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PIPELINE CAPACITY TURNBACK: PROBLEMS AND OPTIONS

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EXECUTIVE SUMMARY

Over the last decade, the interaction of market forces, Federal Energy Regulatory Commission (FERC) policy actions and changes in state public utility commission (PUC) regulation has resulted in an increasingly competitive industry. As the industry becomes more competitive, there is an increasing focus on cost minimization, and efficient use of resources. Local distribution companies (LDCs) and other players in the market face increasing pressure to minimize costs and to use their resources, such as their transportation arrangements, efficiently. As a result, LDCs may reduce their entitlements of long-term firm capacity on interstate pipelines, once their current transportation contracts expire. This may cause an excess capacity problem for pipelines, and underrecovery of their capital investments in pipeline construction. The resulting problem, known as the “capacity turnback problem” or “decontracting problem,” may confront pipelines, LDCs and other stakeholders in the gas industry with a significant challenge. The study examines the causes, the magnitude and scope, and the implications of the capacity turnback problem. The study discusses the three large turnback cases that have been brought before the FERC so far, and examines the policy implications of FERC decisions on these cases.

The capacity turnback problem can be traced back to FERC actions (the straight fixed-variable rate design, rules for capacity release, and electronic bidding requirements), state PUC policies (performance-based regulation, unbundling), and market-driven changes in the industry (growth of market hubs and centers, and proliferation of ancillary services). The study finds that there are significant regional differences in excess capacity and the potential for capacity turnback, and that the problem is likely to be most significant in the West and the Midwest. The study finds that most of the turned back capacity will be resubscribed, but on shorter term contracts (typically with five year terms compared to ten to twenty year terms in the past), and at discounted rates. Therefore, pipelines may be faced with significant revenue erosion.

Studies published by trade organizations of LDCs and pipelines indicate that both LDCs and pipelines anticipate a significant capacity turnback and related revenue erosion problem.

This study examines a number of options for addressing the capacity turnback problem that include departures from the straight fixed-variable (SFV) rate design for allocating fixed costs, alternative rate designs (such as seasonal rates and a price floor for interruptible capacity), revision of capacity release rules, revision of bidding requirements of secondary capacity, unilateral exit fees on decontracting customers, reallocation of decontracting costs on remaining customers, negotiated cost-sharing settlements, rate discounts based on duration of contracts, market-based pricing of pipeline services with flexible terms and conditions, and more stringent certification requirements for new pipelines.

Among these options, the study finds the following choices to be preferable because they are market-oriented and economically efficient.

- Negotiated cost-sharing settlements
- Revision of capacity release rules
- Market-based pricing of pipeline services with flexible terms and conditions

Negotiated cost-sharing settlements typically allow pipelines to recover part of their decontracting costs from customers over an extended period of time. The remaining costs are borne by pipeline shareholders. This cost-sharing arrangement has a number of desirable features including voluntary and mutual acceptance, protection from rate shock and an equitable sharing of costs. In previous turnback cases, FERC has indicated its preference for negotiated cost-sharing settlements over alternatives proposed by pipelines — exit fees and full reallocation of decontracting costs to remaining customers. The negotiated settlements reached so far allocated between 20 percent to 35 percent of decontracting costs to pipeline customers and the remaining costs to pipeline shareholders.

Revision of capacity release rules offers another avenue to mitigate the capacity turnback problem. The lifting of the rate cap on released capacity and relaxing of the bidding requirements can stimulate the secondary market and increase the incentive of shippers to hold firm capacity on the pipeline.

Allowing market-based pricing of pipeline services with flexible terms and conditions is another option that can help mitigate the capacity turnback problem. This option can provide incentives to pipelines to aggressively pursue new markets to offset the potential revenue losses from capacity turnback.

Other options that merit consideration include departures from the SFV rate design, alternative rate designs, and price discounts based on duration of contracts.

The study observes that capacity turnback is likely to be a transitional problem and calls for solutions that facilitate, rather than inhibit, the competitive thrust of the industry. The study offers the following responses by state PUCs and LDCs to the capacity turnback problem.

- State PUCs should continue their current thrust toward unbundling and greater customer choice, regardless of the effect on the capacity turnback problem.

- State PUCs should continue prudence reviews of LDC use of upstream capacity.

- State PUCs may wish to provide cost-sharing incentives to the LDC to release unused capacity on the secondary market.

- State PUCs should encourage LDCs to reach equitable cost-sharing settlements with pipelines and allocate the LDC's share equitably among its customers.

- LDCs may wish to form groups to devise collective strategies to respond to the potential capacity turnback problem.

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FOREWORD

The “capacity turnback problem” may become a particularly challenging one for gas pipelines, LDCs, and regulators alike. This study identifies the causes and scope of the problem and examines the policy implications of the three large turnback cases that have come before the FERC and their disposition. Options for addressing the problem are also presented.

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CHAPTER 1

INTRODUCTION

Background

The natural gas industry has been going through a series of transformations over the last two decades. Beginning in the early eighties, the complex interaction of market forces, policy actions of the Federal Energy Regulatory Commissions (FERC), and changes in state public utility commission (PUC) regulation has transformed every segment of the industry from the production well-head to the end-user burner tip. The gas commodity market has been completely deregulated and now experiences vigorous competition. The interstate pipeline, which was an integrated gas supply and transportation provider, has been transformed into a primarily open access transporter. The local distribution company (LDC), which was subject to traditional rate-of-return (ROR) regulation by the state PUC , has seen a growing trend of a shift toward performance-based regulation.[1] Also, the LDC faces increasing pressures to unbundle its gas sales and transportation services, and to become an open access transporter.[2]

Description of the Problem

The transformations in the natural gas industry has produced a number of outcomes for different industry players. For the LDC, the changes meant a greater impetus for cost-minimization in its gas procurement, transportation arrangements, and

[1] Thirteen states currently have performance-based incentives for LDCs.

[2] Currently, most states have unbundled transportation service or other unbundled services for industrial or large commercial customers. Among these, twenty states and the District of Columbia have implemented residential pilot programs or broader customer choice programs. Full customer choice is offered, or is being considered in ten states.

gas delivery services. In particular, the LDC now has to pay more attention to full and efficient utilization of its transportation capacity arrangements with the pipeline. If the LDC determines that its transportation capacity holdings are not being fully utilized, it may choose to reduce its capacity commitment, that is, the LDC's entitlement of firm capacity rights on the pipeline, once the current contracts expire. For the pipeline, this LDC action means a larger inventory of transportation capacity and the potential underrecovery of its investments in pipeline construction. If this phenomenon of pipeline capacity turnbacks (also known as "decontracting") occurs at a significant level, the consequence may be a massive, industry-wide problem of excess capacity and unrecovered capital costs. Such an outcome may confront the pipeline and its customers (including the LDC), and federal and state regulators, with a set of difficult issues.

Overview of the Issues

There may be a number of options that state and federal regulators, and other stakeholders (including pipelines and LDCs) may be able to use to respond to the decontracting problem. Regulators may choose to either (1) allow regulatory recovery of decontracting costs, or (2) let the pipeline recover such costs through more efficient management and expansion of profit opportunities in the growing market-driven environment.

Faced with the decontracting and the resulting excess capacity problem, the pipeline may demand a full recovery of its investments in pipeline construction. The pipeline may argue that it has a right to a full recovery of its costs, which were determined to be prudent by regulators. Also, regulators may choose to allow such recovery in the interest of maintaining the viability of the pipeline service. On the other hand, there may be counter arguments against regulatory recovery of pipeline investments.

Assuming that there is agreement that the pipeline is entitled to some recovery of its decontracting costs, a related issue is how to allocate the cost between customers and shareholders, and among customer groups. One significant issue arising out of cost allocation mechanisms is the rate impact on different groups of customers. The pipeline may be driven to allocate a higher proportion of the cost on those customers with relatively inelastic demand, that is, customers with fewer options. Such a cost allocation may raise the rates significantly to such customers. The pipeline may also pursue other options such as imposing exit fees on decontracting customers, or reaching negotiated settlements with decontracting customers.

Alternatively, federal and state regulators may be able to facilitate market-driven solutions by allowing pipelines to expand their profit opportunities and by providing them with strong incentives to minimize their costs. Also, regulators may encourage the LDC and other shippers to pursue efficient alternatives to drastically relinquishing their capacity commitments.

The issues arising from the choice of solutions to the capacity turnback problem include, among others, economic efficiency, market power and market competitiveness, and equity among parties.

Objectives of the Study

This study examines the causes and implications of the pipeline capacity turnback problem. The study identifies and discusses the factors that contribute to the problem, and examines the implications of the problem for different segments of the natural gas industry. The study also identifies and evaluates various regulatory and market options to address the problems arising out of the capacity turnback problem.

Organization of the Report

The remainder of the report is organized as follows. Chapter 2 identifies the factors that contribute to the pipeline capacity turnback problem and also the general problem of excess pipeline capacity. Chapter 3 examines the magnitude and potential consequences of the capacity turnback problem, and related implications for different segments of the natural gas industry. Chapter 4 identifies various regulatory and market options for addressing the problem. Chapter 5 discusses various state PUC and LDC options for responding to the capacity turnback problem. Finally, Chapter 6 summarizes the findings and presents the conclusions of the study.

CHAPTER 2

THE CAPACITY TURNBACK PROBLEM: CAUSES

The capacity turnback problem can be traced back to some of the major developments in the gas industry over the last two decades. The general thrust of these developments has been toward greater competition, desegregation of market segments and unbundling of services. There has been a parallel evolution in regulation, sometimes in response to, and sometimes facilitating, these developments. The FERC has continually moved toward greater wholesale competition and market access. Starting from a regulatory regime of cost-plus rate-making and automatic cost pass-throughs, the PUCs have successively moved to heightened scrutiny of utility operations, performance-based regulation (PBR), and more recently, unbundling of services at the retail level.

One of the effects of these developments is the lessened need for long-term firm capacity contracts between shippers and interstate pipeline companies, which in turn may lead to discontinuation of existing long-term contracts after they expire. The following sections identify and examine factors that arise from restructuring of the gas industry and changes in gas utility regulation, and that contribute to the capacity turnback problem.

Factors Leading to the Capacity Turnback Problem

The factors leading to the capacity turnback problem can be classified into four major groups, which are: (1) conditions in the interstate gas market, (2) federal regulatory policies, (3) changes in the local gas distribution market, and (4) state regulatory policies.

Conditions in the Interstate Gas Market

The conditions in the interstate gas market that contribute to the capacity turnback problem can be classified into the following categories: (1) seasonal variations in gas demand, (2) slower than projected growth in demand, (3), interregional diversity in demand growth, (4) development of new gas production areas, (5) competition among pipelines, (6) competition from substitutes to firm transportation (FT) capacity, and (7) excess capacity commitments.

Seasonal Variations In Demand

Gas demand varies substantially between seasons. Shippers, which include local distribution companies, need to hold enough capacity on the pipelines to secure transportation during the peak or heating season. A lot of this capacity is not needed during the nonheating season, particularly by LDCs that have low load factors. Traditionally, LDCs held this excess capacity during the nonheating season, to meet the heating load during the peak season, as no other options were available to tailor the capacity commitments to seasonal variations in demand. Under traditional state PUC regulation, the LDC could recover the cost of all capacity to meet peak load, from ratepayers.

However, with the growth of alternatives, such as interruptible transportation (IT), short-term FT, storage, market centers and hubs, and capacity release, the LDC now can better align capacity commitments to seasonal variations in demand. There is a lessened need for long-term firm capacity contracts covering the entire capacity requirement for the peak period. Also, current state PUC policies generally encourage the LDC to optimize its purchase and utilization of transportation capacity by making full use of all the available market alternatives.

The final result of the emergence of alternatives to better manage seasonal variations in capacity needs, and increasing state PUC emphasis on efficient management of capacity, may be fewer long-term firm capacity contracts, a general shortening of the duration of firm capacity contracts, and a general reduction of firm capacity commitments, all of which contribute to the prospect of capacity turnback.

Slower Than Projected Growth in Demand

Besides the seasonal variation in demand, slower than expected growth in *peak* end-use demand can contribute to the capacity turnback problem. The end-use demand for gas has grown at a slower rate than expected. Gas demand grew at an annual rate of over 3 percent during 1986 to 1995, which was lower than expected because of increases in the use of energy efficiency measures and energy conservation, less than expected growth in the use of gas in electric generation and energy-intensive industries.[1]

As mentioned, the capacity commitments of a shipper are based on anticipated maximum demand. If, however, the maximum demand is less than anticipated, *the shipper is left holding excess capacity* under a long-term contract, for which the shipper must pay, even if the capacity is not being used. This may have been an acceptable arrangement for a traditional gas utility under traditional regulation with a statutory obligation to serve and with an assurance to recover all "prudent" costs. The traditional gas utility was expected to err on the side of caution to secure sufficient transportation to ensure the delivery of gas to its customers as needed.[2] With the changes occurring in the gas industry with the LDC gradually becoming an open access transporter and just one of the many suppliers of gas, the LDC may no longer need to secure as much transportation capacity as under the traditional regime. This provides the LDC with an incentive to reduce its capacity commitments once the existing contracts expire. Given

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[1] Energy Information Administration, *Natural Gas 1996: Issues and Trends* (Washington, D.C.: EIA, December 1996).

[2] The obligation to serve presumably put a high premium on reliability. As a result, the trade-off between reliability and cost would become an important consideration only when the cost exceeded the regulatory standard of "prudence." The prudence standard, in the absence of alternatives to the monopoly utility, could not be expected to correctly capture the optimal level of reliability that would have been "produced" and "consumed" in a competitive market.

the fact that much of the new pipeline capacity was built on the expectation of the projected demand growth and capacity commitments of the shippers, slower than projected growth in the end-use demand for gas may have contributed to the capacity turnback problem.

Interregional Diversity in Gas Demand

The general slower than expected growth in gas demand, however, is not a clear explanatory factor for the capacity turnback problem, particularly for the observed regional variations in capacity turnback. Interregional diversity in the growth of gas demand may provide a much better explanation for the occurrence of significant capacity turnback in some regions of the country and not in others. Table 2-1 shows that the interregional diversity in the growth of gas demand for the period 1985 to 1993 has been quite significant. The demand growth has been very small for California (4 percent) and West North Central regions (10 percent), and significant for New England (49 percent) and Pacific Northwest regions (54 percent). Differences and changes in regional economies, such as different rates of economic growth, relocation of industries, and shifts in job markets, can perhaps explain the interregional diversity in the growth of gas demand over the period of observation.

In general, one can expect excess capacity on pipelines serving low demand growth regions and full capacity utilization or even capacity shortages on pipelines serving high demand growth regions. Therefore, one can expect, if other factors are ignored, excess capacity in the pipelines serving California and West North Central regions, and opportunities for expansion for pipelines serving the New England and the Pacific Northwest regions. This is indeed true for the West North Central (excess capacity) and New England (no excess capacity) regions. However, the California and the Pacific Northwest regions are *currently* being served by the same pipelines, and the effect of demand growth on capacity in these regions is likely to be mutually offsetting in terms of contributing to the excess capacity problem on these pipelines.

TABLE 2-1 PERCENTAGE GROWTH IN GAS DEMAND FROM 1985 TO 1993	
Region	Growth
California (Los Angeles)	4%
West North Central (Minneapolis)	10%
North Central East (Chicago)	16%
East South Central (Louisville)	21%
Middle Atlantic (New York)	24%
South Atlantic (Miami)	29%
New England (Boston)	49%
Pacific Northwest (Seattle)	54%
Source: LDC Caucus, American Gas Association, *An Issue Paper Regarding Unsubscribed Pipeline Capacity* (Alexandria, VA: December 1995).	

Development of New Gas Production Areas

The excess capacity problem, however, does exist on some of the pipelines that *traditionally* served California, for another reason: development of new gas production areas. For example, gas produced from the newly developed fields in Canada and the U.S. Rockies is less expensive than the gas produced from the Permian Basin of Texas and the Andarko Basin of Western Oklahoma. As a result, the economic value of pipelines shipping gas from production fields in the Permian and the Andarko Basins to California has diminished. Therefore, LDCs and other shippers have been relinquishing their capacity on the older pipelines as their contracts expire, and contracting for capacity on the new transmission lines built to access gas from Canada and the Rockies. This may be a contributing factor in the decline of capacity utilization from 84 percent in 1990 to 71 percent in 1994.[3] Similar shifts in gas production areas have occurred for other regions in the country including North Central East and West North Central regions (Table 2-2).

TABLE 2-2
PERCENTAGE INCREASE IN GAS SUPPLIED FROM THE REGION'S TRADITIONAL SUPPLY AREA

Region	Increase
North Central East (Chicago)	-33%
California (Los Angeles)	-25%
West North Central (Minneapolis)	-11%
East South Central (Louisville)	-3%
New England (Boston)	-2%
Middle Atlantic (New York)	-2%
South Atlantic (Miami)	15%
Pacific Northwest (Seattle)	NA

Source: LDC Caucus, *An Issue Paper Regarding Unsubscribed Pipeline Capacity*.

Competition Among Pipelines

The operational economies of pipeline transportation may generally limit pipeline-on-pipeline competition for the same customer. In general, neither a pipeline nor a transportation customer may find any economic advantage in establishing a new connection if the customer is already connected to another pipeline under an existing

[3] Ibid.

contract. Because of the high capital costs of new pipeline construction, the competing pipeline would find itself at a cost disadvantage if it were to attempt to connect a wellhead to the service area of the existing pipeline, assuming that the gas production costs and operating costs of transportation were comparable. The transportation customer or shipper may also find it uneconomic to connect to a new pipeline if the shipper does not have a large enough revenue stream to support a new connection, or if the shipper is limited by long-term contractual obligations with an existing pipeline from relinquishing or reducing its capacity commitments. Both of these constraints, however, can be overcome if certain conditions exist or develop.

A pipeline can overcome the cost disadvantage of connecting to a shipper already served by another pipeline if the new connection can access gas from a newly developed field, with lower gas production costs, or lower gas transportation costs. As previously mentioned, newly developed gas fields with lower production costs caused the shift in transportation capacity serving California from pipelines connected to production fields in West Texas and Oklahoma, to pipelines connected to Canada and Rockies. Similarly, finding a gas field closer to the shipper's service area than the existing field can reduce the transportation cost and allow a new pipeline to offer transportation capacity at lower price than current price being paid by the shipper.

A shipper, such as an LDC, may overcome the economic disadvantage if the shipper has either a large revenue base or existing contracts with the traditional pipeline are close to expiration. Table 2-3 shows the average number of pipelines serving major markets. It is likely that regions served by several pipelines are more likely to develop a capacity turnback problem than regions served by one or two pipelines. A survey conducted by the LDC Caucus of the American Gas Association found that LDC expectations about future capacity reduction was positively correlated with the number of connected pipelines (Figure 2-1).[4]

[4] LDC Caucus, *An Issue Paper Regarding Unsubscribed Pipeline Capacity*.

TABLE 2-3
AVERAGE NUMBER OF PIPELINES
SERVING MAJOR MARKETS

Region	Average
California (Los Angeles, San Francisco)	4.0
North Central East (Chicago, Detroit, Milwaukee, Indianapolis, Cleveland, Columbus)	2.3
New England (Boston)	2.0
Middle Atlantic (New York, Philadelphia, Pittsburgh, Buffalo)	2.0
West North Central (Minneapolis, St. Louis, Kansas City)	2.0
South Atlantic (Miami, Atlanta)	1.5
East South Central (Birmingham, Little Rock, Louisville)	1.3
Pacific Northwest (Seattle, Portland)	1.0

Source: LDC Caucus, *An Issue Paper Regarding Unsubscribed Pipeline Capacity*.

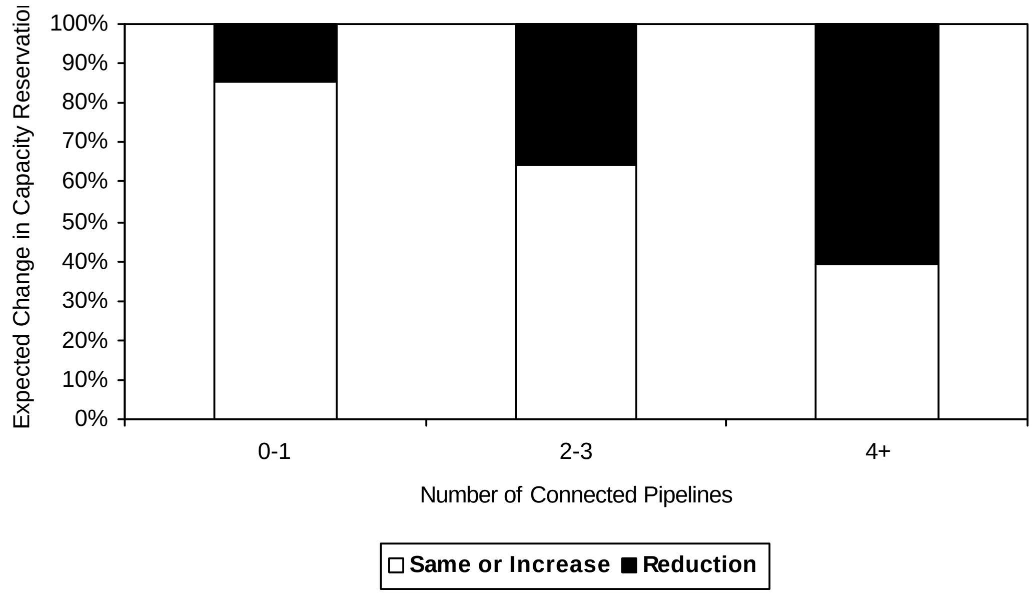

Figure 2-1. LDC expectations about capacity reservation changes between 1995 and 2000 (Source: LDC Caucus, *An Issue Paper Regarding Future Unsubscribed Pipeline Capacity*).

Competition from Substitutes to Firm Transportation Capacity

Until recently, firm transportation capacity was the only means to ensure the delivery of gas when needed. However, a host of substitutes has been emerging that can essentially deliver the same function. Such substitutes include market hubs, storage, interruptible transportation, and capacity in the secondary market.[5]

Market Hubs and Market Centers

Market hubs and market centers offer shippers diversity in choosing their supplies of gas, and provides alternatives for meeting peak-day gas.[6] Market hubs

[5] Ibid.

[6] Rebecca A. McDonald, "Stranded Costs for Interstate Pipelines?" *Public Utilities Fortnightly* 134, no. 7 (April 1, 1996), 24.

and market centers have been growing rapidly since FERC issued Order 636 in 1992 (Table 2-4). The availability of market centers has expanded a shipper's options and flexibility in arranging basic services such as gas sales, transportation and storage. Market centers also provide many ancillary services such as parking, banking, balancing and risk management. Market centers also allow shippers greater flexibility in arranging receipt and delivery points for gas. In combination with released capacity

TABLE 2-4
SUMMARY OF U.S. AND CANADIAN MARKET CENTER OPERATIONS

Item	Number of Operations	Number Reaching Maximum Capability in Jan-Feb 1996[1]	Storage Availability				
			Number of Sites	Total Working Gas (Bcf)	Total Daily Deliverability (Mmcf/d)	Salt/High-Deliverability (Mmcf/d)	Linepack Used for Parking and Loaning (number of centers)
Market Centers							
Pre-1994	12	4	56	568	10,928	1,840	0
1994-1996[2]	27	2	94	1,438	29,221	4,785	3[3]
Total Operational	39	6	150	2,006	30,149	6,625	3
Proposed	6	--	6	104	3,010	1,860	--
Total U.S./Canada Storage (January 1, 1996)	--	--	414	4,306	77,697	10,004	--

Notes:
1. Includes market centers that operated at their maximum (pipeline transfers or storage withdrawals) throughput capability sometime during the two-month period.
2. Does not include sites slated to be in operation after April 1, 1996.
3. Approximately 560 million cubic feet of linepack, on average, is available for parking and gas loaning services at these market centers.

Source: Energy Information Administration, *Natural Gas 1996: Issues and Trends*, 72.

and interruptible transportation, market center services (including storage, parking and banking) help reduce the need for long-haul FT capacity (Table 2-5).[7]

TABLE 2-5
SERVICE PROFILE OF OPERATIONAL U.S. AND
CANADIAN MARKET CENTERS

	Active Centers and Hubs Where Service Is:			
Types of Service	Offered	Most Highly Used [1, 2]	Second Most Highly Used	Third Most Highly Used
Wheeling/Transportation	34	13	6	3
Parking	26	5	12	5
Loaning	23	1	5	8
Title Transfer/Tracking	22	0	1	1
Electronic and Other Trading	17	5	1	1
Buyer/Seller Matching	15	4	1	1
Storage (Separate Service)	12	6	2	3
Peaking	8	1	0	2
Compression	8	0	2	1
Balancing	16	0	0	1
Risk Management	5	0	0	0
Exchanges	6	0	2	0
Hub-to-Hub	2	0	0	1
Administration	4	0	0	0

Notes:
1. Based on volumes, number of transactions, or revenues generated, depending on the individual market center methodology for estimating overall business activity.
2. Level of service information unavailable from four of the thirty-nine market centers.

Source: Energy Information Administration, *Natural Gas 1996: Issues and Trends*, 72.

[7] Ibid.

Storage

Storage provides a viable alternative to firm transportation for pipeline customers. Storage, in combination with interruptible transportation, may provide essentially the same level of delivery assurance as firm transportation capacity. Therefore, the combination of storage and interruptible transportation may be used as a less expensive substitute for firm transportation capacity reservations.

Short-Term Firm and Interruptible Transportation

Short-term FT and IT, when combined with market center services, such as parking, storage, and liquified natural gas (LNG), can be good substitutes to long-term FT. "Parking" refers to a transaction in which a market center holds a shipper's gas for later delivery. Parking can be used to reroute gas deliveries to bypass system bottlenecks. Storage and LNG can be used to secure deliverability of gas supplies. Interruptible transportation can be used to transport gas to meet base load. Short-term FT can be used to transport gas to meet peak load. Therefore, a chosen mix of short-term FT and IT, in combination with selected market center services, can provide the same delivery assurance as long-term FT.

Released Capacity

Firm capacity rights released by other shippers offer a good alternative to holding or renewing firm transportation capacity with a pipeline. The vigorous growth of a secondary market, in which firm capacity rights are traded, may both contribute to and mitigate the capacity turnback problem. The access to firm capacity rights in the secondary market may discourage both new pipeline customers and existing capacity holders from contracting, or renewing contracts, for firm transportation capacity from the pipeline. On the other hand, the opportunity to *sell* capacity in the secondary market increases the incentive to hold firm capacity rights at their present levels, as well as to renew firm capacity contracts.[8]

The net effect of capacity release on an individual pipeline depends on the availability of capacity or capacity rights, from other pipelines. For example, if a given group of customers trade capacity rights belonging exclusively to a single pipeline, the net effect on capacity turnback for that pipeline may be essentially zero, because all trades amount to a redistribution of firm capacity sold by the pipeline. There would likely be new contracts for capacity offsetting any turnback of capacity on existing contracts. On the other hand, if some of the capacity traded belong to another pipeline, the original pipeline may suffer a loss of capacity sales and the competing pipeline may achieve a corresponding gain.

The capacity release market and the value of released capacity have been growing at a rapid rate (Tables 2-6 and Table 2-7). Yet, the potential mitigating effect of capacity release on the capacity turnback problem has not been realized for another reason: the value of released capacity continues to be low relative to the tariff rate[9] (Table 2-8). The value of released capacity has generally been low due to a number of factors that include (1) cumbersome bidding and posting requirements, (2) difficulty of coordinating different contracts, (3) the cap set on released capacity set by FERC Order 636.[10]

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[8] This incentive, however, is present only if the LDC is allowed to retain some or all of the profits from capacity release transactions. States that currently have capacity release incentives include Georgia, Iowa, New York, and North Carolina.

[9] The wide regional variation in the value of released capacity has no apparent correlation with excess capacity (Tables 2-9 and 2-10) and may be an artifact of conditions (bidding and posting requirements) obtained at individual pipelines.

[10] On July 31, 1996, FERC issued a NOPR that proposes to eliminate the price cap on released capacity if the releasing shipper can demonstrate that it lacks market power. More discussion on this NOPR appears in subsequent parts of this report.

TABLE 2-6
REGIONAL CHARACTERISTICS OF RELEASED CAPACITY,
HEATING SEASON (NOVEMBER-MARCH 1994-1996)

Region	1994-95			1995-96		
	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent of Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent of Capacity Subject to Recall
Northeast	3.05	675	74	5.41	847	67
Southeast	1.80	79	98	1.68	84	94
Midwest	3.11	124	80	5.45	349	72
Central	4.47	348	79	4.92	571	82
Southwest	9.18	10	43	5.32	20	2
West	2.90	350	36	4.13	580	39
Total	3.31	1,586	69	4.87	2,451	65

Source: Energy Information Administration, *Natural Gas 1996: Issues and Trends*.

TABLE 2-7
REGIONAL CHARACTERISTICS OF RELEASED CAPACITY,
NONHEATING SEASON (APRIL-OCTOBER, 1994-1995)

Region	1994			1995		
	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent of Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent of Capacity Subject to Recall
Northeast	2.48	724	57	2.10	1,317	60
Southeast	3.79	84	93	1.56	144	91
Midwest	2.51	193	72	2.05	277	75
Central	4.94	489	82	4.03	877	79
Southwest	3.32	10	67	5.77	28	14
West	2.77	539	75	3.15	681	33
Total	3.21	2,038	67	2.83	3,324	61
Total for 12 months, ending March 31	3.25	3,625	--	3.70	5,775	--

Source: Energy Information Administration, *Natural Gas 1996: Issues and Trends*.

TABLE 2-8 THE VALUE OF RELEASED CAPACITY AS A PERCENTAGE OF THE TARIFF RATE	
Region	Value
California (Los Angeles)	14%
West North Central (Minneapolis)	17%
East South Central (Louisville)	20%
New England (Boston)	25%
North Central East (Chicago)	30%
Middle Atlantic (New York)	32%
Pacific Northwest (Seattle)	49%
South Atlantic (Miami)	73%
Source: LDC Caucus, *An Issue Paper Regarding Unsubscribed Pipeline Capacity*.	

Excess Capacity Commitments

Some or all of the above factors may have led to excess capacity commitments by many shippers in certain regions of the country. Lower than expected growth in demand and the emergence of alternatives to better align seasonal variations in gas demand with capacity may have caused many shippers to have more capacity commitments than they need to meet their supply commitments. The low value of released capacity may have prevented shippers from selling off the excess capacity to other shippers in the secondary market. The final outcome is the accumulation of excess capacity in some regions of the country (Table 2-9 and Table 2-10).

TABLE 2-9 EXCESS PEAK DAY CAPACITY (Bcf/D)			
Region	Demand	Capacity	Excess Capacity
California (Los Angeles)	9.5	14.3	51%
East South Central (Louisville)	6.7	10.0	49%
North Central East (Chicago)	30.2	42.8	42%
New England (Boston)	3.8	4.5	18%
Middle Atlantic (New York)	16.5	18.7	13%
West North Central (Minneapolis)	12.8	14.5	13%
Pacific Northwest (Seattle)	2.9	3.2	10%
South Atlantic (Miami)	11.5	12.3	7%
Source: LDC Caucus, *An Issue Paper Regarding Unsubscribed Pipeline Capacity*.			

TABLE 2-10 AVERAGE DAY EXCESS PIPELINE CAPACITY (Bcf/D)			
Region	Demand	Capacity	Excess Capacity
West North Central (Minneapolis)	2.9	7.8	169%
Pacific Northwest (Seattle)	1.1	2.1	91%
New England (Boston)	1.4	2.5	79%
North Central East (Chicago)	10.0	16.8	68%
East South Central (Louisville)	2.7	3.9	44%
California (Los Angeles)	5.3	7.3	38%
South Atlantic (Miami)	4.6	6.0	30%
Middle Atlantic (New York)	6.0	7.3	22%
Source: LDC Caucus, *An Issue Paper Regarding Unsubscribed Pipeline Capacity*.			

Federal Regulatory Policies

FERC Order 636 contained two provisions that may have contributed to the capacity turnback problem. They are, (1) change of pipeline rate design method from MFV (modified fixed variable) to SFV (straight fixed variable), (2) the rate cap on released capacity.

The SFV Rate Design Method

Under Order 636, pipelines are required to use the SFV method, all fixed costs are recovered through a monthly reservation fee. Previously, the MFV or one of its variants was used. Under MFV, a part of fixed costs including the return on equity and related taxes, was allocated to the commodity component of the costs, and the related recovery was based on volume of usage.

The changeover to SFV has the effect of raising the cost of firm transportation to shippers, particularly those with low load factors. Such shippers, therefore, are less likely to renew firm transportation contracts once they expire.

The Rate Cap on Released Capacity

FERC Order 636 adopted a capacity release program that was intended to help shippers offset some of the costs of holding long-term firm transportation capacity. However, as previously discussed, the program has certain features that limited the ability of capacity holders to achieve the intended cost savings. Such features include cumbersome posting and bidding requirements, a rate cap, and a minimum commodity rate set to recover only variable costs.

Changes in the Local Distribution Market

Traditionally, the LDC was an integrated supplier of bundled gas services that included gas commodity, storage, and transportation behind the city gate. An LDC's customers had limited alternatives in finding these services from other providers. However, in keeping with the increasing competition in, and deregulation of, the wholesale gas market, alternatives to the LDC as a supplier of commodity gas has emerged. Many industrial, electric utility, and large commercial customers are able to procure their own supplies of gas, separately arrange for transportation to the city gate, and purchase only distribution service behind the city gate from the LDC. Some large customers are even able to bypass the LDC altogether, and arrange for transportation directly to its premises.

In response to these developments and PUC initiatives, many LDCs are considering, and some have started implementing expanded programs for unbundling LDC services. Most large customers are now able to purchase unbundled distribution service from the LDC. LDCs, at PUC initiative or with PUC approval, are proposing to extend unbundled transportation services to small customers, including residential customers.

One effect of LDCs providing unbundled transportation services, in combination with a significant fraction of customers purchasing their own supplies of gas and interstate transportation services, is that the need for the LDC to hold firm transportation capacity before the city gate is significantly reduced. A significant part of the transportation capacity held by the LDC prior to the unbundling of its services may no longer be needed.

State PUC Regulation

Over the last decade, state PUC regulation has increasingly focused on cost minimization and performance incentives for LDCs. State PUCs have been heightening their level of scrutiny of gas supply portfolios, and transportation and distribution arrangements. State PUCs have also been introducing incentive rates and performance-based mechanisms to encourage cost minimization and efficient utilization of resources. More recently, state PUCs have been moving toward greater unbundling of retail gas services, and offering more customer choice (Tables 2-11 and 2-12).[11] With increasing unbundling of services, the LDC is gradually being transformed into an open access distributor, and the need for reserving firm capacity on the pipeline is on the decline. These developments provide a strong impetus to LDCs for minimizing the costs of procuring, transporting and delivering gas to the customer. The pressures and incentives for cost minimization cause the LDC to turnback any unneeded capacity, unlike an earlier time when an LDC had a fairly reasonable opportunity to recover any or all of its costs that met the regulatory prudence test. The outcome is an increasing trend toward turning back even “marginally surplus” firm capacity.

[11] The data in Table 2-11 represent the status of unbundling for all customer classes as of December 1996. The data in Table 2-12 represent the status of residential unbundling as of June 1997.

TABLE 2-11
UNBUNDLING ACTIONS BY SELECTED STATE PUBLIC UTILITY COMMISSIONS
(as of December 1996)+

State	Significant Actions	Date	Class of Customers Affected
California	Defined core and non-core market segments. Non-core segment allowed to buy unbundled supply and transportation.	1986	Industrial and large commercial.
	Statewide capacity brokering plan for allocation of interstate capacity to non-core customers	11/6/91	Industrial and large commercial
	Adopted rules for a permanent core customer aggregation program that allows small customers to pool together to receive transportation-only service. Pacific Gas & Electric should unbundle its services by 1/1/1998 and Southern California gas and San Diego Gas & Electric should offer unbundled services by 1/1/1999.	7/19/95	Small commercial
Georgia	Public Service Commission issued a policy statement including: unbundling of interruptible service to non-core customers and the establishment of a pilot program for unbundled service to core customers; gradual movement to incentive rates; transition costs should be charged to parties benefiting the most from competition; no cross subsidies between utilities and their marketing affiliates.*	5/31/96	Industrial and commercial
Iowa	Iowa's PUC adopted small customer unbundling in 1986. However, until recently the requirement for telemetering and standby service and a lack of marketers willing to enter the market have prevented effective choice.	1986	Residential
	MidAmerican Energy Corporation conducted a small residential pilot program to unbundle service to all customers.	11/1/95	
Maine	Unbundling proposal by Northern Utilities under consideration by the regulatory commission.	--	Industrial and commercial
Maryland	Maryland Public Service Commission recommendation to unbundle retail sale service into supply and delivery services for all customers.	11/15/94	Residential and small commercial
	Baltimore Gas and Electric's unbundling filings approved.	8/2/95	All
Massachusetts	PUC approved proposal for a pilot residential unbundling program before the 1996 heating season.	12/31/95	Residential

TABLE 2-11
UNBUNDLING ACTIONS BY SELECTED STATE PUBLIC UTILITY COMMISSIONS
(as of December 1996)+

State	Significant Actions	Date	Class of Customers Affected
Minnesota	Minnegasco filed a proposal to unbundle services. Highlights: * Unbundles long-haul pipeline transportation from local delivery * Establishes a 3-year experiment for the aggregation of small transportation customers * In case of a shortage, Minnegasco will make efforts to supply gas to transportation-only customers at special rates	4/14/95	Industrial and large and small commercial
Montana	PUC ordered Montana-Dakota utilities to file a gas-unbundling plan for all customers by July 1, 1996.	--	To be determined
Nevada	Unbundling activity has focused on workshops and issue statements.	--	--
New Hampshire	Transportation offered to customers who consume more than 10,000 therms a month.	--	All
New Jersey	PUC issued guidelines	1/20/93	Nonresidential
	LDCs required to file plans to unbundle rates to nonresidential customers.	3/29/95	
New Mexico	Transmission, distribution, storage, standby service and emergency gas service are fully unbundled.	1984	All
New York	New York Public Service Commission (NYPSC) issued general guidelines and asked the largest utilities to file unbundling plans.	12/20/94	Non-core customers (industrial and large commercial)
	NYPSC approved nine plans.	3/95	
	Brooklyn Union will offer transportation-only service to commercial and residential customers.	5/1/96	Small commercial and residential
Oklahoma	Always allowed transportation-only service.	--	Industrial and commercial
Texas	Always allowed transportation-only service.	--	Industrial and commercial
Washington	Unbundled sales, transportation, storage and standby service have been in place since 1989.	1989	--

TABLE 2-11
UNBUNDLING ACTIONS BY SELECTED STATE PUBLIC UTILITY COMMISSIONS
(as of December 1996)+

State	Significant Actions	Date	Class of Customers Affected
Wyoming	Scheduled a conference on unbundling.	6/6/95	Proposes unbundled rates only for non-core customers (industrial and large commercial)
	Wyoming Public Service Commission approved KN Energy's unbundled service program for its core customers. Under the program, only gas sales would be opened to competition. All other services would continue to be provided by KN Energy.	2/96	All

+ Information on more recent unbundling initiatives, including residential pilot programs, is presented in Table 2-12.
* State law passed in 1997.

Source: Energy Information Administration, *Natural Gas 1996: Issues and Trends*.

TABLE 2-12 RESIDENTIAL PILOT PROGRAMS AND UNBUNDLING INITIATIVES (as of June 1997)					
State	Company	Potential # of Homes	Potential Demand (Bcf)	In-Service Date	Pending or Completed Government Action*
California	Pacific Gas & Electric	3,300,000	198	07/97	CPUC Rulings Issued
	Southern California Gas	450,000	27	In-Service	CPUC Rulings Issued
District of Columbia	Washington Gas	3,000	.3		
Colorado	Public Service of Colorado				PUC Hearings Being Held
Georgia	Atlanta Gas Light	1,215,000	138.9		State Law Passed
Illinois	Central Illinois Light Company	10,000	1.3	10/96	
Indiana	Northern Indiana Public Service	20,000	2.3		URC Study Completed
Iowa	MidAmerican Energy	875	.1	11/95-10/96	
Maine	Northern Utilities	15,000	.9	11/99	PUC Inquiry
Maryland	Baltimore Gas & Electric	25,000	2.3	11/97	PSC Recommendations Issued
	Columbia Gas	10,000	.9	11/96	PSC Recommendations Issued
	Washington Gas	6,000	.5	11/96	PSC Recommendations Issued
Massachusetts	Bay State Gas	10,000	1.0	11/96	Pending Motion to Dept. of Pub. Utilities
	Boston Gas	475,000	45.6	11/97-2000	Pending Motion to Dept. of Pub. Utilities
Michigan	Battle Creek Gas	1,000	.1	04/97	PSC Hearings Being Held
	Consumers Energy	40,000	5.4	04/97	PSC Hearings Being Held

TABLE 2-12
RESIDENTIAL PILOT PROGRAMS AND UNBUNDLING INITIATIVES
(as of June 1997)

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-Service Date	Pending or Completed Government Action*
Michigan (cont.)	Michigan Consolidated Gas	47,000	6.4	04/97	PSC Hearings Being Held
	Michigan Gas Co., SE Michigan Gas Co.	2,500	.3	04/98	PSC Hearings Being Held
Montana	Montana Power	115,000	13	by 2001	State Law, PSC Proceeding
New Jersey	Elizabethtown Gas	10,000	1.0	11/97	State Energy Plan BPU Order Issues
	New Jersey Natural Gas	30,000	3.1	04/97	State Energy Plan BPU Order Issues
	Public Service Electric & Gas	65,000	6.4		State Energy Plan BPU Order Issues
	South Jersey Gas	10,000	1.2	08/97	State Energy Plan BPU Order Issues
New Mexico	Public Service of NM	338,000	24.1		
New York	Statewide	4,040,000	398.7	In-Service	PSC Regulations Issued
Ohio	Cincinnati Gas & Electric	15,000	1.8	10/97	State Law Passed
	Columbia Gas of Ohio	1,150,000	141.7	04/97	State Law Passed
	East Ohio Gas	1,025,000	126.3	04/98	State Law Passed
Oklahoma	Oklahoma Natural Gas	640,000	52.5	05/98	Active OCC Inquiry
Oregon					OPUC Stated Objectives
Pennsylvania	Columbia Gas	20,000	2.3	11/96	Pending Legislation
	Equitable Gas	233,000	24.5	04/98	Pending Legislation
	National Fuel Gas Dist. Co.	19,000	2.4	09/97	Pending Legislation
	Peoples Natural Gas Co.	317,000	38.0	04/97	Pending Legislation

TABLE 2-12 RESIDENTIAL PILOT PROGRAMS AND UNBUNDLING INITIATIVES (as of June 1997)					
State	Company	Potential # of Homes	Potential Demand (Bcf)	In-Service Date	Pending or Completed Government Action*
Virginia	Common-wealth Gas Services	26,000	2.2	09/97	
West Virginia	Mountaineer Gas Co.	180,000	18.3	In-Service	
Wisconsin	Wisconsin Gas	1,000	.1	11/96	
Wyoming	KN Energy	9,000	.9	06/96	PSC Study Completed
TOTAL		13,648,375	1266.9		

* In most cases, regulatory approval is needed for utilities to offer residential transportation services.

Source: American Gas Association, Website: http://www.aga.com.gio/ib97-03, June 1997.

CHAPTER 3

THE CAPACITY TURNBACK PROBLEM: MAGNITUDE AND IMPLICATIONS

At this time, the magnitude of the future capacity turnback is not certain. However, two studies, by Interstate Natural Gas Association of America (INGAA)[1] and by the American Gas Association (AGA)[2], provide some estimates of the magnitude and other characteristics of the potential capacity turnback problem.[3] In the following sections, the two studies are summarized, and then compared, on their projections of the scope and magnitude of the capacity turnback problem. Next, the implications of capacity turnback are discussed.

The INGAA Study

The INGAA study is based on a survey of pipelines. The study attempts to project the amount of contract expirations and resubscriptions through the year 2002. The survey also provides data on contract lengths, estimates the cumulative effects of expirations of capacity contracts and capacity resubscriptions, and analyzes the possible regional differences of the potential capacity turnback phenomenon.

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[1] Interstate Natural Gas Association of America, *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity* (Washington, D.C.: INGAA, September 1995).

[2] LDC Caucus, American Gas Association, *An Issue Paper Regarding Future Unsubscribed Capacity* (Alexandria, VA: LDC Caucus, AGA, December 1995).

[3] Both studies also examine possible causes and examine possible remedies to the capacity turnback problem. Their findings are included in the previous chapter, which examines causes, and a subsequent chapter, which discusses remedies to the problem.

The Baseline Data

The INGAA study uses firm capacity in 1994 as a baseline, since the "survey results did not show a material amount of unsubscribed firm capacity in any one year prior to 1994."[4] The total capacity in 1994, according to the survey, was 76.5 Bcf/day, of which 92 percent was under long-term firm contracts, 4 percent was under short-term contracts, and 4 percent of the capacity was unsubscribed. The study also reports regional differences in capacity subscription in 1994. Unsubscribed capacity was small (Figure 3-1) in all regions. The corresponding volumes of unsubscribed capacity were approximately 113 Mcf/day in the West, 1998 Bcf/day in the Midwest and 316 Mcf/day in the Rockies.

Contract Expirations Through 2002

According to the INGAA , significant amounts of contracted capacity will expire through 2002. On a national basis, between 1.7 Bcf/day (2.2 percent in 2001 and 2002) and 8.7 Bcf/day (11.4 percent in 2000) will expire in different years between 1995 and 2002 (Figure 3-2).

Capacity Resubscriptions Through 2002

Most of the capacity under expiring contracts is expected to be resubscribed, according to survey respondents. The resubscription is expected to vary between 66 percent and 100 percent (Figure 3-2).

[4] Interstate Natural Gas Association of America, *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity*, 1.

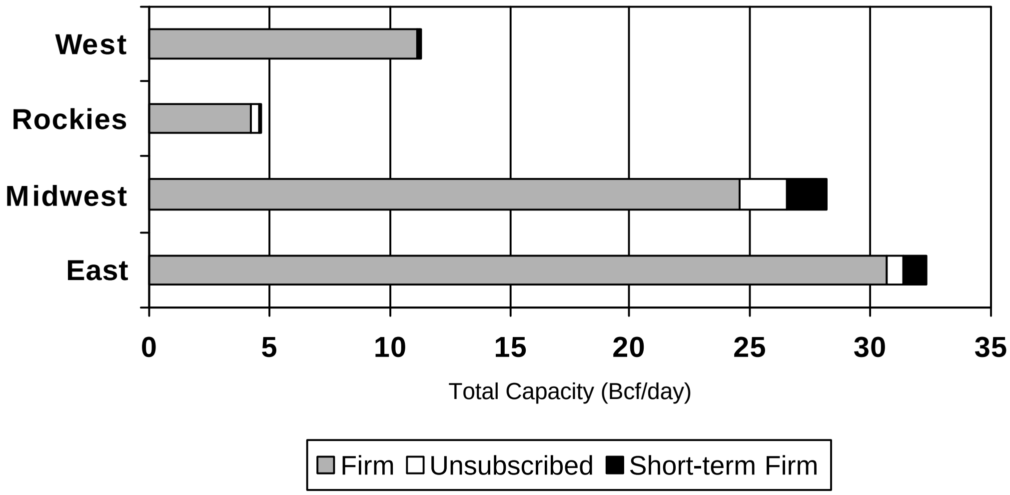

Figure 3-1. Base line data on firm capacity subscription in 1994 (Source: INGAA, *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity*).

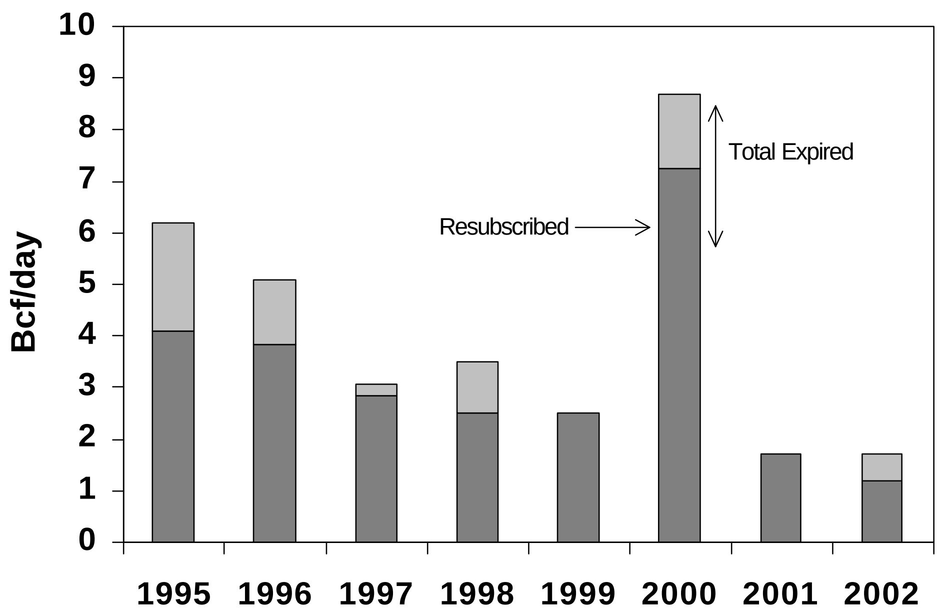

Figure 3-2. Contract expirations and resubscription through 2002 (Source: INGAA, *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity*).

Duration of Future Capacity Contracts

The length of contracts for resubscribed capacity, however, is expected to be shorter than in the past. Future contracts are expected to have lengths between one and twelve years, compared to past contract lengths of ten to twenty years (Figure 3-3). Of the future contracts, only 26 percent of the contracts are expected to have lengths of ten years or more and 21 percent are expected to have a contract term of five to eight years. The majority of contracts, 53 percent, is expected to be four years or less (Figure 3-3).[5]

Cumulative Effect of Contract Expirations and Resubscriptions

The INGAA study also estimates the net cumulative effect of contract expirations and resubscriptions over time. (Figure 3-4) It is estimated that 47 percent, slightly less than half, of the pipeline capacity will expire by the year 2002. Approximately 73 percent of the expired capacity is expected to be resubscribed. Therefore, resubscribed capacity will represent 34 percent (73 percent of 47 percent) of total pipeline capacity. Added to the capacity under contracts unexpired through 2002 (53 percent), the total subscribed capacity in that year is expected to be 87 percent of the total. Therefore, unsubscribed capacity is expected to increase from 4 percent in 1994 to 13 percent by 2002.

Regional Differences in Potential Capacity Turnback

The INGAA study also reports regional differences in expected unsubscribed capacity (Figure 3-5). The increase in unsubscribed capacity is expected to be highest

[5] Ibid, 6.

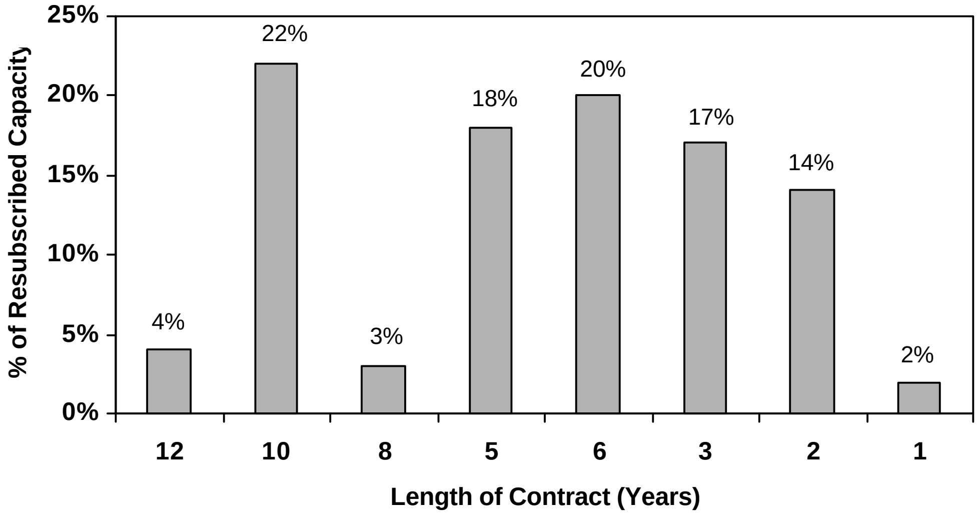

Figure
3-3. Contract lengths for resubscribed capacity (Source: INGAA, *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity*).

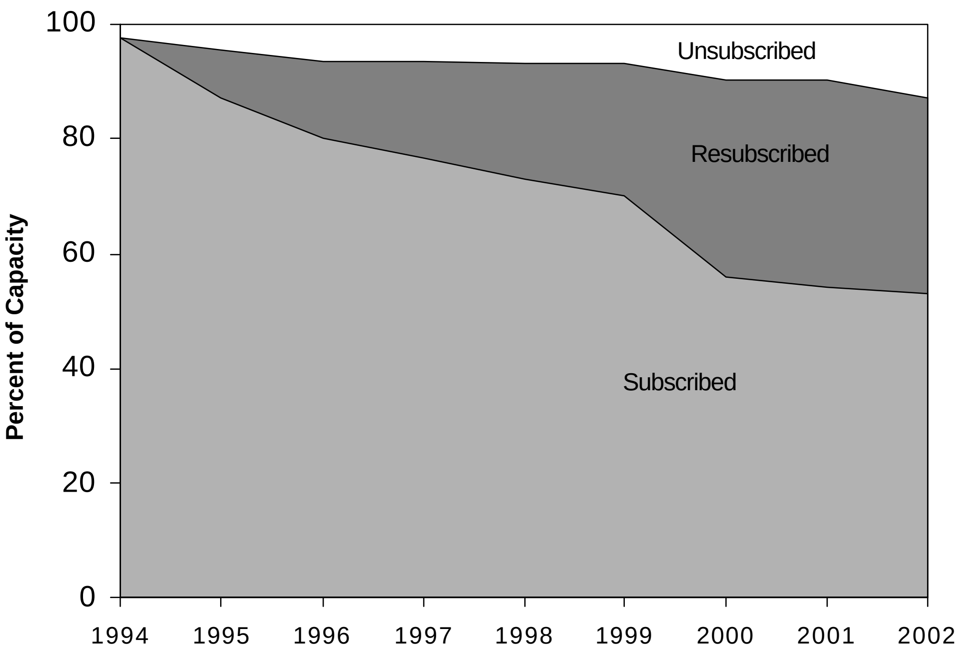

Figure 3-4. Cumulative contract expirations and resubscriptions (Source: INGAA *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity*).

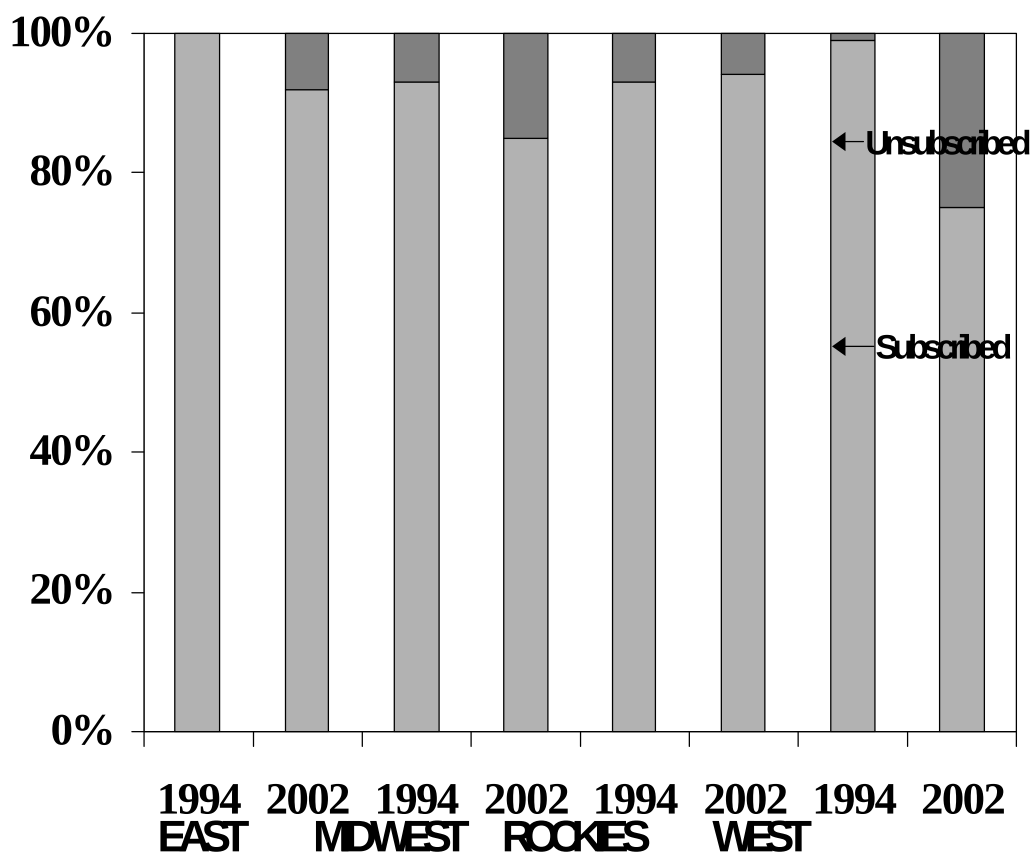

Figure 3-5. Regional differences in potential capacity turnback (Source: INGAA, *The Effect of Restructuring on Long Term Contracts for Interstate Pipeline Capacity*).

in the West (from 1 percent to 25 percent). The Midwest (from 7 percent to 15 percent) and the East (from 2 percent to 8 percent) are expected to experience more modest increases. The Rocky Mountains region is expected to experience a *decline* (from 7 percent to 6 percent) in unsubscribed capacity.

The AGA Study

The AGA study is based on a survey of seventy-five LDCs. The study attempts to assess the capacity turnback problem on the basis of the intent of individual LDCs to increase, maintain or reduce their current level of capacity subscription upon the termination of their firm capacity contracts.

Contract Expirations Through 2000

According to the AGA study, contracts for firm capacity will expire for 52 percent of the LDCs by the year 2000.

Capacity Resubscriptions Through 2000

Of the total seventy-five respondents, 28 percent expected to increase their capacity reservations, 35 percent expected to remain at the current level, 36 percent expected a reduction between 5 percent and 25 percent, and 9 percent expected a reduction of more than 25 percent.[6] The results indicate that 45 percent of the respondents expect to reduce their capacity reservations, to be offset by the 28 percent that expect to increase their capacity reservations.

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6 American Gas Association, *An Issue Paper Regarding Future Unsubscribed Pipeline Capacity*, 17.

Duration of Future Capacity Contracts

Of the sixty respondents who were queried on this issue, 23 percent indicated a preference for contracts for terms of ten years or longer, 47 percent would contract for terms of four to nine years, and 30 percent preferred to contract for one to three years.

Regional Differences in Potential Capacity Turnback

The AGA study develops a composite score on the likelihood of the capacity turnback problem for different regions of the country. The composite score is based on data for a number of factors believed to be precursors or indicators of a potential capacity turnback problem. The factors are: (1) percentage increase in gas supplied from the region’s traditional supply area, (2) excess peak day capacity, (3) average peak day capacity, (4) percentage growth in gas demand from 1985 to 1993, (5) the value of released capacity as a percentage of the tariff rate, (6) average number of pipelines serving major markets, and (7) potential for significant contract terminations by the year 2000. A point was assigned to a region each time it scored “high” on one of the factors. The final scores are on a scale of 1 to 7, where 1 indicates the lowest likelihood and 7 indicates the highest likelihood of turnback. The composite scores are shown in Table 3-1. As the table shows, the likelihood of capacity turnback is highest in California and North Central East regions. The turnback problem is also likely to be significant in East South Central, West North Central and New England regions. The Mid-Atlantic, South Atlantic and Pacific Northwest regions are not expected to have significant turnback.

Comparing the INGAA and AGA Studies

The INGAA and AGA studies use different methods to analyze the capacity turnback problem, and present the findings in different forms. The INGAA study uses a

TABLE 3-1 COMPOSITE SCORE ON POTENTIAL CAPACITY TURNBACK FOR DIFFERENT REGIONS	
Region	Score
California (Los Angeles)	7
North Central East (Chicago)	7
East South Central (Louisville)	5
West North Central (Minneapolis)	5
New England (Boston)	4
Middle Atlantic (New York)	2
South Atlantic (Miami)	1
Pacific Northwest (Seattle)	1
Source: LDC Caucus, *An Issue Paper Regarding Future Unsubscribed Capacity*.	

survey of pipelines to estimate capacity *volumes* that may remain unsubscribed once the existing contracts expire. The AGA study, on the other hand, uses a survey of LDCs and empirical data on what may be characterized as "turnback precursors" to develop *qualitative* scores on the potential of a capacity turnback problem. Therefore, it is difficult to compare the two studies given the dissimilarity of method and the lack of correspondence between the variables used to present the findings. However, certain conclusions common to both studies can be drawn.

Conclusions from the INGAA and AGA Studies

Most Contract Expirations Will Occur in the West and the Midwest

Both the INGAA and AGA studies indicate that most of the contract expirations will occur in the West and the Midwest, as shown in Table 3-2.

TABLE 3-2 PROJECTIONS OF FUTURE CAPACITY SUBSCRIPTIONS					
INGAA		LDC Caucus			
Region	Estimated Unsubscribed Firm Capacity by 2002 (MMBtu/d)	Region	Probability of Experiencing Unsubscribed Capacity (7 = very likely)	Excess Capacity Average Day (MMBtu/d)	Excess Capacity Peak Day MMBtu/d)
West	2,832,500	California	7	2,060,000	4,944,000
East	2,636,800	East South Central	5	1,236,000	3,399,000
Midwest	4,171,500	Middle Atlantic	2	1,339,000	12,978,000
Rockies	247,200	New England	4	1,133,000	721,000
		North Central East	7	7,004,000	2,266,000
		Pacific Northwest	1	1,030,000	1,751,000
		South Atlantic	1	1,442,000	309,000
		West North Central	5	5,047,000	824,000

MMBtu/d = Million Btu per day.

Source: Energy Information Administration, U.S. Department of Energy, *Natural Gas 1996: Issues and Trends*; Interstate Natural Gas Association of America, *The Effect of Restructuring on Long-term Contracts for Interstate Pipeline Capacity*; and LDC Caucus, *Future Unsubscribed Pipeline Capacity*.

Most Capacity Turnbacks Will Occur in the West and the Midwest

Both the INGAA and AGA studies indicate that the bulk of the unsubscribed capacity will occur in the West and the Midwest (specified as "Midwest" in the INGAA study and as "North Central East" in the AGA study), as shown in Table 3-2.

Future Contracts will be of Shorter Duration

Both the INGAA and the AGA studies suggest that future contracts will be of shorter duration than those of existing contracts. The INGAA study reports that the pipelines in the survey expect only 26 percent of the resubscribed capacity to have terms of ten years or more, and the majority of the contracts (53 percent) will have terms of four years or less. The AGA study indicates that only 23 percent of the 60 LDCs surveyed on the issue would prefer to have contracts for a term of ten years or more, and approximately one third (30 percent) preferred to contract for terms of one to three years.

Comparison of Magnitude of Capacity Turnback from the Two Studies

The INGAA study predicts that the cumulative unsubscribed capacity in 2002 will be 13 percent of the total available capacity. The AGA study, on the other hand, indicates that 45 percent of the LDCs surveyed expected to reduce their capacity reservations by the year 2000. It is not possible to compare these two measures of turnback potential (volume vs number of companies). It is interesting to note that 54 percent of the LDCs that expected to reduce their capacity reservations in the AGA study were relatively *large* and had a throughput exceeding 300 Mmcf/d.

Implications

Capacity turnback has significant implications for all segments of the natural gas industry. The implications include, (1) financial impact on pipelines, (2) effect on interruptible capacity (3) effect on the secondary market for capacity,
(4) effect on alternatives to firm capacity, and (5) changes in FERC rate design.

Financial Impact on Pipelines

The combination of a general increase of unsubscribed capacity and a general reduction of capacity contract lengths may have adverse financial impact on pipelines, including potential revenue erosion, and an increase in the pipelines' cost of capital in the financial markets. However, there may be other effects that would mitigate the adverse financial impacts of capacity turnback.

Potential Revenue Erosion

There may be a significant decrease in pipeline revenues because of the reduction of subscription volumes. According to an estimate by the U.S. Department of Energy (DOE), a 20 percent reduction in capacity subscriptions in 2001 could result in at least $686 million dollars reduction in pipeline revenues.[7] If the unsubscribed capacity is assumed to be the much lower amount of 12 percent projected by the INGAA study for the year 2001, the expected annual revenue reduction would be $411 million.

Increase in A Pipeline's Cost of Capital

As noted, most of the firm resubscribed capacity will be of shorter duration than existing capacity contracts. Combined with the potential for revenue erosion due to reduced capacity subscriptions, the shortening of contract lengths may lead investors in a pipeline company to perceive a greater risk and demand a higher return on their investment. As a result, a pipeline's cost of capital may increase.[8] Finally, the combination of revenue erosion and increased financing costs may reduce the profits of

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[7] The revenue reduction was estimated using data on the lowest firm transportation rates published in H. Zinder and Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies* (March 15, 1996). See Energy Information Administration, *Natural Gas 1996: Issues and Trends*.

[8] For a statistical study on the relationship between electric utility market-to-book ratios (M/B) and estimates of "stranded costs," see Augustin Ros, John L. Domagalski, and Philip O'Connor, "Stranded Costs: Is the Market Paying Attention?" *Public Utilities Fortnightly* 134, no. 10 (May 15, 1996): 18-21.

a pipeline, thereby putting it in financial difficulty.

Effects that May Mitigate the Adverse Financial Impact

Faced with significant capacity turnback and its potential financial impacts, a pipeline may market its services, including interruptible service (see the discussion in the following section), more aggressively and with a lower price. This may compensate for some of the revenues lost due to turnback of firm service. Further, shippers that turn back firm capacity may substitute interruptible capacity for firm capacity. Furthermore, the availability of a larger capacity reserve may cause interruptible customers to be interrupted less frequently, and thereby raise the value and the price of interruptible capacity. Furthermore, a significant portion of the turned back capacity may be resold as short term firm capacity, perhaps with lower prices. Finally, the pipeline may be driven to cut costs and become more efficient if faced with the adverse financial consequences of capacity turnback. All of the above effects may significantly reduce the adverse financial impact of capacity turnback by mitigating revenue loss and by reducing costs. Therefore, the estimates of revenue loss based on firm transportation rates and an assumed turnback fraction, and associated projections of financial harm, may be overstated.

Effect on Interruptible Capacity

If significant capacity turnback occurs, a pipeline will have a significant reserve of capacity available on its system. This may have two opposing effects. To mitigate the effect of firm capacity turnback, a pipeline is likely to market its interruptible transmission service more aggressively and with a lower price. On the other hand, because of a large capacity reserve, interruptible customers are likely to be interrupted less frequently. This may increase the value of interruptible transmission capacity to shippers, who may be willing to pay a higher price for this service.[9] The pipeline may

[9] Energy Information Administration, *Natural Gas 1996: Issues and Trends*, 61.

also be driven to charge a higher price for its interruptible service in an attempt to recover some of its fixed costs traditionally associated with firm service.[10] The net result of these two opposing effects on the price of transmission capacity is uncertain and will probably depend on the unique circumstances of each pipeline, including the level of competition offered by rival pipelines, and by alternatives to pipeline capacity. However, regardless of the effect on price, both of these effects are likely to increase the pipeline's revenues from interruptible transmission service, and thereby mitigate the effect of revenue loss from the turnback of firm capacity.

Effect on the Secondary Market for Capacity

If significant capacity turnback occurs, less firm capacity will be available to be traded in the secondary market. Therefore, the price of available secondary capacity may increase. On the other hand, the increased availability of primary capacity may drive down the demand for, and the price of, secondary capacity. After an initial adjustment period, the price of secondary capacity may reach some stable level. In the short run, interruptible capacity, released firm capacity, and short-term firm capacity will compete with each other. In the long run, there also may be an equalizing effect between the prices of primary and secondary firm capacity.

Effect on the Alternatives to Firm Capacity

As discussed in Chapter 2, availability of alternatives to firm capacity is one of the *causes* of the potential capacity turnback problem. Therefore, if significant turnback occurs, the market for these alternatives (combination of firm short-term capacity, interruptible capacity, market area storage, market centers and hubs, and so forth) will be further strengthened.

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[10] Ibid.

Changes in FERC Rate Design

As discussed in Chapter 2, the SFV rate design is one of the causes that made holding firm capacity on long-term contracts expensive, and may drive shippers to decontract their long-term firm capacity. As also discussed, the rate cap on secondary capacity creates a disincentive for holding firm capacity. It is likely that FERC will allow departures from the SFV rate and remove the rate cap on released capacity, as indicated in a past case[11] and FERC notices released over the last year.[12]

[11] Energy Information Administration, *Natural Gas: Issues and Trends*.

[12] Federal Energy Regulatory Commission, *Secondary Market Transactions on Interstate Natural Gas Pipelines*, Notice of Proposed Rulemaking, Docket No. RM96-14-000, July 31, 1996.

CHAPTER 4

ADDRESSING THE PROBLEM

Although the magnitude and scope of the potential capacity turnback problem are uncertain, stakeholders in different segments of the gas industry are well advised to prepare and position themselves to respond if the problem turns out to be significant. As the gas industry continues to see more competition and restructuring, solutions to this problem must be crafted that promote, rather than inhibit, competition and yet sustain a viable pipeline industry. Also, it should be recognized that capacity turnback is a transitional problem for the gas industry, and solutions to the problem may have to be of a transitory nature. A general and enduring regulatory policy to specifically address the problem is not needed.

Before examining different regulatory options to address the potential capacity turnback problem, it may be useful to delineate salient characteristics of the problem and to review the relevant regulatory precedents.

Is This Another Stranded Cost Problem?

One may be tempted to liken the potential capacity turnback issue to the "stranded cost" problem that has been at the center of the debate on electric utility industry restructuring.[1] One may also find similarities with other instances in the public utility industry, including the gas industry itself, in which transformations occurring in the industry confronted one party or another with significant "transition costs." The common characteristics of the transition cost in every one of the above instances can be summarized as the following.

- There is increased competition in one or more of the formerly regulated sectors

[1] Rebecca A. McDonald, "Stranded Costs for Interstate Pipelines," *Public Utilities Fortnightly*, (April 1, 1996).

of a utility industry.

- One or more sectors of the industry owns assets or has long-term contracts with related financial obligations.

- In the past, regulation provided the opportunity for a utility to recover costs associated with the above financial obligations.

- In the face of increased competition, weakened regulation or impending deregulation, the utility cannot expect to fully recover the costs associated with the above financial obligations. These costs are generally called “transition costs.”

- The utility seeks regulatory intervention to recover the transition costs.

A review of how such costs were dealt with historically may throw some light and provide a helpful context for examining the options for addressing the capacity turnback problem.

Transition Costs in the Gas Industry in the Past

There are two instances in the gas industry’s recent past where certain segments of the gas industry were hit with transition costs as a result of regulatory changes and industry restructuring. One was the transition costs confronting interstate pipelines strapped with expensive “take-or-pay” contracts with gas producers in the years preceding and following the issuance of Order 436 by FERC in 1985. The other was the transition costs facing the pipelines immediately after the issuance of Order 636 by FERC in 1992.

The Take-or-Pay Transition Costs of the Early 1980s

Prior to 1985, the contract written between a pipeline and a producer generally contained a “take-or-pay” clause. The “take-or-pay” clause required the pipeline to take or pay a minimum volume of gas from the producer regardless of the pipeline’s needs. The rationale for take-or-pay clauses was that a producer often had to make large investments to explore and develop gas wells in response to a pipeline's requirements reflected in the contract demand; therefore, a mechanism had to be in place to recover these costs even if the projected demand did not materialize. A pipeline was usually able to pass the take-or-pay costs downstream to LDCs in the form of minimum bill provisions (which mirrored take-or-pay clauses).

One reason pipelines were willing to take on the expensive and long-term obligations underlying the take-or-pay provisions in their gas purchase contracts was that gas prices were expected to rise rapidly following the partial deregulation of wellhead gas in 1983. However, the expected increase in gas prices did not materialize. The lower than expected rise in gas prices prompted a segment of the pipeline customers to switch to alternative suppliers. This left the pipelines strapped with huge long-term take-or-pay obligations.

Other contemporaneous events affecting the gas industry, including actions by the FERC, merit discussion for a fuller understanding of the take-or-pay problem. Between 1978 and 1985, FERC issued a series of orders and instituted a set of programs to implement the Natural Gas Policy Act (NGPA) of 1978. The orders and programs were intended to open up the market for wellhead gas to many sellers and buyers, extend the markets for gas beyond traditional geographic boundaries, and promote open access transportation on interstate pipelines.

The blanket certification program, issued through Order 234 in June 1982 was designed to extend the gas transportation provisions of the NGPA (as set forth in section 311 of the Act) to include more categories of gas, and provide for automatic authorization of new transportation arrangement. FERC's statement of policy on off-system sales, issued in April 1983, allowed interstate pipelines to sell gas to customers outside their traditional service area. FERC introduced special marketing programs (SMPs) also in 1983 that allowed pipelines to release contractually dedicated gas for direct sales by producers and other suppliers. All of the above FERC initiatives, although designed primarily to foster greater access to wholesale gas market, and to expand the market, also addressed the problem of take-or-pay costs, directly or indirectly. The blanket certification program reduced the costs of new pipeline service through the automatic authorization arrangement, and expanded the market for pipeline services by including more categories of gas under section 311 transportation provisions of the NGPA. The FERC statement of policy on off system sales required pipelines to demonstrate significant take-or-pay problems as a condition for being allowed to sell gas outside their service areas. In SMPs, producers were to discount prices and provide take-or-pay relief to pipelines in return for direct transportation of gas to third parties.

As mentioned, however, FERC policy actions prior to 1985 were designed primarily to foster competitive forces in the gas wholesale market. As a consequence, these actions exacerbated, in spite of some of their mitigative provisions, the take-or-pay problem by allowing pipeline customers greater access to alternative, and less expensive sources of gas. FERC's issuance of Order 436 in 1985 to further open up the wholesale market exacerbated the problem even more. Order 436 required a pipeline, which chose to become an open access transporter, to offer contract demand (CD) reduction to its customers. The Order also allowed customers to convert CD for firm sales to firm transportation. Therefore, while market forces and FERC actions prior to 1985 had the overall effect of contributing to the take-or-pay problem, Order 436 closed some avenues for the pipeline to pass this obligation downstream. Unlike the previous FERC actions, Order 436 also did not explicitly address the take-or-pay problem.

In response to certain equity concerns regarding Order 436 articulated by LDCs, and also to pipeline concerns about the take-or-pay problems, FERC issued Order 500 in August 1987. Order 500 retained the option for an LDC to convert CD to firm transportation option but eliminated the CD reduction option. The Order also required producers to extend take-or-pay relief to pipelines in exchange for transportation. The Order also allowed a pipeline to recover part of the take-or-pay costs from its customers through a fixed charge on transportation services and a volumetric charge on gas sales, provided the pipeline agreed to *absorb 25 to 50 percent* of the cost itself. To prevent recurrence of the take-or-pay problem, the Order introduced the Gas Inventory Charge (GIC), which is to be paid to a pipeline holding sufficient supplies of gas so that the pipeline stands ready to deliver during peak demand periods.

Prior to 1985, the annual take-or-pay exposure was $6 billion, which increased to $9.34 billion in 1985. In 1986, the liability increased at a slower rate, to $10.7 billion. However, pipelines also settled a significant part of the take-or-pay liability with the producers. By mid-1987, before the issuance of Order 500 in August, 1987, pipelines had resolved nearly $14 billion (cumulative) of take-or-pay exposure, which was about 56 percent of the total take-or-pay exposure of $24 billion up to that date. The settlements in no year averaged more than 17 cents to the dollar.[2]

Order 500 allowed pipelines to receive take-or-pay credit against transportation service offered to pipelines. This crediting mechanism furthered the pace and the magnitude of take-or-pay settlements. By March, 1989, pipelines received a total relief of approximately $44 billion worth of direct take-or-pay costs and related indirect costs. To get this relief, pipelines had to pay producers $8.2 billion in settlement costs and related indirect costs (which worked out to about 18.6 cents to the dollar), of which pipelines absorbed 39.3 percent with the remaining 60.7 percent passed through to pipeline customers.[3] In the final analysis, *pipeline customers had to pay only about 11 percent (60.7 percent of 18.6 percent) of the total take-or-pay liability*.

Order 636 and Transition Costs

The FERC issued Order 636 (also referred to as "the Restructuring Rule" in the remainder of the report) on April 8, 1992 to further open up the gas wholesale market and "to create a regulatory environment whereby gas purchasers and gas sellers can structure their relationships as much as possible by private commercial contracts." The Restructuring Rule (1) required that pipelines unbundle their gas sales and transportation services, and completely deregulated gas sales, (2) granted specific rights to third party transporters on a pipeline's mainline capacity, storage facilities and upstream pipelines, (3) required pipelines to provide "no notice" transportation service, (4) allowed "pregranted abandonment" of long-term firm pipeline transportation service

[2] *Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol*, Docket No. RM87-34-000, Order No. 500-H Final Rule, Federal Energy Regulatory Commission, 18 CFR Parts 2 and 284 (December 13, 1989), 21.

[3] Ibid., 43-45.

subject to a “right of first refusal” by the customer, (5) required pipelines to provide firm transportation customers flexible receipt and delivery points, (6) introduced a capacity release program, and (7) changed the rate design from the MFV method to the SFV method for assigning fixed costs related to transportation.

Order 636 also introduced transition costs for the pipeline. The transition costs can be classified into four groups: (1) Account 191 balance, (2) new facilities costs, (3) stranded costs, and (4) gas supply realignment (GSR) costs.

Account 191 balance was the unpaid balance or credit for the gas already being used. The stranded costs were the costs of facilities rendered obsolete by the implementation of Order 636. The new facilities costs were the costs of facilities that were required by the implementation of Order 636.

Unlike the three previous categories of transition costs, the estimation of GSR costs was less straightforward. These were costs incurred by the pipeline as a result of renegotiating contracts with producers. The GSR costs were also the largest part of the transition costs. The initial estimate of the total transition cost, as calculated by the FERC, was $4.8 billion, of which the GSR cost was $3.2 billion.[4] A later estimate, by the General Accounting Office (GAO), of the transition cost was $5.7 billion.[5] The GAO review of transition costs indicated that about 90 percent of these costs would have been paid by customers even if the Restructuring Rule (Order 636) had not been adopted.[6]

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[4] See “Chair Moler Responds to House Energy Committee Questions about Order No. 636 and FERC Policies in General; Pipeline Estimates Indicate Transition Costs Could Reach $4.8 Billion,” *Foster Natural Gas Report* (March 18, 1993): 1-7.

[5] “Draft GAO Report on Cost Impact of Order No. 636 Projects $400 Million Greater Cost Shift to LDCs and Their Customers Than FERC Forecasted, Resulting in A Cost Increase to Residential Customers of 9 Percent or Less,” *Foster Natural Gas Report* (July 22, 1993): 1-4.

[6] Ibid.

In Order 636, the FERC permitted full recovery of all prudently incurred costs that were threatened with under recovery as a result of the rule. For the Account 191 balance, a pipeline was allowed to bill its former bundled, firm-sales customers whether or not the customers elect to remain as firm-sales customers after implementation of the rule.[7] Stranded costs and new facilities costs were to be treated like all other prudently-incurred costs.[8] The rule allowed a pipeline to recover the *full amount* of eligible prudently incurred GSR costs, and the pipeline was permitted to use either a negotiated exit fee or a reservation surcharge recoverable from firm transportation customers.[9]

Lessons Learned from Past Instances of Transition Costs

The conclusions drawn from past instances of transition costs can be divided into two groups, which are (1) federal regulatory policies toward transition costs, and (2) utility behavior in response to transition costs and federal regulatory policies.

Federal Regulatory Policies Toward Transition Costs

FERC response to transition costs has been varied. FERC has adopted policies that range from allowing *full recovery* of all prudently incurred transition costs to allowing partial recovery of the transition costs.

As mentioned in Order 500, FERC required producers to extend take-or-pay relief to pipelines in exchange for transportation, allowed a pipeline to recover a part of the take-or-pay costs provided the pipeline agreed to absorb 25 to 50 percent of the cost, and introduced the GIC to prevent the future recurrence of the take-or-pay

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[7] Daniel J. Duann, *The FERC Restructuring Rule: Implications for Local Distribution Companies and State Public Utility Commissions* (Columbus, OH: The National Regulatory Research Institute, November 1993), 23.

[8] Ibid.

[9] Ibid.

problem. In this instance, FERC policy distributed the transition cost between the *suppliers* of the pipeline (producers), the pipeline itself, and pipeline *customers* (LDCs and other shippers). In adopting the GIC, FERC shifted the entire risk of future take-or-pay liability to pipeline customers.

FERC policy toward transition costs was quite different in Order 636. Here, FERC allowed *full recovery* of all *prudently incurred* transition costs. One important distinction between the two instances may explain the difference in FERC policy toward them. One can view the take-or-pay problem stemming primarily from the operation of market forces, with FERC policy arguably contributing little if anything to the problem. The transition costs occurring as result of the adoption of Order 636, on the other hand, may be viewed as primarily an *effect* of FERC policy. Therefore, FERC presumably was inclined toward allowing only partial recovery of take-or-pay costs, while it felt more compelled to allow fuller recovery of post-636 transition costs.

In case of electric utility transition costs, FERC chose to allow full recovery of "legitimate, prudent, and verifiable stranded costs."[10] The stranded cost provisions only apply to wholesale requirements customers. In adopting the rule, FERC makes a clear distinction between stranded costs caused by market forces alone and stranded costs resulting from regulatory policies. FERC states that it will not ignore "the effects of significant statutory and regulatory changes" on the "past investment decisions of utilities"[11] and in the Commission's view, the recovery of related costs are warranted. However, the Commission also states that the rule is not applicable to "normal risks of competition, such as self-generation, cogeneration, or industrial plant closure."

A review of FERC's policies on transition costs in the energy utility industries indicates a strong inclination in favor of allowing recovery of stranded costs, provided the Commission believes that the transition costs are caused primarily by, or by changes in, Commission policy, and not due to the operation of market forces. However, this distinction may not be totally clear. FERC policy changes themselves

[10] Federal Energy Regulatory Commission Order No. 888, Final Rule, mimeo, (released April 24, 1996).

[11] Ibid.

have primarily been *in response to changes in the market*. FERC acknowledges this fact when it states that its actions in Order 888 were in response to "fundamental changes. . .taking place in the industry." Therefore, one can argue that transition costs are *ultimately caused by the operation of market forces*, often facilitated by the actions of the FERC.

Based on past decisions, one can reasonably assume that future FERC policy toward transition costs will most likely be guided by whether such costs are perceived to be (1) unanticipated consequences of changes in regulatory policy or (2) normal consequences of the operation of market forces. If the former holds, FERC will most likely favor a policy that allows regulatory recovery of such costs. If the latter holds, FERC may be more inclined toward letting market forces determine the final dispensation of such costs. An examination of the causes of capacity turnback, as presented in Chapter 2 of this report, indicates that market forces, rather than changes in regulatory policy, have been the major contributors of this phenomenon.[12] Therefore, FERC is more likely to favor market-based mechanisms over regulatory mechanisms for the recovery of costs of capacity turnback. FERC's decisions on the three major cases involving capacity turnback appear to support this conclusion.

Recent Turnback Cases and FERC Decisions

Transwestern Pipeline and El Paso Natural Gas

Two pipelines in the western U.S., Transwestern Pipelines (Transwestern) and El Paso Natural Gas (El Paso) were the first to face large capacity turnbacks. These turnbacks constituted about 18 percent of the total capacity under contract on the Transwestern and El Paso systems.[13] Transwestern experienced a 457 billion Btu per day reduction effective November 1, 1996. El Paso faces a reduction in firm capacity

[12] It can be argued that Order 636, a regulatory rule, rather than market forces, played a major role in precipitating the capacity turnback problem.

[13] Energy Information Administration, *Natural Gas: Issues and Trends* (Washington, D.C.: EIA, December, 1996), 51.

contracts of 1.5 trillion Btu per day effective between January 1, 1996 and January 1, 1998.[14]

To address the impending capacity turnback problem, customers of Transwestern and El Paso formed a coalition, called the Southwest Customer Coalition. The group was formed with the goal of finding mutually acceptable solutions to the excess capacity problem. The group included most of the LDCs in California, Nevada, Arizona and New Mexico.[15]

Transwestern ultimately reached a settlement with the Southwest Customer Coalition, which was approved by FERC. The settlement stipulated that Transwestern would share approximately 70 percent of the revenue shortfall caused by the relinquishment of capacity by Southern California Gas (a coalition member), the remaining 30 percent would be shared by Transwestern customers.

In contrast to Transwestern, El Paso did not initially pursue a negotiated settlement with its customers. Instead, it filed a rate case on June 30, 1995 in which it proposed to reallocate costs to remaining firm customers, and also to unilaterally impose exit fees on certain firm capacity holders.[16] FERC rejected the El Paso proposal to unilaterally impose exit fees, noting that in "the cases following Order 636, the Commission has consistently rejected pipeline attempts to unilaterally impose exit fees."[17] Also, it is interesting to observe that the Commission rejected "the notion, suggested in El Paso's argument, that a policy for imposition of a unilateral exit fee has been opened for discussion because of the Commission's *electric policy* [author's italics]."[18] The Commission, in its July 26, 1995 suspension order, adopted El Paso's

[14] Ibid.

[15] The LDC Caucus, the American Gas Association, *An Issue Paper Regarding Future Unsubscribed Pipeline Capacity* (Arlington, VA: The LDC Caucus, December 1995).

[16] Ibid.

[17] Ibid.

[18] Ibid.

suggestion to implement a negotiation and settlement process, and encouraged El Paso and its customers to discuss a cost-sharing proposal.

El Paso finally reached a settlement with its customers, which was approved by FERC on April 16, 1997.[19] The settlement allocates 65 percent of unsubscribed capacity costs to El Paso "associated with the anticipated contractual step downs and terminations" over the first eight years of the settlement. El Paso's existing customers will pay 35 percent of such costs, called "risk sharing amounts." The customers may elect to pay El Paso the risk sharing amounts "over a period of up to the shorter of eight years or the remaining term of their Transportation Service Agreements."[20]

Natural Gas Pipeline Company of America

The third of the major capacity turnback cases occurred in the Midwest and involved the Natural Gas Pipeline Company of America (Natural). In August, 1995, Natural filed a rate application that included a proposal for the recovery of costs associated with capacity relinquishment of about 6 billion Btu per day effective December 1, 1995. The turned back capacity represents almost 17 percent of Natural's total capacity commitments.[21] Natural proposed to defer the recovery of those costs for a period of up to five years. The deferral was intended to prevent a rate hike of 50 to 60 percent that would result if immediate recovery of the turnback costs were allowed. The collection of the deferred balance, according to the proposal, would begin by December 1, 2000, but could start earlier. The charges would be based on the costs deferred to that date, amortized over a five year period.

Natural's customers opposed the recovery proposal on grounds that it was an attempt to insulate Natural completely from risk. On October 11, 1995, FERC rejected Natural's proposal either to reallocate to remaining customers the cost of unsubscribed

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[19] Federal Energy Regulatory Commission, *Order Approving Contested Settlement*, Docket Nos. RP95-363-000 et al. (April 16, 1997).

[20] Ibid.

[21] Energy Information Administration, *Natural Gas: Issues and Trends*, 51.

capacity or to establish a deferral mechanism for subsequent cost recovery. Reiterating the July 26, 1995 decision on El Paso, FERC noted that it will

> not permit a pipeline losing customers simply to shift the costs of resulting unsubscribed capacity to the remaining customers without regard to the adverse effects on those customers. Rather the pipeline must have an incentive to recover those costs of its unsubscribed capacity from new markets. This principle is an important safeguard for the pipeline's existing customers, particularly captive customers, against pipeline overreaching.[22]

Natural also reached a settlement with its customers under which it assumed responsibility for 80 percent of the revenue loss resulting from turned back capacity. As part of the settlement, FERC allowed Natural to consider alternative rate designs, such as departures from straight fixed-variable rates. [23]

Utility Responses to Transition Costs

When faced with transition costs, the common, and understandable, response of the utility industry has been to pursue regulatory recovery of such costs. The following reasons are often offered for supporting such recovery.

The Regulatory Bargain

The regulatory bargain can be used as the basic rationale to support regulatory recovery of transition costs. Arguably, the regulatory bargain implies a commitment to ensure recovery of all prudently incurred costs in exchange for the utility's obligation to serve. Those arguing against the regulatory recovery of transition costs point out that

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[22] Federal Energy Regulatory Commission, *Order Following Technical Conference*, Docket Nos. RP95-326-000 et al. and RP95-242-000 et al. (October 11, 1995).

[23] Energy Information Administration, *Natural Gas: Issues and Trends*, 51.

the regulatory bargain implies the granting of *an opportunity* to recover all prudently incurred costs, *not an assurance* for such recovery.[24]

Transition Costs Are Caused by Unanticipated Changes Beyond Utility Control

Another argument for transition cost recovery is that transition costs are often imposed on regulated utilities by unanticipated changes in regulation or in the market over which the utility had little control. Consistent with the "regulatory bargain" argument, it can be argued that a utility should not be penalized by the consequences of unforeseen events over which the utility had little control, and for which the utility bears no responsibility. The above argument seeks to insulate the utility against the risk of future unforeseen events. Opponents of transition cost recovery point out that neither legal precedent nor past regulatory decisions *guarantees* such protection.[25]

Another variant of the above argument is that although the utility may be arguably expected to bear some risk of the consequences of the normal operation of the market, the utility cannot be held responsible for consequences of regulatory decisions. This is the argument used by FERC in its support of stranded cost recovery for the electric utilities, and is also consistent with FERC's position on transition cost recovery in Order 636. However, as pointed out previously, the distinction between market-induced changes and regulation-induced changes may not always be a logically valid distinction. Therefore, the argument for the recovery of transition costs caused supposedly by *regulatory actions* may be based on a weak rationale. Only when transition costs can be traced *exclusively* to regulatory actions, does regulatory intervention for recovery of such costs have some merit.

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[24] Kenneth Rose, *An Economic and Legal Perspective on Electric Utility Transition Costs* (Columbus, OH: The National Regulatory Research Institute, January 1997), 43.

[25] Ibid.

Pursuit of Market Alternatives

Although the pursuit of regulatory recovery of transition costs may be a preferred response of regulated utility companies, there is at least one major instance where utilities have been able to absorb a large part of the costs when forced by a competitive market environment. As noted previously in this chapter, *pipeline customers absorbed only about 11 percent of the total take-or-pay costs* occurring as a result of industry restructuring in the early 1980s.[26] This instance shows that a utility is able to respond well to transition costs and compensate for revenue losses when faced with competition and when there is no assurance of full regulatory recovery of transition costs.

There are several reasons why a utility may be able to reduce potential revenue losses during a industry transition toward competition. First, there may be inefficiencies in the management and operation of the utility which may have remained undetected or uncorrected during a time of assured regulatory recovery of costs, which become exposed during a transition toward greater competition. The utility is able to correct these inefficiencies, cut costs and thereby offset some of the revenue losses occurring due to the transition. Second, the utility may not have fully utilized all the opportunities for marketing its services because the utility has a reasonable guarantee of being made whole, through adjustment of rates, regardless of the volume or the variety of the services it sells under regulation. With more competition, the utility is more likely to pursue these profit opportunities, and thereby offset some of the revenue losses during the transition. Third, competition also opens up *new* opportunities and markets for the utility's services. Under a more competitive regime, the utility is likely to pursue these new opportunities and markets for its services, and this too can offset some of the revenue losses during the transition. Finally, the utility may be able to restructure its finances to be better able to mitigate the adverse financial consequences due to the transition. For example, the utility may be able to refinance its debt

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[26] See *Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol*, Docket No. RM87-34-000, Order No. 500-H Final Rule, Federal Energy Regulatory Commission, 18 CFR Parts 2 and 284 (December 13, 1989), 43-45.

instruments at lower interest rates and, for extended terms, this can mitigate the adverse financial consequences of the transition.

Options for Addressing the Capacity Turnback Problem

Some of the options for addressing the capacity turnback problem have been previously mentioned. The options mentioned include exit fees, reallocation of turnback costs to remaining customers, cost-sharing settlements, and use of market opportunities for pipeline services. The options can be divided into two classes: regulatory and market-based. One can define regulatory options as those which cannot be implemented in an unregulated market setting and without the direct support of the regulatory authority. Such options include exit fees, reallocation of costs, and alternative *cost-based* rate designs. Market-based options can be defined as those which can be implemented in a market setting, with or without direct regulatory authority. Such options include negotiated settlements, and *market-based* rate designs. It must be pointed out that both kinds of options require regulatory approval as long as the pipeline service retains monopoly characteristics and continues to be regulated. However, there is a fundamental distinction between the two kinds of options. One cannot contemplate the regulatory options being implemented in a hypothetical unregulated market setting, but one can certainly do so for the market-based options. For example, unilateral exit fees would never work in an unregulated market but negotiated settlements might.

Regulatory Options

All regulatory options will involve some allocation of the unrecovered investments, arising from capacity turnback, among various customer segments and the pipeline. The regulatory challenge is to find options that is most consistent with the multiple, and somewhat conflicting, regulatory objectives of economic efficiency, stakeholder equity, and the “public interest.” For example, economic efficiency may dictate that all the costs of capacity turnback be absorbed by pipeline shareholders, and yet this may be seen as inequitable under the "regulatory bargain;" and as another example, consequent impact on the financial viability of the pipeline may be seen as inconsistent with the "public interest" goal of ensuring a viable supply of gas to all customers.

The subsequent sections briefly describe selected regulatory options to mitigate the capacity turnback problem, highlighting their implications with regard to economic efficiency, equity, and the financial impact on the pipeline.

Unilateral Exit Fees

A pipeline may choose to impose exit fees on those customers who either reduce or relinquish their capacity commitments at the expiration of their current firm capacity contracts. This would both be an inefficient and inequitable solution to the capacity turnback problem.

This option would be inefficient because it forces a leaving customer either to remain with the pipeline and forego a less costly substitute for firm capacity, or it imposes an additional cost on the customer without any corresponding service or benefit. One undesirable consequence of implementing this option would be that it will inhibit competition in the gas industry by limiting the choices of a customer.[27]

This option may also be considered inequitable because it penalizes a party (the exiting customer) for events (excessive investments in capacity, and the emergence of substitutes to firm pipeline capacity) over which the party had no control.

[27] It can be argued that exit fees promote static efficiency by preventing "uneconomic bypass" if the alternative supplier's marginal cost exceeds the utility's marginal cost, even if the utility's price is greater than the alternative supplier's price. However, the resulting inhibition of competition would impede dynamic efficiency. For an exposition of these arguments, see Kenneth Rose, *An Economic and Legal Perspective on Electric Utility Transactions* (Columbus, OH: The National Regulatory Research Institute, 1996), 7-38.

Full Reallocation of Costs to Remaining Customers

Instead of imposing a fee on exiting customers, a pipeline may seek to reallocate the cost of unsubscribed capacity on the remaining customers. Like the exit fee, this is both an inefficient and inequitable solution to the problem. It is inefficient because it imposes a cost on the remaining customers without a corresponding benefit or service.

This option may be considered inequitable because of the same reasons the exit fee is inequitable: A party (the remaining customer) is being penalized for events (excessive investments in capacity, and the emergence of substitutes to firm pipeline capacity) over which the party had no control.

This option is also unviable because by raising the cost to remaining customers, it would cause an increasing number of customers to relinquish their capacity, causing a "vicious spiral" of "*increased* capacity reservation prices for a *shrinking* number of remaining firm customers (author's italics)."[28]

Full Allocation of Costs to Pipeline Shareholders

Both exit fees and cost reallocation to remaining customers allocate costs of unsubscribed capacity to one group of customers or another. Another alternative would be to assign these costs entirely to pipeline shareholders. From a purely economic point of view, this would be an efficient option. However, this option may be considered inequitable, unworkable and not in the public interest.

The option is economically efficient because this is how an unregulated, and competitive market would allocate sunk costs. In such a market, prices and revenues are governed by demand and supply, and are not affected by historical sunk costs, such as the unrecovered costs of investment in pipeline capacity. Faced with unrecovered sunk costs, a firm would try to remain profitable by reducing costs, increasing sales, and finding new markets for its products, or developing new products

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[28] The LDC Caucus, *An Issue Paper Regarding Future Unsubscribed Pipeline Capacity*.

for unserved markets, or any combination of the above. Some firms may succeed and thrive in such a market, and other may fail and become insolvent or bankrupt. From an economic perspective, such an outcome is efficient because the resulting production and consumption of a service (pipeline capacity) would be optimal.

However, assignment of the entire cost of unsubscribed capacity may be considered inequitable for a number of reasons. The reasons are exactly the same as those previously discussed in support of transition cost recovery. First, the regulatory bargain may be invoked to support the position that there is a regulatory obligation to allow the pipeline to recover all of its prudently incurred costs from its customers. Second, denying full cost recovery may be considered tantamount to penalizing the pipeline for unanticipated changes in the market, and in regulatory policy, over which the pipeline had no control and for which the pipeline bears no responsibility. Finally, full assignment of the costs to the pipeline not only denies full recovery of prudently incurred costs, it denies even partial recovery of such costs. If anything short of full recovery of the pipeline's prudently incurred costs is considered inequitable, than denying even partial recovery makes it even more inequitable.

Finally, assignment of all costs of unsubscribed costs to the pipeline may be unworkable. If the pipeline cannot successfully market the unsubscribed capacity to recoup the resulting revenue loss, it may be driven to insolvency or bankruptcy, and such an outcome may jeopardize the regulatory objective of assuring a viable and reliable gas delivery service.

Alternatives to SFV Rate Design

In Order 636, FERC mandated the use of the SFV rate design for capacity contracts. In the SFV rate design, all fixed costs related to the transportation capacity are assigned to demand portion of the rate. Prior to Order 636, the rate design used was the MFV, in which a part of the fixed costs, consisting of the rate of return, and taxes, was assigned to the commodity portion of the rate. The switch from MFV to SFV was intended to provide incentives to shippers to maximize throughput and thus encourage efficient utilization of firm capacity. With the growth of alternatives to firm pipeline capacity, however, SFV had the effect of causing the LDC to relinquish firm capacity, because the higher capacity reservation charge raised the price of capacity relative to other alternatives. Particularly in regions of high excess capacity, SFV encourages relinquishment of capacity. Thus, SFV contributed to the capacity turnback problem.

The efficiency characteristics of the SFV are mixed. The SFV certainly promotes *consumption efficiency*. A shipper can minimize its unit cost of gas transportation by maximizing throughput. On the other hand, the SFV reduces the incentive of the pipeline to be efficient about either building new pipeline capacity (the well-known "A-J Effect") or fully utilizing its capacity, because the reservation charge fully compensates the pipeline for its capacity costs, regardless of the level of capacity utilization. This can lead to overbuilding of capacity or excess commitment of capacity. However, to the extent that the SFV is consistent with the notion of cost responsibility by allocating the fixed costs to the fixed component of rates, it may be viewed as more equitable than the alternatives.

In spite of the consumption efficiency benefits of the SFV rate design, and its desirable equity characteristics, the emergence of competitive alternatives has turned it into a contributor to the capacity turnback problem. It may be helpful to observe that the merits of SFV are predicated on the existence of a regulated and uncompetitive market environment.[29] As the gas industry has been continuing to move away from such an environment, it is understandable that the SFV rate design did not have the intended effect on the firm capacity market transactions.

One way to relieve the capacity turnback problem would be to allow departures from the SFV rate design. In its decision on the Natural Gas Pipeline case, FERC has indicated that it will allow departures from the SFV rate design. Alternative rate designs, such as the MFV may reduce the reservation charge for firm capacity, and encourage LDCs and other shippers to retain more capacity than otherwise once their

[29] Of course, an unregulated and competitive market does not guarantee the recovery of fixed costs of a firm.

current capacity contracts expire.

Alternatives to SFV, which shifts part of the fixed costs to the commodity or variable portion of the rate, also have mixed efficiency characteristics. In theory, and relative to SFV, such rate designs improve production efficiency, promoting more efficient addition of capacity and better utilization of existing capacity by pipelines, while reducing consumption efficiency, encouraging LDCs to reserve more capacity than they expect to use. In practice, however, LDCs and shippers are not likely to make excess commitments for firm capacity on the pipelines, regardless of the rate design, given the availability of other, less expensive, alternatives. The reason alternatives to SFV can help mitigate the capacity turnback problem is that it can encourage LDCs to retain a larger proportion of their existing capacity rights once the current contracts expire.

Other Rate Design Options

Other rate design options also merit consideration. Examples include seasonal rates, a rate floor for interruptible transportation, rate discounts based on duration of contracts, and prospective penalty provisions in firm capacity contracts. By more closely aligning the value or the cost of the relevant transportation service with price, and therefore, by sending more accurate price signals, such rate designs can both mitigate the current capacity turnback problem and prevent the recurrence of the problem in the future.

Seasonal rates can more accurately capture the variation in the value and demand of the transportation service with changes in the season. Such rates can reduce the need for holding excess capacity in periods of low demand, and thereby prevent the problem of excess capacity commitments. Such rates can also provide more accurate price signals for the value of released capacity.[30] Such rates also can allow a customer to revise his contractual rights and select monthly service levels,[31]

[30] Ibid, 24.

[31] Ibid.

thereby obviating the need for relinquishing contractual capacity rights.

A rate floor or a minimum rate for interruptible transmission can be designed to include some of the pipeline's fixed costs, which assures that all shippers are bearing an appropriate share of the costs because interruptible service requires a certain minimum of facilities for its provision and the expenditure of related fixed costs.[32] Such a rate may also accurately reflect the cost of providing this service and prevent the overvaluing of the interruptible transportation service relative to firm service, thereby having a mitigating effect on the capacity turnback problem.

Rate discounts based on the duration of a contract is another concept worth considering. Such discounting is common in other businesses. For example, the rent per day is less if a car is rented for a week rather than a day.[33] The underlying economic rationale is that such discounting would reflect the "premium" the pipeline would be willing to pay to protect itself from the longer-term "revenue risk," and to ensure a revenue stream for a longer duration of time. The correct level of discount would be a function of the current prices of alternatives to long-term firm capacity, customer and pipeline expectations on the future prices of these alternatives, and of course, the duration of the contract.

Certification of New Pipelines

Another remedy proposed for mitigating the capacity turnback problem is for the FERC to carefully evaluate the need for new pipeline capacity before certifying new pipeline construction. This proposal calls for abandoning the current policy of granting blanket certifications and approval of at risk projects. The proposal also suggests that

[32] Ibid.

[33] Ibid.

FERC clearly articulate its policy for future cost recovery, outlining allocation of risk for future surplus capacity. [34]

The proposal appears to be of limited merit. By assigning greater, and almost full, responsibility to the FERC for evaluating the future need for new pipeline construction projects, the proposal appears to go against the very spirit of more competition and less regulation that inspires much of the current regulatory reforms. The competitive thrust of the restructuring of the gas industry should provide the appropriate market signals about how much new pipeline capacity is needed and should be built. Pipelines and the financial markets are expected to have much better knowledge of the prospects of future success and failure of new pipeline projects. Also, as discussed, the problem is not that turned back capacity and new capacity will be unmarketable but that they probably will be sold on shorter term contracts at discounted prices. Pipelines can make a much better evaluation of future need for pipeline capacity, based on available information regarding current capacity utilization, secondary market activity and other relevant data, than FERC can.

However, the proposal does have a component that merits favorable consideration, namely that FERC should better articulate future cost responsibility and risk allocation for future surplus capacity. By establishing clear guidelines, FERC can promote better planning of future needs by all parties involved with the purchase and sale of firm capacity rights. As long as these guidelines do not disproportionately assign the cost responsibility and risks on any one party, and closely reflect the risk sharing in a truly competitive market, the guidelines can simulate the correct market signals about the need for new pipeline capacity.

Market-Based Options

Market-based options have previously been defined as those that could be implemented in a hypothetical unregulated market. In the presence of regulation, such options need the approval and support of the relevant regulatory authority. But unlike

[34] Ibid, 25.

regulatory options, regulatory direction and intervention do not govern the working of market-based options. Instead, the regulatory role in implementing market-based options is facilitative, rather than interventionist. Some of the proposed market-based options include, (1) stimulation of the secondary market for capacity, (2) negotiated cost-sharing settlements, and (3) market-based rates with flexible terms and conditions.

Stimulation of the Secondary Market for Capacity

As previously noted, the working of the market for released capacity, also known as secondary capacity, has been impeded by a number of factors. These factors include, (1) the as-billed rate cap on released capacity and (2) cumbersome bidding requirements. Addressing these factors and implementing other measures to facilitate the working of the secondary market would encourage LDCs to retain more of their current capacity rights and thereby mitigate the capacity turnback problem.

Order 636 allowed LDCs and other shippers to release their capacity to others, subject to a rate cap that equaled the rate charged by the pipelines, and subject to electronic bidding standards. The FERC intent was to stimulate secondary market transactions. However, the secondary market has failed to grow at the desirable pace because of the disincentives inherent in the rate cap and the bidding requirements.

The rate cap discourages LDCs and other holders of primary capacity.[35] There may be shippers in the market who value the capacity above the as-billed rate cap. However, they are unable to purchase the capacity because of the rate cap restriction. The rate cap, therefore, prevents an efficient trade that would have otherwise occurred.

The electronic bidding requirements also inhibit the release of secondary capacity. These requirements are cumbersome, and depress the value of secondary capacity. It has been suggested that the bidding requirements may have had a significant role in impeding secondary market transactions, and in causing the release

[35] In most states, the revenues from capacity release flow through to customers. In four states, LDCs are allowed to retain part of the profits from capacity release. In the latter states, LDCs would be discouraged from releasing capacity by the rate cap.

capacity to have a low market value. The recent FERC adoption of bidding standards developed by the Gas Industries Standards Board (GISB) should alleviate this problem.[36]

In a NOPR issued one year ago, FERC proposed lifting the rate cap, conditioned on a showing of the lack of market power by the LDC, and eliminating the bidding requirement.[37] While there is general consensus on the elimination of the bidding requirement, the specifics of the proposal for the lifting of the rate cap have generated much controversy and debate. State PUCs and LDCs generally disagree with the conditions tied to the lifting of the rate cap, while interstate pipelines and others generally agree with these conditions.

The NOPR calls for a showing of a lack of market power of the LDC behind the city gate as a condition for lifting of the rate cap. The NOPR states that this condition can be met if it can be shown that the state PUC regulation requires open access transportation behind the city gate. Both state PUCs and LDCs have argued against this requirement on grounds that the requirement constitutes an assertion of FERC authority beyond its jurisdiction. Furthermore, LDCs have argued that FERC's definition and analysis of market power is flawed.

The reasons cited by the AGA, the trade organization of LDCs, against the FERC position on the LDC's market power include (1) lack of an appropriate delineation of the relevant product and geographic markets, (2) lack of recognition of the absence of entry barriers, and (3) lack of LDC incentives to exercise market power behind the city gate.

AGA asserts that the NOPR fails to appropriately account for substitutes to released FT capacity including (1) IT capacity, (2) short-term firm capacity, (3) competitive rebundled sales (the "gray market" sales), and (4) market area storage. The AGA also states the relevant geographic market is not an individual delivery point, as claimed by the FERC NOPR, but all delivery points that are routinely accessible

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[36] Federal Energy Regulatory Commission, *Standards For Business Practices of Natural Gas Pipelines*, Order No. 587-B, February 6, 1997.

[37] Federal Energy Regulatory Commission, *Secondary Market Transactions of Interstate Pipelines*, Notice of Proposed Rulemaking, Docket No. RP96-14, July 31, 1996.

under a shipper's transportation contracts.[38] Furthermore, the availability of flexible delivery and receipt points, as required by FERC, allows other parties than the LDC to serve other markets.[39]

The AGA also states that the entry barriers to the market for secondary capacity are minimal, as evidenced by the growth of bundled sales on the interstate pipeline system and to end-use customers.[40] Finally, the AGA states that FERC's concern for the LDC's exercise of market power because of the LDC's control over take-away capacity at primary delivery points is overstated. Also, the LDC has no incentive to restrict the use of delivery point capacity at its city gate, since the LDC has an interest in maximizing throughput on its distribution system.

Although the AGA raises some legitimate objections to FERC's concern over the LDC's exercise of market power behind the city gate, the concern is generally valid. If the ultimate delivery point takes the gas to the city gate of an LDC, the LDC has some control over the delivery point, and the LDC has upstream capacity rights, these capacity rights will have more value than capacity rights held by other shippers, and the LDC will be able extract above-market prices for the resale of its capacity rights. This is true regardless of how many shippers compete in the market for the secondary capacity rights, and how weak the barrier to entry in this market is. However, it is also true that the LDC's incentives for exercising its market power over this small segment of secondary capacity may not be strong. The primary source of LDC revenues is the throughput on its distribution system. The LDC has a strong incentive to maximize this throughput rather than try to extract some economic rent by exploiting its control over take-away capacity at primary delivery points. One cannot definitively say whether this market power will be exercised or not, once the rate cap is lifted on released capacity. That question can only be settled by the empirical test of actually lifting the price cap.

Since the LDC has the ability to exercise market power, although every LDC

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[38] "Comments of the LDC Caucus of the American Gas Association Before the Federal Energy Regulatory Commission," *Secondary Market Transactions on Interstate Natural Gas Pipelines*, Docket No. RM96-14-000 (October 3, 1996), 30.

[39] Ibid.

[40] Ibid, 31.

may not be willing to do so, the rate cap on released capacity cannot be unconditionally lifted as a generic policy. However, requiring open access transportation behind the city gate may be too strong a condition for the lifting of the cap, besides creating the perception that FERC may be usurping jurisdictional boundaries. Since lifting of the cap will encourage the LDC and other holders of primary capacity rights to retain such rights, and thereby mitigate the capacity turnback problem, a compromise solution might be in order. The open access transportation requirement can be dropped, and FERC's market analysis indices (such as the Herfindahl-Hirshman Index) can be combined with other mechanisms to provide adequate protection against the exercise of market power by the LDC. For example, on a case by case basis, FERC can lift the rate cap for specific capacity release transactions but increase the after-the-fact public disclosure requirements if the market power analysis is inconclusive.[41]

Negotiated Cost-Sharing Settlements

Negotiated cost-sharing settlements may provide the best and mutually satisfactory resolution of the capacity turnback problems. In past turnback cases, FERC has clearly indicated its preference for negotiated settlements. Such settlements typically allow the pipeline to recover from its customers less than half of the decontracting costs over an extended period of time. After that period, the pipeline is responsible for all future decontracting costs. The extended recovery reduces the rate shock to customers relative to the alternative of a shorter term recovery. By putting the higher burden of these costs on the pipeline, it provides the pipeline with strong incentives to market its services and to minimize its costs of operation.

[41] Public disclosure requirements should be designed such that the information disclosed is enough to identify cases of undue discrimination yet not sufficient to offer unfair competitive advantages to competing providers or competing customers — not an easily achievable proposition.

Market-Based Pricing and Flexible Service Terms and Conditions

Another market-based option is to allow the pipeline to sell its services at market-determined prices if there is a showing of the lack of market power. In its NOPR, FERC has indicated that it would consider lifting of the rate cap on interruptible and short-term firm services if there is a showing of lack of market power. INGAA proposes a simplification of market power tests for the purposes of lifting the rate cap on interruptible and short-term firm transportation.[42] Given the fact that the markets for short-term firm and interruptible capacity is open to competition from other alternatives, such as released capacity and rebundled “gray market” services, the suggested simplification of market power tests merits consideration.

Another way to provide incentives to pipelines to recover decontracting costs from the market is to allow them to offer flexible service terms and conditions to customers. Such incentives would allow pipelines to market their services aggressively, stimulate demand, and offset potential revenue loss due to decontracting.

FERC may be concerned that allowing such flexibility may allow the pipeline to exercise market power. Flexible terms and conditions will necessarily allow price flexibility, making it difficult to detect undue discrimination and preferential treatment, as well as to ensure service comparability among competing providers and customers. However, it may be possible to develop rules to test for and ensure comparability, and to design after-the-fact public disclosure requirements to protect against potential market power abuse. In the increasingly competitive gas industry, a customer would like to have the choice of purchasing an individually tailored package of services; therefore, such choice should be offered. When a customer can buy exactly what she needs, no less and no more, only then the price offered for the product will match its value to the customer. FERC may wish to consider allowing flexible service terms and

[42] “Comments of The Interstate Natural Gas Association of America on Secondary Market Transactions on Interstate Natural Gas Pipelines,” Docket Nos. FERC RM96-14-000 and FERC RM96-14-001.

conditions, with adequate safeguards against potential market power abuse by pipelines.

CHAPTER 5

STATE PUC AND LDC OPTIONS FOR RESPONDING TO THE CAPACITY TURNBACK PROBLEM

As explained, the capacity turnback problem may be caused primarily by the growing competitiveness in the gas industry. Therefore, one way to mitigate the problem would be to restrain or inhibit the competitive thrust that the industry is experiencing. In fact, many of the regulatory options that could be adopted to relieve the pipeline of the consequences of the turnback problem would directly or indirectly inhibit competition. For example, imposing unilateral exit fees on decontracting customers would inhibit competition by limiting customer choice. Similarly, reallocating the cost of capacity turnback on the remaining customers would force these customers to pay a higher than competitive price for a pipeline service.

One can also contemplate state PUC regulatory actions that would provide relief to pipelines from the adverse consequences of capacity turnback. As mentioned, an increasing number of state PUCs, often supported by state legislatures, are adopting a policy of unbundling LDC retail services.[1] This has the effect of shifting the responsibility of securing interstate transportation services from the LDC to other parties. Therefore, the increasing adoption of unbundling would have the effect of reducing the capacity commitments of LDCs. As LDCs have traditionally been the largest purchaser of firm capacity rights, any reduction of capacity commitments by LDCs would either cause or exacerbate the capacity turnback problem.

Therefore, the capacity turnback problem would be mitigated if PUCs did not pursue or support the unbundling of LDC services. Most would agree, however, that

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[1] See Tables 2-11 and 2-12 in this report.

such a position does not have any persuasive rationale, and that the competitive benefits of unbundling far outweigh the adverse consequences of capacity turnback.

One is led to the conclusion that state PUCs and LDCs must pursue solutions to the capacity turnback problem that do not inhibit competition in any significant way.[2] Also, the focus of state PUC and LDC responses to the problem should be primarily be the protection of the ultimate customers from the adverse consequences of capacity turnback. This focus is quite different from the focus of FERC policies, which would understandably be to balance the interests of both the pipeline and its customers, consistent with the objectives of economic efficiency, equity among parties, and the financial viability of the pipeline. The following sections examine possible state PUC and LDC options for responding to the capacity turnback.

Continue the Present Thrust Toward Greater Unbundling of Gas Services

Unbundling of gas services and greater customer choice may expand the market and the customer base for interruptible and short-term firm transportation and for ancillary services such as storage, balancing, and backup, and provide pipelines greater opportunities to market these services. Such market opportunities may allow pipelines to partly recoup the revenues lost due to capacity turnback. Therefore, state PUCs may wish to continue the present thrust toward greater unbundling of gas services and customer choice.

Continue to Require LDCs to Efficiently Procure and Utilize Transportation Arrangements

State PUCs generally require LDCs to procure and utilize their transportation arrangements efficiently. LDC contracts for firm capacity on the pipelines are open to

[2] Regulatory solutions to a problem primarily caused by competition cannot be completely free of anti-competitive effects. The regulatory challenge is to devise solutions that minimize possible anti-competitive effects.

prudence reviews. Until recently, state PUCs may have allowed or encouraged LDCs to err on the side of caution and secure sufficient transportation capacity to ensure reliable service and full deliverability; this may partly explain the excess capacity commitments of many LDCs. With greater unbundling of LDC services, and with the real possibility that the LDC may become a distribution-only utility, the LDC's interstate transportation arrangements are likely to be open to closer scrutiny. This is more likely if greater unbundling is accompanied by a reduction or elimination of the LDC's obligation to serve.[3] The ultimate effect may be a general reduction of the LDC's capacity commitments on the interstate pipeline, and an exacerbation of the capacity turnback problem.

Although greater emphasis on *efficient procurement* of firm capacity may exacerbate the capacity turnback problem by reducing future commitments of capacity, state PUC regulation may also be able to mitigate the occurrence of capacity turnback problem by requiring *efficient utilization of existing capacity*, such as release of unneeded capacity in the secondary market. State PUCs currently lack well-established standards to evaluate secondary-market transactions of LDCs. Such standards should be developed.

Provide Incentives for Releasing Capacity

State PUCs may wish to consider providing cost-sharing incentives to LDCs for releasing unneeded capacity in the secondary market.[4] Incentives can be provided for both release of firm capacity in the secondary market, as well as selling of rebundled capacity and gas sales services in the "gray" market. In the past, the secondary capacity market has not worked well due to the cumbersome bidding requirements and the rate cap imposed by FERC on released capacity. The recent FERC adoption of

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[3] The LDC may still remain a supplier of last resort for emergency and lifeline services, and for low income customers.

[4] States that currently have capacity release incentives include Georgia, Iowa, New York, and North Carolina.

standards for electronic bidding developed by the GISB, and FERC's expression of willingness to release rate caps on a showing of lack of market power of the LDC at the city gate, increase the prospects of a more vigorous secondary market.

Many state PUCs may understandably oppose, on jurisdictional grounds, the market power condition for the lifting of the rate cap. However, many LDCs whose services have been unbundled may be able to meet this condition,[5] and therefore be able to resell their unused firm capacity rates at market-based prices. State PUCs and LDCs may wish to consider a strategy of concurrently opposing the FERC market power condition and yet taking full advantage of allowing the LDC to resell their firm capacity when the requirement can be met.[6]

In providing incentives for reselling of capacity, the state PUC must guard against encouraging the LDC to purposely purchase excess capacity and reselling the capacity. One way to protect against this possibility is to set a date after which new purchases of capacity will not be subject to capacity release incentives, or to make the incentives for reselling of capacity purchased after the target date much weaker.

Encourage LDCs to Reach Equitable Settlements with Pipelines

State PUCs can help mitigate the capacity turnback problem without unduly harming LDC customers by encouraging or supporting LDCs to reach equitable settlements to the decontracting problem. As the three recent cases of large capacity turnbacks have shown, an LDC may be able to reach settlements that typically allocate between 65 to 80 percent of the turnback costs on the pipeline over a transition period after which the pipeline assumes full responsibility for future turnback costs. This is a

[5] Unbundling of services, if correctly implemented, may generally reduce an LDC's willingness and ability to exercise market power at the city gate. For example, if a state PUC requires functional separation or divestiture of the LDC's distribution services from its other services, the LDC may be less willing or able to discriminate against other providers of these services.

[6] State PUCs may require LDCs to release their firm capacity commitments with the recall option, to ensure deliverability.

reasonable resolution to the problem which may otherwise engage all parties in costly litigation and impose a significant risk on the LDC and its customers for future turnback costs.

Allow or Encourage LDCs to Form Groups to Design Collective Strategies to Respond to the Capacity Turnback Problem

An LDC will have greater bargaining power in reaching a settlement with a pipeline if the LDC teams up with other customers of the pipeline. As the examples of the Transwestern Pipeline and El Paso have shown, pipeline customers banding together to collectively negotiate with the pipeline can result in an equitable and less expensive settlement. Also, FERC is also more likely to be supportive of settlements that are reached collectively than bilateral settlements.[7]

Protect Captive Customers from Adverse Consequences of Capacity Turnback

State PUCs may also wish to consider, regardless of how the capacity turnback problem is resolved, the allocation of the LDC's share of the related costs among the LDC's customers. Given the fact that certain customers (such as residential and small commercial customers) of the LDC have presently limited choices, and will continue to have limited choices in the future, the LDC may be willing and able to allocate disproportionate share of turnback-related costs on such customers. State PUCs may wish to adopt policies to prevent such cost-shifting. For example, the state PUC may require the LDC to allocate the costs of capacity turnback among the customers the same way the costs of firm contracted capacity are allocated.

[7] Since bilateral settlements allow the pipeline to exercise more market power than multilateral settlements, FERC may be less favorably disposed toward such settlements.

CHAPTER 6

SUMMARY AND CONCLUSIONS

Over the last decade, the gas industry has undergone a massive transformation. The interaction of market forces, FERC policy actions, and changes in state PUC regulation has resulted in an increasingly competitive industry. One result of these developments has been an increasing focus on cost minimization, and the efficient use of resources. LDCs face increasing pressures to minimize costs and to use their resources, such as their transportation arrangements, more efficiently. As a result, LDCs may reduce their capacity commitments, once their current long-term transportation contracts expire. This may cause an excess capacity problem for pipelines and underrecovery of their capital investments in pipeline construction.

The resulting “transition cost problem,” reminiscent of such problems in the gas industry in earlier times (e.g., the “take-or-pay” problem in early eighties) and in other utility industries (e.g., the more recent “stranded cost” problem in the electric utility industry), may confront regulators and other stakeholders in the gas industry with a significant challenge.

The capacity turnback problem can be traced back to market-driven changes in the industry, FERC actions, and state policies. The market-driven changes include the growth of market hubs and centers, proliferation of ancillary services, and increasing availability of services and service packages that are good substitutes to long-term firm transportation capacity. For example, an LDC can use short-term FT and storage services and essentially secure the same reliability of service as long-term firm capacity. Therefore, the LDC may relinquish its long-term firm capacity commitments once the current contracts expire.

FERC actions, most notably Order 636, also contributed to the capacity turnback problem. One provision of Order 636, the SFV rate design for capacity, which allocates all fixed costs to the demand component of the rate, makes unused or underutilized capacity to LDC and other shippers more expensive. Therefore, LDCs and other shippers are likely to relinquish long-term firm capacity entitlements, which are subject to the SFV rate design, once the current contracts expire. Order 636 also intended to stimulate the secondary market for capacity by allowing LDCs and others shippers to release their long-term firm capacity holdings to other parties. If the capacity release market had worked as intended, the problem of excess capacity commitments would probably have been mitigated. However, the electronic bidding requirements and the as-billed rate cap on released capacity have impeded the full maturation of this market. Therefore, the industry has not been able to exploit an important avenue for mitigating the capacity turnback problem.

State PUC policies, with an increasing focus on cost minimization, efficient use of resources, and more recently, on service unbundling and customer choice, also may have contributed to the capacity turnback problem. The focus on cost minimization and efficient use of resources, through increasing scrutiny and adoption of PBR, puts increasing pressure on the LDC to minimize the costs of their transportation arrangements. PUC initiatives to introduce greater unbundling of services, and to offer greater customer choice, may drive the LDC to the role of a distribution-only utility, with reduced or no responsibility for securing upstream capacity. These developments may induce the LDC to relinquish its long-term firm capacity rights once the current contracts expire.

The study found significant regional differences in excess capacity and the potential for capacity turnback. The problem may be significant in the western midwestern, and northeastern regions of the country. The other parts of the country do not appear to have a significant excess capacity problem. There already have been three large capacity turnback cases, in the West (involving Transwestern Pipelines and El Paso Natural Gas Company) and in the Midwest (involving Natural Gas Pipeline Company).

The study examined possible regulatory and market-based options to address the capacity turnback problem. The regulatory options addressed include unilateral exit fees, reallocation of decontracting costs to remaining customers, full assignment of decontracting costs to the pipeline shareholders, alternative rate designs (other than SFV), discounts based on duration of contracts and prospective exit fees. The market-based options include negotiated cost-sharing settlements, lifting of price cap on released capacity, IT and short-term FT, elimination of electronic bidding requirements on released capacity, and use of market-based rates and flexible service terms for pipeline capacity.

Among the regulatory options, the study found that alternative rate designs, discounts based on duration of contracts and prospective exit fees (for new contracts) to have more merit than the other options. All the other regulatory options appear to be flawed on both economic efficiency and equity grounds. In the past turnback cases, FERC has indicated that it will not allow unilateral exit fees and reallocation of costs to remaining customers.

Among the market-based options, the study found that negotiated settlements, lifting the rate caps on released capacity, short-term firm and interruptible capacity, revising or eliminating electronic bidding requirements for released capacity, market-based pricing of pipeline services, and flexible terms and conditions for pipeline services to merit consideration. In past turnback cases, FERC has indicated its preference for negotiated cost-sharing settlements.

With regard to the lifting of rate caps, FERC has concern about the exercise of market power by LDCs and pipelines in relevant markets. The study found that FERC should consider relaxing market power tests, and rely more on after-the-fact public disclosures to detect instances of market power abuse, and to lift rate caps to stimulate the relevant markets. The adoption of uniform standards by the GISB should also facilitate the secondary market transactions.

The study concludes that the capacity turnback problem can be effectively addressed by a combination of regulatory and market-based options, and that FERC should, consistent with their policy positions in past turnback cases, opt for solutions that are pro-competitive and economically efficient. Furthermore, FERC should also initiate steps to stimulate the secondary market for capacity, allowing the excess capacity problem to be mitigated through market-based opportunities and avenues.

The study also concludes that state PUCs should continue their current thrust toward unbundling and greater customer choice, regardless of the effect on the potential capacity turnback problem. State PUCs should continue to require, and provide incentives for, efficient utilization of the LDC's transportation arrangements. Furthermore, state PUCs may wish to provide cost-sharing incentives to the LDC to release unused capacity on the secondary market, as well as rebundled services on the "gray" market. State PUCs should establish appropriate mechanisms to shield the captive customers from the inequitable or inappropriate pass-through of decontracting costs.

The study concludes that LDCs should attempt, with PUC support, to work out equitable settlements with pipelines. LDCs may wish to form groups to devise collective strategies to respond to the potential capacity turnback problem.

Finally, the study observes that capacity turnback is likely to be a transitional problem and calls for solutions that facilitate, rather than inhibit, the competitive thrust of the industry, supported by FERC and state PUC policies.