. Reg. 30,334 (1987) (to be codified at C.F.R. pts. 2, 284), *remanded*, *American Gas Ass'n v. FERC*, 888 F.2d 136 (D.C. Cir. 1989), *readopted*, Order No. 500-H, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1986-1990] F.E.R.C. STATS. & REGS. ¶ 30,867 (1989), 54 Fed. Reg. 52,344 (1989) (to be codified at C.F.R. pts. 2, 204), *reh'g granted in part and denied in part*, Order No. 500-I, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1986-1990] F.E.R.C. STAT & REGS. ¶ 30,880

pipelines had been released from liabilities measured in the hundreds of billions of dollars for a price measured in the tens of billions of dollars, and natural gas consumers paid approximately half of these costs.

Subsequent to Order No. 436, Congress supplemented the NGPA with the Wellhead Decontrol Act³⁸ which provided, unlike the solomonic approach of the NGPA, that the prices for new natural gas sales contracts would be free of all federal price regulation. Unquestionably, the new and higher prices permitted by the NGPA had, beginning in 1979, greatly spurred exploration and production activity. These higher prices, however, together with an early 1980's recession, severely dampened gas demand.³⁹ The result was the "gas bubble," which lasted for fifteen years, beginning in the mid 1980s and ending in the winter of 2000-2001. During this period natural gas prices in wholesale markets hovered in the \$2.00 range (reaching lows at times slightly above \$1.00), and most, if not all, buyers could be assured of finding ample supply.⁴⁰

2. The Second Wave of Unbundling

In 1992, the FERC carried the process further with the issuance of Order No. 636.⁴¹ Unlike the *permissive* changes announced in Order No. 436, the FERC in Order No. 636 *mandated* changes to pipeline services. Most important for present purposes, Order No. 636 mandated the unbundling of the sales function into transportation and sales services, which were then sold separately.⁴² Ultimately the changes mandated by Order No. 636 led to yet further profound changes in the natural gas industry.

The separation of transportation and sales functions led all interstate pipelines to abandon the sales function entirely, even though Order No. 636 did not require this result.⁴³ It also ultimately led to essentially pushing the central

(1990), 55 Fed. Reg. 6605 (1990) (to be codified at C.F.R. pts. 2, 284), *aff'd in part and remanded in part*, Am. Gas Ass'n v. F.E.R.C., 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991); Order No. 528, *Nat'l Fuel Gas Supply Corp.*, 67 F.E.R.C. ¶ 61,147, at p. 61,408 (1994).

38. 15 U.S.C. § 3413 (2000), *repealed by* Pub. L. No. 101-60, 103 Stat. 159 (1989) (effective Jan. 1, 1993).

39. The natural gas industry had operated from the 1950s through the 1970s in an environment where regulated gas prices were significantly below market values. As a result, the concept of price elasticity had little or no meaning for the industry. This changed dramatically as price ceilings were lifted in the 1980s.

40. Subsequent to 2000, as supply and demand have become more tightly aligned, wholesale gas prices have more than tripled. At present, wholesale prices are hovering in the \$5-7.00 range and are anticipated to remain in that range for the foreseeable future, with occasional spikes into the range of \$15.00.

41. Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, [Regs. Preambles 1991-1996] F.E.R.C. STAT & REGS. ¶ 30,939 (1992), 57 Fed. Reg. 13,267 (1992); Order No. 636-A, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, [Regs. Preambles 1991-1996] F.E.R.C. STATS. & REGS. ¶ 30,950 (1992), 57 Fed. Reg. 36,128 (1992), *order denying and remanding*, Order No. 636-B, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, 61 F.E.R.C. ¶ 61,272 (1992); Order No. 636-C, 78 FERC ¶ 61,186 (1997), *aff'd in part, remanded in part*, *United Distribution Companies v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied*, 520 U.S. 1224 (1997).

42. See also Tussing & Tippee, *supra* note 2, at 221-48.

43. It is often stated that Order No. 636 *required* pipelines to abandon the merchant function. This is incorrect. Order No. 636 required pipelines to unbundle their transportation and sales services. The sales

merchant function downstream, where it was to be performed largely by local distribution companies, rather than with pipelines, through bundled sales service, having a key role in the process. The result was also a significant increase in the regulatory risk assumed by local natural gas utilities.⁴⁴

In the late 1990s the FERC revisited a number of issues addressed (or unaddressed) by Order No. 636. In 2000 FERC issued its Order No. 637.⁴⁵ In that order, the FERC fine-tuned its Order No. 636 in a number of ways, largely based upon the years of experience under the new regime. It is fair to say that with the issuance of the Order No. 637 series, the FERC process of restructuring the natural gas industry, utilizing its exclusive oversight authority over interstate natural gas pipelines was complete. No significant, broad reaching gas initiatives have been undertaken since Order No. 637, and none appear to be likely in the future.

Order No. 636 also led to progressively greater unbundling and finer sculpting of interstate pipeline services, a process that continues to the present. Initially, pipelines offered standalone firm,⁴⁶ interruptible,⁴⁷ and storage services. In the years since Order No. 636, the variety of pipeline services has increased dramatically.⁴⁸ Moreover, with pipelines abandoning the merchant function, the nascent energy marketing community exploded, and a flood of new entrants appeared. Innovative merchants such as Enron and Dynegy grew dramatically, as did merchant affiliates of pipelines, natural gas utilities, and natural gas producers. Ultimately, the market in natural gas as a commodity

service could for the first time be provided on a basis that was not subject to federal price regulation. At the time, pipelines generally already had marketing affiliates that were engaged in unregulated sales of gas. Undoubtedly, most pipelines concluded that it was unnecessary to retain two entities in the corporate family performing essentially the same function. Thus, it was more accurate to say that while Order No. 636 permitted pipelines to remain in the merchant function, it had the practical effect of motivating them to leave the merchant function.

44. State public service commissions may not generally challenge rates approved by the FERC. *See, e.g.,* Nantahala Power & Light v. Thornburg, 476 U.S. 953 (1986); Public Serv. Co. of Colo. v. Pub. Util. Comm'n, 644 P.2d 933 (Colo. 1982); United Gas Corp. v. Miss. Public Serv. Comm'n, 127 So. 2d 404 (Miss. 1961); City of Chicago v. Ill. Commerce Comm'n, 150 N.E.2d 776 (Ill. 1958); Citizens Gas Users Ass'n v. Pub. Util. Comm'n, 138 N.E.2d 383 (Ohio 1956). As a result, the rates charged by interstate natural gas pipelines to local natural gas utilities were almost entirely exempt from state commission scrutiny. In the era of bundled sales, these FERC-approved rates accounted for the bulk of a utility's gas-supply costs.

45. Order No. 637, *Regulations of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, [Regs. and Preambles 1996-2000] F.E.R.C. STAT & REGS. ¶ 31,091 (2000), 65 Fed. Reg. 10,156 (2000) (to be codified at 18 C.F.R. pts. 154, 161, 250, and 284); Order No. 637-A, *Regulations of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, [Regs. and Preambles 1996-2000] F.E.R.C. STAT & REGS. ¶ 31,099 (2000), 65 Fed. Reg. 35,705 (2000) (to be codified at 18 C.F.R. pts. 154, 161, 250, and 284); Order No. 637-B, 92 F.E.R.C. ¶ 61,062 (2000), *aff'd in part, remanded in part*, Interstate Natural Gas Ass'n of Am. v. F.E.R.C., 285 F.3d 18 (D.C. Cir. 2002).

46. A pipeline provides firm transportation service on a firm basis generally subject only to events of *force majeure*.

47. A pipeline provides interruptible transportation service only as capacity is available. The rate for interruptible transportation service is typically less than for firm service.

48. The traditional pipeline services—firm and interruptible—continue to exist. Gradations of firm service have begun to appear over the past several years. Additionally, various forms of “hub” services have appeared. Moreover, new variations on traditional storage services have been offered. Whereas fifteen years ago, interstate pipelines might offer ten or so discrete services, some pipelines now offer dozens.

expanded dramatically, with a number of market centers appearing across the United States. Indeed, today there are literally dozens of markets centers around the United States where natural gas is freely traded and where prices are reported on a relatively contemporaneous basis. Gas can now be purchased at a number of geographic points for terms sometimes shorter than a day. In addition, it can be purchased over the counter and on exchanges for future delivery and can be purchased in manners associated with a variety of financial instruments to mitigate risk. In short, the utility world after Order No. 636 looks entirely different from the utility world of the early 1980s. Tussing, in his important work *The Natural Gas Industry*, gives a good thumbnail description:

[t]housands of traders, aggregators, disaggregators, and reaggregators; hedgers, speculators, and arbitrageurs are linked electronically and constantly monitor and act upon hundreds of different kinds of actual and virtual price spreads at hundreds of geographic nodes, in the present and far into the future. The price signals their actions generate reverberate across the continent instantly, with actual prices and allocations adjusting constantly to dampen external disturbances and make and restore the balance between the supply and demand within each market's myriad subdivisions.⁴⁹

The two waves of unbundling undertaken by the FERC were, from a consumer perspective, undoubtedly an unmitigated success. Natural gas wellhead prices declined from the highs reached in the mid-1980s and instead were in the \$2-3.00 per million British thermal unit throughout the 1990s. Moreover, the federal unbundling process led to a plethora of new pipeline services as well as pipeline and distributor unit costs that declined over time.⁵⁰ Taken together, consumers benefited significantly from the effects of the FERC policies in savings on natural gas as well as the costs of transmitting and distributing it.

State governments watched developments at the federal level. Many concluded that, given the benefits spawned by the federal wholesale unbundling process, unbundling at the retail level could only magnify consumers' savings. Thus, in the 1990s a number of regulators or legislatures created state "retail customer choice" plans.⁵¹ In broad-brush terms, under these plans, retail consumers (typically homeowners) were permitted to pick an alternative supplier for natural gas (rather than their local utility), which the local utility would deliver to the consumer.⁵² The natural gas utility was usually required to be the provider of last resort should an alternative energy supplier fail to deliver for any reason. However, the enthusiasm for these plans has abated substantially from 2000 to the present. The verdict is still out on retail unbundling. Many of these plans were extremely expensive to implement, and it is difficult to determine

49. Tussing & Tippee, *supra* note 2, at 249.

50. American Gas Association analyses, drawn from data of the U.S. Department of Energy's Energy Information Administration, show that the costs of transmission and distribution fell between 1985 and 2005 from the mid-\$2 range to the mid-\$1 range.

51. For a variety of reasons, the movement to retail choice has stalled. For a current overview of the states' policies on retail choice, see generally Energy Information Administration, *National Gas Residential Choice Programs*, Apr. 17, 2006, available at http://www.eia.doe.gov/oil_gas/natural_gas/restructure/restructure.html.

52. In most states, larger industrial customers had been permitted to select their own gas suppliers since as early as the 1980s. In such instances the local natural gas utility has simply acted as a transporter.

whether in the end they produced significant consumer savings. It may be the case that all of the savings to be had for consumers were had at the wholesale level and that retail choice did little to reduce consumers' bills.⁵³

For present purposes, however, the important point is that retail unbundling, where it exists, makes it more difficult for local natural gas utilities to plan their operations, as it is uncertain how many current sales customers will remain sales customers in the months and years ahead. They make it difficult to plan gas supply on a long-term basis, and, depending upon how the program is structured, may make it difficult to plan for long-term interstate pipeline capacity. As of 2005 approximately thirty-four million of America's natural gas customers (roughly one half of the total) in twenty-one states were eligible to participate in retail choice plans, and approximately four million actually did so.⁵⁴ The highest level of participation has occurred in the states of Georgia and Ohio.⁵⁵ Clearly participation rates have been relatively low over the last several years, but the challenge for the local utility remains in estimating how many customers will opt out of purchasing utility natural gas in each year of the utility's planning horizon.

C. *That Was Then, This Is Now*

The current pattern of contracting, for both natural gas and for transportation capacity, is dramatically different from the historic pattern.⁵⁶ The precise differences somewhat elude quantification, as there does not appear to be an entirely reliable data set. Most natural gas purchased today is undertaken under bilateral contracts, and there has not been, and is not at present, any requirement at the federal level for the reporting of contract terms.⁵⁷ With regard to pipeline transportation agreements, the FERC maintains an Index of Customers that is a reasonably reliable source of data.

There is not, however, significant controversy as to the anecdotal evidence. There is no doubt that current gas-purchase contracts are as short as a day, or even less. A contract longer than one year for the purchase of natural gas is now considered "long term." It is unlikely that even a small number of the traditional twenty-year gas-purchase contracts remain.⁵⁸

53. The ultimate question is whether retail choice plans have afforded consumers with savings or simply with choices.

54. See also Energy Information Administration, *supra* note 51.

55. Natural gas retail choice customer has mirrored the breakup of the telephone industry in the sense that inertia appears to keep large numbers of customers with their historic supplier.

56. See generally Tussing & Tippee, *supra* note 2, at 249-50.

57. The Natural Gas Act authorized the FERC to issue rules requiring price reporting. See also Energy Policy Act of 2005, Pub. L. No. 109-58, § 316, 119 Stat. 594 (to be codified at 15 U.S.C. 717). In late 2005, the FERC began the process of exploring what, if any, action it will take pursuant to this authority.

58. The American Gas Association, the trade association of local natural gas utilities, annually compiles a report on natural gas utilities supply sources. See generally AMERICAN GAS ASS'N, 2004-05 LDC WINTER HEATING SEASON PERFORMANCE SURVEY (July 19, 2005). The report samples approximately fifty natural gas utilities with regard to their sources of supply. The report does not purport to represent the practices of the several hundred natural gas utilities in the United States. Nor does it seek to determine average, median, or mean contract lengths. There is no apparent source of data with regard to the contracting practices of marketers, industrial customers, or electric generators.

The situation is somewhat different with regard to pipeline transportation contracts. Order No. 636 converted bundled sales contracts into unbundled transportation and sales contracts. Most of these transportation contracts terminated of their own terms during the mid-1990s.⁵⁹ The twenty-year norm for contracts promptly disappeared. Anecdotal evidence suggests that transportation contracts, whether new or renewed through the right-of-first refusal process,⁶⁰ shifted toward terms of five and six years. As noted previously, the data is not entirely complete, but most observers would agree that this has tended to be the term of pipeline transportation contracts. On the other hand, there are clearly some contracts with longer terms. Open seasons held to gauge interest in new facilities or additions to existing facilities have tended to attract contracts falling more in line with the traditional definition of “long term.” Indeed, it has not been unusual to see such contracts for terms of ten, fifteen, and twenty years.⁶¹ These, have, however, appeared to be in the minority. In short, as to both gas-purchase contracts and pipeline transportation contracts, the day of “long term” contracts as the governing paradigm is apparently past.

The change in term of these contracts also coincides, not coincidentally, with the rise of the unregulated merchant energy sector. That sector has recently experienced contraction as a result of, among other things, the Enron Corporation bankruptcy, the California electricity crisis, and the fallout from the instances of false and misleading price reporting. It will, however, of necessity continue to play an important role in energy markets, although it is beginning to become apparent that a different set of players will perform this intermediary function in the future. These participants have over the last decade or more become the holders of a large portion of the natural gas supply and transportation contracts that were previously held by natural gas utilities. Unlike natural gas utilities, they are not subject to public service obligations, and they approach these contracts from an entirely different perspective, viewing them as profit centers rather than essential requirements for meeting public service obligations. There is no indication that the historic pattern of most contracts being held by natural gas utilities will return.

The change in contracts also coincides with the growth in demand for natural gas for electricity generation. Over the last fifteen years, almost all of the

59. This fact led to a vigorous discussion concerning the prospect of “decontracting.” Pipelines were concerned that large numbers of expiring transportation contracts in the 1990s would not, as a result of the changes in regulation and markets, be renewed by their incumbent customers and that the costs associated with those contracts would be reallocated to the remaining customers. Although this prospect was discussed at length in the literature and before the FERC, it ultimately was a nonevent. It overlooked the fact that in a growing gas market, and one characterized by gas supplies that are remote from markets, a need would remain for transportation capacity to move gas from supply areas to market areas. Indeed, pipelines’ customer profiles changed during this period, but the predicted evaporation of demand for transportation services never materialized.

60. *American Gas Ass’n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005).

61. For example, the recent Cheyenne Plains pipeline project attracted a number of ten-year contracts with two longer contracts. Similarly, the North Baja Pipeline attracted contract terms as long as twenty-five years. *See generally* INGAA FOUNDATION, DISCUSSION OF EFFECTS OF LONG-TERM GAS COMMODITY AND TRANSPORTATION CONTRACTS ON THE DEVELOPMENT OF NORTH AMERICAN NATURAL GAS INFRASTRUCTURE at 65-68 (2005), available at <http://www.ingaa.org>.

electricity generating stations constructed in the United States have utilized natural gas as a fuel source. Electric generators infrequently enter into long-term contracts, with many opting instead for interruptible service or transportation service utilizing released pipeline capacity. This has especially been true in the Northeast. Particularly for gas-fired generation stations that are peaking units (which operate a limited number of hours per year), long-term contracts with high monthly reservation charges are uneconomic given the market and pricing structures of the electricity markets into which they sell. When the generating unit will be dispatched only a fraction of the days of the year, a year-round demand charge simply cannot be justified.⁶²

It is quite clear that the market changes resulting from the various FERC initiatives that have led to a restructuring of the natural gas industry have in fact been a major cause of the decrease in the terms of natural gas contracts and natural gas transportation contracts. As noted above, these initiatives have resulted in a dramatic expansion of the number of entities selling natural gas throughout the United States. They have resulted in a veritable explosion of natural gas “products” being offered by these new merchants (some of whom are partially or exclusively in financial businesses). In short, natural gas purchasers (such as utilities) can meet their needs by selecting from a variety of products and a variety of purchasers. Similarly, the services offered by pipelines have increased manifold since 1990. As a result, customers can select from narrowly tailored pipeline services to meet their needs at the lowest possible cost. Furthermore, with the success of the open-access regime championed by the FERC, many customers can now select from multiple pipeline suppliers. They can place multiple pipeline services end-to-end in order to attain access to remote natural gas producing basins.

In short, the era of open access has broken the longstanding nexus between specific customers, specific pipelines, and specific producers. The rigid patterns of vertical integration and long-term contracts binding contracting parties together, all as a means to minimize risk, that characterized the industry for many years have been severely disrupted. From the customer perspective, there is now confidence that natural gas supply and transportation requirements can be met by a much wider array of suppliers. From the producer perspective, the integrated, open-access national grid provides regulatory and commercial assurance that natural gas can be sold into any geographic area in North America. From the pipeline perspective, the array of customers, both upstream and downstream, to utilize the infrastructure is vastly larger. All of this militates for a diminution in the risk of “hold up” at all levels of the industry among parties that were bound together by geographical, regulatory, or other constraints. From the economist’s perspective, FERC’s actions of the 1980s and 1990s have largely altered the “asset specificity” of interstate pipelines.⁶³

62. From the electric market perspective, this is a challenging problem that is only now beginning to be addressed, and it is unclear how this electric reliability conundrum will ultimately be resolved.

63. See generally Makhholm, *supra* note 7.

III. THE CONCERNS RAISED ABOUT THE CHANGES IN THE PATTERNS OF LONG-TERM CONTRACTS

Over the last two years considerable discourse has occurred about the arguably deleterious effects of the demise of the historic pattern of long-term contracts. In 2005 the INGAA Foundation, which is associated with the interstate natural gas pipeline trade association, issued a lengthy study on the relationship between natural-gas supply contracts and transportation contracts and the development of infrastructure.⁶⁴ The report notes that, if gas supply is available, U.S. natural gas markets could be expected to grow from 22-23 trillion cubic feet of consumption to 30 trillion cubic feet on an annual basis by 2020.⁶⁵ Growth of this magnitude would necessitate the investment of approximately \$60 billion in natural gas infrastructure at all levels of the industry over the next fifteen years.⁶⁶

The INGAA report highlights the fact that the current lack of long-term contracts makes the financing of new infrastructure more challenging. It notes that the lack of long-term transportation contracts can prompt lenders to insist on debt maturities that are suboptimal from the point of view of the project sponsor and that are dramatically shorter than the useful life of the facilities. It also demonstrates in considerable detail that lenders for projects that lack long-term contracts are likely to increase the returns required for debt for such projects, an additional cost that is ultimately borne by pipeline transportation customers. Among other things, the report encourages state and federal regulators to review their policies to examine which of them may discourage local natural gas utilities and electric generators from entering into long-term contracts.⁶⁷

In May 2005, the Interstate Oil and Gas Compact Commission (IOGCC)⁶⁸ and the National Association of Regulatory Utility Commissioners (NARUC)⁶⁹ formed a joint task force to offer policy recommendations “on the advisability of encouraging government support of long-term natural gas transportation and storage agreements as a way to increase investment in natural gas and LNG delivery infrastructure.”⁷⁰ The task force invited the natural gas industry to participate in a workshop and to file comments on these issues. In October 2005, the task force issued a report, which concluded that “[o]verall, long-term contracting reduces risks to pipelines, underpins financing for new investments and allocates risk among project operators and consumers.”⁷¹ The report also

64. INGAA FOUNDATION, DISCUSSION OF EFFECTS OF LONG-TERM GAS COMMODITY AND TRANSPORTATION CONTRACTS ON THE DEVELOPMENT OF NORTH AMERICAN NATURAL GAS INFRASTRUCTURE (2005), available at <http://www.ingaa.org>.

65. *Id.*

66. INGAA FOUNDATION, DISCUSSION OF EFFECTS OF LONG-TERM GAS COMMODITY AND TRANSPORTATION CONTRACTS ON THE DEVELOPMENT OF NORTH AMERICAN NATURAL GAS INFRASTRUCTURE (2005), available at <http://www.ingaa.org>.

67. *Id.*

68. IOGCC is an interstate compact of the thirty-two states that produce oil and gas.

69. NARUC is the trade association of state public utility commissioners.

70. NARUC/IOGCC JOINT TASK FORCE, POLICY RECOMMENDATIONS ON LONG-TERM CONTRACTING FOR NATURAL GAS TRANSPORTATION, STORAGE SERVICES AND LIQUEFIED NATURAL GAS DELIVERY at 1 (2005).

71. *Id.* at 12.

recognized the importance of long term gas-supply contracts in reducing the price volatility of natural gas that is ultimately passed on to consumers. (Natural gas prices, which have increased dramatically since 2000, have also become increasingly volatile in this time frame). Following issuance of the IOGCC-NARUC report, NARUC adopted a resolution suggesting that state commissions should review their policies and procedures to determine whether they in some fashion act to discourage utilities from entering into long-term contracts.⁷²

IV. THE FUNCTIONS OF NATURAL GAS CONTRACTS

In order to assess whether the shortening of contract terms is desirable or undesirable and to determine whether regulators can or should take any action in that regard, it is useful to consider the functions of natural gas contracts as well as the advantages and disadvantages of long-term contracts. Generally contracts provide certainty, and they allocate risk among the contracting parties. This is most evident in gas-supply contracts.

In its gas-supply function, a local natural gas utility must attempt to address two types of risk: volume risk and price risk. Volume risk is the risk that the utility will either not have enough natural gas to meet its customers' needs or, alternatively, have too much. Utilities must engage in an analysis to determine the amount of natural gas that will be needed for any given period that involves, among other things, the size of the bundled-sales base, the effect of economic conditions on that sales base, and the effect of weather on that sales base.⁷³ Each utility must make its own determination, based on the circumstances unique to it, of how much of the volume risk to cover with forward gas-purchase contracts and how much to cover in the spot market should the need arise. Given that reliability is the cornerstone of the natural gas industry, the tendency will be to cover much, if not all, of the anticipated needs with forward gas-purchase contracts, leaving perhaps only a relatively small portion to be met in the market on a current basis.⁷⁴ Given that demand and weather forecasts are by definition unrepresentative of actual events, a natural gas utility will certainly be compelled over the course of a year either to go into the market to acquire additional supply or to dispose of supply that turns out to be beyond actual needs. Notwithstanding the constrained natural gas markets of the last five years, most utilities are confident that natural gas will be available to meet consumer needs. The issue will instead be one of price.

In point of fact, the situation is usually considerably more complicated than posited above. Many utilities utilize a portfolio approach to meeting their gas-supply needs, which is one approach to meeting needs that will vary. It is also possible to address the divergence of forecasted needs and actual needs through contracts that permit a range of purchases between a minimum and a maximum volume. In such instances, the natural gas utility buyer has in essence laid off part of its volume risk on the seller. From an economic perspective, such a

72. NARUC, RESOLUTION ON LONG-TERM CONTRACTING (Nov. 16, 2005).

73. Each such endeavor is intensely company-specific, taking into account the weather in the local area, the composition of the customer base, available underground natural gas storage or peaking facilities, local economic conditions, and pipeline services available to the local area.

74. For purposes of covering volume risk, contracts may either be market-priced or fixed price.

contract must necessarily include an implicit risk premium for the seller. Such a result can also be achieved by using financial instruments, the use of which has grown dramatically in the natural gas industry in the last fifteen years (the importance of the availability of financial instruments to address risk will be touched upon below). Additionally, operational means to exist to meet varying needs, such as underground storage, contracted storage, propane-air injection, and citygate liquefied natural gas.

Price risk, however, is perhaps more significant for the purposes of this article. In a firm, fixed-price natural gas contract, the seller assumes the risk that market prices will exceed the contract price, while the buyer assumes the risk that the market price will be below the contract price. Stated another way, should prices go below the contract price, the seller reaps the benefit; should prices go above the contract price, the buyer reaps the benefit.

As will be discussed below, in the natural gas utility context, where gas supply costs are passed on directly to customers subject to regulatory oversight, this principle leads to a regulatory asymmetry in the gas-supply function. There is, unfortunately, often an inclination among regulators to view contracts, particularly in hindsight, as prudent if prices go up and imprudent if prices go down. This dynamic has tended to push utilities toward contracts that are priced on a market-based rather than fixed-price basis, because market-priced contracts are generally not susceptible to after-the-fact second-guessing should prices drop.⁷⁵ Market-priced contracts can, however be criticized should prices rise, on the theory that the utility should have locked in a fixed price before prices began to rise.

V. WHAT HAS CAUSED THE DIMINUTION OF LONG-TERM CONTRACTS?

This article has to this point chronicled the regulatory and market developments, spurred by the Congressional and the FERC actions over the past two decades, in natural gas markets. There is no question that there is a connection between these governmental actions and the recent trend toward shorter-term contracts. Chronicling the history does not, however, make the source of the connection clear. Nor are there empirical or analytical tools by which this connection can be analyzed or measured. Economic theory and various sources of industry commentary, however, point in several directions. The discussion that follows attempts to elaborate upon at least several apparent causes of the shortening of contract terms for both natural gas supply and pipeline transportation service.

A. *The Rise of Competitive Markets Has Produced Shorter Contract Terms*

It is a challenge to approach this issue analytically for several reasons. *First*, it appears to have attracted little attention among academics and analysts. At least at this point there appears to be a paucity of literature, notwithstanding

75. See generally *Kelliher Cites Need For Long-Term Supply Deals*, GAS DAILY, Jan. 4, 2006, at 1. Market-priced contracts can, however, be (and have been) criticized should the price rise, the argument being that the utility should have locked in a fixed price when prices were lower.

the interest of the last several years.⁷⁶ *Second*, with regard to gas supply contracts, there is no reliable data set to analyze. In the era when the Federal Power Commission regulated producer prices of natural gas, producer-pipeline contracts were a matter of public record. Today there is generally no requirement that these gas-supply contracts be made public. Although there are industry trade publications that publish current and future prices for natural gas, they do not report contract terms. (The situation is rather different with regard to natural gas transportation agreements, which are generally publicly available at the Federal Energy Regulatory Commission.) As two commentators note, this paucity of data causes difficulty in analyzing the issues presented:

[t]he interpretation of long-term contracts also depends to a certain degree on subjective assessments, and sometimes on pure interests: thus, adherents of market competition are generally less enthusiastic about the (re-)emergence of long-term contracts, as those may reduce the scope for short-term competition. On the other hand, industry and a large part of policymakers defend the (often collusive) nature of long-term contracts with its positive impact on investment decisions. Competition authorities therefore have a difficult time when assessing the total impact of long-term contracts on social welfare.⁷⁷

These same commentators have blended theory and analysis (largely in European markets where data appears to be more available) to conclude:

[o]ur hypothesis, derived from theoretical work and more recent empirical analysis, is that the move from a monopolistic industry to more competitive market structures implies that long-term contracts lose some of their importance, and that they are likely to play a considerable role (only) when large-scale asset-specific investment decisions are at stake.⁷⁸

From an economic perspective long-term contracts make sense in two particular types of scenarios. *First*, where transaction costs are high, and a long-term contract permits the avoidance of these costs over a lengthy period of time. *Second*, where costly assets are either principally or significantly dedicated to the contract.⁷⁹ The discussion above underscores that both of these factors have diminished as the U.S. natural gas market has made the transition to a more competitive regime.

On the first count, the transaction costs of acquiring natural gas have diminished dramatically over the last twenty years. With multiple sellers at multiple sales points, with gas readily available in hourly, daily, and futures markets, and with the rise of standard forms of contracts,⁸⁰ it is not hyperbole to state that a natural gas contract can now be formed by telephone call, by email,

76. A large part of the analytical and academic work on the issue appears to date from the 1980s and the early 1990s. As a result, this literature is of limited value today. Two recent works, however, are illuminating and helpful in addressing these issues. See generally Makhholm, *supra* note 2; See also Anne Neumann & Christian von Hirschhausen, *Long-Term Contracts and Asset Specificity Revisited—An Empirical Analysis of Producer-Importer Relations in the Natural Gas Industry* (Ctr. for Energy and Env'tl. Policy Research, Working Paper No. 06-010, 2006).

77. Neumann & von Hirschhausen, *supra* note 75 (working paper at 2).

78. *Id.*

79. Neumann & von Hirschhausen, *supra* note 75 (working paper at 8) (“According to standard theory, transaction costs are expected to increase with growing asset specificity and uncertainty, and to decrease with the frequency of transactions.”).

80. See generally Karen Goepfert, *For the Long Haul: The Suitability of the Base Contract for the Sale and Purchase of Natural Gas for Long-Term Transactions*, 27 ENERGY L.J. ___ (2006).

or even by instant message. Similarly, the transaction costs of acquiring interstate transportation capacity have declined. New capacity is today offered in a transparent open-season process. Renewal capacity is also put up for public bid. Secondary market transportation capacity—capacity release—is offered through pipeline electronic bulletin boards operated on the internet. In short the processes for acquiring natural gas and transportation capacity today are remarkably more efficient than twenty years ago.

On the second count, as a result of wellhead price decontrol and pipeline open access, natural gas fields and wells are no longer dedicated on a long-term basis to a particular purchaser. Indeed, the output of a well or a field may go to dozens or hundreds of purchasers, and the set of purchasers may change from day to day. The situation is somewhat different with regard to pipeline transportation facilities. With open access and a now largely integrated national grid, the set of potential pipeline customers for any given pipeline is enormously larger than under the prior regulatory regime. The evidence seems to suggest that a shortening of contract terms has occurred where the pipeline facilities are being utilized by a large number of customers (e.g., the mainline contracts, where the terms seem to gravitate toward the four-six year range). The terms have not, however, been shortened as much with respect to contracts for facilities that are more dedicated to a particular customer (e.g., a lateral into a specific market) or where capacity constraints continue to exist. In these markets, where ten-year and longer contracts terms appear to be seen, transportation contracts seem to mirror the historic pattern.

These results appear to mirror what the economic theories of asset specificity discussed previously would predict. The fact that the empirical and the anecdotal evidence comport with the economic theory suggests strongly that the movement toward competitive markets in natural gas and transportation capacity over the last twenty years is a major cause of the shortening of contract terms. For purposes of the present discussion, the importance of this fact is that regulatory actions, absent a wholesale reversal of the policies of the last twenty years, are quite unlikely to reverse the impact of these market forces on contracting practices.

B. The Regulatory Risk-Reward Asymmetry

Local natural gas utilities are collectively the largest purchasers of natural gas in the United States. With few exceptions, state public service commissions regulate utilities' merchant functions on a cost-of-service basis. Usually the costs of purchased gas are recovered from retail customers through a revolving mechanism such as a Purchase Gas Adjustment or a Gas Cost Recovery factor. Utilities are not generally permitted to earn a profit on the gas commodity portion of the rates charged to their customers. Rather, they earn their income almost entirely only from *distributing* natural gas. Therefore, unless a public service commission has authorized an incentive mechanism, which is somewhat infrequent today,⁸¹ a utility has no direct profit potential in connection with its gas-acquisition function.

81. Kenneth Costello & James F. Wilson, *A Hard Look at Incentive Mechanisms*, FORTNIGHTLY MAGAZINE – PUBLIC UTILITIES REPORT, Feb. 2006, at 42.

A utility does, however, face the prospect of losing money in its gas-acquisition function.⁸² State public service commissions periodically review gas costs, just as they do other utility costs.⁸³ A public service commission may, in its after-the-fact review of gas-purchasing practices, find that a utility has been imprudent.⁸⁴ In such instances, some portion of the costs involved will be disallowed. Given that gas-supply costs are the predominant cost incurred by utilities, any such disallowances are disproportionately large relative to utility net income. Moreover, they normally flow directly to the income statement bottom line.⁸⁵ Thus, although a utility cannot add income to its bottom line in the gas-acquisition function, it faces the prospect of diminishing the bottom line in doing so.

This risk-reward asymmetry has important consequences for contracting practices. *First*, it places pressure on natural gas utilities to enter into market-based, natural gas supply contracts rather than fixed-price natural gas supply contracts. Given that public service commission review of gas purchasing is done after the fact, fixed-price contracts bear a significant risk of being second-guessed. By definition, a public service commission cannot challenge a market-based contract for being above the market; in contrast it can challenge a fixed-price contract as being above the market.⁸⁶ *Second*, public service commission after-the-fact review of purchasing practices similarly exerts pressure on utilities to enter into shorter-term contracts. Shorter-term natural gas supply contracts allow greater flexibility to respond to future market changes. They therefore carry a lesser risk of being second-guessed.

C. *The Retail Choice Conundrum*

Historically, natural gas utilities have held franchises to serve geographic areas. Franchises typically convey the right, explicit or implicit, to be the exclusive gas supplier within a service territory. Following the lead of the FERC's unbundling orders, some states have, as noted previously, made the policy determination that some or all customers should be free to purchase their

82. *Report of the Natural Gas Regulation Committee*, 25 ENERGY L.J. 217, 256-57 (2004).

83. A significant portion of the case law with regard to prudence has addressed assets deemed to be prudent or imprudent, particularly cases arising in the 1970's and 1980's with regard to nuclear generation stations. Richard J. Pierce, *The Regulatory Treatment of Mistakes in Retrospect*, 132 U. PA. L. REV. 497 (1984). See also William J. Baumol & J. Gregory Sidak, *The Pig in The Python: Is Lumpy Capacity Investment Used and Useful?*, 23 ENERGY L.J. 383 (2002).

84. Prudence reviews are governed by either state statutory or common law. See generally *Commonwealth Edison Co.*, Docket No. 84-0395 (Ill. Comm. Comm'n, Oct 7, 1987) (the Illinois Commerce Commission stated, "Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible. Imprudence cannot be sustained by substituting one's judgment for that of another. The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being 'imprudent.'").

85. A large utility in today's environment could have gas costs on the order of \$1 billion annually. The net income of such a utility might be in the range of \$50-100 million annually. Thus, a five percent disallowance for gas costs holds the prospect of wiping out the net income for the year.

86. In recent years, some public service commissions have criticized natural gas utilities for entering into market-based contracts because they do not mitigate the extreme price volatility found in natural gas markets today.

natural gas from suppliers other than the local natural gas utility.⁸⁷ These “retail customer choice” plans vary markedly in their details, as each state and each regulated utility must address a myriad of regulatory and operational questions that must be resolved before such a program can be implemented.⁸⁸ One critical dimension in these programs is how often the customer may *change* its choice of natural gas supplier, including reverting to the local natural gas utility if it has previously chosen to purchase its supplies elsewhere. Where a state has adopted a retail choice plan or where it may do so in the future, a natural gas utility therefore suffers uncertainty as to the future size and composition of its retail customer base.

The analysis in these circumstances faced by the natural gas utility can be daunting. It must decide how many of its customers will be purchasing gas from it in a given period. It must determine how many customers of other suppliers it will be required to serve if it has been designated as the provider of last resort and should a supplier fail to deliver. Even more daunting is the analysis required in determining the needs for pipeline capacity, which is typically contracted for over much longer periods of time than gas supply. Thus, the utility must determine what capacity to reserve to meet the needs of its customer base five or more years in the future.⁸⁹

Retail choice (as well as simply the prospect of retail choice)⁹⁰ has plainly added pressure to the movement toward shorter-term contracts. A natural gas utility signing a long-term gas purchase contract may find itself in the position of holding entitlements that were previously acquired to serve customers that now purchase their gas elsewhere. In such a circumstance a long-term gas-purchase contract could conceivably become a “stranded cost.” Public service commissions typically analyze stranded costs under a prudence standard such as that utilized in reviewing gas-purchasing practices. As with prudence reviews of gas costs generally, the disparity between the gross amount of costs involved and the net income of the utility promotes extreme caution when approaching such decisions. Thus, the prospect of unneeded gas supply becoming a stranded cost attributable to a retail choice plan can be intimidating.⁹¹

87. In most areas, industrial customers were permitted to purchase gas from alternative suppliers in the 1980s. The impetus for retail choice programs with regard to core residential customers began in the 1990s and is the more important aspect of this issue for present purposes. The industrial market of natural gas utilities has not generally posed a significant forecasting challenge for natural gas utilities.

88. Among the more significant issues presented in formulating a retail-choice plan are: whether the utility is to remain in the merchant function at all; whether the utility is to retain all of its interstate pipeline capacity; how often customers can change suppliers; whether the utility will bill for itself as well as for the marketer; and whether the utility will be the provider of last resort.

89. To some extent, this issue can be addressed by transferring interstate pipeline capacity held by the natural gas utility to the marketer serving the retail customer. The FERC requirements for doing so, however, are numerous, and the process is often not as seamless as both the utility and the marketer might prefer.

90. It is clear that the pace of states moving toward new retail choice plans has slowed following the energy market events of 2000-2001, including the rise in natural gas prices, the bankruptcy of the Enron Corporation, and the meltdown of the energy marketing sector.

91. Given the dynamic nature of natural gas markets today, it would almost be a certainty that a utility could cover by selling unneeded natural gas. The issue really boils down to situations in which it must sell excess gas supply at a loss.

These concerns apply equally with regard to long-term contracts for transportation service. It may well be, however, that the concerns are even more acute there. In the event that a utility should have an oversupply of gas at any particular point in time, it may be possible to recover a relatively large portion of the cost of gas that is unneeded by selling it into the open market. In contrast, there are far more limited opportunities to dispose of pipeline capacity that turns out to be unnecessary at the moment. Excess gas can be consumed in any market to which it can be transported. In contrast, pipeline capacity only has value in the markets that it connects. In any event, more often than not the choice in disposing of excess pipeline capacity is to release the capacity under the FERC's capacity-release regulations. These transactions are subject to the FERC's rules, which do not permit the free and unfettered transfer of the capacity.⁹² Quite importantly, in many instances, such transactions may yield cents on the dollar. Thus, disposing of excess pipeline capacity may be far more challenging and expensive than disposing of excess natural gas.

Plainly, concerns about adverse consequences resulting from prudence reviews are central to natural gas utilities' activities. A recent survey of utility executives revealed that the greatest perceived cause of "regulatory uncertainty" was "the potential for cost disallowances in after-the-fact prudence reviews . . ."⁹³ Similarly, another commentator has noted that "when left undefined, 'prudent' can mean anything, and that 'anything' tends to lean toward 'good in retrospect'."⁹⁴

D. The Perceived Lack Of Advantage In Long-Term Contracts

A more powerful force than the risk of prudence reviews and the uncertainties of retail choice may be in play with regard to the movement toward shorter terms of contract, at least as regards natural gas supply contracts. Clearly the regulatory changes undertaken by the Congress, the FERC, and, to a somewhat lesser extent, state public service commissions have led to a wholesale revamping of natural gas markets. Natural gas markets today bear no resemblance to those that existed in 1980. Competitive forces largely govern markets today, while in 1980 regulators governed markets in many regards.

It may well be that, in these competitive commodity markets, market forces simply favor shorter-term contracts by in essence having a very flat "yield curve." In other words, there may be inadequate return for a buyer in committing for the long term. There may be any number of reasons why this is the case. The perception that gas will always be available for a price (in contrast to the actual shortages of the curtailment years) may tilt the decision maker away from long-term contracts (especially with those that still remember the consequences of the ubiquitous long-term take-or-pay contracts of the 1970s and 1980s). The increasing complexity, volatility, and risk in those markets, which is orders of magnitude beyond the markets of the 1980s, may have reduced

92. 18 C.F.R. § 284.8 (2006).

93. Russell A. Feingold, *Utilities and Regulators: A Search For Harmony*, FORTNIGHTLY MAGAZINE – PUBLIC UTILITIES REPORT, Nov. 2005, at 52.

94. Robert S. Linden, *Gas Price Prudence: From Hedge-And-Hope to Best Practice*, FORTNIGHTLY MAGAZINE – PUBLIC UTILITIES REPORT, Oct. 2001, at 37.

players' risk tolerance and may have reduced their planning horizons, all leading to shorter-term contracts.

An important factor from the utility point of view is the growth of the financial gas markets and financial products over the last decade or more. Natural gas utilities may perceive that financial hedges are a more attractive means to address future needs than physical contracting for longer terms. Hedges involve out-of-pocket cost,⁹⁵ while long-term contracts have the potential to become balance-sheet liabilities. While such financial instruments may bear significant costs, they appear modest when compared to the impact upon a corporate balance sheet of a long-term contract. To many utilities financial hedges may naturally appear to be more appropriate than long-term contracts.

As discussed above, natural gas supplies today will almost always be available, although, as has been very evident over the last three years, the market price may be high by historical standards. If natural gas utilities accept this as a working principle, it becomes difficult to justify, from a business perspective, entering into a long-term contract, which brings with it both market and regulatory risk when a relatively inexpensive hedge can cover the most extreme of future market risks.

Moreover, natural gas supply markets may not at present be providing any price incentive to justify foreclosing other options by entering into long-term gas-purchase contracts. Committing to a long-term contract today precludes the utility from taking other actions in the future when new, more accurate information becomes available. In an environment where future gas prices are highly uncertain (as they are today), long-term contracts can expose the utility to considerable risk, namely having to buy natural gas at above-market prices. Entering into long-term contracts, especially with rigid pricing terms, can be suboptimal decision-making in a highly uncertain market. In order to take the risk associated with committing to a long-term contract rather than a short-term contract, the buyer needs an incentive of some sort. Likewise, sellers need an incentive to justify foreclosing possible higher future prices if they are to enter into long-term contracts. Additionally, given recent history, sellers need some assurance that long-term purchasers will retain adequate credit quality over the term of the agreement.

The market does not appear to be offering sufficient incentives to push buyers to make these longer commitments. Typically, a longer-term gas purchase contract will be priced utilizing the forward prices for the commodity at the time it is executed. It does not appear that such contracts often include a discount from these futures prices to reflect the risk the buyer is undertaking by committing for a longer term.

Additionally, financial markets and investors penalize companies that carry large liabilities on their balance sheets or face potential liabilities associated with long-term contracts. At current (and expected) commodity prices, a long-term commodity contract can add millions of dollars of liabilities or potential

95. See generally Kenneth W. Costello & John Cita, NAT'L REGULATORY RESEARCH INST., USE OF HEDGING BY LOCAL GAS DISTRIBUTION COMPANIES: BASIC CONSIDERATIONS AND REGULATORY ISSUES (May 2001).

liabilities to the books of even a mid-sized gas utility without recognition of significant benefit.

The prevalence of shorter-term contracts is underscored by the activities of the North American Energy Standards Board (NAESB). The NAESB has prepared a standard form of gas-purchase contract. That contract contemplates a term of one year.⁹⁶

VI. THE BENEFITS AND BURDENS OF LONG-TERM NATURAL GAS CONTRACTS

A. Natural Gas Supply Contracts

As discussed previously, long-term gas-purchase contracts mitigate a natural gas utility's volume risk, thus ensuring that supply is available to meet consumer needs.⁹⁷ In current market circumstances where gas is readily available, however, what benefit, in terms of volume risk, do long-term natural gas purchase contracts actually bring to consumers? Undoubtedly, many in the industry still remember the shortages of the 1960s and 1970s that resulted from federal cost-of-service price regulation of natural gas. Were such shortages to recur, those holding long-term contracts would clearly enjoy substantial benefit.

The curtailment-era shortages ended quickly with the passage of the NGPA, and ample supplies of natural gas have marked the succeeding decades. From the winter of 2000-2001 forward, however, supply and demand at the wellhead have been in narrow alignment, and the "gas bubble" that marked most of the prior decade had dissipated. Nevertheless, in the years since that watershed winter, we have not seen widespread, or even occasional, reports of natural gas shortages. The occasional reports of short supply have usually been extremely local in nature. Additionally, they often appear to result from either inadequate delivery infrastructure (e.g. New York and New England) or events of *force majeure* (e.g., Hurricanes Katrina and Rita).⁹⁸

Are there, then, benefits in terms of volume risk in entering into long-term natural gas purchase contracts? They certainly do act as a hedge should supply become uncertain. The evidence suggests, however, that industry stakeholders do not believe there is a compelling need to enter into longer-term purchase contracts to ensure that supplies are available for consumers. Longer-term contracts necessarily bring with them the risk of being in a long position, and that risk does not appear to be overcome at present by the risk of being in a short position. To be sure, many utilities maintain a portfolio of contracts with different terms. Some of those contracts extend beyond the "one year" watershed between "short term" and "long term." Nevertheless, contracts lasting a decade or even longer, are plainly out of vogue today. The market and its many players, therefore, seem to be offering ample testimony to a belief that natural gas supplies will continue to be available to meet market needs well into the future. In short, it is difficult to quantify the value of long-term contracts in

96. The contract form is available at <http://www.naesb.org>.

97. The purchaser's risk is limited then to the risk of nonperformance or perhaps the risk of events of *force majeure*.

98. As a general matter, events of *force majeure* excuse performance under contracts. Thus, in such circumstances a contract does not mitigate volume risk.

terms of mitigating volume risk. Doing so is essentially an exercise in quantifying the value of reliability.

Long-term contracts may well offer greater benefits to natural gas utilities with regard to price risk. For purposes of this discussion we are of necessity discussing fixed-price contracts,⁹⁹ as market-priced contracts provide no similar amelioration of price risk, even though they may ameliorate volume risk. A long-term fixed-price natural gas contract clearly acts as a hedge as market prices rise above the contract price. Thus, in a market where prices are rising above the contract price, such a contract is plainly a benefit to the purchaser and the consumers served. Conversely, in a market where prices drop below the contract price, such a contract is a detriment to the purchaser.

Many utilities follow a portfolio approach to gas-purchase contracts, with some fixed-price, some market-priced, and all of varying terms, depending upon the philosophy and particular circumstances of each utility. In the context of such an approach, fixed-price contracts have the additional benefit of moderating the price volatility that has characterized wholesale natural gas markets since the winter of 2000-2001. To the extent that a utility holds fixed-price contracts, its customers are insulated from the upward and downward gyrations of wholesale markets. While economists may not see this as a particular benefit,¹⁰⁰ retail natural gas consumers clearly see it as a benefit in that it tends to make their monthly bills more predictable than would be the case were they linked entirely to contemporaneous wholesale markets. It would be difficult to quantify that value, but it is clear that consumers perceive natural gas utilities' gas-purchasing function and its price-buffering effect as value-added activities. To a significant degree, however, that levelizing function that consumers desire is performed simply by a utility's having a diverse portfolio of gas-supply contracts and also by virtue of the fact that gas-cost pass-through mechanisms are priced annually, semiannually, or monthly, rather than anything approaching a real-time basis. Thus, from the consumer perspective, price remains constant for the period of time established by the regulator for the cost-recovery mechanism.

It may well be today that utilities that see benefits of mitigating price risk in the future are more inclined to achieve that objective with financial instruments than with long-term contracts. Financial instruments plainly have an out-of-pocket cost. They do not, however, have the same potential to appear on the balance sheet as a liability or to lead to major cost disallowance by regulators as do long-term contracts.

There is also a school of thought at present that says that a higher prevalence of fixed-price natural gas contracts would have an entirely broader effect on the market. This line of thinking postulates that, if markets contained a significantly larger proportion of fixed-price contracts, volatility of the entire market would be dampened.¹⁰¹ This theory is well beyond the scope of this

99. Fixed-price contracts can take any number of forms, the only essential element being that they are not tied to the market.

100. An economist would assert that the lowest price over time would be generated by a market-based contract, as any fixed-price contract necessarily bears a premium.

101. This was particularly discussed after the California electricity crisis that began in 2000. The market design for California did not permit utilities to hold long-term contracts for power. Rather, the entire market operated on a spot basis.

article, but no consideration of the issues surrounding long-term contracts would be complete without at least identifying it.

Long-term, fixed-price natural gas contracts are technically a liability when market prices drop below the contract level. This theoretical principle was burned into the psyches of many industry participants by the enormous liabilities that were absorbed by interstate pipelines and local distribution utilities in the 1980's, when the market price for natural gas fell dramatically below the weighted average cost of gas supply for interstate pipelines. These contracts essentially were "stranded assets." The exact numbers will never be known precisely, but it appears that several hundred billions of dollars of contractual exposure of pipelines were extinguished by expending approximately twenty or thirty billion dollars. This is indeed a dramatic and important example of what can occur when market prices drop dramatically below long-term contract prices. Wholly apart from the dollars involved, the "take-or-pay crisis" spawned literally hundreds of proceedings at the FERC and in the courts, spanning a period of nearly a decade. There is no doubt that this experience has made many industry participants examine closely whether it is truly advantageous to enter into long-term fixed price natural gas contracts.

B. Natural Gas Transportation Contracts

Entering into a long-term gas transportation agreement moderates a natural gas utility's volume risk for transportation. As a result of their public service obligations, utilities simply cannot operate without having ample natural gas transportation service to their city gates. By definition, the longer the term of the gas transportation agreement, the less the risk that the utility will not have this essential service.

Any given utility's analysis of its needs with regard to transportation contracts is exceedingly complex. In many markets, there are potentially multiple paths between the producing areas and the customer. Some may be more economical than others. Some may be more physically constrained than others. Some may be fully subscribed and not immediately available to be placed under contract. These and many other factors must be considered in determining which pipeline to contract with, for what quantity, for what type of service, and for what period of time.

While the primary benefit of a long-term transportation contract is increased reliability of service, the burden is that the pipeline customer will have excess pipeline capacity should market needs decline, whether from declining markets, changing weather, or the effects of retail choice programs. As noted previously, in present markets it is much easier to dispose of natural gas than natural gas transportation capacity.

The question of price risk with regard to transportation contracts is more complex. The FERC regulates the rates of interstate natural gas pipelines on a cost-of-service basis. Thus, price risk does not exist in the same sense that it does with regard to natural gas as a commodity. Natural gas pipelines can be permitted to charge market-based rates if they can demonstrate that they operate in competitive markets, but no pipeline has yet done so with regard to its core mainline services. Many pipelines are permitted to charge "negotiated" rates, with stated cost-of-service rates as a backstop. Moreover, all pipelines are

permitted to discount their stated cost-of-service rates. In the context of negotiated rates or discounted rates, pipelines are permitted to charge essentially market-based rates with certain perimeters.¹⁰²

There has apparently been little, if any, analysis of the question whether long-term contracts for transportation service lead to less price risk for pipeline customers. In simple terms, a long-term contract will not generally reduce price risk with regard to that particular pipeline, because transportation price levels are established by the FERC under the Natural Gas Act. Some longer-term negotiated or discount contracts may reduce the customer's price risk because the price agreed to in the transportation agreement may survive a pipeline's rate filing, thus bringing lower rates to the customer than would be the case for a more recent customer.

In the Order No. 637 series,¹⁰³ the FERC, seeking yet again to improve the efficiency of the natural gas transportation market, announced that it would look with favor upon term-differentiated rates. Essentially, a customer signing a longer-term contract for service could be granted a more advantageous rate. In the Order No. 637 rule-making, one of the issues discussed extensively was the trend toward more short-term contracting for pipeline services. The Commission's favorable view of term-differentiated rates provided a means for pipelines to encourage longer-term transportation contracts. It is, therefore, somewhat surprising, given the pipelines' general calling for longer terms of contract that no pipeline has yet done so. Order No. 637 required any pipeline that desired to charge term-differentiated rates to submit a full general rate case. It is generally believed that, although pipelines believe it would be desirable to have term-differentiated rates in order to encourage longer contract terms, the costs and risk of filing a general rate proceeding in order to do so are simply too great.

Wholly apart from issues of price and volume risk, long-term transportation contracts have two important consequences for pipeline customers and the consumers they serve. *First*, more long-term contracts improve the credit quality of a pipeline and reduce costs of financing, to the benefit of all of its customers. Credit analysts look at the contractual profile of a pipeline in making their determinations of the pipeline's creditworthiness. Assuming all of a pipeline's customers are equally creditworthy, the longer the term of the pipeline contracts as a whole, the more secure the revenue stream and the higher the credit rating that the pipeline will receive. Better credit ratings measurably lower the costs of financing.¹⁰⁴ Lower costs of financing, all other things being equal, lead to lower rates to customers. The argument that the trend away from long-term

102. In the instance of traditional rates, the perimeters are the minimum and maximum rates authorized on a cost-of-service basis by the FERC. In the instance of negotiated rates, the FERC has developed policies with regard to certain types of rates that are not permitted.

103. Order No. 637, *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, 65 Fed. Reg. 10156 (Feb. 25, 2000), III FERC Stats. & Regs. ¶ 31,091 (Feb. 9, 2000); *order on reh'g*, Order No. 637-A, Order on Rehearing, III FERC Stats. & Regs. ¶ 31,099 (May 19, 2000); *final rule*, Order No. 637-B, *Order denying rehearing*, 92 FERC ¶ 61,062 (July 26, 2000), *aff'd in part, remanded in part*, *Interstate Natural Gas Assn. of Am. v. FERC*, 285 F.3d 18 (D.D.C. Cir. 2002).

104. The INGAA Foundation study discusses this point at considerable length.

natural gas transportation contracts is reducing pipelines' credit quality, thus increasing customer rates, has logical merit. The question is, however, is it so significant as to call for a regulatory sea change?

The natural gas industry itself may also offer some evidence that runs counter to this contention. Natural gas distribution utilities generally do not have contracts with their customers.¹⁰⁵ Moreover, in most instances their retail rates are designed largely on a volumetric basis,¹⁰⁶ unlike interstate natural gas pipelines, which enjoy the benefits of fixed-variable rate design, which removes significant market uncertainty from a pipeline's revenue stream. From the credit-rating point of view, natural gas utilities seemingly enjoy less revenue certainty than interstate pipelines. On the other hand, however, natural gas utilities generally enjoy local franchises and customers that do not have multiple service providers, as is true with some pipeline customers.¹⁰⁷ Natural gas utilities likely have, under prevailing rate designs, less volume certainty than interstate pipelines, while they may well have greater customer certainty (at least with regard to residential and commercial customers). In general, state regulators permit lower rates of return for natural gas utilities than do federal regulators with respect to interstate pipelines. There, thus, seems to be an anomaly present. The experience of natural gas utilities may undercut somewhat the argument that interstate natural gas pipelines require longer-term contracts in order to assure the most economic financing rates for infrastructure.

Second, by all accounts, the natural gas market has been growing over the last decade, led significantly by the growth in gas-fired electric generation. Even with the increase in natural gas prices over the last five years, natural gas consumption is likely to increase in the future. This growth will require the addition of additional infrastructure at the production, transmission, and distribution level. It is likely that this infrastructure will be measured in the tens if not hundreds of billions of dollars. A number of commentators suggest that, if this infrastructure is to be constructed, it will need to be anchored by long-term natural gas transportation contracts (and perhaps natural-gas supply contracts as well). Indeed, in the ongoing conversation concerning long-term contracts, this point appears to be the one that attracts the most attention and concern.

There are, of course, countervailing arguments. There certainly are other capital-intensive industries that attract sufficient capital without having long-term contracts as a foundation. These industries appear to construct and operate adequate infrastructure at reasonable prices without a requirement for long-term contracts. An important FERC responsibility is to ensure that the nation enjoys adequate energy infrastructure. Yet there has been no call from the FERC in

105. Some, but not all, natural gas utilities have transportation agreements with industrial customers. It would be unusual for such agreements to be of the twenty-year variety that historically characterized interstate gas transmission agreements.

106. Most natural gas utility rates are volumetric with the exception of a "customer charge," which usually collects something on the order of between \$5 and \$10 per month on a fixed basis. In the last several years there has been the beginnings of a movement away from this historical practice. Some regulators are concluding that volumetric rate designs discourage natural gas utilities from promoting conservation. They have, therefore, adopted "conservation tariffs" or "energy efficiency tariffs", the goal of which is to make the utility indifferent to throughput declines caused by conservation or energy efficiency.

107. The concepts discussed in the text are, of course, generalizations. Determining whether natural gas utilities or interstate pipelines face greater revenue certainty requires analysis of specific cases.

recent years to promote longer-term contracts in order to assure that adequate infrastructure is in place.¹⁰⁸ Indeed, the history of the FERC policies in certificating interstate natural gas pipelines underscores this view. The long-time practice of the FERC, and its predecessor the Federal Power Commission, in the certificate of public convenience and necessity process for new pipelines was to ensure that they were anchored at the upstream end by long-term producer contracts and at the downstream end by long-term sales agreements. The FERC began to reconsider this policy in the 1980s and into the 1990s.

Its present views are contained in its 1999 certificate policy statement. That document does not require that pipeline projects seeking a certificate under section 7 of the Natural Gas Act be fully subscribed with customer contracts, much less with long-term contracts.¹⁰⁹ The policy statement is interesting in regard to the issue of long-term contracts. The FERC there reviewed its then-current policy:

[u]nder the Commission's current certificate policy, an applicant for a certificate of public convenience and necessity to construct a new pipeline project must show market support through contractual commitments for at least 25 percent of the capacity for the application to be processed by the Commission. An applicant showing 10-year firm commitments for all of its capacity, and/or that revenues will exceed costs is eligible to receive a traditional certificate of public convenience and necessity.¹¹⁰

An applicant unable to show the required level of commitment may still receive a certificate but it will be subject to a condition putting the applicant "at risk." In other words, if the project revenues fail to recover the costs, the pipeline rather than its customers will be responsible for the unrecovered costs.¹¹¹

Thus, by the 1990s, the FERC policy, with regard to permitting new pipeline infrastructure, was that long-term contracts were not necessary. If a pipeline were not fully subscribed, the pipeline would simply be at risk for the revenues for unsubscribed capacity.

In considering how it should modify its then-current policy in the future, the FERC recognized that its practice had been to "[use] the percentage of capacity under long-term contracts as the only measure of . . . demand for a proposed project."¹¹² The Commission concluded that doing so was not sound "because the industry has been moving to a practice of relying on short-term contracts . . ."¹¹³ Indeed, the Commission was concerned that its "current policy's preference for contracts with 10-year terms biases customer choices toward longer term contracts."¹¹⁴ In its policy statement the Commission announced that it would no longer require presentation by the applicant of customer contracts as part of the certification process.

108. The author has confirmed this in informal conversations with the FERC staff responsible for energy infrastructure.

109. *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227 (1999), *clarification* 90 F.E.R.C. ¶ 61,128 (1990), *further clarification*, 92 FERC ¶ 61,094 (2000).

110. 88 F.E.R.C. ¶ 61,227, at 61,737.

111. *Id.*

112. 88 F.E.R.C. ¶ 61,227, at 61,744.

113. *Id.* at 61,744.

114. 88 F.E.R.C. ¶ 61,227, at 61,744.

Although the Commission traditionally has required an applicant to present contracts to demonstrate need, that policy, as discussed above, no longer reflects the reality of the natural gas industry's structure, nor does it appear to minimize the adverse impacts on any of the relevant interests. Therefore, although contracts or precedent agreements always will be important evidence of demand for a project, the Commission will no longer require an applicant to present contracts for any specific percentage of the new capacity. Of course, if an applicant has entered into contracts or precedent agreements for the capacity, it will be expected to file the agreements in support of the project, and they would constitute significant evidence of demand for the project.¹¹⁵

The 1999 FERC policy statement makes clear that the FERC, the federal agency with responsibility for ensuring the adequacy of the interstate pipeline grid, was aware of the industry's movement toward shorter-term contracts, that it did not perceive this to be a problem, and that it concluded that it would no longer mandate that contracts of any particular duration or for any particular amount of capacity be filed as a prerequisite to a certificate. The FERC's policy statement suggests strongly that the agency does not perceive the movement toward shorter term contracts to be an impediment to infrastructure development in the United States.¹¹⁶ Commentators appear to share this view.¹¹⁷

VII. SPECIAL SITUATIONS: ALASKA NATURAL GAS AND LIQUEFIED NATURAL GAS

A significant portion of the discussion over the last several years has centered on Alaska natural gas and liquefied natural gas (LNG). Since the winter of 2000-2001, it has become apparent that natural gas supply and demand are very narrowly in balance. One consequence is that slight increases in demand or reductions in supply produce disproportionately large increases in prices. Initially, most commentators believed that increases in production, in response to the generally increased price levels, would bring forth significant additional supply. Over time, analysts came to recognize that production would not significantly increase as drilling increased. Now, five years later, the consensus is that, under today's conditions, significant increases in domestic natural gas production will be difficult absent major changes in federal policies. The policy discussion has now shifted to what can be done to bring forth more natural gas and to bring down prices. Two of the several options available are construction of an Alaska natural gas pipeline and increased imports of LNG.

At present, prodigious amounts of natural gas are produced daily with the oil production on the North Slope of Alaska. The gas is essentially stranded, as there is no means to transport the gas to market, and it is, therefore, reinjected. An Alaska natural gas pipeline, which might increase daily U.S. natural gas supplies by between five and ten percent, was authorized in the 1970s but never

115. *Id.* at 61,748.

116. While the Commission has not taken any formal action to promote long-term contracts in order to ensure that sufficient infrastructure is constructed, the current Chairman has expressed the view that longer-term contracts will boost infrastructure. *See also Kelliher Cites Need For Long-Term Supply Deals*, GAS DAILY, Jan. 4, 2006, at 1.

117. Costello, *supra* note 1, at 45, 50.

constructed.¹¹⁸ In 2004, Congress passed a further series of provisions aimed at spurring and expediting construction of an Alaska pipeline.¹¹⁹ Similarly, decreases over the last twenty years in the costs of delivering LNG and the maturation of that worldwide business have made it possible for LNG to become a significant component of the U.S. gas supply portfolio. In 2005, as part of the Energy Policy Act of 2005, Congress enacted a number of provisions to expedite and streamline the siting of marine import LNG terminals.¹²⁰

Both Alaska natural gas and increased supplies of LNG are viewed by most as important parts of the plan to meet the nation's future natural gas needs. Concern has been raised, however, that long-term contracts will be essential to support these enormous infrastructure projects. Traditionally, local natural gas utilities have been the single largest group to contract for natural gas supply and pipeline transportation service. Yet for all of the reasons discussed at length previously, it is at best uncertain that natural gas utilities will enter into long-term natural gas purchase contracts or natural gas transportation agreements associated with either Alaska natural gas or new LNG marine import terminals. In addition to the more wide-reaching factors that appear at present to be militating against long-term contracts, each of these unconventional types of supply bears with it additional complicating factors.

If an Alaska natural gas pipeline is constructed, with costs expected to exceed \$20 billion, it will likely extend across Alaska and into Canada, connecting to both new and existing natural gas infrastructures in Alberta. Natural gas utilities are likely to be hesitant to contract to purchase natural gas at the North Slope wellhead, at the U.S.-Canadian border, or perhaps even at the Alberta Hub, given the market structures in those areas of North America, particularly the market dominance of the producers in that corner of the continent. In the face of a market that seems to be tilting away from long-term natural gas purchase contracts, long-term contracts to purchase Alaska natural gas face additional business and regulatory obstacles that will pose considerable challenges. Similarly, contracts for transportation on any Alaska natural gas transportation system will face business and regulatory obstacles that may be difficult to surmount.

There is no doubt that an Alaska natural gas pipeline will be *sui generis*. Unlike most other pipelines, it will not be fully integrated into the North American natural gas grid. In essence, it will largely be a single-use asset. Project sponsors will face considerable market risk. It appears that the project will require special means for mitigating this risk. One means of doing so is to revert to the original structure of the natural gas industry—vertical integration. In this case the likely scenario would be that the natural gas producers would own the pipeline as well as hold the transportation capacity on it. Alternatively,

118. Alaska Natural Gas Transportation Act, 15 U.S.C. §§ 719-719(o) (2000).

119. See also *id.*; Alaska Natural Gas Pipeline Act, Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, Pub. L. No. 108-324, 118 Stat. 1220 (2004); American Jobs Creation Act of 2004, Pub. L. No. 108-357, 118 Stat. 1418.

120. Energy Policy Act of 2005, Pub. L. No. 109-58, § 311, 119 Stat. 594. In this provision Congress confirmed exclusive FERC jurisdiction over the siting of marine LNG import terminals and codified existing FERC policy that import terminals need not be operated on an open-access basis.

mirroring the middle phase of the natural gas industry in the United States, the pipeline could be anchored by long-term contracts.

If long-term natural gas purchase and transportation agreements are perceived as necessary prerequisites to construction of a pipeline, then it would be unlikely to expect that natural gas utilities will be the contracting parties. If indeed long-term natural gas purchase and transportation contracts are essential to development of an Alaska natural gas pipeline, then it may be that this function will have to be served by intermediaries that are willing to enter into long-term gas-purchase contracts as well as long-term transportation contracts that will be necessary for the project to go forward. A logical candidate for such a role is large financial institutions. They have the balance sheets and the creditworthiness to take on such obligations. Moreover, they are experienced in risk management and, to some degree, in commodities as well.

The recent growth in interest in LNG is also important for purposes of this discussion. It has been suggested that there must be a resurgence of long-term contracts in order for new LNG terminals, bringing much-needed natural gas to the United States, to be constructed and operated. Without question the LNG chain will require enormous investment. A regasification terminal, tankers, and liquefaction facilities require more than \$1 billion in investment. Admittedly, this is a fraction of the cost of the Alaska pipeline but the number of LNG facilities for the United States collectively may rival in magnitude the capital cost of the Alaska pipeline. There does not, however, appear to be quite such a cry for long-term contracts in this context.¹²¹ Indeed, several dozen projects have been announced and/or have filed applications with the FERC over the last several years.

Even before the resurgence of interest in LNG, several global players in the LNG trade had entered into significant long-term contracts for terminalling and vaporization service at the LNG import terminals constructed in the United States in the 1970s. These long-term contracts apparently occurred because they made commercial sense. These contracts have typically been entered into by parties not regulated at the state or federal level in the United States, a fact that may be telling for this entire question.¹²²

The LNG situation may again be explained by the economic theorems of asset specificity. Most, if not all, of the projects proposed for the United States will be fully integrated parts of the national natural gas grid. Their output will be able to reach regional, if not national, markets. They will deliver in most cases directly into the open-access grid. As a result they will have a wide array of potential customers. Thus, neither vertical integration nor long-term contracts may be essential to meet the market risks that they face.

121. See also *Officials See Bumps in the Road to LNG Spot Market*, GAS DAILY, Jan. 31, 2006, at 3. (U.S. LNG buyers are willing to enter into one and two year contracts rather than the 15-20 year contracts that are standard in the rest of the world).

122. See, e.g., *Merrill Lynch, Semptra Sign LNG Capacity Deal*, GAS DAILY, Mar. 10, 2006, at 1. (fifteen year agreement for capacity at LNG terminal for 500,000 Mcf per day).

VIII. IS THERE A ROLE FOR REGULATORS?

It is clear that a large part of the movement toward shorter terms of contract is the result of market forces, while at least some part is also attributable to fears of regulatory second-guessing and the prospect of retail choice. The ultimate public-policy question presented with regard to long-term contracts is whether regulators, at either the state or the federal level, should take action to change the *status quo*. In the simplest terms, regulators have several choices: taking no action; ensuring that their actions in general do not interfere with the market; encouraging long-term contracts; or mandating long-term contracts. If regulators should make the policy determination that long-term contracts are beneficial for their jurisdictions, they can do little about the impact of the market forces that have produced shorter contract terms unless they determine that the regulatory initiatives that have moved markets over the past two decades have been unsound. There does not, however, appear to be any movement to undo the events of the last twenty years with regard to the natural gas industry.

Regulators can, however, examine their policies and practices to determine which of them may act as impediments to long-term contracts. Most critical in this regard is that regulators not adopt policies that encourage long-term contracts, only to second-guess them years down the road. Moreover, in adopting policies, regulators need to be keenly attuned to the financial consequences of their actions.

There does not appear to be any ready role for regulators at the FERC in terms of long-term contracts. They fundamentally have no jurisdiction over natural gas purchase contracts or most of the entities in the market that purchase natural gas. While they do have jurisdiction over natural gas pipelines, the regulatory trend of the last twenty-five years at the FERC,¹²³ which is not likely to change in the near future, is such that it is entirely unlikely that the FERC would embrace a policy of requiring pipelines to present long-term transportation contracts as a prerequisite to issuing a certificate of public convenience and necessity. This was the policy for many years, and it has now been soundly rejected in favor of letting market forces operate.

State regulators, however, may well have a role given their obligations to regulate natural gas utilities for the benefit of their citizens. Ultimately, state regulators must determine whether they see benefits for their jurisdictions in encouraging more long-term contracts, whether gas supply contracts or gas transportation contracts. State public service commissions must, therefore, determine whether they believe that long-term contracts provide benefits to the consumers they serve that outweigh the risks associated with them. Those decisions would necessarily be different from state to state and perhaps different for different natural gas utilities within a state. Should a state decide to move in that direction, it is critical that it be clear in deciding why it wants to encourage long-term contracts and be fully cognizant of the benefits and risk of doing so.

Assuming that a regulatory body has decided that it is desirable that there be more long-term contracts, what action should it take? It might mandate that utilities in its state enter into long-term gas purchase or transportation contracts

123. That trend is in part inspired by the various Congressional actions bringing market forces to bear on the natural gas industry.

in order to benefit consumers. Experience suggests, however, that this would be unwise. Various government mandates—state and federal—have been imposed on the natural gas industry over the last fifty years. Most have proved to be improvident, almost always for reasons that were not, or could not have been, anticipated at the time the mandate was imposed. This lesson has been learned time and again over the last several decades, and at an expense measured in the billions of dollars. Federal wellhead regulation of prices, the aftermath of the repeal of wellhead deregulation coupled with open access producing take-or-pay liabilities, and the mandatory purchase requirement applied to electric utilities with respect to cogeneration facilities quickly come to mind in this regard.

Another path would be for regulators to encourage utilities to enter into long-term contracts as a means to benefit consumers. The downside of such an approach, however, is that the visible hand of government might well interfere with the invisible hand of the market. Perhaps a greater challenge would be with regard to both the nature and the consequences of “encouragement.” It would likely produce ambiguity both in the execution of the policy and in the consequences flowing from it. Encouragement may lead to greater uncertainty than silence. Moreover, a policy of “encouragement” will almost certainly fail to convey what the consequences will be in an *ex post facto* review of the conduct that has been “encouraged.”

Perhaps a more measured path, should a regulatory agency decide that there is a benefit flowing from long-term contracts, is for the regulator to make a critical assessment of whether its policies, practices, and procedures act as impediments to long-term contracts that the market might otherwise look upon favorably.¹²⁴ As the earlier discussion suggests, market forces, spurred by initiatives in Congress and at the FERC, appear to be a major reason why contracts have trended away from longer terms and toward shorter terms. Regulators can examine their policies and practices to determine whether they unwittingly produce shorter terms of contracts than would market forces. As the earlier discussion also suggests, uncertainties surrounding state prudence reviews are clearly a force that has pressed utilities toward shorter-term contracts. Virtually all commentators have viewed this result as undesirable. Uncertainty regarding the standards for prudence review promotes essentially conservative conduct that may be economically inefficient and that may not best serve the interests of customers of local utilities. If a regulator believes that promoting more long-term contracts is in the interests of citizens, then it must take a critical look at its practices in terms of its review of contracts. The fear of regulated entities is essentially two-fold: (1) that the rules of the game will change over time and be applied both retroactively and unfairly; and, (2) that a regulator will, when circumstances change, determine that a contract that was deemed prudent when entered into is no longer prudent.

The first point, that rules may change over time and essentially be applied retroactively, is a concern of regulated entities that extends far beyond the issues

124. For example, the IOGCC-NARUC report suggests that portfolio analysis should be applied to assess the merits of long-term contracts. Under this paradigm, the gas utility would examine different alternatives on the basis of cost, risk management, and reliability. Portfolio analysis can assist in identifying the right mix of gas supply and transportation commercial arrangements for a particular utility. Long-term contracting may well emerge as a component of an optimal portfolio.

associated with long-term contracts. It presents a difficult tight rope. On the one hand, utilities require certainty concerning the regulatory regime. They make decisions concerning capital investment and operations expenses based in significant measure upon the tenets of the given regulatory regime. Changes in that regulatory regime often will mandate changes in utilities' decisions, at the expense of utility customers, utility shareholders, or both. Regulators often do not have sufficient appreciation of these consequences when they change the regulatory course. On the other hand, regulators believe they need to have the flexibility to adapt their policies to changes in the world and changes in the markets. There is often insufficient appreciation of the consequences of exercising such authority.

The second point, that regulatory decisions will be retroactively amended or reversed, is perhaps more specific to contracts of the type under discussion here. This issue was the subject of considerable comment in the 2005 IOGCC-NARUC joint task force on long-term contracts. In its final recommendations, the task force made a number of recommendations. It concluded that in some situations regulators should consider pre-approval of contracts. It also suggested establishing safe harbor rules or establishing guiding principles to mitigate hindsight reviews. Moreover, given the financial exposure involved, regulators should, if they determine long-term contracts to be beneficial, support them in advance. As an extension of those principles, the IOGCC-NARUC task force stated "[s]tate regulators should minimize second guessing and taking [sic] a short-term perspective when evaluating long-term contracts."¹²⁵ The task force report importantly emphasized that long-term contracts must be evaluated over the course of their term rather than over shorter periods when they may not actually be advantageous.

NARUC endorsed the task force report and adopted a resolution concluding that state regulators should: (1) consider long-term contracts "as a potentially appropriate ingredient in a" utility's portfolio; (2) encourage utilities "to develop long-term strategies for capacity and supply;" (3) "not discourage long-term" contracts; and (4) "consider pre-approval of long-term contracts."¹²⁶

The IOGCC-NARUC task force appropriately advanced the discussion on the topic of long-term contracts. It generally landed in the right place about the importance of long-term contracting and struck an appropriate balance as to a policy course. Long-term contracts can serve an important and beneficial function. Yet they should be neither mandated nor forbidden. Rather, regulators need to examine whether their actions, particularly in the area of prudence reviews discourage long-term contracts that may be appropriate in the circumstances.

One commentator, who was also associated with the IOGCC-NARUC effort, essentially reached the same result:

[c]ommissions may want to consider granting upfront approval of long-term contracts and their costs within the context of a strategy proposed by a utility.

125. NARUC/IOGCC JOINT TASK FORCE, POLICY RECOMMENDATIONS ON LONG-TERM CONTRACTING FOR NATURAL GAS TRANSPORTATION, STORAGE SERVICES AND LIQUEFIED NATURAL GAS DELIVERY at 15 (2005).

126. NARUC, RESOLUTION ON LONG-TERM CONTRACTING (Nov. 16, 2005).

Giving preapproval may alleviate a utility's doubts over whether the costs associated with long-term contracts ultimately will be recovered. To say it differently, preapproval could overcome a potential stranded-cost problem for gas utilities providing default service. Of course, on the other hand, preapproval of costs shifts risks onto retail customers.¹²⁷

The heart of the issue is prudence reviews. The law is fairly clear that the prudence of a contract is to be measured at the time it is entered into and in light of the circumstances as they existed at that time. There appears to be an unfortunate tendency, whether *de jure* or *de facto*, to revisit long-term contracts long after they have been executed and to review them in light of the circumstances that exist at that time. Such practices can operate as a virtual prohibition of long-term contracts. No utility can, in the exercise of its sound management discretion, enter into a long-term contract knowing that it may be reviewed for prudence years down the road in light of whatever circumstances might exist at the time. *Ex post facto* prudence reviews, or the prospect of them, are, unfortunately, not rarities in the natural gas industry. This prospect may be the greatest impediment to long-term natural gas contracts, a fact that was certainly recognized by the IOGCC-NARUC task force.

The task force appears to be headed in the correct direction. The difficulty, however, is that the impediments are both wide-ranging and longstanding. Even if regulators should decide that long-term contracts are an important benefit to consumers and decide to announce publicly that they will exercise their prudence reviews in a fashion that does not discourage long-term contracts, the effects will not be felt immediately. Rather, it will take an extended period and an iterative process in which regulators act over a period of time and utilities build confidence that, not only are regulators announcing the appropriate policies, but they are also acting consistently with those pronouncements, for the industry to go forward with confidence that it will not be unfairly second-guessed.

IX. CONCLUSION

There is no question that the terms of contracts—both gas supply and transportation—have shortened over the last decade. The cause appears to be a combination of market forces and regulatory issues. The dramatic change in natural gas markets, from highly regulated to market-driven, dynamic, and volatile, has plainly played a critical role in changing perceptions of the market by participants, shortening forecasting horizons, increasing market risk, and increasing the reliability of gas supply. Similarly, the movement of the principal gas-supply function from the interstate pipeline to the local distribution company together with the advent of retail choice have increased the regulatory risk associated with entering into natural gas contracts.

There is no question that longer-term contracts have benefits for consumers. Longer terms for transportation contracts may make it easier to construct needed infrastructure. They may also result in lower capital costs for infrastructure which will benefit consumers in the long run. Similarly, longer terms of natural gas supply contracts may serve to dampen gas price volatility to consumers and, perhaps, in the market in general. Longer-term contracts also improve reliability

127. Costello, *supra* note 1, at 45, 49.

of supply for consumers. In the case of LNG and particularly the Alaska gas pipeline, they may facilitate bringing these important sources of energy online for consumers.

Longer contract terms also carry with them risks. They can result in natural gas utilities holding transportation capacity in excess of future needs. Long-term gas-supply contracts can result in consumers' paying prices in out years that are above market levels. They can also result in natural gas utilities being committed to supply that exceeds future needs, largely as a result of market changes and retail-choice programs. Given the fungible nature of natural gas, however, the financial risks associated are likely less than those associated with holding pipeline capacity greater than future needs.

Ultimately the decision as to appropriate contract terms must be a collaborative decision by utilities and their regulators, taking into account the particular circumstances in their states. At a minimum it would be wise for regulators to examine their policies and procedures to determine if they interfere with market choices with regard to contract term. Moreover, if regulators should determine on a broader basis that longer contract terms are desirable, it is essential for them to identify the precise reasons for doing so and the goals they seek to achieve. They also must be fully aware of the risks associated with such a course of action. And, having charted such a course, they should ensure that they do not second-guess utilities that seek to implement regulators' goals. Ultimately, such a decision must involve careful and close cooperation between regulators and utilities, with the goal of producing a result that is optimal, from both a market perspective and a regulatory perspective, for energy consumers.