NATURAL GAS PIPELINE CERTIFICATION AND RATEMAKING

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The Honorable Norman C. Bay, Chairman
The Honorable Colette Honorable, Commissioner
The Honorable Cheryl LaFleur, Commissioner
888 First Street, N.E.
Washington D.C. 20426

Re: Natural Gas Pipeline Certification and Ratemaking

Dear Commissioners Bay, Honorable, and LaFleur:

Enclosed please find the paper that I have authored entitled, "Natural Gas Pipeline Certification and Ratemaking." In the course of my research for this paper, I conducted a thorough review of (1) the past regulatory structure of pipeline financing; (2) a history of deregulation and its impacts on pipelines and LDCs; and (3) the new natural gas industry, including a review of the different shale plays, natural gas demand, generation and exports, concerns about adequate infrastructure, shortages, and electricity transmission.

I also discuss the Federal Energy Regulatory Commission's historical approach to implementing its Certificate Policy Statement. I believe that the Commission will find this paper helpful when considering how to apply its gas pipeline certification policy, given the challenging new economic and environmental issues it faces. The Commission's historical concern about balancing risks between shareholders and ratepayers suggests that serious consideration be given to the risk of underwriting overbuild in natural gas transmission systems in light of this changing regulatory environment.

Sincerely,

Dr. Steve Isser

Attached: Natural Gas Pipeline Certification and Ratemaking
C.V. of Dr. Steve Isser

EXECUTIVE SUMMARY

The Federal Energy Regulatory Commission (FERC) has endeavored to keep up with changes in the natural gas and electricity industries since the 1970s, and this changing economic environment has impacted the natural gas pipeline certification process. The end of rapid growth in energy demand, natural gas deregulation, electricity deregulation, rollercoaster energy prices, the emergence of shale gas production and climate change has made it difficult to sustain coherent policies. Given that natural gas and electric infrastructure is long-lived, and energy policy is rapidly changing, FERC today finds itself making decisions with unexpected ramifications decades down the road.

It is not surprising that FERC, once it had formalized its pipeline certificate policy in 1999, left the process to staff. As long as existing customers weren't required to cross subsidize new investments, projects were supported by long-term contracts, and proposed pipelines didn't create too much controversy or opposition, there was no reason to closely scrutinize applications for new facilities. Over time, the pipeline certificate process became a "checklist" procedure with the primary focus of avoiding establishment of barriers to all but egregiously deficient projects. This process, combined with generous financial incentives, encouraged the building of infrastructure to open markets to new supplies of natural gas, making natural gas markets more competitive.

However, in the last few years a "perfect storm" of conflicting policy goals and strategic behavior has raised questions about the efficacy of this certificate approval process. The expansion of shale gas production has provided both the opportunity to replace coal plants with cleaner, more efficient natural gas generators, but also the spectre of new embedded fossil fuel infrastructure that could hinder long-term reduction in greenhouse gas emissions. Generous financial incentives, designed to encourage risky greenfield gas infrastructure to serve new customers, encouraged corporate parents to divert affiliate demand from existing pipelines to new self-owned facilities to provide lucrative, low risk returns.

It may be time for FERC to revisit how it has applied its 1999 policy statement, and delineate more sharply the balance between goals. While the basic concept of balancing public benefits with adverse effects, and to avoid burdening existing ratepayers with the risk of new investment is still valid, in light of changing circumstances in the 27 years since the statement was issued, the balance of interests should be re-examined. One possibility would be to initiate a Technical Conference to discuss how the balancing tests should be applied in the current economic and environmental context. FERC should examine how the concepts in the policy statement, such as "subsidization," "adverse effects," and "public benefits" should be interpreted and weighted given current policy concerns.

A simple rule of thumb can combine the benefits of "muddling through" and protection of the public interest. As the size of projects and the potential for adverse consequences increase, both the standard of persuasion and the level of scrutiny by the Commission should increase. Upgrades to the electricity grid should be prioritized over upgrades to the natural gas pipeline system to enhance electricity reliability. Financial returns for projects should reflect the level of risk. While FERC has neither the mandate nor the authority to make environmental policy, it is obligated by its own policies to consider environmental impacts. FERC should be wary of "path dependence," where infrastructure decisions can create sunk costs that increase the cost of complying with EPA regulations and may expose ratepayers to additional costs in the future.

Given low demand growth, and alternative means of addressing electricity peaks, there is no pressing need for massive upgrades of the natural gas pipeline system. An additional level of caution is called for when such projects are financed by natural gas or electricity utility ratepayers, exposing them to future risks of potentially imprudent investments.

I. INTRODUCTION

The Federal Energy Regulatory Commission (FERC) has had to struggle to keep up with changes in the natural gas and electricity industries since the 1970s, as a tsunami of world events, regulatory dysfunction (due more to legislative actions and inaction and legal decisions than Commission incompetence) and technological change that has swept away the old order and left chaos in its wake. The energy crisis of the 1970s changed the relation between economic growth and energy consumption, and inspired the development of demand side management and cogeneration. The elimination of natural gas price controls on new sources of gas lead to a supply surge and price crash in the 1980s, followed by the collapse of OPEC's dominance of the oil market in the mid-1980s, which in turn provided FERC with the opportunity to restructure the natural gas market. No sooner than the unbundling of supply and distribution from pipelines was accomplished, FERC found itself shifting its attention and resources to the new electricity markets and the California crisis. The massive Northeast blackout raised concerns about the reliability of the electric grid, while the threat of declining natural gas supplies and price peaks shifted attention to the need for LNG import terminals and incentives for gas production, just as a flood of new gas began arriving on markets from newly tapped shale gas reservoirs.

It is not surprising that FERC, once it had formalized its pipeline certificate policy in 1999, essentially left approval of gas pipeline projects to a small group of staffers. Given the urgency of the other issues buffeting the agency during the next decade, gas pipeline approval seemed almost a trivial matter. As long as existing customers weren't required to cross subsidize new investments, projects were supported by long-term contracts, and proposed pipelines didn't create too much controversy or opposition, there was no reason to closely scrutinize applications for new facilities. The pipeline certificate process became a "checklist" procedure, with each criteria, such as economic need and the NEPA balancing of interests, becoming items to check off during the approval process. The primary focus was to avoid establishing barriers to all but egregiously deficient projects.

However, "we live in interesting times." Increasing concern with the threat of climate change (a polite euphemism for what is literally global warming) has led to executive branch efforts to join in international efforts to reduce greenhouse gas (GHG) emissions, as exemplified by both the Sino-American accord[1] and the recent Paris Accord.[2] The Environmental Protection Agency (EPA)'s Clean Power Plan (CPP) is one of the measures the Administration hoped to meet its announced goals of greenhouse gas mitigation.[3] While the CPP is currently being litigated in the DC Circuit Court, and any decision is certain to be appealed (and in light of its importance, accepted) to the Supreme Court, whether or not the CPP is sustained, some measure to reduce GHG emissions is inevitable in the future.

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[1] White House, *U.S.-China Joint Announcement on Climate Change*, November 11, 2014 at https://www.whitehouse.gov/the-press-office/2014/11/11/us-china-joint-announcement-climate-change. The United States pledged to reduce emissions by 26%-28% below its 2005 level in 2025 and China intends to achieve the peaking of CO_2 emissions and increase the share of non-fossil to around 20% by 2030.

[2] Paris Agreement, Dec. 1/CP.21, Annex, UN Doc. FCCC/CP/2015/10/Add.1 (January 29, 2016) (*Paris Agreement*) at http://unfccc.int/resource/docs/2015/cop21/eng/10a01.pdf.

[3] *Carbon Pollution Emission Guidelines for Existing Stationary Sources; Electric Utility Generating Units, Final Rule*, 80 Fed. Reg. 64,662 (Oct. 23, 2015).

While FERC has neither the mandate nor the authority to make environmental policy, it is obligated by its own policies to consider environmental impacts in deciding whether to grant certificates or authority to build new natural gas facilities. This does not extend to FERC usurping EPA authority to control GHG emissions, rather, it counsels caution in approving new generation or natural gas facilities that may create difficulties in meeting EPA mandates. FERC should be wary of "path dependence," where infrastructure decisions can create sunk costs that increase the cost of complying with EPA regulations and may expose ratepayers to additional costs in the future. Natural gas pipelines and storage facilities are long-lived assets, and if past experience teaches us anything, predicting the future is extremely difficult. Given the high level of uncertainty regarding future regulatory policies and energy technologies, FERC should proceed carefully when evaluating proposals for large projects that are based on "business as usual" projections. An additional level of caution is called for when such projects are financed by natural gas or electricity utility ratepayers and exposes them to future risk of potentially imprudent investments. The incentives provided by generous returns on equity (ROE), combined with risk shifting to captive customers, may encourage overbuilding natural gas pipeline capacity.

II. BRIEF HISTORY

Natural gas was initially a nuisance byproduct of oil drilling, often flared off at the well to prevent fire hazards and provide light for night time work in the oil fields. Artificial natural gas had been used for street lights in many cities, but the distance of most oil fields from major cities limited the market for natural gas. The first pipelines were made of cast iron, which was brittle and unreliable for pipelines of any length. By the end of the nineteenth century, steel had replaced iron, but the early steel pipelines, which were rolled from flat sections, had seams that couldn't withstand high pressures. The introduction of oxyacetylene welding in 1911 and electric arc welding in 1922 made long-distance gas pipelines feasible.[4]

The northeastern US oil and gas fields were insufficient to supply a natural gas industry, but the new fields in the Southwest, discovered just after WWI, led to the growth of major gas suppliers. These large fields prompted the building of new pipelines to deliver the gas to Midwestern customers. However, the Great Depression stopped expansion, as no major pipeline was built for a decade.[5]

The Public Utility Holding Companies Act (PUHCA) of 1935 reshaped the corporate structure of the gas industry. Four holding companies had controlled 60% of production and transportation. PUHCA required large holding companies to divest many of their subsidiaries, separating pipelines and production, and prevented local distribution companies (LDCs) from

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[4] Christopher Castaneda, *Regulated Enterprise: Natural Gas Pipelines and Northeastern Markets, 1938-1954* (Columbus: Ohio State University Press, 1993): 17-18.

[5] Castaneda, *Regulated Enterprise: Natural Gas Pipelines and Northeastern Markets,* 20-23.

integrating backwards into pipelines and production. The result was a three tier industry, which required complex contractual relations to coordinate production, transport and distribution.[6]

The lack of state power to control the activities of interstate pipelines left a regulatory gap. A series of Federal Trade Commission Reports documented numerous abuses by natural gas companies, and recommended federal regulation of interstate natural gas prices. A 1937 bill, H.R. 4008, finally gained the approval of Congress, and President Roosevelt signed it into law as the Natural Gas Act of 1938 (NGA). The NGA had to satisfy three constituencies, the states, who wanted to maintain their authority over retail sales, local distributors, who wanted assurance that their supply of natural gas would not be interrupted, and the pipelines. Congress included licensing provisions limiting entry in all markets served by existing pipelines, established a presumption of monopoly power and explicitly put forth the goal of consumer protection as a priority of natural gas regulation.[7]

The NGA granted the Federal Power Commission (FPC) jurisdiction to regulate sales for resale in interstate commerce, transportation in interstate commerce and facilities used for interstate sales and transportation. § 4 (a) of the NGA required that all natural gas rates subject to the jurisdiction of the Commission "shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful." § 7 (c) provided, it was "the intention of Congress that natural gas shall be sold in interstate commerce for resale . . . at the lowest possible reasonable rate consistent with the maintenance of adequate service . . ."[8]

The requirement for a certificate of public convenience and necessity is standard practice in utility regulation, used to prevent wasteful investment that would impose costs to consumers by companies recovering those investments in their regulated rate base. In the gas industry those certificates served an additional purpose, ensuring that a pipeline had under contract an adequate supply of natural gas to provide sufficient supplies for the pipeline's customers, and requiring the pipeline to be sized efficiently relative to reserves. § 7(c) of the NGA required a certificate from the FPC to build a pipeline to a market served by another natural gas company, which meant the FPC determined whether and the extent to which competing supplies of gas would be allowed to enter a region.[9]

Natural gas at the wellhead was sold to either interstate pipeline companies or intrastate pipelines. Interstate pipeline rates were regulated by the FPC and its successor agency, the FERC. Intrastate pipelines were regulated by state public utility commissions (PUCs), as the FPC had no jurisdiction on natural gas produced and consumed within a state. Pipeline companies then sold the gas to the LDCs. A PUC could punish a LDC for paying excessive

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[6] Castaneda, *Regulated Enterprise: Natural Gas Pipelines and Northeastern Markets,* 26; Richard Vietor, *Energy Policy in America Since 1945* (Cambridge: Cambridge University Press, 1984): 60-70.

[7] Report of the FTC to the U.S. Senate, Doc. No. 92, 70th Cong. 1st Sess., pt. 84-A (1936), cited in Richard Pierce, "Reconstituting the Natural Gas Industry From Wellhead to Burnertip," 9 *Energy Law Journal* 1, 5, nt. 16 (1988); *Legislative History of the Natural Gas Policy Act: Title I*, 59 *Texas Law Review* 106-107 (December 1980); Jeff D. Makholm, *The Political Economy of Pipelines: A Century of Comparative Institutional Development* (University of Chicago Press, 2012): 54; M. Elizabeth Sanders, *The Regulation of Natural Gas: Policy and Politics, 1938-1978* (Temple University Press, Philadelphia, 1981): 49, 67; John G. Clark, *Energy and the Federal Government: Fossil Fuel Policies, 1900-1940* (University of Illinois Press, Urbana, 1987): 280.

[8] *Atlantic Refining et al v PSC of NY*, 360 U.S. 378, 388 (1959).

[9] Castaneda, *Regulated Enterprise: Natural Gas Pipelines and Northeastern Markets, 1938-1954,* 30.

prices for gas by disallowing part of the purchase cost. PUCs also determined prices paid by final customers for natural gas. The NGA preserved this structure, as repeated attempts to make natural gas pipelines common carriers, similar to oil pipelines, were thwarted in Congress. The failure to establish common carrier status for pipelines, and require divestiture of pipeline producer affiliates, greatly complicated the FPC's regulatory task.

The FPC ruled in a 1945 case that the price of gas produced by a pipeline company fell under its jurisdiction, confirmed by the Supreme Court. When a pipeline purchased gas from its own production division or subsidiary, the FPC was concerned that the pipeline might pay itself an excessive price, recovering the cost through regulated rates. The Supreme Court ignored the issue of affiliated production, and focused on whether production for interstate use was interstate commerce, and thus fell under the jurisdiction of the FPC. The Court reasoned that the purpose of the NGA was to close the jurisdictional gap over interstate transactions, including sales for resale.[10] The 1954 Supreme Court's decision in *Phillips Petroleum v Wisconsin*[11] interpreted the NGA as extending FPC authority to wellhead natural gas prices.[12] *Phillips* established federal price controls over the entire industry.

Between 1949 and 1970 natural gas consumption increased from 5 trillion cubic feet (Tcf) per year to 21 Tcf per year. Natural gas became a major fuel for home heating, as it was significantly cheaper than heating oil. Low prices allowed gas to penetrate coal markets in electricity generation, while both price and process use flexibility made it the fuel of choice for many industries. However, this growth wasn't uniform, gas barely penetrated the New England region, and its primary market in Florida was electricity generation.[13]

While there were warnings of declining reserves and eventually production, they had not reached a level of urgency in the late 1960s. The change in 1970 was as sudden as it was unexpected. By September, 1971, the intrastate gas price had jumped ahead of the interstate price, and would remain higher over the next few years.[14] Natural gas producers anticipated this development, as they made a drastic reversal in 1970, refusing to dedicate any new gas reserves to the interstate market. The growing disparity between interstate supply and demand eventually led to the gas shortage of the 1970s.[15]

In the winters of 1971-72 and 1972-73 gas supplies were cut off with increasing frequency, and for longer periods of time, throughout the Northern and Eastern portions of the United States. This included both cutting off supplies in peak periods to industry, and systematic curtailments of deliveries. By 1973 it was no longer possible to have gas lines installed in new

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[10] *Interstate Gas Co. v. Power Comm'n*., 331 U.S. 682, 689-91 (1945).

[11] *Phillips Petroleum v Wisconsin*, 347 U.S. 672 (1954).

[12] *Phillips Petroleum v Wisconsin*, 347 U.S. at 674-685.

[13] EIA, *Historical Natural Gas Annual, 1930 Through 2000*, DOE/EIA-E-0110(00) (December 2001), various tables.

[14] Ronald Braeutigam and R. Glenn Hubbard, "Natural Gas: The Regulatory Transition," in Leonard Weiss & Michael Klass, editors, *Regulatory Reform: What Actually Happened* (Little, Brown & Co., Boston, 1986): 143.

[15] Jay Chaffee, "Natural Gas Rate Regulation: The Conflict in the Application of the Just and Reasonable Standard," *Tulsa Law Review* 12 (1976): 313, nt 108, citing Moody, "1974-The Gathering Storm," *Oil & Gas Institute* 26 (Matthew Bender 1975): 1, 4.

homes built in many regions of the country, and a larger number of industrial consumers found their supplies curtailed.[16] The jump in oil prices in 1974 made natural gas relatively less expensive for end users,[17] requiring the reduction of natural gas demand by fiat until supplies could be increased. The country avoided major curtailments due to a mild winter in 1975-76. The following winter was the coldest in 100 years in many regions, focused nationwide attention on the gas deliverability problem. Gas curtailments nationwide were 23% of firm requirements, and the shortage was particularly severe along the East Coast.[18]

A. Pipeline Financing Under Regulation

The traditional role of the interstate pipeline company was as a merchant or sole intermediary between buyers (LDCs) and sellers (natural gas producers), though many interstate pipelines purchased gas from both subsidiaries and independent producers. Long-term contracts, twenty years or longer, were the traditional mode of governance. The seasonal nature of the demand for natural gas required some means of maintaining relative constant pipeline throughput. Gas storage, as well as "line pack" (the inherent storage in large diameter pipelines), provided a buffer, while interruptible delivery service and peak-period pricing allocated capacity. The overall goal was to achieve the mix of production, transmission capacity and storage which yielded the minimum service cost. Embedded in regulated pipeline rates were all the products and services associated with the merchant function, including the commodity, transportation, storage, and all complementary goods.[19]

New pipeline construction and expansion of existing pipelines required a finding under the NGA by FERC that the project was in the public interest. If so, FERC would issue a “certificate of public convenience and necessity.” Before the advent of open access transportation, a pipeline seeking a certificate to expand its mainline or build a new line generally executed long-term sales contracts matched by long-term gas supply agreements. Accordingly, there was no question as to the new facility's usefulness. Once the project was

[16] Paul W. MacAvoy and Robert S. Pindyck. "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," *Bell Journal of Economics and Management Science* (1973): 454-498, citing Federal Power Commission, *Proceedings on Curtailment of Gas Deliveries of Interstate Pipelines* (1972); Robert Pindyck, “Prices and Shortages: Evaluating Policy Options for the Natural Gas Industry,” Working Paper, MIT-EL 77-022WP (July 1977): 1.

[17] EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011)(September 2012): Table 3.4: Consumer Price Estimates for Energy by End-Use Sector, 1970-2010.

[18] Congressional Quarterly, *Energy Policy, 2nd Edition* (Wash., D.C.: CQ Press, March 1981): 183; Energy Information .Agency (EIA), U.S. Department of Energy, *Monthly Energy Review* (Dec. 8, 1980); *State of NC v. FERC*, 584 F. 2d 1003, 1008 (DC Cir. 1978); Robert Pindyck, "Price and Shortages: Evaluating Policy Options for the Natural Gas Industry," MIT Working Paper (July 1977).

[19] Carol Dahl and Thomas Matson, "Evolution of the US Natural Gas Industry in Response to Changes in Transaction Costs," *Land Economics* 74(3)(August 1998): 392-93. Most long-term contracts were negotiated before 1970. Congressional Budget Office, *Understanding Natural Gas Price Decontrol* (U.S. Government Printing Office, Wash. D.C., April 1983): 8; Daniel J. Duann, *The FERC Restructuring Rule: Implications for Local Distribution Companies and State Public Utility Commissions* (National Regulatory Research Institute, NRRI 93-12, November 1993): 43.

approved, the certificate assured the pipeline of rate base inclusion of the project's costs in its next general NGA § 4 rate case.

Expansion of existing facilities represented only a small fraction of total installed capacity in terms of pipeline miles but a much larger fraction of book value. The Commission traditionally favored rolled-in or average-cost pricing for new pipeline construction when the new facilities provided benefits to the pipeline's existing customers and existing customers didn't subsidize those customers who benefited from the new facilities. The primacy of an integrated system was the rationale for averaging in the costs of the new facilities.[20] After a couple of D.C. Circuit decisions questioning the "rolling in" policy,[21] FERC responded by opening a new docket on pipeline pricing, holding hearings, and issued a policy statement in 1995. To determine whether a proposed project warranted the use of rolled-in pricing, the Commission would look to the extent to which the new facilities were integrated with existing facilities and to the specific system benefits produced by the project. There were two general classes of benefits: operational benefits such as increased access, reliability, flexibility, or new services; and monetary benefits such as fuel or other cost savings or the prevention of rate increases from unrelated load loss. To the extent that rolled-in pricing would cause a rate increase of more than 5%, the Pricing Policy Statement created a rebuttable presumption in favor of incremental treatment.[22]

B. A Very Short History of Deregulation

President Carter's energy package was introduced on May 2, 1977, as the National Energy Act. The key issue which the two chambers of Congress could not agree upon was the deregulation of natural gas wellhead prices. In September a compromise was reached in conference, resulting in a gas deregulation bill, HR 5289. The conference committee bill combined price control and deregulation by creating nationwide incentive based price ceilings, and allowed phased deregulation of certain categories of gas. The battle then moved to the Senate where the administration conducted an intensive lobbying effort to ensure passage. Congress settled for a phased deregulation plan, ending controls by 1985. The bill which emerged from conference, the Natural Gas Policy Act (NGPA), retained the extension of controls to the intrastate market and phased-in deregulation of the wellhead price of new natural gas.[23]

The Department of Energy (DOE) Organization Act of 1977 created a new cabinet level Department to govern most energy related issues. DOE consolidated in one cabinet level department major energy related functions previously vested in several different agencies. Within DOE, FERC was created as an "independent regulatory commission," and given many of

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[20] *Battle Creek Gas Co. v. FPC*, 281 F.2d 42, 46-48 (D.C. Cir. 1960)

[21] *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 13-12-13 (D.C. Cir. 1991); *TransCanada Pipelines Ltd., v. FERC*, 24 F.3d 305, 309-11 (D.C. Cir. 1994).

[22] *Pricing Policy For New And Existing Facilities Constructed By Interstate Natural Gas Pipelines, Statement of Policy*, 71 FERC ¶ 61,241, 61,915-16 (May 31, 1995), *reh'g denied*, 75 FERC ¶ 61,105 (1996).

[23] *CQ Weekly Report* (Sept. 2, 1978): 2395-2396; *CQ Weekly Report* (Sept. 16, 1978): 2451-2454; Richard Corrigan and Dick Kirschten, "The Energy Plan--What Has Congress Wrought?" *National Journal* (Nov. 14, 1978): 1760-1768.

the powers of the FPC over natural gas and electricity, as well as substantial additional authority relating to oil pricing and allocations. DOE assumed the FPC's authority under the NGA to authorize imports and exports of natural gas and to establish curtailment priorities. FERC inherited all other rate, certificate and licensing functions. In addition, the authority to regulate exports and imports of natural gas or electricity could be assigned to FERC by the Secretary.[24] FERC, as an independent regulatory agency involved in adjudication and rule making, was bound by the Administrative Procedures Act, and FPC precedent.

The passage of the NGPA meant a huge workload for FERC, as numerous orders needed to go through the administrative law procedure of proposal, response, initial order, modified order, litigation (since aggrieved parties had the option of appealing orders to the Appeals Courts under § 19(b) of the NGA), and finally a Court approved and/or modified order that would govern the subject under dispute. The NGPA established a highly complicated pricing scheme for natural gas, including various categories, price tiers, escalation factors and timelines for decontrol.

The pipelines, worried about obtaining sufficient supplies, signed long-term contracts at above current market prices. A pipeline that refused to pay these prices could have found itself short of gas and thus in breach of both contractual and regulatory duties to supply gas.[25] Numerous contracts had 'favored nation clauses' that raised prices to match higher cost contracts upon deregulation.[26] Many contracts had take-or-pay clauses, requiring the purchaser to buy a certain quantity of gas. At first, average pricing blended together legacy low cost "old gas" with higher priced "new gas." As the supply of higher priced new gas increased, so did the average price of gas, eventually exceeding the declining cost of oil due to a glut on the world oil market. As a result, end-users did not want to pay for higher-priced natural gas, and began to revert back to using petroleum products. A surplus appeared in 1982 and increased in magnitude the next year. As the average price of regulated gas continued to rise, there was less room to roll in the cost of unregulated gas, and demand for these resources declined precipitously. Fuel switching, and the threat of additional fuel switching by industrial customers resulted in a 180 degree shift in FERC pipeline ratemaking.

Demand for gas by residential and small commercial users is highly seasonal, especially in northern states, where demand for gas for heating peaks in the winter. Pipelines are designed to service the peak demand. Variable costs of pipeline operation are incurred in proportion to the gas actually used. Historically, pipeline companies' fixed costs such as the depreciation of the pipeline, operation and maintenance expenses, and return on equity, had been distributed between the demand and commodity charges. The demand charge is based on the quantity that a customer has contracted for the right to take during the peak period. The commodity charge is based upon the volume of gas consumed by the customer. To the extent that fixed costs are

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[24] Edward Grenier and Robert W. Clark III, "The Relationship Between DOE and FERC: Innovative Government or Inevitable Headache?" 1 *Energy Law Journal* 325, 336-39 (1980).

[25] "Note: Contractual Liability of Pipelines for Damages Caused by Gas Supply Curtailments: Texasgulf, Inc. v. United Gas Pipeline Co.," 6 *Energy Law Journal* 280 (1985).

[26] Pierce, "Reconsidering the Roles of Regulation and Competition in the Natural Gas Industry," 97 *Harvard Law Review* 345, 351, nt 43, nt 44 (December 1983); Benjamin Schlesinger, "Impact of Natural Gas Price Decontrol on Gas Supply, Demand and Prices," Proceedings from the Fourth Industrial Energy Technology Conference Houston, TX (April 4-7, 1982): 262.

included in the demand portion of the rate, the pipeline is assured of cost recovery. Under the Atlantic Seaboard formula, established in 1952, variable costs were assigned to the commodity component because they fluctuated according to the volume of gas delivered. Fixed costs, incurred to provide the capacity to supply peak demand, were divided equally between demand and commodity components. In the 1980s, FERC began to approve interruptible rates that required industrial customers to make only minimum contributions to the fixed costs of pipelines to retain them as customers.[27] Many industrial customers employed interruptible service purchases, and paid only a commodity charge, while customers on firm supply paid both commodity and demand charges.

Full requirements customers purchased their entire natural gas supply from one pipeline. They were sometimes referred to as "captive" customers since, in most cases, they were located in areas where there is only one pipeline supplier. LDCs generally made up this group. Partial requirements customers bought from more than one pipeline and could swing off the system from one pipeline to another, reducing sales which, in turn, resulted in under recovery of costs for the pipeline which lost the customer. If the pipeline was unable to make up the lost volume of sales by selling the excess supply of gas elsewhere, it could file for new rates to offset the decreased revenue. In these new rates, the pipeline's fixed costs were spread over a lower volume of gas, resulting in higher fixed rates on that system. The captive customers had no alternative to paying these rates.[28]

One of the Congressional objectives of the NGPA was to ease the regulatory roadblocks imposed by the NGA to integration of the facilities of interstate and intrastate pipelines into a more efficient national transportation network. The key provision of the NGPA was § 311, which authorized the Commission to allow interstate and intrastate pipelines to transport gas in interstate commerce without being subject to the certificate and abandonment requirements of § 7 of the NGA. This allowed pipelines the freedom to construct facilities to penetrate new markets, but only if the facilities were used for transportation and not for commodity sales. The traditional certificate requirements of § 7(c) continued to apply to construction of facilities to effectuate a pipeline's sale of gas to any new market.

Natural gas decontrol was a contentious political issue, and attempts to either freeze decontrol or accelerate it both floundered in Congress in the 1980s. FERC, reacting to the impasse in Congress, began a campaign of administrative decontrol. Congress did repeal provisions of the Fuel Use Act in 1987 to end the prohibition on additional gas use by new industrial businesses and electric utilities. This opened up new industrial and utility customers for the emerging spot market to service (as gas was released from long-term contract commitments, it became available for sale on the spot market, along with new, uncommitted gas

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[27] Wendell Adair & David Bloom, "Flexible Pricing and Other Partial Solutions to the Problems Faced By Gas Distributors," *Energy Law Journal* 4 (1983): 247-48.

[28] *Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions* (Order No. 380), 49 Fed. Reg. 22,778 (June 1, 1984), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,571; *reh'g denied and stay granted in part*, Order No. 380-A, 49 Fed. Reg. 31,259 (Aug. 6, 1984), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,584; *reh'g denied and order clarified*, Order No. 380-B, 29 FERC ¶ 61,076; *reh'g denied*, Order No. 380-C, 49 Fed. Reg. 43,625 (Oct. 31, 1984), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,607; *reh'g denied*, Order No. 380-D, 29 FERC ¶ 61,332 (1984); *aff'd in part, remanded in part sub nom. Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied sub nom. Transwestern Pipeline Co. v. FERC*, 476 U.S. 1114 (1986); *order on remand*, Order No. 380-E, 35 FERC ¶ 61,384 (1986); *reh'g denied*, Order No. 380-F, 40 FERC ¶ 61,190 (1987).

supplies). In 1989, Congress built upon the significant changes in the natural gas industry by enacting the Natural Gas Wellhead Decontrol Act of 1989[29] which end federal controls over natural gas prices by January 1, 1993.

The FERC had two main goals in its series of natural gas orders during the late 1980s and early 1990s, to open up the interstate natural gas pipeline system to access by customers to facilitate competition for gas supplies, and to resolve the fiscal threat posed by take-or-pay purchase contracts to the pipelines and their customers. Numerous orders were appealed to the D.C. Circuit Court of Appeals where they were remanded back to the Commission, modified and/or replaced by a subsequent order.[30] This game of regulatory litigation whack-a-mole had the desired effect, gas producers settled take-or-pay contracts for far less than their face value, and the pipelines gradually became common carriers.

In 1985, Order 436 imposed an "open-access" commitment on any pipeline that secures a blanket certificate (i.e., a certificate authorizing general transportation service) to provide gas transportation under § 311 of the NGPA. If a pipeline wanted to take advantage of blanket certification, it had to commit to provide transportation on a nondiscriminatory basis (and thus become an "open-access" pipeline). All types of transportation were covered, including back-hauls, exchanges, displacement, and contract storage. Both firm and interruptible service must be offered by interstate pipelines, subject to available capacity. Capacity must be allocated on a "first-come, first-served" basis. Since transactions under § 311 and blanket certificates included virtually every major pipeline, this would open up most of the gas transportation system to open access transportation of gas.[31]

The Commission attempted to combine accelerated decontrol of old gas prices with incentives to renegotiate onerous take-or-pay contracts. On August 7, 1987, the Commission issued Order No. 500,[32] an "interim" rule responding to the remand of Order 436. Order 500 readopted most of Order 436, but added and deleted various provisions in an effort to respond to the DC Circuit's mandate. After the Commission issued Order 500, producers and pipelines

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[29] Pub. L. No. 101-60, 103 Stat. 157 (1989).

[30] For example, Order No. 436, *Office of Consumer's Counsel, Ohio v FERC*, 783 F.2d 206, 214 (D.C. Cir. 1985), *Associated Gas Distributors v FERC*, 824 F.2d 981, 984 (D.C. Cir 1987); Order No. 500, *American Gas Ass'n*, 888 F.2d 136 (D.C. Cir. 1989); *Associated Gas Distributors v FERC*, 893 F.2d 349 (D.C. Cir 1989); *American Gas Association v FERC*, 912 F.2d 1496 (D.C. Cir 1990).

[31] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol* (Order No. 436), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,665 (1985), 50 Fed. Reg. 42408, 42424-25 (October 18, 1985); *modified*, Order No. 436-A, FERC Stats. & Regs., ¶ 30,675 (1985), 50 Fed. Reg. 52,217 (December 23, 1985); *modified further*, Order No. 436-B, FERC Stats. & Regs. ¶ 30,688, 51 FR 6398 (Feb. 14, 1986), *reh'g denied*, Order No. 436-C, 34 FERC ¶ 61,404 (Mar. 28, 1986), *reh'g denied*, Order No. 436-D, 34 FERC ¶ 61,405 (Mar. 28, 1986), *reconsideration denied*, Order No. 436-E, 34 FERC ¶ 61,403 (Mar. 28, 1986), *vacated and remanded sub nom.*

[32] Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, FERC Stats. & Regs. ¶ 30,761 (1987); Order No. 500-A, FERC Stats. & Regs. ¶ 30,770, *modified in part*, Order No. 500-B, FERC Stats. & Regs. ¶ 30,772 (1987), *modified further*, FERC Stats. & Regs. ¶ 30,786 (1987), *modified further*, FERC Stats. & Regs. ¶ 30,800 (1988), *modified further*, Order No. 500-F, FERC Stats. & Regs. ¶ 30,841 (1988), *remanded, American Gas Ass'n*, 888 F.2d 136 (D.C. Cir. 1989), *order on remand*, Order No. 500-H, FERC Stats. & Regs. ¶ 30,867 (1989), *order on reh'g*, Order No. 500-I, 50 FERC ¶ 61,172 (1990).

renegotiated a substantial portion of their take-or-pay contracts. By the end of 1987, almost 80% of pipelines' potential liability had been resolved, and most of the rest in 1988.[33]

FERC's orders, despite being remanded and vacated, were impacting the natural gas market. The changes promulgated in the 1980s by the FERC gradually opened up the interstate gas pipelines. With increased direct gas purchases and wide use of transportation-only service, the traditional structure of a regulated pipeline buying at the wellhead and selling gas to the LDCs was being replaced by commodity gas purchases by LDCs and large end user customers, with interstate transportation provided by pipelines.[34]

As parties attempted to implement contract demand conversions, however, they were confronted by a new series of restrictive terms and conditions imposed by the pipeline-as-transporter. These new tariff restrictions had the common trait of making the firm transportation services provided to competitors distinctly inferior to the implicit transportation service that the pipeline provided to itself as a merchant. To receive a level of supply security comparable to that offered by pipeline system sales, the LDC would have to "book" more capacity for transport than needed to purchase firm sales from the pipeline.[35] The availability of storage was a key component of making firm transportation comparable to firm sales because system storage provides "swing" capability to handle winter peak demand. The Commission proceeded to require pipelines to offer interruptible open access storage in addition to firm service.[36]

In Order No. 636, in 1992,[37] the Commission concluded that many customers had not taken advantage of Order 436's option to convert from firm-sales to firm-transportation service because the firm-transportation component of bundled firm-sales service was "superior in quality" to stand-alone firm-transportation service. The Commission concluded that the main problem was the continued existence of the pipelines' bundled, city-gate, firm sales service.[38] The Commission's remedy was to require pipelines to unbundle the sales and transportation components of their firm sales services. Storage was redefined as transportation, which must also be unbundled from sales. The Commission introduced the concept of "no-notice firm transportation," stand-alone firm transportation without daily balancing and scheduling penalties.

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33 *American Gas Association v FERC*, 888 F.2d 136, 145-146; Thomas Johnson, "Order No. 451—Market-Based Pricing for 'Old' Gas," 24 *Tulsa Law Journal* 627, 631 (1988).

34 Daniel J. Duann , *Gas Storage: Strategy, Regulation, and Some Competitive Implications* (Columbus, OH: The National Regulatory Research Institute, 1990); Daniel J. Duann, *The FERC Restructuring Rule: Implications for Local Distribution Companies and State Public Utility Commissions* (Columbus, OH: The National Regulatory Research Institute, 1993): 36.

35 *Williams Natural Gas Co*., 52 FERC ¶ 61,152, 61,612 (1990).

36 "Report of the Committee on Natural Gas Certificate and Authorization Regulations," 12 *Energy Law Journal* 173, 175-76 (1991).

37 Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead De-control*, FERC Stats. & Regs. ¶ 30,939 (1992), 57 Fed. Reg. 13,267 (1992), *order on reh'g*, Order No. 636-B, 57 Fed. Reg. 57911 (1992), 61 FERC ¶ 61,272 (1992), *reh'g denied*, 62 FERC ¶ 61,007 (1993), *aff'd in part, rev'd in part, United Distrib. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996) , *cert. denied sub nom*, 520 U.S. 1224 (1997); *on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

38 Order 636, FERC Stats. & Regs. ¶ 30,939, 30,400-05.

Pipelines must separately identify the cost components of the "no-notice" transportation service rates in their rate schedules.[39] Each pipeline was required to go through an individual restructuring proceeding, to conform its operations to the new regulations and to address pipeline-specific issues. All firm and interruptible sales services would be provided as unbundled services. Pipelines could adopt a market-based pricing mechanism for gas sales upon full compliance with the final rule. The Commission reasoned that open-access transportation, combined with its finding that adequate divertible gas supplies exist in all pipeline markets, would ensure that the market for gas would keep rates within the zone of reasonableness.[40]

Order 636 represented the latest change in FERC's policy goals for rate design. In 1983 FERC adopted the modified fixed variable cost classification and rate design, which removed all fixed costs, except for a pipeline company's return on equity and associated taxes, from the commodity charge. In its 1989 policy statement on rate design, FERC suggested that the usage charge be eliminated, shifting fixed costs into the capacity charge. FERC maintained that, by lowering the costs charged to customers who purchase large volumes (thus potentially raising their demand for gas), pipeline companies would increase the volume of gas they transport.[41] Pipelines had differing amounts of fixed costs in their usage charges because fixed costs are determined by reference to revenue requirement criteria that differed on each pipeline. This hindered competition and the development of a national gas market. In Order 636 the Commission required pipelines to use the straight fixed variable method of assigning all fixed costs to the reservation charge. The Commission didn't preclude the pipeline, its customers, and interested parties from agreeing to an alternative method. However, parties advocating something other than the straight fixed variable method carried a heavy burden of persuasion.[42]

C. Impact of Deregulation on Pipelines and LDCs

The rule changes in Order 636 placed a new set of burdens on LDCs. The LDC became responsible for securing gas supplies to assure availability and arranging for its transportation. Responsibility for reviewing the LDC's gas costs shifted to the states. Order 636 further encouraged bypass (purchasing directly off the pipeline instead of through the LDC) by removing existing barriers to transportation.[43] The straight fixed variable rate design imposed additional costs on customers (such as residential consumers) who had relatively inflexible demand during peak periods, if the LDC had to recover more costs from peak demand charges. Switchable pipeline customers would bypass the LDC if they weren't granted rates that reflected

[39] Order 636, ¶ 30,939, at 30,406-13, 30,421-25, 30,462-69; Order 636-A, ¶ 30,950, at 30,527-46, 30,570-77; Order 636-B, ¶ 61,272, at 61,988-92, 62,006-10.

[40] Order No. 636, ¶ 30,939, 30,437-43; Order No. 636-A, ¶ 30,950, 30,609-24; Order No. 636-B, ¶ 61,272, 62,024-25.

[41] General Accounting Office, *Costs, Benefits and Concerns Related to FERC's Order 636* (November 1993): 33-34.

[42] Order No. 636, ¶ 30,939, 30,431-37; Order No. 636-A, ¶ 30,950, 30,593-609; Order No. 636-B, ¶ 61,272, 62,013-24.

[43] Frank Darr, "A State Regulatory Strategy for the Transitional Phase of Gas Regulation," *Yale Journal of Regulation* 12 (1995): 81-83.

the lower cost of interruptible gas service. Overall small consumers still received lower delivered prices from lower natural gas prices at the well head due to deregulation and rationalization of gas markets, but they no longer benefited from cross-subsidization. The impact of these changes on the overall cost of gas to residential end-users depended on the LDC's customer portfolio and change in purchased gas costs.[44]

Development of national gas markets had begun before Order 636, but the order accelerated the movement to market integration. By late 1988, all regions were connected via an open access pipeline. Spot markets gradually became more integrated between 1987 and 1991, but the reliability of these spot markets was not assured until trading grew to give the market the depth required to assure it as a reliable source of gas. Convergence of regional gas prices accelerated after the issuance of Order 636.[45] By 1997, there were 38 operating market centers as compared to only five when Order 636 was issued.[46] These market centers provide a variety of services that increase the flexibility of the system and facilitate connections between gas sellers and buyers. Electronic trading of gas and capacity rights became commonly available. Electronic trading systems enable buyers and sellers to discover the price and availability of gas at transaction points, submit bids, complete legally binding transactions, and prearrange capacity release transactions. Electronic information services offer capacity release and tariff information aggregated from pipeline electronic bulletin boards, gas futures prices, weather information, and determination of least cost routing.[47]

The spot market consists of a large network of buyers and sellers of gas that operate in different regions. The buyers include gas distribution companies, electric utilities, industrial firms, commercial businesses, and trading companies. The sellers of gas include the major and independent gas producers, gas marketers, intrastate pipeline companies, and utilities. Spot markets operate at several locations, including city gates such as New York, Los Angeles, Chicago, and Toronto, and market centers such as Rocky Mountains and East and South Texas, the Henry Hub, Louisiana, and El Paso, Texas. Gas price movements tend to be highly correlated across these regional markets, but they are higher near the consumer markets than at the producer end of the pipeline. The spot market is a physical market because its function is physically to deliver gas from one owner to another.

Once pipelines opened their systems to transportation, the demand for interconnections rose. In the mid 1980's, pipeline companies began to organize their systems into a hub-and-spoke configuration. The hubs allow pipelines with different operating pressures to "wagon wheel" their customers' gas through the hub and over the network. In contrast to the old system of merchant carriage, tradeable transportation rights permitted gas buyers to transact at all

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[44] General Accounting Office, *Costs, Benefits and Concerns Related to FERC's Order 636*, 46-53; Daniel J. Duann, *The FERC Restructuring Rule: Implications for Local Distribution Companies and State Public Utility Commissions* (National Regulatory Research Institute, NRRI 93-12, Nov. 1993): 64.

[45] Arthur De Vany and W. David Walls, "Pipeline Access and Market Integration in the Natural Gas Industry: Evidence from Cointegration Tests," *Energy Journal* 14 (1993); David Finnoff, Curtis Cramer and Sherrill Shaffer, "The Financial and Operational Impacts of FERC Order 636 on the Interstate Natural Gas Pipeline Industry," *Journal of Regulatory Economics* 25 (2004): 248.

[46] Stewart Holmes, *The Development of Market Centers and Electronic Trading in Natural Gas Markets* (FERC, Office of Economic Policy, June 1999): 1.

[47] Order No. 636-C, 78 FERC ¶ 61,186, 61,767-68.

directly or indirectly connected nodes. Because open access allowed these exchanges to be made, field markets previously separated by regulation became more integrated. When there is no congestion, the basis differential should equal the pipeline charge for transportation of that gas from the origin to the upstream point of delivery. When demand for transportation increased beyond capacity in these networks, gas was shipped at the spot price plus transportation price, but resold at the line exit hub at the market clearing price. The difference was a scarcity (congestion) rent to the broker-dealer in spot gas. The problem was the broker-dealer wasn't normally the investor in new transportation, so a potential source of revenue to finance pipeline expansion was dissipated.[48]

Because of FERC's unbundling of pipeline services, LDCs were now responsible for storing their own gas supplies. With the growth of alternatives, the LDC could better align capacity commitments to seasonal variations in demand. In general, two types of storage facilities are used for natural gas: (1) underground storage in a depleted oil or gas field, an aquifer, or a solution-mined salt cavern, and (2) above-ground storage tanks for propane, liquefied natural gas, and compressed natural gas. LDCs can either contract for capacity or build their own storage facilities. By contracting for storage services, LDCs may be able to reduce their need for fixed pipeline transportation services and lower the overall costs to deliver gas.

The key to deregulated markets is the absence, or at most, the limited exercise of market power. Studies conducted for FERC suggested there was limited market power, and that entry by new pipelines into existing service areas would generally eliminate what market power existed. By 1995, prices had converged between geographically separated spot markets, evidence that a national gas market (at least East of the Rocky Mountains) had emerged.[49] However, the national gas network was still separated into three regional markets, the Northeast, the Midwest and California. The Midwest was primarily supplied from West Texas and Canada, while the Northeast from East Texas and Louisiana.[50]

III. THE NEW NATURAL GAS INDUSTRY

The emergence of shale gas had a dramatic impact on the natural gas industry, especially the development of the Marcellus shale field. As production grew in the Appalachian gas region, the traditional flow of gas from Texas and Gulf of Mexico fields to the Northeast was first supplanted, and then replaced by this new source of natural gas.

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[48] Paul MacAvoy, "Chapter 4: The Basis Differentials on Partially Deregulated Pipeline Transportation," in Paul MacAvoy et al. eds., *Natural Gas Networks Performance After Partial Deregulation: Five Quantitative Studies* (World Scientific, Singapore, 2007): 97, 129.

[49] Robert Michaels and Arthur DeVany, "Market Based Rates for Interstate Pipelines: The Relevant Market and the Real Market," 16 *Energy Law Journal* 299, 316-32 (1995).

[50] Vadim Marmer and Dmitry Shapiro, "Chapter 2: Regional Markets for Gas Transmission Services," in Paul MacAvoy et al. eds., *Natural Gas Networks Performance After Partial Deregulation: Five Quantitative Studies* (World Scientific, Singapore, 2007): 24-30.

A. Shale Gas

Shale formations across the U.S. have been used to produce natural gas in small but continuous volumes since the earliest years of gas development.[51] The first recorded horizontal well was drilled in 1929 and the first recorded hydraulic fracturing was undertaken in 1947.[52] However, gas production through these combined techniques became commonplace only in the 1990s after years of federal support and further innovations. Mitchell Energy & Development played the primary role in developing the Barnett play in Texas, and it was the successful development of the Barnett play that jump-started the shale gas boom. Mitchell Energy drilled its first well in the Barnett in 1981, but it wasn't until about 2000 that a combination of technologies allowed profitable drilling in the Barnett. Horizontal drilling in the Barnett didn't begin on a major scale until 2003, aided by the purchase of Mitchell Energy by Devon Energy in 2002. The combination of improved efficiency and expertise, financial resources and an uptick in natural gas prices in 2000 ignited the shale gas boom.[53] Barnett production would peak in 2012 before steadily declining.[54]

The development of the Barnett, Haynesville and Permian basin shale reserves had little fundamental impact on the US natural gas market, other than increasing aggregate supply. Since these fields were located in or close to Texas, they fed the Texas intrastate market and the interstate pipelines originating in Texas and Louisiana. It has been the development of the Marcellus shale, both due to its size and location, that changed the structure of the US natural gas market. While production in the Marcellus began in 2006, it wasn't until 2010 that production growth began to accelerate. By 2015, the Marcellus shale was responsible for 20% of US natural gas production.[55] This flood of new gas supply temporarily created congestion and chaos, as it supplanted Gulf of Mexico and Texas gas supplies. Accordingly, the value of point-to-point transportation from the Gulf Coast, as a primary commercial impetus for new pipeline capacity began to diminish[56] and new pipelines from shale gas supply areas were needed to transport the increased production.

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[51] John Harper, "The Marcellus Shale – An Old "New" Gas Reservoir in Pennsylvania," *Pennsylvania Geology* 28 Spring (2008):

[52] Carl Montgomery and Michael Smith. "Hydraulic Fracturing: History of an Enduring Technology." *Journal of Petroleum Technology* (December 2010): 27.

[53] Zhongmin Wang and Alan Krupnick, *A Retrospective Review of Shale Gas Development in the United States*, Resources for the Future, RFF DP 13-12 (April 2013).

[54] http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf.

[55] Energy Information Administration (EIA), *Energy in Brief, Shale in the United States*, July 20, 2016 http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm (last visited August 7, 2016).

[56] Beginning in 1990, the New York mercantile exchange normalized standard natural gas contracts by using the cost of delivery at Henry Hub, a distribution hub on the natural gas pipeline system in Erath, Louisiana, as the primary pricing point for futures and over-the-counter contracts. Because the vast majority of North American supply originated from the Gulf, spot market pricing premised on the cost of natural gas plus transportation from Henry Hub provided a common reference for establishing the value of delivered gas at the various interstate pipeline delivery locations (i.e., city gates) around the country. Stewart Holmes, *The Development of Market Centers and Electronic Trading in Natural Gas Markets* (FERC, Office of Economic Policy, June 1999): 8-9; Mark Haedicke, "Contracts For the New Natural Gas Business," 13 *Energy Law Journal* 313 (1992).

B. NG Demand, Generation, LNG exports

By 2000, the natural gas market had reached maturity in most regions and there was limited growth potential, as natural gas had replaced petroleum products in most submarkets where it provided a cost or operational advantage. Between 2000 and 2014, there was zero growth in nationwide consumption of natural gas for purposes other than electricity generation. Beginning around 2005, natural gas consumption for electricity generation gradually increased as environmental regulations discouraged construction of new coal plants. This trend accelerated after 2009 as both the threat of new air pollution and other regulations under the Obama Administration, and a precipitous decline in natural gas prices, encouraged a shift away from coal.[57]

The Northeast region followed the national trend of near zero growth in natural gas consumption other than electricity generation. Given the limited potential for further penetration of gas into traditional petroleum markets, any future growth in natural gas consumption depends on the interplay between economic growth and the impact of aggressive energy conservation programs in place in most of these states. The potential for conversion from coal fired generation in the Northeast is limited outside of western and central Pennsylvania, and many of the remaining oil fired generators are dual fuel units that want to maintain that flexibility.[58]

The natural gas transmission and distribution system in the Northeastern United States was traditionally built around supplies from the Southwest and Canada. Domestic natural gas flows into the region from the Southwest into Virginia and West Virginia, and from the Midwest into West Virginia and Pennsylvania. Canadian imports come into the region principally through New York, Maine, and New Hampshire. LNG supplies currently enter the region through import terminals located in Massachusetts, Maryland, and New Brunswick, Canada.

In the Marcellus and Utica[59] plays, production has grown rapidly over the past several years, and infrastructure growth has not kept pace. This is partly because pipeline projects may take several years to bring online. As a result, there is a large backlog of wells that have been drilled but won't produce until there is available infrastructure or until the price of natural gas increases. These wells allow Marcellus production to ramp up quickly when new infrastructure comes online. Pipelines have been added in 2015 and 2016, with more projects approved, to transport natural gas to population centers along the Atlantic Coast. Natural gas production in the region increased as producers obtained access to new takeaway capacity. In 2015, 6.0 billion cubic feet per day (Bcf/d) of new pipeline takeaway capacity in the Northeast was commissioned to transport natural gas to the east, south, and west of the Marcellus and Utica shales. In 2016, 2.2 Bcf/d of new pipeline capacity currently under construction is scheduled to come online in the Northeast.[60]

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[57] EIA, *Natural Gas Consumption by End Use*, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm (last visited August 7, 2016); EIA, *Natural Gas Prices*, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm (last visited August 7, 2016).

[58] *Id*.

[59] The Utica shale formation lies below and to the West of the Marcellus Shale.

[60] EIA, "Many Natural Gas-Fired Power Plants Under Construction are Near Major Shale Plays," May 19, 2016, at http://www.eia.gov/todayinenergy/detail.cfm?id=26312 (last visited August 7, 2016).

As the pipeline network expanded the spread in gas prices narrowed. Some natural gas prices at trading hubs in the Appalachian Basin's Marcellus Shale play were trading well below the national benchmark spot price at the Henry Hub in Louisiana.[61] Since the summer of 2012, rising growth in natural gas production in the Marcellus outpaced growth in the region's available pipeline takeaway capacity. As new pipeline capacity came on line, the gap between Marcellus region price points and Henry Hub has narrowed. The price at Transcontinental Pipeline's Leidy Hub in central Pennsylvania averaged 93 cents per MMBtu below the Henry Hub price from December 1 through January 15, 2016. In July 2015, this differential was $1.65/MMBtu. Where pipelines could back out deliveries of Gulf Coast production, and had access to a more diverse pipeline network supplying multiple markets in the Northeast and Midwest, the spot price traded at close to parity with Henry Hub prices.[62]

The major growth market for Marcellus Shale gas will be Midwest markets, especially to areas where substantial coal plant retirements are planned or have already occurred. Marcellus gas will back out Texas and Gulf of Mexico gas, freeing it for export as LNG. Cheniere Energy Inc.'s Sabine Pass terminal in Louisiana has been exporting gas since October, 2015.[63] The expansion of the Panama canal will open up Asian markets by lowering costs of moving LNG out of the Gulf of Mexico.[64] While numerous LNG export terminals are planned, and a number have been proposed to FERC,[65] most will never get built in light of a world LNG glut.[66]

C. Concerns About Adequate Infrastructure

Traditionally, energy policy in the US was built around expanding infrastructure to meet growing energy demand. The energy crisis of the 1970s upended this paradigm due to slower energy growth, first due to slower economic growth and then to policies emphasizing demand side management. However, while energy demand growth is no longer a major driver of energy infrastructure investment, changes in market structure due to the restructuring of the gas and electricity industries and environmental regulations shifted patterns of fuel consumption and

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[61] Matthew Oliver, "Economies of Scale and Scope in Expansion of the U.S. Natural Gas Pipeline Network," *Energy Economics* 52 (2015): 265.

[62] EIA, "Some Appalachian Natural Gas Spot Prices are Well Below the Henry Hub National Benchmark," October 15, 2014 at http://www.eia.gov/todayinenergy/detail.cfm?id=18391 (last visited August 7, 2016); EIA, "Spread between Henry Hub, Marcellus natural gas prices narrows as pipeline capacity grows," January 27,2016 at http://www.eia.gov/todayinenergy/detail.cfm?id=24712 (last visited August 8, 2016).

[63] Naureen Malik, "LNG Exports Shaved 35 Billion Cubic Feet From the U.S. Gas Glut," Bloomberg, April 19, 2016 at http://www.bloomberg.com/news/articles/2016-04-19/lng-exports-shaved-35-billion-cubic-feet-from-the-u-s-gas-glut.

[64] Bill Loveless, "New Panama Canal a Big Boon for LNG Exports," *USA Today*, July 3, 2016 at http://www.usatoday.com/story/money/columnist/2016/07/03/new-panama-canal-big-boon-lng-exports/86471838/.

[65] FERC, *North American LNG Export Terminals Proposed*, August 3, 2016, at http://www.ferc.gov/industries/gas/indus-act/lng/lng-proposed-export.pdf.

[66] Wim de Vriend, "Where Is the LNG Glut Going?" *OilPrice.com*, April 15, 2016 at http://oilprice.com/Energy/Gas-Prices/Where-Is-The-LNG-Glut-Going.html.

electricity generation to different technologies and regions. The massive migration to the Sunbelt also resulted in regional reliability issues requiring infrastructure investments.

The Energy Policy Act of 2005 reflected increasing concerns with reliability of energy infrastructure, especially the electrical transmission grid. Title XII authorized FERC to certify a national electric reliability organization (ERO) to enforce mandatory reliability standards for the bulk power system. The Act also required the Secretary of Energy within a year of enactment and every three years thereafter to conduct a study of electric transmission congestion. The Secretary may designate any geographic area experiencing electric energy transmission capacity constraints or congestion as a national interest electric transmission corridor and override state opposition to building new transmission in that corridor. FERC was to establish incentive-based rate treatments for transmission to promote capital investment in transmission facilities.[67] Under Order 679, FERC provides returns on equity at the upper end of the zone of reasonableness for transmission investments.[68]

EPAct Subtitle B dealt with natural gas issues. The NGA was extended to imports and exports of natural gas, and FERC was given exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal.[69] The Commission was also granted authority over natural gas storage facilities.[70] FERC was designed as the lead agency for the purposes of coordinating all applicable Federal authorizations and for the purposes of complying with the National Environmental Policy Act of 1969 with regard to section 3 authorization and section 7 certificates.[71]

A number of studies, many financed by the natural gas industry, publicized the potential for supply shortfalls if additional pipeline infrastructure failed to be approved by regulators.[72] While Congressional efforts, such as the Natural Gas Pipeline Permitting Reform Act, to expedite approval of natural gas projects were never enacted, they did send a message to FERC.

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[67] Steve Isser, *Electricity Restructuring in the United States: Markets and Policy form the 1978 Energy Act to the Present* (Cambridge: Cambridge University Press, 2015): 343-44, 348.

[68] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (Order No. 679) at PP 91-96; *order on reh'g*,, *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 72 Fed. Reg. 1152 (January 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007) (Order No. 679-A); *order on reh'g*, *Promoting Transmission Investment through Pricing Reform*, 119 FERC ¶ 61,062 (2007).

[69] 15 U.S.C. 717b(e)(1).

[70] 15 U.S.C. 717c (f)(1).

[71] 15 U.S.C. 717n

[72] Energy and Environmental Analysis, Inc., *An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market: Adverse Consequences of Delays in the Construction of Natural Gas Infrastructure*, Prepared for the INGAA Foundation (July 2004); National Petroleum Council, *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy, Volume I Summary of Findings and Recommendations* (September 2003); Mohammad Shahidehpour, Young Fu and Thomas Weidman, "Impact of Natural Gas Infrastructure on Electric Power Systems," *Proceedings of the IEEE* 93 (May 2005): 10-42-56.

D. Polar Vortex and Gas Shortages

The January 2014 "Polar Vortex" event brought home the increasing dependence of the electricity grid on natural gas supplies as gas generation began to supplant coal as the dominate fuel for electric generation. In the 2013/2014 and 2014/2015 winters, many Northeast natural gas pipelines were operating at close to full capacity to meet heating needs. Increased pipeline utilization rates on peak days stressed the natural gas transport system. The limited and somewhat inflexible scheduling windows prevalent in natural gas markets and the lack of alignment between natural gas and wholesale electricity markets created difficulties in scheduling deliveries of natural gas to meet the demand of gas-fired generators. During the evening of January 7, 2014, PJM set a new wintertime peak demand record while dealing with higher than normal generation outages. During the peak demand hour, 22 percent of generation capacity was out of service (one-quarter of these outages were due to natural gas shortages).[73] Following the Polar Vortex, a second series of winter storms and extremely cold weather hit the region January 17 through January 29. To ensure that gas would be delivered during the few hours per day they needed to be in service, generators were required to schedule gas deliveries for a full day at extremely high prices. Spot natural gas and electricity prices soared and natural gas scheduling issues caused most of the $597 million in uplift charges for January 2014.[74] PJM responded by developing a Capacity Performance product which encourages generators to employ such techniques as direct interconnection to one or more pipelines, firm transportation contracts, and installation of back up oil supplies to ensure performance under extreme conditions.[75]

New England experienced similar conditions and high prices during the 2014 cold weather incident. To maintain sufficient fuel supplies, the following winter dual fuel units were recommissioned, and both gas distribution companies and electric generators entered into contracts for LNG imports. While spot prices at the Algonquin Citygate surged past $30/MMBtu in winter of 2013–2014, in the winter of 2014–2015, despite colder temperatures, gas price spikes remained more muted, only exceeding $10/MMBtu.[76] The ISO's Winter Reliability program paid dual fuel units for storing oil, and in the winter of 2014/15, also paid for LNG storage. The program cost $70 million the first winter and $50 million the next year.[77] Using the

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[73] PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014): 4-5, 24.

[74] PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014): 31-32, 39-45.

[75] Reliability Technical Conference, Testimony of Chantal Hendrzak on Behalf of PJM Interconnection, L.L.C. under AD16-15, et. al., May 26, 2016. Natural gas price spikes in the winter of 2016 in PJM were far smaller than 2015. Monitoring Analytics, LLC,, *State of the Market Report for PJM: January through June 2016* (August, 11, 2016): 163.

[76] Jeffrey Logan, Kenneth Medlock III and William Boyd, *A Review of Sector and Regional Trends in U.S. Electricity Markets: Focus on Natural Gas*, Technical Report NREL/TP-6A50-64652 (October 2015): 16.

[77] Jonathan Raab and Paul Peterson, *New England Overview: A Guide to Large-Scale Energy Infrastructure Issues in 2015*, Raab Associates, Ltd. And Synapse Energy Economics, Inc. on behalf of the Boston Green Ribbon Commission (June 30, 2015): 21-22.

most extreme weather conditions (based on winter 2004 which was colder than 2014 or 2015), a study found that there would be no electric sector reliability deficiency, rather, the issue boiled down to the most economic means to meet peak winter demand.[78] Incremental upgrades to existing gas pipelines are expected to increase pipeline delivery capacity by around 400-600 million cubic feet per day by winter 2017/18.[79] Reliance on LNG imports has become increasing economic, especially as a means to meet winter peak needs in comparison to new pipeline capacity,[80] as a glut on the world market has detached LNG prices from oil prices, encouraging a downward pricing trend.[81]

Regulators took a variety of actions to prevent a reoccurrence of events during the Polar Vortex. Peak winter constraints in the supply of natural gas have been addressed by the most economic means to meet peak winter demand, which in many instances has proven to be LNG rather than additional pipeline capacity.

E. Electricity Transmission

Regional increases in demand for electric generation can be met through a variety of options, including energy efficiency, demand response and renewable energy. Nevertheless, where additional gas-fired generation is required to meet demand, , there is a choice between bringing gas to generating sites close to population centers, or bringing gas fired electricity to those demand pockets through upgraded electricity transmission infrastructure. The three system operators, ISO-NE, NYISO and PJM, have been aggressively expanding and coordinating their transmission systems. With the New England power system undergoing a transformation through generation retirements and an increasing reliance on renewable resources and natural gas-fired generation facilities, the addition of transmission will help the region maintain reliability. The plan includes the addition of 210 transmission projects over the next 10 years at a cost of $4.8 billion. From 2002 to June 2015, 634 transmission projects were placed in service at a cost of $7.2 billion, with the investments dramatically reducing congestion. ISO-NE and the NY ISO have implemented a new interregional market system that will streamline electric energy transactions and improve power flow between the two markets.[82] PJM has proposed numerous

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78 Paul Hibbard and Craig Aubuchon, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*, Analysis Group (November 2015): 14-15.

79 Energyzt Advisors, *Analysis of Alternative Winter Reliability Solutions for New England Energy Markets* (August 2015): ES-2.

80 Hibbard and Aubuchon, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*.

81 Fatema Alhashemi, “LNG in the Global Energy Market, Explained,” Brookings , May 10, 2016 at https://www.brookings.edu/2016/05/10/lng-in-the-global-energy-market-explained/ (last visited August 10, 2016).

82 Corina Rivera-Linares, “The Electric Transmission Year in Review by Transmission Hub,” *Electric Power & Light*, January 6, 2016 at http://www.elp.com/articles/2016/01/the-electric-transmission-year-in-review-by-transmissionhub.html (last visited August 9, 2016).

upgrades to address congestion, but has seen no need for a long-lead-time, larger-scope transmission solution to potential reliability concerns.[83]

These transmission investments have significantly reduced congestion in the Northeast region. This trend began in the 2009-2011 period and has continued to the present. Generation and transmission additions across the Northeast in recent years have contributed to lower overall congestion, particularly within New England and PJM. Some congestion still exists, especially into load centers in central New York and the New York City and Long Island areas. There are some restrictions on the delivery of wind generation from the Midwest as existing transmission facilities were designed to meet the on-peak demands of load centers rather than deliver off-peak generation from the remote wind locations. There are also some administrative and institutional issues arising from different market rules, scheduling practices, and transmission reservations between neighboring RTOs and ISOs. RTOs and ISOs in the Northeast are aware of these issues and are actively working to address them.[84]

There are a number of advantages of upgrading the electricity transmission over expanding the natural gas pipeline system. First, since electricity is more expensive to store than gas, overcapacity in electricity is less of an issue than overcapacity in gas transport. Storage of natural gas is often more cost effective than pipeline expansion, particularly to meet variable demand and peak needs, rather than base load demand. Electric storage is relatively expensive compared to the cost of building excess transmission capacity, while the costs of excess transmission are balanced by the benefit of increased reliability and generator market power mitigation. Second, while additional gas pipeline capacity for gas generation locks in one technology, expansion of the electricity transmission grid provides more options as generation technology changes over the coming decades. Third, expansion of the electric transmission grid provides more options for maintaining reliability, from demand response and storage to imported electricity.

IV. FERC AND NG PIPELINE FINANCING

A. 1999 Policy Statement

In the wake of deregulation, FERC began balancing the benefits of increased competition against the costs of new facilities. To promote competition among pipelines, the Commission wanted to ease market entry and exit restrictions by providing for optional certification. The Commission wanted to accelerate the procedure for obtaining §7(c) certificate authority, as it felt that it was good public policy to process applications efficiently and expeditiously to allow consumers to receive gas supplies quickly and benefit the workings of a competitive market.[85]

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[83] NERC, *2015 Long-Term Reliability Assessment* (December 2015): 67.

[84] U.S. Department of Energy, *National Electric Transmission Congestion Study* (September 2015): 62-78. See also North American Electric Reliability Corporation, *2015 Long-Term Reliability Assessment* (December 2015): 52, 56-57,

[85] *Revisions to Regulations Governing Certificates for Construction*, Notice of Proposed Rulemaking, 55 Fed. Reg. 33,027, 33,035 (August 13, 1990).

Optional construction certificates were introduced in Order No. 436. Applicants were not required to demonstrate markets or gas supply to the extent required for traditional construction certificate applications. Rather, the applicant had to be willing to bear the risk of under-utilization of the proposed project. A pipeline was eligible if it agreed to provide nondiscriminatory, open access transportation, and if the proposed rates for the service were designed so that no inappropriate costs were borne by the pipeline's existing customers.[86]

In 1991, FERC began conditioning certain NGA § 7(c) construction certificates so that pipeline companies would bear the risk of recovering project costs. With the on-set of open access transportation, projects were built without the pipeline's having in hand firm, long-term contracts covering 100% of the new capacity. The Commission issued the requested certificate, but included language to impose an "at risk" condition.[87]

Responding to the court's decision in *Algonquin*,[88] the Commission provided policy guidance to determine whether a proposed project warrants the use of rolled-in pricing. The Commission would look to the extent to which new facilities are integrated with the existing facilities and the specific system benefits produced by the project. Benefits included operational and monetary benefits. Absent from the list of benefits were any long-term "social" benefits as they were difficult to substantiate and quantify.[89] The Commission, in evaluating whether a pipeline project was correctly sized, gave great weight to whether the pipeline conducted an open season for all new capacity prior to submitting the application.[90]

In the 1999 policy statement, the Commission saw § 7 approval as a flexible balancing process during which it weighs the proposal's market support, economic, operational, and competitive benefits, and environmental impact. The threshold question applicable to incumbent pipelines is whether the project can proceed without subsidies from their existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the existing customers of the pipeline proposing the project, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. The Commission will proceed to evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. Public benefits could include meeting unserved demand, eliminating bottlenecks, access to new supplies, lower costs to consumers, providing competitive alternatives, increasing electric reliability, or advancing clean air objectives.[91]

The Certificate Policy Statement should be viewed in light of the circumstances that existed at the time of its issuance. Natural gas wholesale markets had just been deregulated, and

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[86] *Id. at* 33,029-30.

[87] "Report of the Committee on Natural Gas Certificate and Authorization Regulations," 14 *Energy Law Journal* 485, 485-87 (1993).

[88] *Algonquin Gas Transmission Company v. FERC*, 948 F.2d 1305 (D.C. Cir. 1991).

[89] *Pricing Policy For New And Existing Facilities Constructed By Interstate Natural Gas Pipelines*, Statement of Policy, 71 FERC ¶ 61,241, 61,915,16 (1995).

[90] *Pricing Policy For New And Existing Facilities Constructed By Interstate Natural Gas Pipelines*, at 61,917.

[91] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

electricity markets were on the verge of emerging across the country. A flood of independent power projects had been proposed in some of the new electricity markets, which could spike demand for natural gas. Obtaining sufficient gas supplies, whether through incentives for drilling or imported LNG was a serious policy question. The Commission, having deregulated pipelines and separated production and marketing of gas from its transport, was content to establish basic rules for approval of new projects, avoiding subsidization by existing customers. With the advent of electricity restructuring and the growth of electricity markets, regulatory staff were shifted away from pipeline regulation.

Distributors supported the end of pipeline rolled-in ratemaking that allowed pipeline companies to raise rates on existing capacity contracts to subsidize the building of new capacity. Groups of gas distributors funded much of the analysis and litigation. Ironically, one result has been excessive earnings by pipeline companies, because eliminating cross-subsidization also meant that existing assets continued to earn revenues on a declining asset base. The elimination of periodic rate cases increased the burden on shippers, customers and FERC to monitor rates, allowing excess earnings to persist. Investments in upgrades and major maintenance projects became new incremental investments which were priced independently of existing transportation contracts.[92]

B. Recent Precedents

FERC seems to be prejudiced in favor of approval of pipeline proposals, as the only denial of a certificate the last few years was the application for the pipeline associated with the Jordan Cove LNG export project. In this particular case, Pacific Connector presented little or no evidence of need for the Pipeline. Pacific Connector had failed to enter into any precedent agreements for its project, nor conducted an open season.[93] However, the high approval rate is partially due to self-selection. The optimal project for easy FERC approval will be fully subscribed without adversely affecting any other pipelines or their customers, will not be subsidized by existing customers, and involves expansion or modification of an existing pipeline so as to minimize adverse effects on landowners or communities.[94]

One application that does not fit the "quick and easy" project approval mold is the joint Florida Southeast/Sabal Trail/Hillabee Expansion project, which extends from Alabama to Florida. Florida Southeast is a wholly owned subsidiary of NextEra Energy, and Sabal Trail is a joint venture of Spectra Energy Partners and a NextEra subsidiary. The project will supply gas to

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[92] Jeff Makholm and Kurt Strunk, "Zone of Reasonableness; Coping with Rising Profitability, a Decade After Restructuring," *Public Utilities Fortnightly* (July, 2011): 18-22; Jeff Makholm and Wayne Olson, "Fueling the Price of Power (and Gas): The Rising Profitability of Pipelines and the Need for Collective Action," *Electricity Journal* 24 (June 2011): 7-12. One perverse implication of regulatory lag in pipeline ratemaking, combined with the elimination of rolled-in pricing, is that pipeline companies have an incentive to delay maintenance investments until they can package them as upgrades. This reduces current expenses and raises earnings, and allows the new investment to be charged to sales of incremental capacity created by the upgrades at higher rates.

[93] *Jordan Cove Energy Project*, 154 FERC ¶ 61,190 at P89 (2016).

[94] *Tennessee Gas Pipeline Company, L.L.C.*, 150 FERC ¶ 61,160 (2015); *Algonquin Gas Transmission*, 150 FERC ¶ 61,163 (2015); *Transcontinental Gas Pipe Line Company, LLC*, 155 FERC ¶ 61,016 (2016); *Northern Natural Gas* 155 FERC ¶ 61,264 (2016); *Transcontinental Gas Pipe Line*, 156 FERC ¶ 61,022 (2016); *Tennessee Gas Pipeline Company, L.L.C.*, 156 FERC ¶ 61,156 (2016).

a power plant owned by Florida Power & Light, a subsidiary of NextEra. The Commission relied on a Florida Public Service Commission order finding that Florida Power & Light had demonstrated a need for additional firm capacity. The Commission did not consider it subsidization for Florida Power & Light to pay for gas services that the Florida Public Service Commission permits to be passed onto its ratepayers.[95]

Traditionally, FERC has repeatedly granted a 14 percent rate of return on equity for "greenfield" pipelines whose equity investors not only face development risk, but also significant financial risk, while granting lower rates of return for pipelines with less risk.[96] The Commission approved a 14 percent return on equity for the Florida project, referring to earlier decisions,[97] ignoring the changes in world financial markets and the lower level of risk through self-dealing. The 14% ROE standard can be traced back to the 1997 decision in *Alliance Pipeline.*[98] In 1997, Moody's Aaa bonds yielded 7.26% and Baa bonds yielded 7.86%, in 2015 their respective rates were 3.89% and 5.00%.[99] The decline in corporate bond rates suggests that 14% is too high a return even for highly leveraged greenfield projects, much less conservatively financed projects backed by regulated affiliated customers with captive ratepayers.[100]

C. Balancing Competitive Pipelines With Efficient Pipeline Network Expansion

Merchant pipelines have to obtain customer commitments, which impose market discipline on new projects. Kinder Morgan Inc. scrapped its proposed $3.3 billion Northeast Energy Direct project when it didn't receive the commitments from big customers needed to proceed.[101] This provides confidence to the Commission that the project is probably economically efficient, since it is unlikely that gas purchasers and/or shippers would subscribe to long-term firm capacity contracts unless they received substantial savings.

Traditionally, FERC has been concerned with the potential for affiliate abuse. One purpose of nondiscriminatory access under Order 436 and Order 636 was to prevent pipelines from favoring gas producing or marketing affiliates. In Order 637, the Commission expressed concern about market power implications of vertical integration between pipelines and LDCs, and between pipelines and electricity generators. FERC was concerned that a pipeline affiliate

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[95] *Florida Southeast Connection et al*, 154 FERC 61,080 (2016).

[96] Makholm and Strunk, "Zone of Reasonableness; Coping with Rising Profitability, a Decade After Restructuring," at 20.

[97] *Bison Pipeline LLC*, 131 FERC ¶ 61,013, at P 24 (2010), *vacated in part*, 149 FERC ¶ 61,243 (2014); *MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165, at P 27 (2008).

[98] *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149 (1997). The proposed recourse rate reflected a 14% ROE and a 70/30 debt-equity ratio, based on the pipeline's actual capital structure.

[99] *Economic Report of the President* (February 2016), Table B-25. Bond Yields and Interest Rates, 1947-2015.

[100] See also the discussion of rates in Comments of the New Jersey Division of Rate Counsel, PennEast Pipeline Company, LLC, Docket No. CP15-558-000 (September 9, 2016): 9-14.

[101] Jon Chesto, "Kinder Morgan Shelves $3 Billion Pipeline Project," *Boston Globe*, April 20, 2016 at https://www.bostonglobe.com/business/2016/04/20/kinder-morgan-shelves-billion-new-england-pipeline-project/iEafnAP2P41o0B9tmM0lEI/story.html (last visited August 10, 2016)

might aid the parent corporate entity by refusing to build capacity , and would be particularly sensitive to complaints that pipelines, on which affiliates hold large amounts of transportation capacity, were refusing to undertake construction projects.[102] FERC also blocked the strategy used by some entities of bidding with multiple affiliates in open seasons for available capacity.[103] The focus on market power reflects the application of market based rates in both electricity and natural gas,[104] and adverse experiences with market manipulation.[105]

There has been less concern in recent years with cross-subsidization of regulated entities in the age of deregulated markets, despite that fact that regulated electricity transmission and natural gas pipelines comprise a substantial portion of the capital investment and related charges that contribute to consumer costs in both industries. The Commission has expressed concern about protecting ratepayers in mergers and similar transactions under the FPA,[106] and this protection should be extended to natural gas pipelines and gas/electric transactions.

Where pipelines are financed through long-term contracts with LDCs or utilities that are subsidiaries of the parent company building the pipeline, the efficiency of the pipeline cannot be presumed by a full subscription to its capacity. Cross-subsidization can be accomplished by risk shifting as well as direct side payments. An uneconomic project that creates excess capacity can be financed in this manner by guaranteeing its income stream at the expense of alternative transport options. In this case, the Commission would be advised to bring a higher level of scrutiny to these projects, including a closer examination of the ROE. Traditionally, regulatory agencies have been wary of the Averch-Johnson effect,[107] whereby if the allowed rate of return is greater than the regulated utility's cost of capital, the regulated utility will inefficiently increase its rate base. While the empirical evidence is mixed,[108] one reason may have been the widespread dissemination of the article among regulators, putting utilities on notice that "gold

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[102] *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, FERC Stats. & Regs. ¶ 31,091 (February 9, 2000); *order on reh'g*, Order No. 637-A, FERC Stats. & Regs, ¶ 31,099 (May 19, 2000); *order denying reh'g*, Order No. 637-B, 92 FERC ¶ 61,062 (2000).

[103] *Bidding by Affiliates in Open Seasons for Pipeline Capacity*, Order No. 894, 137 FERC 61,126 (2011).

[104] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007) (Clarifying Order), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012).

[105] *American Electric Power Service Corp., et al*., 103 FERC ¶ 61,345 (2003); *Enron Power Marketing, Inc., et al*., 103 FERC ¶ 61,346 (2003); *Policy Statement on Natural Gas and Electric Price Indices*, 104 FERC ¶ 61,121 (2003); *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202, 114 FERC ¶ 61,047 (Jan. 19, 2006) (Order No. 670).

[106] *Policy Statement on Hold Harmless Commitments*, 150 FERC ¶ 61,031 (2015).

[107] Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (Dec. 1962): 1053–1069.

[108] Paul L. Joskow, "Regulation and Deregulation After 25 Years: Lessons Learned for Research in Industrial Organization," *Review of Industrial Organization* (2005): 188; Stephen M. Law, "Assessing Evidence for the Averch-Johnson-Wellisz Effect for Regulated Utilities," Working Paper, 2008, at http://

plating" may result in disallowance of investments. FERC should be careful to balance incentives for needed and risky investment with encouragement of excess investment.

The Commission relies on the Supreme Court's statements that "the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[109] A return on equity that compensates a merchant project for taking the risk of bringing capacity to a market may be excessive for a project financed by self-dealing which minimizes risk to the parent company, especially if it shifts the risk to captive customers.[110] Failure to curb affiliate financed projects may end up killing independent pipeline projects and reinstitute vertical integration, both within the natural gas industry and across the natural gas/electricity interface. Given that the Commission has attempted to open up electricity transmission to third parties and outsider scrutiny through Order 1000,[111] it would be ironic if it were to close off natural gas pipeline transmission through a failure to closely scrutinize affiliate financed projects.

V. CONCLUSION

FERC is entrusted with multiple and sometimes conflicting policy goals, to ensure reliability, protect consumers, promote competition, and encourage efficient investments. It may be time for FERC to revisit how it has applied its 1999 policy statement to the threshold economic question that precedes the NEPA inquiry, and delineate more sharply the balance between goals. This is not a call to rewrite the policy statement, but to reinterpret the language in light of changing circumstances in the 27 years since it was issued. One possibility would be to initiate a Technical Conference to discuss how the balancing tests should be applied in the current economic and environmental context. For example, should "subsidization" extend past rolled-in prices to incorporate affiliate customers and the proper balance between ROE and risk? Should "adverse effects" put greater weight on carbon emissions? Should "interests of existing pipelines" be expanded past the piecemeal project by project analysis to include the cumulative

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www.unb.ca/fredericton/arts/departments/economics/acea/pdfs/2008 3.pdf; Donald Vitaliano and Gregory Stella, "A Frontier Approach to Testing the Averch-Johnson Hypothesis," *International Journal of the Economics of Business* 16 (2009): 347–363.

[109] *Composition of Proxy Groups for Determining Pipeline Return on Equity*, Policy Statement, 123 FERC 61,048 at P 47 (2008), *citing FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); quoting *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001).

[110] One of the issues raised in a Massachusetts proceeding was that gas fired generators were unwilling to assume the risks associated with long-term gas pipeline capacity contracts and wanted to shift that risk to the customers of electricity distribution companies. The Court rejected the proposal because it was exactly the sort of risk allocation that the Massachusetts deregulation statute was designed to prevent. *Engie Gas & LNG LLC vs. Department of Public Utilities*, No. SJC-12051 (Mass. May 5, 2016), Slip Opinion at 32-34.

[111] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012); *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

impact of gas pipeline upgrades? Should public benefits explicitly examine alternatives to proposed projects, such as electricity transmission and gas storage (since most of the natural gas growth in the future will be for electricity generation) to determine net benefits in light of opportunity costs?

FERC should also maintain a posture of informed skepticism toward claims by industry actors that there is an infrastructure crisis that only major investments can resolve. This claim has been put forth the last two decades, lobbying for mega-transmission projects, LNG import facilities and new pipelines. Experience shows that the facts on the ground often change much faster (moving from an impending shortage to a surplus of natural gas within a decade) than large scale infrastructure projects can be planned, financed and built. Path dependence is especially severe in the energy industry, where infrastructure projects impact markets for decades.[112] This skepticism should extend to supposedly neutral arbiters. Some ISOs have lobbied to expand the natural gas pipeline network as a solution to gas fired reliability issues. However, ISO management has an innate prejudice toward overbuilding natural gas pipelines. The metrics by which ISO management performance is measured include electricity prices and reliability performance, but not the overall cost to consumers of less than globally optimal solutions.

FERC has not been granted the authority to make environmental policy, as its mandate is to encourage reliable supplies of electricity and natural gas at the lowest cost to consumers. While FERC is not an environmental agency and should not usurp EPA's primary role, it should take environmental considerations into account on the margins when determining the public interest/benefit. Given the overwhelming evidence that climate change is real and a serious threat to the nation,[113] FERC should follow the lead of the executive branch at least to the extent of considering the impact of its decisions on the efforts of other federal agencies to mitigate greenhouse gas emissions.[114] For example, if the EPA's Clean Power Plan is upheld by the Courts, it makes no sense for FERC to pursue policies that contravene the EPA's policies.

A simple rule of thumb can combine the benefits of "muddling through" and protection of the public interest. Projects should be ranked first by "do no harm," and as the size of projects and the potential for adverse consequences increase, both the standard of persuasion and the level of scrutiny by the Commission (from rubber stamping to open hearings) should increase. Upgrades to the electricity grid should be prioritized over upgrades to the natural gas pipeline system to enhance electricity reliability. Financing by arm length contracts is preferable to

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[112] Complex market/institutional systems such as the electricity and natural gas industries tend to be characterized by path dependence and lock-in on multiple levels. Path dependence occurs when initial conditions are followed by a series of contingent (or chance) events whose influence on the path taken is larger than that of the initial conditions themselves. Once a path has been contingently selected, various mechanisms can lead to its self-reinforcement. In the case of energy infrastructure projects, large electricity transmission and gas pipeline projects may determine the scale, choice of technology and location of generation and storage facilities for an extended period of time.

[113] *See Massachusetts et al v EPA*, 127 S.Ct. 1438 (2007); http://data.giss.nasa.gov/gistemp/tabledata_v3/GLB.Ts+dSST.txt; James Hansen et al, "Ice Melt, Sea Level Rise and Superstorms: Evidence From Paleoclimate Data, Climate Modeling, and Modern Observations that 2 °C Global Warming Could be Dangerous," *Atmospheric Chemistry and Physics* 16 (2016): 3761-82.

[114] Council on Environmental Quality, *Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews*, August 2, 2016.

financing by subsidiaries, whether LDCs or electric utilities, where captive customers, not shareholders, bear the risk. ROE for projects should reflect the level of risk, with the highest rate for arm length projects where the developer shoulders the burden. For example, the potential for affiliate abuse may be tolerable when there is no other way to finance a pipeline that would otherwise provide public benefits (increased competition, supplies to underserved regions) that are significantly larger than the potential costs of abuse. But the burden of persuasion should fall upon those who nominate a less than arms-length competitive proposal, or a ROE that is excessive relative to risk, to show sufficient public benefits to justify a financial and corporate structure that creates the potential for self-dealing or additional cost for consumers.

This shift in policy would have minimal impact on most FERC pipeline certificate proceedings, as the majority of proposed projects tend to be upgrades to existing facilities, involving new connections, larger pipes or more powerful compressors. Since these projects tend to be financed by arm length contracts with customers to take the incremental increase in capacity and have minimal adverse impacts on landowners, the community and the environment, they would not require additional regulatory resources.

Focusing the highest level of scrutiny on a few large projects will limit the burden on FERC staff while providing the kind of oversight that will protect the public interest. Heightened scrutiny does not mean all such projects should be rejected, merely that the combination of far larger adverse consequences, the risks posed by path dependence generated by large projects, and the financial risk that may involve customers as well as shareholders counsel greater regulatory attention and critical oversight. Each situation should be judged on its own merits, it may well be that some regions like Texas present lower adverse consequences.

FERC's experience with electricity mega-transmission projects can be extended to gas infrastructure. Massive projects like Project Mountaineer and a new 765-kV system and other huge transmission projects, proposed in the wake of the Northeast Blackout, never materialized. And grid reliability managed to improve despite the failure of these major projects to get off the ground. PJM, MISO, and SPP built and planned tens of billions of dollars of new transmission without any Big Transmission. The envisioned Big Transmission projects didn't survive review relative to the alternative of incremental network upgrades. It turned out that mega-projects are lumpy, present large financial risks and the potential to immediately overbuild the grid. Incremental improvements were less risky, less expensive and less disruptive to markets.[115] FERC should keep this object lesson in mind when revisiting gas pipeline certification policy.

[115] Steve Huntoon, "The Rise and Fall of Big Transmission: The Alternatives May Make More Sense," *Public Utilities Fortnightly* (September 2015): 32-41.

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- *Conducted Market Studies for Demand Response and Solar Energy in North America*.

Analyzed the market for demand response services in North America for a major international energy company, including a review of potential competitors, the regulatory environment and the economic potential of the market.

Analyzed the market for utility scale solar for a major European company, including a review of potential competitors, current and potential technologies, the regulatory environment including federal and state subsidies, and renewable portfolio standards, and the economic potential of the market.

- *Authored a Cost Benefit Analysis of the Texas Energy Efficiency Programs*

The paper included a thorough literature review of the economics of energy efficiency programs, and applied the California Standard Practice Manual tests to Texas data.

- *Developed Business Plans and Market Analyses for Energy Startup Firms*

Firms included a thermal storage company and a solar inverter firm, among others.

- *Analyses of Market Power and Market Structure in Various Electricity Markets*

At Potomac Economics, Dr. Isser participated in the preparation of presentations and annual market reports for the NY ISO, the Midwest ISO and ERCOT.

At PA Consulting Dr. Isser conducted market power analyses in electric utility mergers.

- *International Energy Experience:*

Legal and Economic advisor to the Energy Commissions of the Republics of Georgia and Armenia, for USAID, 1998-1999. Provide support for electricity ratemaking and the development of electricity markets.

Provided financial analysis and support for privatization of electricity sector assets in the Republic of Georgia.

- *Miscellaneous*

Determined the economic value and potential for energy efficiency to enable Texas to meet its targets under the EPA's Clean Power Plan.

Reviewed various options for electric utility ratemaking to provide incentives for utilities to promote energy efficiency.

Analyzed coal leases for contract negotiations.

Conducted analyses for testimony presented in the Pennsylvania and New Jersey electricity restructuring hearings.

LEGAL AND REGULATORY EXPERIENCE

- *Represented Clients in Proceedings before the Texas PUC*

Competitive Renewable Energy Zones (Transmission for Wind) Rulemaking
Energy Efficiency Rulemakings
Demand Response Rulemakings
Energy Storage Rulemakings
Advanced Metering Rulemaking and Implementation Docket
Renewable Portfolio Standard (RPS) Rulemakings

- *ERCOT*

Dr. Isser was an active participant in the Demand Response working group, the Advanced Metering working group, and the Emerging Technologies working group.

- *FERC - Electricity*

Counseled and represented ISO New England before the FERC

- *FERC – Natural Gas*

Provided counsel and representation regarding exempt wholesale generator, natural gas import and export authority, and natural gas pipeline regulation issues.

- *Energy Transactional Work*

Participated in due diligence for the purchase of a LNG facility and related generation and the potential acquisition of four cogeneration plants.

ECONOMIC CONSULTING EXPERIENCE

Conducted a study of the impact of the East Asian Financial Crisis on the environment in Indonesia for the Asian Development Bank.

Calculated the value of lost profits and damages in business litigation. Developed financial models, analyzed industry structure and potential growth, and determined valuation of potential client exposure.

Determined the extent of market power in antitrust cases, including market definition, market power calculations and the probability of new entry into markets.

Evaluated financing alternatives for Texas highways

PUBLICATIONS

A Review of Carbon Markets: EU-ETS, RGGI, California, the Clean Power Plan and the Paris Agreement (September 22, 2016).
http://ssrn.com/abstract=2827620 or http://dx.doi.org/10.2139/ssrn.2827620

Economics and Politics of the United States Oil Industry: 1920-1990 (reissued, Routledge, 2016).

Efficiency and the Low-Carbon Future, for the South-Central Partnership for Energy Efficiency as a Resource, March, 2016. https://eepartnership.org/wp-content/uploads/2016/03/Efficiency-and-The-Low-Carbon-Future.pdf.

(with Robert King) "The Price is Right? Demand Response on Appeal Before the U.S. Supreme Court," *Public Utilities Fortnightly,* December, 2015.

Generation Investment and Resource Adequacy in Electricity Markets (November 13, 2015).
http://ssrn.com/abstract=2690408 or http://dx.doi.org/10.2139/ssrn.2690408

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Electricity Restructuring in the United States: Markets and Policy from the 1978 Energy Act to the Present (Cambridge: Cambridge University Press, 2015).

(with Jay Zarnikau, Amy Martin) "Energy Efficiency Programs in a Restructured Market: The Texas Framework," *Electricity Journal* (March 2015).

(with Marcella Tribble) "Wholesaling in Electricity: Inching Along," *Review of Policy Research* (2003).

"Electricity Deregulation: Kilowatts for Nothing and Your BTUs for Free," *Review of Policy Research* (2003).

Texas, Oil, and the New Deal (NY: Edwin Mellen Press, 2001).

(with Steven Mitnick) "The Enron-PECO Battle: A View From the Inside," *Public Utilities Fortnightly,* March 1, 1998.

(with Robert Michaels) "Stranded Investment: Utility Estimates or Investor Expectations?" *Public Utilities Fortnightly,* June 1, 1997.

(and N. Ballouz, F. McFarland), *Evaluation of Financing Alternatives For Texas Transportation*, FHWA/TX-93/1277-1F, Federal Highway Administration and the Texas Department of Transportation, November 1992.

(and Sten Thore), A Goaling Format for National Energy Security, *Mathematical Modeling*, 9(1) 1987.

(and Dilip Limaye), *Review of Industrial Energy Data Bases*, Electric Power Research Institute, EM-2647, November 1982.

(and Dilip Limaye, D., B. Hinkle, and W.R. Friedman), *Industrial Cogeneration Case Studies*, Electric Power Research Institute, EM-1531, September 1980.

(and Limaye, D., K. Karnofsky, T. Davis, along with SERI staff), *Current and Future Industrial Energy Service Characteristics*, 3 Vols., Solar Energy Research Institute, TR-733-790, Oct., 1980