2. Changes in Firm Transportation Capacity Contracting

Shippers in today's natural gas market are under increasing pressure to manage their gas supply and transportation portfolios efficiently to reduce costs. When possible, they are choosing some of the new services that compete with primary firm transportation services offered by interstate pipeline companies, such as high-deliverability storage, "high quality" interruptible capacity, released capacity, and market center services.

Under Order 636, the "restructuring rule" issued by the Federal Energy Regulatory Commission (FERC) in April 1992, firm sales entitlements of pipeline companies' customers were converted to firm transportation rights. However, Order 636 provided little opportunity for customers to reduce their firm commitment levels.[1] With the changes in rate design, development of new services, and the ability to identify the cost of each component of natural gas service, customers are finding that the long-term contracts entered into years earlier may no longer reflect current market conditions. In addition, demand has not increased as much as expected in some areas because of changes in regional economies, as well as increases in energy efficiencies and greater conservation efforts. Consequently, available firm capacity exceeds customers' requirements along some pipeline routes.

The cost of firm transportation has also become more expensive for some shippers because of the current rate design method. Order 636 changed the way rates are calculated by requiring pipeline companies to use the straight fixed-variable rate design, which increases the costs of reserving capacity but lowers the variable cost of the gas transported. Shippers whose peak-period needs for capacity are very high compared with their average needs are particularly affected by this change.

Some shippers have reduced their capacity costs by using the capacity release market, which was established under Order 636. This market allows shippers to resell unused firm transportation capacity as long as rates do not exceed the maximum regulated rate.[2] In practice, however, most capacity rights have been traded at substantial discounts, which limits the market's effectiveness in offsetting the high costs of reserving firm capacity. The market also has been hindered by its somewhat cumbersome posting and transaction procedures. In some cases, shippers instead repackage unneeded capacity with another service and sell rebundled services outside their usual market area (the "gray market").

Because the capacity release and gray markets have not solved the long-term problem of excess capacity commitments, some shippers have "turned back" all or part of their capacity commitments when these contracts come up for renewal. This has significant implications for the natural gas market and raises a number of issues for shippers, pipeline companies, and regulators.

The extent and implications of a reduction in the amount of capacity reserved is an emerging concern for the transportation industry. Turnback of pipeline capacity, which was limited to two U.S. geographic regions (West and Midwest) in 1995 and 1996, could increasingly become a nationwide challenge. Between April 1, 1996, and December 31, 2001, contracts covering 51 percent of transportation capacity (under contract as of April 1, 1996) will expire. In monetary terms, the potential impact of capacity turnback is significant. If pipeline companies are unable to remarket 20 percent of the capacity expiring through 2001, for example, it would represent at least a $686 million reduction in annual pipeline revenues.[3]

Pipeline cost recovery is a major concern in this circumstance. Increasing rates to remaining customers is not a viable solution since this would lead to even further reductions in capacity reservations. Such rate increases would make it difficult for pipeline companies in competitive markets to attract new customers and may drive their current customers to other transporters, services, and service providers.

Capacity turnback may signify a period of adjustment for the transportation market similar to the transition from long-term to short-term and spot contracts that occurred in the wellhead market for gas in the 1980's. Over the long term, the current

[1]Order 636-A did permit firm customers to reduce or terminate capacity entitlements if another customer contracted for and assumed liability for the cost of the capacity or the pipeline company assumed responsibility for the capacity and associated costs. Federal Energy Regulatory Commission, Order 636-A, 57 F.R. 36128 (August 12, 1992).

[2]The Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking on July 31, 1996, which proposes to remove the price cap on released capacity provided the releasing shipper can demonstrate that it does not exercise market power (Docket No. RM96-14).

[3]The $686 million annual reduction in pipeline company revenues was estimated using the amount of capacity due to expire through the year 2001 and firm transportation tariff rates for a sample of 44 interstate pipeline companies. In order to estimate the minimum revenue impact of contracts that are not renewed, it was assumed that the lowest firm transportation rate for each pipeline company would apply to the full expiration amount. Transportation rates were taken from H. Zinder & Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies* (March 15, 1996). The product of the transportation rates and capacity expirations was multiplied by 0.2 to estimate the annual reduction in pipeline company revenues for 20 percent of contracted capacity.

changes may lead to the development of alternative products to current transportation services. Other possibilities include a spot market for transportation, increased commoditization of capacity, and the development of financial instruments for the transportation market.

This chapter focuses on the development of excess capacity commitments by shippers and the potential implications of capacity turnback for the transportation market. The chapter also discusses the use and effectiveness of the secondary capacity market for reducing capacity commitments and costs. In addition, it quantifies the potential for capacity turnback and examines three cases of large turnbacks that occurred in 1995 and 1996 to assess pipeline company approaches, financial impacts, and evolving regulatory policy.

Factors Leading to Excess Capacity Commitments

Industry restructuring, deregulation of the wellhead market, availability of new competing services, as well as changes in gas supply, regional economies, and system deliverability are contributing factors to a reduced need for long-term firm capacity reservations (see box, p. 41).

Regulatory Changes

Until the mid-1980's, all interstate natural gas pipeline companies were primarily gas merchants, combining gas sales with transportation. They would purchase natural gas from producers, transport it largely along their own proprietary pipeline system, and resell the rebundled product to local distribution companies (LDCs) and other large customers. The prices paid by customers reflected the cost of gas and all services required for delivery. This institutional structure, together with the relatively concentrated nature of the interstate pipeline industry, meant that each producer could sell gas to a limited number of buyers (pipeline companies). Moreover, LDCs and large end users usually had limited options in terms of the number of pipeline companies from which they could purchase gas.[4]

Under this market structure, interstate pipeline company rates were regulated by FERC, and distribution rates charged by LDCs to move gas from the citygate to end users were regulated by State regulatory agencies.[5] Traditionally, pipeline companies and LDCs are allowed to charge prices that recover all reasonable costs of delivering gas to their customers. In practice, most of the costs fall on the captive customers who have no other options for obtaining gas service. Also, regulators have traditionally required LDCs to purchase sufficient pipeline capacity to meet their maximum seasonal requirements for firm sales service. Under these circumstances LDCs tended to enter into long-term firm transportation contracts with pipeline companies, which both parties perceived would reduce contract management costs, protect their capital investments, reduce deliverability uncertainties, and lock-in price terms. Both the industry and regulators believed that long-term contracts would provide the stability and service reliability necessary for investment in a capital-intensive industry.

Long-term security came at a cost, usually to the captive customers of pipeline companies and LDCs. Capacity commitments and gas flows were based largely on moving gas along proprietary systems. Many customers paid maximum regulated rates for their gas service. There was little opportunity for savings from rerouting the flow of gas, moving gas from one system to another, and entering into alternative contract vehicles. LDCs were required to reserve sufficient capacity to meet their maximum loads, although this meant that for the rest of the year they were paying for unused capacity and passing these costs to their customers.

FERC restructured interstate pipeline company services during the 1980's and early 1990's and transformed the way the industry operates. Among other things, FERC abolished pipeline company bundled services; adopted a uniform transportation rate design method; and established a secondary market for storage and pipeline capacity. Under the new market structure, natural gas customers can build and manage a portfolio of supply, storage, and transportation services that best meets their needs.

Concurrent with Federal regulations, State regulators offered incentives for LDCs to increase efficiency and reduce operating costs. A number of States established incentive-rate mechanisms that allowed LDCs to keep a portion of any savings derived from managing their gas supply and transportation portfolios more efficiently. As States unbundle LDC sales and transportation for smaller customers, LDCs may face increased pressure to reduce their service costs (see Chapter 6).

A direct consequence of industry restructuring and regulatory reform is that the mix of various natural gas services has changed. New services that compete directly with long-term capacity are commonplace compared with just a few years ago. Market hubs offer an array of services that allow shippers to "park" and reroute gas to bypass system bottlenecks. New storage and liquefied natural gas (LNG)

[4] Small end users, such as residential customers, had no choice but to purchase gas from LDCs.

[5] Intrastate pipeline companies also deliver gas to end users and are governed by State regulatory agencies.

Factors Leading to Capacity Turnback

Industry Restructuring

- Increased options for shippers to ship gas.
- Shippers reduced use of sales service.
- New market center services and improved grid integration.
- Increased use of high-deliverability and market area storage.
- Improved access to U.S. and Canadian suppliers.

Regulatory Reform

- Capacity reservation is more expensive for low load customers under the new straight fixed-variable rate design.
- Price offsets from releasing excess capacity onto the capacity release market are limited (rate cap and large discounts).
- Incentive rate programs established by states that encourage LDCs to cut costs.

Competition

- Shippers are under pressure to reduce costs to remain competitive.
- Development of downstream alternatives to firm transportation.
- Expansion of pipeline and storage capacity.

Other

- Changes in regional economies result in lower than expected gas demand.

facilities give shippers additional access to gas sources to meet peak-day requirements. LDCs can now substitute a mix of high-deliverability storage, short-term firm transportation, interruptible transportation, released capacity, and gray market transportation for long-term firm transportation (FT).

With cost-conscious shippers seeking cheaper alternatives to expensive FT capacity, a number of specific conditions have made long-term firm capacity contracts increasingly unattractive. For example, the cost of reserving pipeline capacity is more expensive. FERC Order 636 requires interstate pipeline companies to develop rates using a straight fixed-variable method. This new tariff design made it more expensive for most gas shippers to reserve pipeline capacity, but lowered the usage charge for transported gas. This change especially affects low-load-factor customers (customers whose ratio of annual gas throughput to reserved capacity is low) who must reserve sufficient pipeline capacity to meet seasonal peak demand. Low-load-factor customers now pay significantly more to transport gas because of the higher capacity reservation fee, even though the usage fee paid for the actual quantity of gas shipped has declined.

LDCs who must reserve enough capacity to meet peak demand during cold winters are examples of low load customers that are hurt by the change to straight fixed-variable rates and therefore may seek alternative arrangements to long-term firm transportation. For example, a 1995 Energy Information Administration report found that low-load-factor customers of a sample of U.S. pipeline companies consistently had changes in rates between 1991 and 1994 that were less advantageous than for the high-load-factor customers.[6] For some LDCs, the cost of reserving firm pipeline capacity has also increased because of discounts given to other customers. FERC permits pipeline companies to discount prices for competitive services in order to retain customers and to recover the revenue reduction from remaining firm customers.

For many firm capacity holders, releasing unused firm transportation (FT) capacity on the secondary market generally does not offset the expense of reserving the capacity. FERC Order 636 established a secondary or capacity release market that enables shippers to resell their excess FT capacity. Depending on the price for the released capacity, this mechanism had the potential to offset the expense of reserving long-term FT capacity. Because of the cumbersome nature of this market and the low prices received for released capacity, however, shippers have released only small amounts of capacity and at prices that do not offset

[6]Energy Information Administration, *Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rate*, DOE/EIA-0602 (Washington, DC, October 1995), p. 48. The study found that for customers with low load-factors, two-thirds of sampled pipeline companies had rate increases between 1991 and 1994. Further, for each company in the sample, the increase was larger in both absolute and percentage terms for the low-load-factor (40 percent) customers than for those with a 100-percent load factor.

reservation costs. Consequently, shippers are looking for other alternatives to deal with unused, long-term FT capacity.

Changes in Regional Economies

Expected increases in gas demand and the need for operational flexibility led to a 14-percent increase in interregional pipeline capacity between 1990 and 1994.[7] Of the total 10.4 billion cubic feet per day of pipeline capacity added during this period, 3.7 billion cubic feet per day was new capacity built to import gas from Canada to the Northeast, Central, and Western United States.

Much of the new pipeline capacity was built on the premise that natural gas markets would expand at a much faster pace than has proved to be the case. Although U.S. gas demand increased at an average annual rate of more than 3 percent between 1986 and 1995, growth was lower than expected because of increases in energy efficiency, greater conservation efforts, relatively slow growth in gas use by energy-intensive industries and electric utility generators. As a result, excess pipeline capacity has developed in some regional markets, contributing to the risk of capacity turnback by gas shippers who now have more transportation options.

In California, new pipeline capacity was built by Pacific Gas Transmission Company and Kern River Transmission Company to ship relatively inexpensive natural gas from Canada and the U.S. Rockies. Pipeline capacity into the Western Region, primarily designed to increase access to Canadian supplies, increased by 41 percent between 1990 and 1994. As a result, LDCs and other pipeline customers have begun to relinquish capacity on the older pipelines, which access more expensive production from the Permian Basin of Texas and the Anadarko Basin of western Oklahoma, as their contracts expire. One indication of the growth of excess capacity in the Western Region is the fact that the pipeline capacity utilization rate declined from 84 percent in 1990 to 71 percent in 1994.[8]

Short-Term Solutions to Excess Capacity Commitments

There are three methods currently available to shippers who wish to reduce their capacity costs:

- **The capacity release market** – wherein shippers may offer the rights to some or all of their firm capacity in exchange for revenue credits

- **The gray market** – wherein shippers may bundle their unneeded capacity with additional service and sell the rebundled package to others

- **The turnback of capacity** – wherein shippers, when their contracts expire, return or "turn back" all or part of their firm contracted capacity to the pipeline company.

The first two options are short-term solutions that are discussed in this section. The third is a permanent solution to excess capacity and is discussed separately later in the chapter.

Capacity Release

The release market offers several advantages for the selling or "releasing" shipper:

- **Allows shippers to respond quickly to market changes**. The capacity release market operates every business day, and releasing shippers are not required to provide excess lead time before posting their releases.

- **Includes flexible terms with respect to amount of capacity and duration of release**. A shipper may release all or only part of its capacity for as little as a day or as long as the duration of its contract with the pipeline company.

- **Releasing shippers may set specific pricing terms, subject to the maximum regulated rate cap**. They may request rates based on capacity reserved, capacity used, or rates that are indexed to a particular benchmark.

- **Releasing shippers may reserve the right to recall the capacity.** By placing a recall option on the released capacity, the releasing shipper avoids any risk to ongoing operations. The releasing shipper may reclaim the capacity from the replacement shipper when market or operating conditions reach a predetermined level.

The capacity release market also offers many advantages to "replacement" shippers who purchase the released capacity:

- **Moderate lead time required**. The acquisition of capacity on the release market requires very little lead time. This allows the replacement shipper to use the capacity release market to satisfy incremental loads

[7] Energy Information Administration, *Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates*, p. 32.
[8] Energy Information Administration, *Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates*, p. 32.

economically instead of subscribing to firm capacity that may be underutilized.

- **Flexible terms with respect to duration of contract**. The replacement shipper can acquire capacity for the period it will be needed instead of being constrained by standard contract periods.

- **Ability to obtain capacity.** The replacement shipper is able to obtain firm capacity even when the pipeline is fully reserved.

- **Released capacity is usually priced below tariff rates**. The replacement shipper often can acquire released capacity at a fraction of the maximum regulated rate.

However, the capacity release market has some significant drawbacks that can more than offset the advantages and could present obstacles for both releasing and replacement shippers. The disadvantages include:

- **Some of the electronic bulletin boards (EBBs), through which the release market is accessed, are cumbersome**. Released capacity is posted on pipeline company EBBs, each of which can have a different user interface. Therefore, shippers would need to learn the operating methods of several EBBs to access a desired flow path.

- **Coordination of multiple contracts may be difficult**. A replacement shipper wishing to acquire several segments (parcels) of released capacity to ensure access to a specific supply area might not be able to close deals simultaneously. The shipper might have to acquire the desired segments of capacity in a piecemeal fashion. If the shipper fails to acquire a critical segment of capacity, then the acquired segments could be of less use.[9]

- **Released capacity rates are less than tariff rates for firm capacity**. During the nonheating season when capacity is plentiful, rates are well below tariff rates. Even during the heating season, the price for released capacity is capped at the maximum tariff rate.[10] Therefore, on average, releasing shippers might receive only a fraction of the amount they paid for the capacity, which might provide only a partial offset for the cost of reserving firm capacity.

- **Released capacity may be unavailable**. Particularly during peak periods, released capacity might not be available or offered for release.

Activity in the Capacity Release Market Continues to Grow

The release market has grown steadily in terms of capacity traded, indicating that shippers are becoming experienced in capacity trading. When capacity held by replacement shippers is considered over entire heating and nonheating seasons, two patterns emerge. First, the overall amount of capacity held by replacement shippers has increased year to year. The amount of capacity held by replacement shippers during the 12 months ended March 31, 1996, was 5.8 trillion cubic feet, or 59 percent more than the 3.2 trillion cubic feet held for the 12 months ended March 31, 1995.

The increase in release activity was mirrored in the heating (November through March) and nonheating (April through October) seasons (Figure 14).[11] Although the growth in capacity held by replacement shippers during the heating seasons slowed from its initial pace, there was still a significant overall increase between the 1994–95 and 1995–96 heating seasons (Figure 15). The amount of capacity held by replacement shippers during the 1994–95 heating season was 1,587 billion cubic feet (Bcf), over two and one-half times the 1993–94 level. The capacity held by replacement shippers during the 1995–96 heating season increased to 2,451 Bcf, which is 54 percent higher than the 1994–95 level. The capacity held during nonheating seasons also grew. Capacity held during the 1995 nonheating season was 3,324 Bcf, representing a 63-percent increase over the amount held during the 1994 nonheating season.

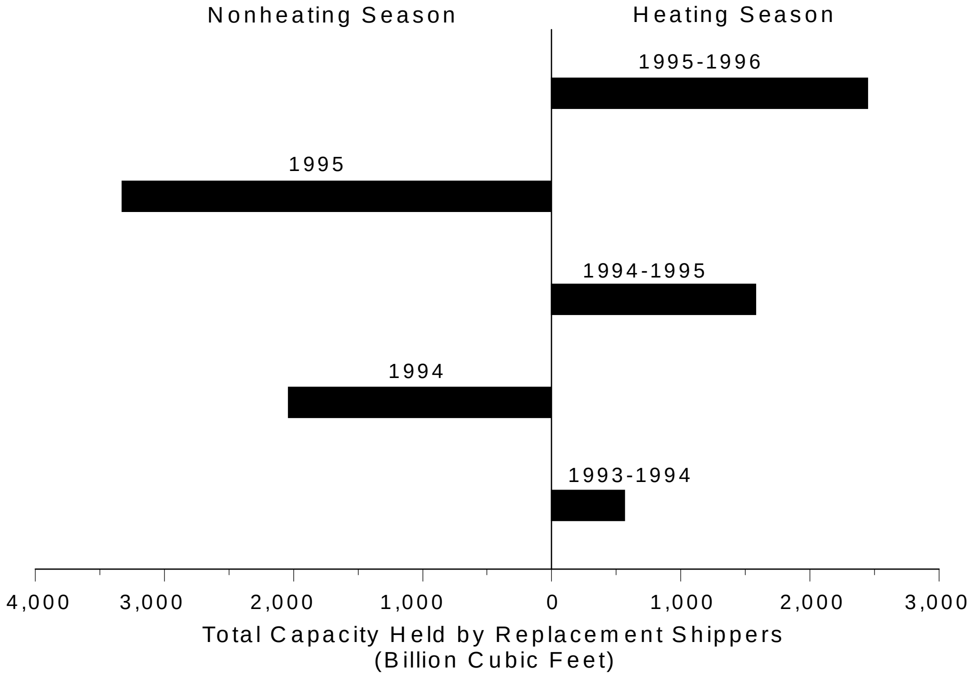
The amount of capacity held by replacement shippers during the heating and nonheating seasons may indicate that many holders of firm capacity are using the release market to shed unneeded capacity year-round. The level of capacity held by replacement shippers represents a significant amount of interstate pipeline capacity. As much as 23 percent of the

[9]The capacity release procedures, adopted by the Federal Energy Regulatory Commission (FERC) in its Order 587, may help alleviate the coordination problem. Beginning April 1, 1997, pipeline companies must establish procedures to process capacity release transactions within one hour of receipt if the transaction is a prearranged deal, not subject to bidding, and within one day if the deal is subject to bidding. FERC Docket No. RM96-1-000 (July 17, 1996).

[10]On July 31, 1996, FERC issued a Notice of Proposed Rulemaking that proposes to remove the price cap on released capacity provided the releasing shipper can demonstrate that it does not exercise market power (Docket No. RM96-14).

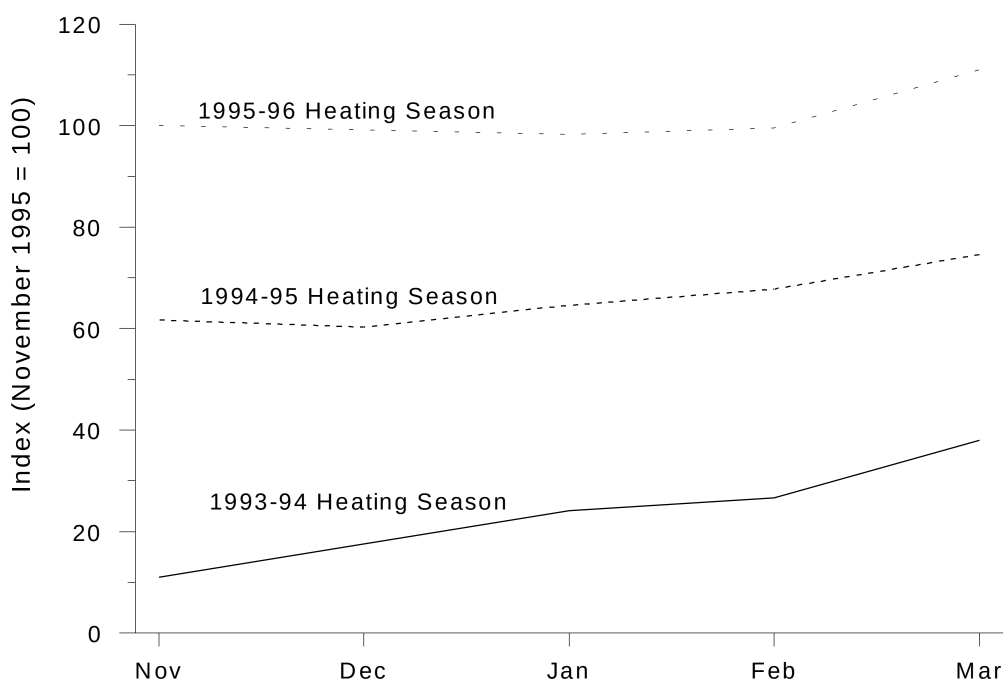
[11]The total volume of released capacity held by replacement shippers during a season is the sum of the capacity effective on each day of the season. For example, if a 60-day contract for Z thousand cubic feet per day is effective within a season, then the sum of capacity held for the season would include Z thousand cubic feet 60 times for that contract. If that 60-day contract were only effective, for example, for the last 20 days of the season, then the sum for the season would include Z thousand cubic feet 20 times, and the sum for the next season would include Z thousand cubic feet 40 times for that contract.

Figure 14. Seasonal Capacity Held by Replacement Shippers, November 1993 - March 1996



Note: The nonheating season extends from April through October, and the heating season is from November through March.
Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1996:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

Figure 15. Index of Capacity Held by Replacement Shippers During Heating Seasons



Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1996:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

deliveries to end users could have moved using released capacity during the 1995–96 heating season. The fact that a large amount of capacity is available for release during the peak season also indicates that shippers are holding a substantial amount of unneeded capacity.

The second pattern that can be seen in the capacity release market is the distinct seasonal patterns of capacity held by replacement shippers (Figure 16).[12] The daily amount of capacity held by replacement shippers generally grows from the beginning of the nonheating season until it peaks just before the beginning of the heating season. Then the amount of capacity held gradually falls until the middle of the heating season when it begins to climb again. The downturn in capacity held by replacement shippers may be due to releasing shippers retaining their capacity rights until they are more certain what their own needs will be.

The sharper downturn experienced during the 1995–96 heating season may have been caused by the colder weather in the 1995–96 heating season compared with the 1994–95 heating season.[13] During the 1995–96 heating season, consumption and capacity utilization increased, leaving less capacity available for shippers to release (see Chapter 1). Unusually low levels of working gas in storage heading into the 1995–96 heating season also may have been a factor in the sharper decline in capacity held by replacement shippers.[14]

An important feature of the capacity release program is that the releasing shipper may include with the release a provision that allows the shipper to recall the capacity. About 63 percent of the capacity held between April 1, 1995 and March 31, 1996 had recall provisions. Unfortunately, no data are available on the amount of capacity that has actually been recalled once the replacement contracts became effective. Such data would be very useful in understanding how the industry is using the capacity release market, especially during times of extremely cold weather such as the 1995–96 heating season.

[12]The amount of capacity held by replacement shippers on any day is the sum of all capacity for which a contract is effective on that day. For example, if a contract for X million cubic feet of released capacity was effective March 1–March 31, 1996, then X million cubic feet from this contract would be included in the total, daily capacity held for March 1–March 31, 1996. See Appendix B for a description of the data sources and methodology used to calculate the amount of capacity held by replacement shippers.

[13]The 1995–96 heating season was 15 percent colder than the 1994–95 heating season as measured by heating degree days. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(96/04) (Washington, DC, April 1996).

[14]Working gas was 2,495 billion cubic feet (Bcf) in August 1995 and 2,802 Bcf in September 1995. These were the lowest levels for these months since 1976.

There is evidence that indicates replacement shippers are using the capacity release market as a rapid response source of capacity. Of the capacity traded since November 1, 1993, 90 percent became available for use by replacement shippers within 2 weeks of the contract award date. For the released capacity under contracts in effect during the 1995–96 heating season, 90 percent of the awarded capacity was under contracts that became effective within the first 2 weeks after they were awarded. Also, 79 percent of the capacity awarded was under contract for terms of 31 days or less. This, along with the increase in capacity held by replacement shippers during the last 2 months of the heating season, implies that there was sufficient excess capacity for new releases to occur, even though 65 percent of the capacity held by replacement shippers that season was subject to recall.

Revenues from Capacity Release Activity Have Also Increased

Revenues generated from released capacity total $1.2 billion for transactions between November 1993 (when the program began) and March 1996. Generally, the trend in revenue received from released capacity has paralleled the trading activity of the release market. Total revenue from released capacity increased by 81 percent, from $388 million for the 12 months ended March 31, 1995, to $702 million for the 12 months ended March 31, 1996.[15] In comparison, total transportation and distribution revenues for 1995 were approximately $32 billion.[16]

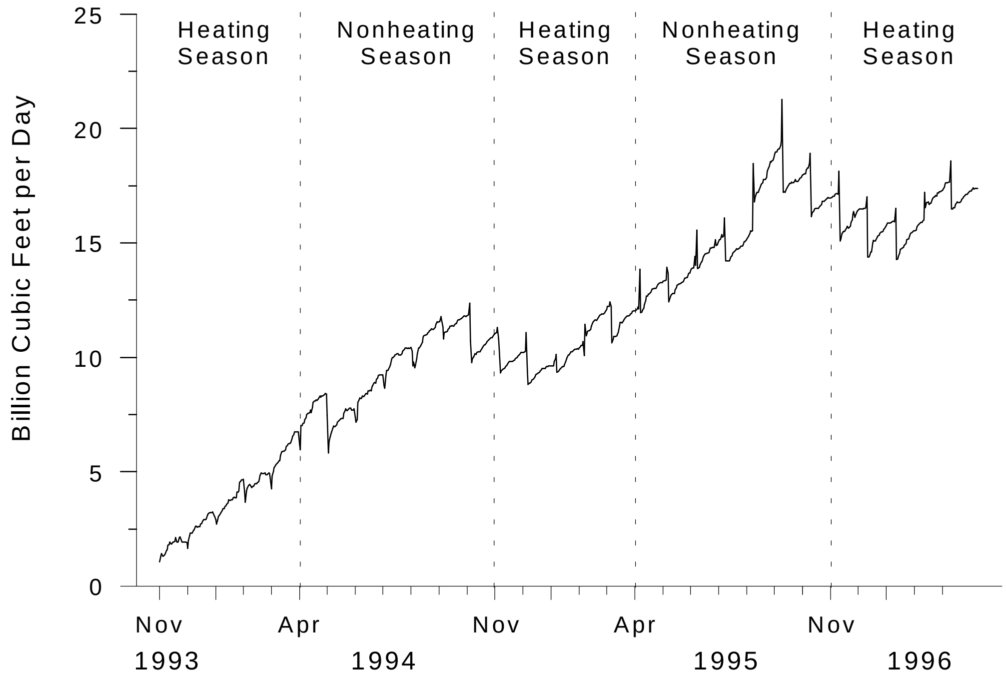
Capacity release revenues received during the heating season and nonheating season also rose. Total revenue from released capacity doubled between the 1993–94 and 1994–95 heating seasons, from $78 to $173 million, and doubled again to $392 million during the 1995–96 heating season. The revenue from released capacity during nonheating seasons increased by 44 percent, from $215 million in 1994 to $309 million in 1995.

While the increase in release activity was partially responsible for the growth in revenues, it appears that the average price for capacity traded during the heating season has also increased. The average monthly price for released capacity during the heating season increased by 47 percent, from $3.31 per thousand cubic feet (Mcf) in the 1994–95 heating season to $4.87 per Mcf in the 1995–96 heating season. In contrast, the average monthly price of capacity released during the

[15]All the revenue and volume calculations have been performed assuming no recall and 100-percent load factor. In other words, it is assumed that the total capacity awarded will be used by the replacement shipper (see Appendix E).

[16]Unless noted otherwise, dollar amounts are stated in nominal terms.

Figure 16. Capacity Held by Replacement Shippers, November 1993 - March 1996



Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1996:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

nonheating season has declined by 12 percent, from $3.21 per Mcf in 1994 to $2.83 per Mcf in 1995. This reduction possibly is the result of the increased availability of capacity during the nonheating season in 1995–96 and the relatively high storage levels at the end of the 1994–95 heating season that lessened the need to build storage inventories during the nonheating season.

The increase in the average price for released capacity during the heating season can be the result of several factors. First, the increase in capacity held by replacement shippers may indicate that more shippers are looking to the capacity release market to satisfy their transportation requirements. This boost in demand for released capacity could be pushing up the price. Second, weather conditions may be influencing the average price of capacity. The average rate was lowest in the 1994–95 heating season when the winter was mildest, and the average rate was highest in the 1995–96 heating season during the prolonged cold winter.

The average term of the contract duration for the released capacity has grown for contracts that became effective during the heating season, from 60 days in 1994–95 to 90 days in 1995–96. This could indicate that the released capacity is more valuable. It may also indicate that releasing shippers have an improved understanding of the extent of their excess capacity or have alternative methods of meeting loads. Much of the increase in contract duration was due to several long-term releases of capacity. Nevertheless, the median contract term for the past two heating seasons increased from 29 days in 1994–95 to 31 days in 1995–96.

The increase in average rates resulted in heating season revenues exceeding the nonheating revenues for the first time during the 1995–96 period. The 1995–96 heating season revenues were over 27 percent greater than the nonheating season revenues, although the heating season is only 5 months long compared with 7 months for the nonheating season.

Notwithstanding the increase, average rates for released capacity are still well below maximum tariff rates. The rates were discounted, on average, 65 percent from the maximum rates during the 1995–96 heating season, and 83 percent during the 1995 nonheating season. Although the average discount amount has declined compared with the previous seasons (82 percent and 92 percent for the 1994–95 heating and 1994 nonheating seasons, respectively), it appears that the capacity release market still does not fully compensate releasing shippers for their firm capacity costs. FERC's recent proposals to change the secondary market[17] may affect the rates for released capacity in the future (see Chapter 1).

Regions Have Quite Different Capacity Release Markets

The trends in the capacity release market for some regions differ markedly from the national trends. For example, the national release market, on average, experiences more activity and higher prices during the heating season, but not all regions experience the activity increase during that season. The Southeast and Southwest regions may be driven by summer consumption for cooling rather than the winter heating demand. Also, the level of trading in these regions is an order of magnitude less than the level in other regions. Nevertheless, capacity release revenues increased for the 1995–96 heating season in all regions except the Southeast compared with the 1994–95 heating season (Figure 17). The Midwest Region had the largest percentage increase, with 1995–96 heating season revenues that were five times the revenues for the previous heating season. The 1995–96 heating season revenues were twice the comparable 1994–95 levels for each other region except the Southeast and Southwest.

The average prices for released capacity also increased in most regions between the 1994–95 and 1995–96 heating seasons. The increases ranged from 4 percent in the Central to 124 percent in the Midwest. The Southwest and Southeast Regions experienced price declines between the 1994–95 and 1995–96 heating seasons. However, the Southwest had unusually high prices during the 1994–95 heating season. The lowest monthly price for released capacity was in the Southeast Region at $1.68 per thousand cubic feet (Mcf).[18] All other regions had monthly prices between $4.13 and $5.45 per Mcf during the 1995–96 heating season (Table 3). The Midwest commanded the highest average monthly price for released capacity at $5.45 per Mcf.

The dramatic increase in rates for released capacity during the 1995–96 heating season may have been the result of several factors, including the cold weather during that period and the change in some characteristics of the released capacity. As mentioned earlier, most regions experienced colder-than-normal weather during the 1995–96 heating season. Overall the 1995–96 heating season was 3 percent colder than normal and 15 percent colder than the previous heating season, as measured by heating degree days.[19] This prolonged cold weather may have caused some shippers to refrain from releasing capacity on the market, thus reducing the supply of released capacity and driving up the price.

Shippers have been releasing capacity for longer periods, thereby increasing the value of the capacity to some shippers. The longer periods may indicate that shippers have become more experienced in managing system requirements and more aware of the costs associated with unused capacity. The average term of a contract for released capacity varies widely across regions, but in all six regions the average term increased between the 1994–95 and 1995–96 heating seasons. The Midwest and Southeast regions had the lowest average term of 51 and 52 days, followed by the Central and Northeast at 71 and 82 days, and then the Western Region at 183 days. The Southwest had no transactions initiated during the 1995–96 heating season. The average contract term increased from the 1993–94 heating season to the 1994–95 heating season for the Central and West regions, but decreased for the other four regions.

In addition to releasing capacity for longer terms, shippers overall have been placing recall restrictions on lesser amounts of released capacity. This may be another indicator of shipper experience in the market and their confidence that the capacity will not be needed during the release period. Thus, the quality of the released capacity has increased. During the 1993–94 heating season, all released capacity was subject to recall. By the 1994–95 heating season, however, the amount of capacity subject to recall ranged from 98 percent in the Southeast to 36 percent in the West (Table 3). Even the Northeast Region, where the most release activity occurred, had only 74 percent of its transactions subject to recall. The amount of released capacity subject to recall increased somewhat in the Central and West regions during the 1995–96 heating season, whereas it declined in all other regions.

While the low price for released capacity is advantageous to replacement shippers, it is a big disadvantage to releasing shippers who wish to mitigate the high cost of reserving firm capacity. Released capacity rate discounts averaged 65 percent during the winter of 1995–96. That high discount is significant, as it occurred in the winter months when capacity generally is most highly valued.[20] As a result, the

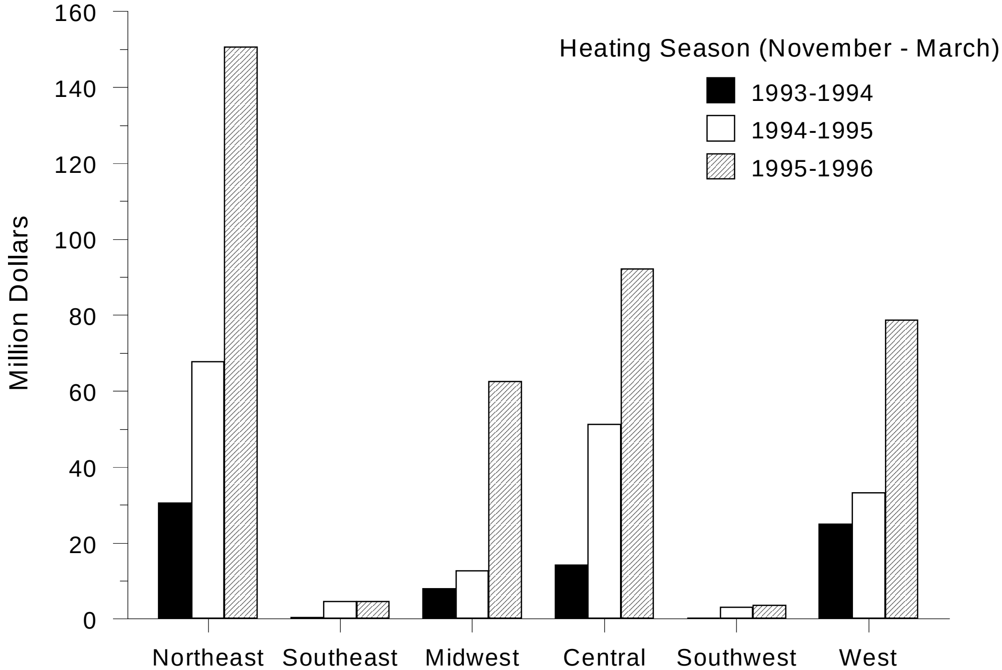
[17]Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Secondary Market Transactions on Interstate Natural Gas Pipelines, Docket Nos. RM96-14-000 and RM96-14-001 (July 31, 1996).

[18]The price levels for capacity release traded between 1994 and 1995, presented in this report, differ from those published by the Energy Information Administration in *Natural Gas 1995: Issues and Trends*, DOE/EIA-0560(95) because of reporting errors in the Pasha data for several pipeline companies. For this report, the errors in the Pasha data have been revised and data from the Federal Energy Regulatory Commission, provided by the pipeline companies via electronic data interchange, are used whenever possible.

[19]Energy Information Administration, *Natural Gas Monthly,* DOE/EIA-0130(96/04) (Washington, DC, April 1996), Table 25.

[20]However, the amount of the discount varies with the time of year and the region in which the capacity is released.

Figure 17. Heating Season Capacity Release Revenues by Region



Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1996:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

release market in the past has been limited in its ability to offset the cost of reserving capacity.[21]

The Gray Market

Shippers with excess capacity can avoid some disadvantages of the capacity release market by participating in the gray market. Through gray market transactions, LDCs and marketers bundle their excess capacity with other services (such as gas sales) and sell the packaged service. The significance of activity in the gray market is difficult to quantify because of the lack of data on these transactions. In the case of an LDC, it may involve a sale to an offsystem customer. One advantage claimed for the gray market is that it is unregulated and therefore not subject to FERC's posting requirements or price caps. Therefore, shippers can avoid the burdens of completing and posting transactions on the EBBs. In addition, releasing shippers may be able effectively to earn prices above maximum regulated rates on the gray market.

Not all shippers, however, are positioned to sell their excess capacity on the gray market. To sell capacity on the gray market successfully, a shipper must be able to repackage the capacity with another desired service and be able to reach prospective customers. The shipper may not have excess gas or other services that it could economically bundle with excess capacity. Or the shipper may have a combination of services but not be able to deliver these services to the willing buyer. Buyers of gray market services usually are located outside the seller's traditional service area. If the buyer and seller cannot connect at an interchange, the transaction might not take place. Therefore, the gray market might not be an effective solution for all shippers with unused firm transportation capacity.

The capacity release and gray markets may provide only partial or short-term relief from the cost of holding long-term firm capacity. However, by selling capacity on these markets, the shipper may discover that it can release the unused capacity during peak periods without degrading its service. The shipper can confirm the true level of its firm capacity requirements without risking severe operational or economic penalties. Shippers can thereby better plan the level of capacity held in their firm transportation contracts that they can turn back.

[21]Some pipeline companies are proposing reservation charge mechanisms that may raise the effective rate cap on released capacity during winter periods. Foster Associates, Inc., *Foster Natural Gas Report,* No. 2078 (Washington, DC, May 2, 1996), p. 7.

Table 3. Regional Characteristics of Released Capacity, November 1993 - March 1996

Heating Season (November - March)

Region	1993-94			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	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent of Capacity Subject to Recall
Northeast	4.44	210	--	3.05	675	74	5.41	847	67
Southeast	1.18	10	--	1.80	79	98	1.68	84	94
Midwest	3.77	64	--	3.11	124	80	5.45	349	72
Central	3.82	113	--	4.47	348	79	4.92	571	82
Southwest	2.16	5	--	9.18	10	43	5.32	20	2
West	4.61	164	--	2.90	350	36	4.13	580	39
Total	**4.21**	**567**	**--**	**3.31**	**1,586**	**69**	**4.87**	**2,451**	**65**

Nonheating Season (April - October)

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**	**--**

$/Mcf-Mo. = Dollars per thousand cubic feet per month. Bcf = Billion cubic feet. -- = Not applicable.

Note: See Appendix D for a list of the pipeline companies and commitments included in the sample.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1996:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

For example, Southern California Gas Company (SoCal) has been an active releasing shipper on the El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern) systems since the capacity release program began in November 1993. In fact, the awards of SoCal's released capacity represented between 24 and 46 percent of its total commitments on El Paso's system during the 1994–95 heating season.[22] This clearly indicates that SoCal had a significant amount of unused capacity during this period (Figure 18). Once a shipper identifies the existence of year-round excess capacity, it may decide to reduce its contracted capacity at the expiration of its contract with the pipeline company.

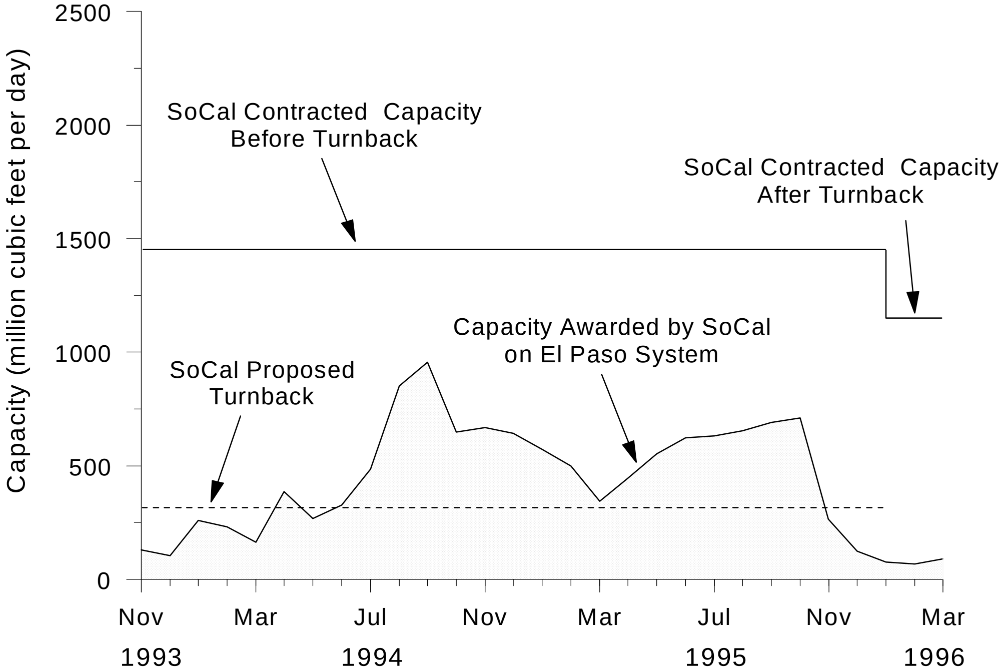
[22]Average monthly award capacity for March 1995 and November 1994 of 345 and 668 million cubic feet, respectively, divided by SoCal's pre-turnback contract demand of 1,450 million cubic feet.

Capacity Turnback: Realigning Contracts with Requirements

The reduction or returning of capacity to the pipeline company at the expiration of the contract, also called capacity turnback, severs the contractual ties and obligations between the shipper and the pipeline company. However, turnback is not inevitable when a contract expires. For instance, the shipper may enter into a new contract for the same amount of capacity under the "right of first refusal" if the shipper is willing to pay the maximum rate or the shipper and pipeline company may negotiate a new contract with alternative terms and prices.

To date, there have been only three cases of significant turnbacks of capacity: El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern) in the West and Natural Gas Pipeline Company of America

Figure 18. Southern California Gas Company Activity on El Paso Natural Gas Company System



Sources: Energy Information Administration, Office of Oil and Gas, derived from: **Capacity Awards November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1996:** Federal Energy Regulatory Commission (FERC), Electronic Data Interchange (EDI) data. **SoCal Proposed Turnback:** El Paso Natural Gas Company, FERC Docket No. RP95-363. **SoCal Contracted Capacity Before Turnback:** El Paso Natural Gas Company, FERC Docket No. RP95-363, Statement G-6. **After Turnback:** FERC Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

(NGPL) in the Midwest. These cases provide insights into the difficulties associated with turnbacks. Since the cases are localized in only two geographic regions, however, it is unclear whether they are anomalies or indicate a fundamental shift in the industry much like the take-or-pay situation of the mid-1980's. The operational, economic, and legal issues that arise from turnbacks create problems that have no simple solutions. There are two major areas of concern in a turnback case: (1) the apportionment of costs and (2) the implications for pipeline operations.

The cost impact of a turnback can be significant for both the pipeline company and the remaining shippers. For the Transwestern, El Paso, and NGPL systems, annual revenue reductions were estimated by the companies to be $51, $140, and $60 million, respectively, assuming that the pipeline companies are not able to remarket any of the turnback capacity. The magnitude of these costs makes their distribution among the stakeholders (pipeline company, decontracting shippers, and remaining customers) a serious issue. Allocating the cost of turnbacks to the remaining firm customers may be inappropriate because these customers would pay higher rates without a corresponding increase in the quality of service. In addition, passing turnback costs directly to remaining shippers may inspire additional turnbacks as shippers would try to avoid increases in their capacity reservation fees. Although the cost of a turnback may be associated with one or more decontracting customers, requiring these customers to shoulder all turnback costs could create a barrier that in turn could discourage a competitive market. For example, a shipper may decide to renew the contract to avoid turnback charges. If, on the other hand, pipeline companies are required to absorb these costs, they will be subject to increased business risks and less likely to build new facilities in the future.

Capacity turnbacks can present operational problems to participants. Depending on the amount and location of the turnback, it can affect service on other segments of the pipeline system and necessitate changes in the operation of the pipeline that could lead to increased pipeline costs. If service to a specific delivery point is severely reduced, the pipeline company might have to increase linepack dramatically to transport gas beyond that point. The pipeline company's operational options can be limited because a shipper who decontracts only a portion of its capacity has the right to select its receipt and delivery points, as provided for in Order 636. Therefore, while shutting down facilities to a particular supply area might balance operational and contracted capacity, this might also restrain interstate commerce and prevent buyers and suppliers from reaching each other.

Several means of resolving these issues have been pursued. Some pipeline companies initially have sought solutions through rate increases or litigation. In the large turnback cases that have transpired thus far, FERC has favored negotiation between the pipeline company and its customers in lieu of litigation. Although the large cases of capacity turnback have been localized with respect to geographic regions, they provide a view of the general problems and approaches to capacity turnback that indicate how the industry and regulators will accommodate the effects of changes in capacity commitments.

The Experiences from Large Turnback Cases

The significant cases of capacity turnback to date have occurred in only two regions of the United States: the West (Transwestern Pipeline and El Paso Natural Gas) and the Midwest (Natural Gas Pipeline Company of America). These cases demonstrate an important characteristic of capacity turnback—the combination of factors that lead to turnbacks can be concentrated in a specific market. For example, the turnbacks on Transwestern and El Paso are primarily because of stepdowns, or reductions, in the amount of firm contracted capacity by California customers. These turnbacks represented 18 percent of the respective total capacity commitments on the Transwestern and El Paso systems. Transwestern experienced a 457 billion Btu per day reduction effective November 1, 1996. El Paso faces a reduction in firm capacity contracts of 1.5 trillion Btu per day effective between January 1, 1996, and January 1, 1998 (Table 4).

Transwestern ultimately reached a settlement agreement with its customers (Table 4) that provides for sharing of the turnback cost between the pipeline company and its customers over a 5-year period. At the end of the 5 years, Transwestern will assume full responsibility for any revenue shortfall from the turnbacks. The settlement also provides rate certainty for the shippers. Transwestern's shippers will pay negotiated rates that include an annual escalation factor. Transwestern also receives a stable revenue stream under the agreement, since the settlement participants have extended their firm contracts for 10 years. This will give Transwestern time to develop marketing strategies for uncommitted capacity including marketing to new areas and developing competitive rate methods. To combat the downturn in the California market, the pipeline company is expanding its facilities in the San Juan production basin to offer better access to eastern market centers. El Paso has filed a similar settlement, which is awaiting FERC approval. In addition, El Paso has agreed to acquire Tenneco's energy division, thus allowing for geographical extension of its pipeline system.[23]

The turnback case in the Midwest was a result of certain NGPL customers relinquishing 600 billion Btu per day of capacity effective December 1, 1995. The capacity reductions represent almost 17 percent of NGPL's total capacity commitments.[24] If the cost of the turnback were passed through to customers, it would contribute to a 50 to 60 percent increase in firm transportation rates.[25] NGPL also reached a settlement with its customers under which it assumed responsibility for about 80 percent of the revenue loss resulting from the relinquished capacity. As a part of the agreement, FERC allows NGPL to consider alternative rate designs, such as a departure from straight fixed-variable rates.

These cases indicate that pipeline companies and shippers are addressing three areas to mitigate the impacts of capacity turnbacks.

- Negotiating acceptable cost-sharing procedures and rate levels.
- Pipeline companies are moving to new markets with greater growth potential.
- Developing plans for competitive rate strategies for the unused capacity.

In the future, additional turnbacks on Transwestern, El Paso, and NGPL are possible. For instance, while Transwestern's settlement locks in a large portion of its capacity commitment for the next 10 years, it did not resolve all of its potential capacity turnbacks. Approximately 25 percent (634,612 million Btu per day) of Transwestern's total firm capacity commitments will expire during 1996 (Figure 19). Most of these contracts are short-term (less than one year) and rollover contracts. The next significant firm capacity contracts will not expire until the year 2000. While there is no indication that these expiring contracts will result in a turnback, strengthening of California's economy and Transwestern's eastern market link to the Waha Hub may absorb a portion of

[23]El Paso Energy Corporation, Press Release (June 19, 1996).

[24]The 17-percent reduction is based on the difference between NGPL'S July 11, 1995 filing, which showed the firm customers' market area peak-period contract demand to be 3,845 billion Btu, and its August 18, 1995 filing showing a projected contract demand of 3,201 billion Btu. Federal Energy Regulatory Commission, Order Following Technical Conference, Natural Gas Pipeline Company of America, Docket Nos. RP95-326-000 et al (October 11, 1995).

[25]In addition to turning back capacity, some of NGPL's customers changed their service paths, opting for service zones with lower rates. Federal Energy Regulatory Commission, Order Following Technical Conference, Natural Gas Pipeline Company of America, Docket Nos. RP95-326-000 et al (October 11, 1995).

Table 4. Capacity Turnbacks in the U.S. Western Region

Company	Pre-turnback Contracted Capacity[1] (MMBtu/d)	Turned-Back Capacity (MMBtu/d)	Effective Date	Revised Contracted Capacity[2] (MMBtu/d)	Potential Revenue Impact[3] (million dollars)	Settlement Revenue Impact (million dollars)	Other Terms
Transwestern Pipeline						35.7[4]	
Decontracting Customers							
Southern California Gas	963,281	457,281	11/1/96	506,000	22.3	9.1[4]	(a)
Remaining Customers							
Settlement Participants	650,000	--	--	650,000	28.7	6.2[4]	(a)
Others	923,667	--	--	923,667			
Total	**2,536,948**	**457,281**	**--**	**2,079,667**	**51.0**	**51.0**	**--**
El Paso Natural Gas							
Decontracting Customers							
Gas Co. of NM	71,618	41,200	4/1/96	30,418	1.5	--	--
Southern California Gas	1,493,500	309,000	1/1/96	1,184,500	58.6	--	--
Pacific Gas and Electric	1,174,200	1,174,200	1/1/98	--	--	--	--
Remaining Customers							
Settlement Participants	1,616,609	--	--	1,616,609	79.9	--	--
Total	**4,355,927**	**1,524,400**	**--**	**2,831,527**	**140.0**	**140.0**[5]	**--**

[1]Transwestern: FERC Index of Customers for April 1, 1996. El Paso: FERC Docket No. RP95-363, Statement G-6.
[2]Pre-Turnback contracted capacity less decontracted capacity.
[3]Total annual revenue shortfall allocated among settlement customers based on revised contracted capacity.
[4]Total annual revenue shortfall of $51 million allocated between Transwestern and SoCal and Settlement Participants on the basis of settlement-sharing mechanism (70 percent, 18 percent, and 12 percent, respectively). Current customers share the costs equally (50/50) with Transwestern in the first year and then 25 percent of the annual costs are recovered by the current customers for each of the next 4 years. In the sixth year, Transwestern absorbs 100 percent of the costs. Under an alternative option, current customers take a 30.67 percent share of the revenue shortfall for the entire 5 years. If it selected the second option, SoCal's share would be the amount for SoCal derived under the first option less the total amount due from the other customers. The costs are allocated among customers on the basis of their mainline transmission capacity billing determinants as of November 1, 1996.
[5]El Paso filed a comprehensive settlement on March 29, 1996, which, as of October 15, 1996, has not been approved. The settlement would establish rates, subject to an annual inflation adjustment, effective through 2005. Under the proposed settlement, El Paso would assume responsibility for 65 percent of the fixed costs associated with the capacity turnbacks. SoCal and PG&E would pay the largest portions of the customers' turnback responsibility.
[a]Customer contracts are extended until 2006. Negotiated rates take effect on November 2, 1996, and include an automatic annual escalation in base rates. Effective November 1, 1998, current customer settlement base rates will increase annually by 60 percent of the increase in the implicit price deflator to the gross domestic product.
MMBtu/d = Million Btu per day.
Sources: Energy Information Administration, Office of Oil and Gas, derived from: **Transwestern Pipeline Company:** Federal Energy Regulatory Commission (FERC) Docket No. RP95-271 et al. **El Paso Natural Gas Company:** FERC Docket No. RP95-363, Foster Associates, Inc., *Foster Natural Gas Report* (April 11, 1996) and FERC Index of Customers for April 1, 1996 (August 28, 1996).

the decontracted amount or prevent it from being decontracted in the first place.

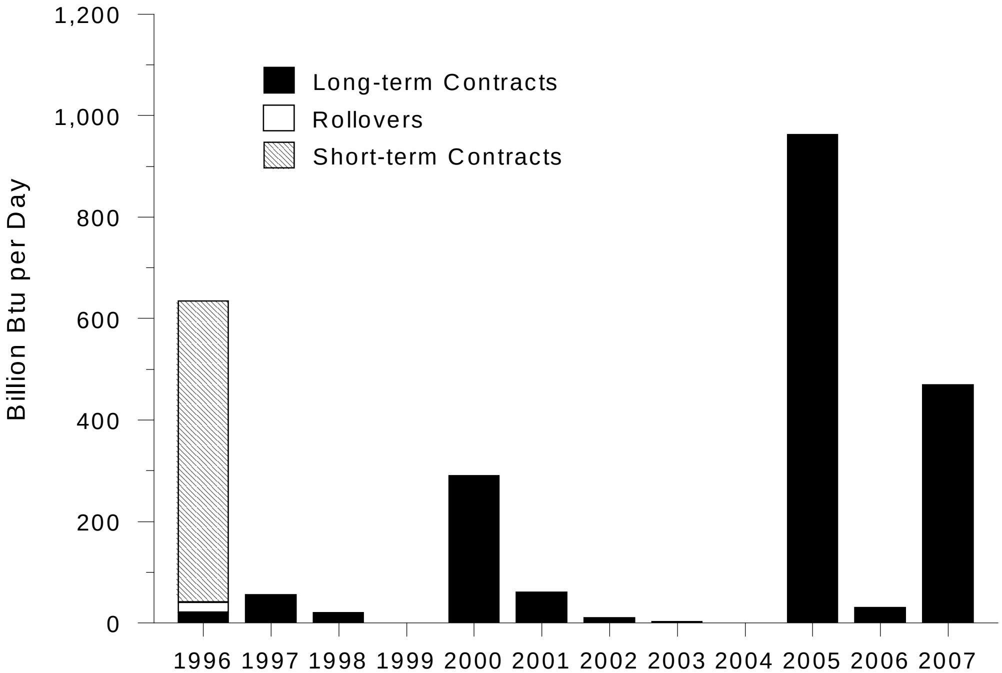
The pipeline industry is alert to the threat posed by capacity turnbacks and is responding with new marketing and cost reduction strategies. In general, turnbacks can be expected togrow in regions where shippers have a variety of options and alternatives to long-term firm transportation.

Capacity Turnback: Opportunities and Expectations

Shippers will have significant opportunities to change their transportation contracts through the year 2001 when contracts covering approximately 51 percent of firm transportation capacity are scheduled to expire.[26] At that time, they will be able to turn back all capacity reserved or negotiate a new

[26]Absent a contract rollover in which the terms and conditions of the original contract may be renewed by the shipper for a predetermined period of time.

Figure 19. Capacity Associated with Expiring Firm Transportation Contracts on Transwestern System



Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

contract that may include revised contract terms for capacity reservations. Under the assumption that all expiring contracts lead to turnback of all reserved capacity, a review of current contracts can provide an upper bound on the potential amount of capacity that could be turned back to transporters. It is important to note that expirations are a measurement of the maximum potential turnback. Shippers may instead resubscribe (e.g., negotiate a new contract) for all or part of the capacity reserved in the expiring contract.

This section identifies the potential for turnback in the transportation industry by examining the amount of capacity currently reserved under firm contracts and the expiration of those contracts over the next 15 to 30 years. The maximum amount of capacity that can be turned back is the amount associated with an expiring contract. The expiration of a contract generally provides the shipper its first opportunity to reduce firm contracted capacity.

Capacity Reservations in 1996 Totaled More than 100 Trillion Btu per Day—A Significant Increase from 1990 Levels

As of April 1, 1996, reservations for transportation capacity in the United States totaled 107.4 trillion Btu per day (Table 5) for the 63 interstate pipeline companies reporting to FERC on the Index of Customers survey.[27] These companies accounted for more than 90 percent of interstate throughput in 1995. Total capacity reservations represent the amount of capacity that shippers could have used for firm transportation services on April 1, 1996, under the terms and conditions of their contracts. This figure may not equal capacity reservations on other days of the year because some contracts may include service levels that vary throughout the year.

If shippers fully utilized their reserved capacity and if the April 1, 1996, daily reservation amount were the same throughout the year, total throughput for firm services would total 39.2 quadrillion Btu per year, far in excess of the 18.7 quadrillion Btu of firm transportation throughput and the 24.4 quadrillion Btu of total throughput reported by the pipeline

[27]Beginning April 1, 1996, interstate pipeline companies are required to report information to FERC on all existing contracts for firm transportation and storage service. This Index of Customers includes a snapshot of information on those contracts that are active on the first day of the quarter including: shipper name, capacity reserved, and beginning and end date of the contract. The pipeline companies are required to file these data quarterly. As of August 28, 1996, 63 interstate pipeline companies provided useable information to FERC. Information on additional pipeline companies are expected to be available in the future.

Table 5. Current Capacity Commitments and Cumulative Expirations by Region and Period
(Billion Btu per Day)

Region	Commitments as of April 1, 1996	Cumulative Capacity Expirations					
		1997	2001	2005	2010	2020	2025
Central	14,447	6,112	9,180	12,018	13,444	14,447	14,447
Midwest	27,376	8,641	19,132	24,046	25,684	27,145	27,376
Northeast	37,642	3,248	12,124	27,891	31,770	37,642	37,642
Southeast	4,964	465	2,520	3,309	4,214	4,961	4,964
Southwest	6,235	2,523	5,828	6,221	6,221	6,235	6,235
West	16,717	4,442	5,457	9,385	14,195	15,488	16,717
Total	**107,381**	**25,432**	**54,240**	**82,870**	**95,528**	**105,918**	**107,381**

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

industry for 1995.[28] The primary reason for this difference is that shippers requiring high-priority firm services typically reserve sufficient capacity to satisfy their peak-period demands but they do not use all of it during the nonpeak period. Pipeline companies must stand ready to provide service up to the reserved amount under firm contracts, even though their customers may not actually request transportation of that amount of gas.

Customer commitments for firm services by interstate pipeline companies in 1996 have grown significantly since 1990, the prior year for which comprehensive data are available. For a sample of pipeline companies that represent 92 percent of capacity commitment in 1996, capacity reservations were 26 percent[29] higher in 1996 than the 77.7 trillion Btu per day of firm commitments in 1990 (Figure 20). Over 87 percent of current capacity commitments are under longer term contracts (more than 1 year) and over two-thirds exceed 5 years in duration (Figure 21).

Three factors, in particular, have contributed to the increase in capacity commitments:

- **Increased gas consumption.** Total end-use consumption of natural gas in the United States in 1995 was 19.7 trillion cubic feet, a 17-percent increase over the 1990 level.

- **Increased pipeline capacity.** U.S. pipeline capacity increased by 13 percent between 1990 and 1995.

- **Increased preference for firm rather than interruptible services.** Many shippers have shifted to firm service from interruptible service. Firm services represented 86 percent of the gas delivered to market by interstate pipeline companies in 1995, up from 49 percent in 1990.

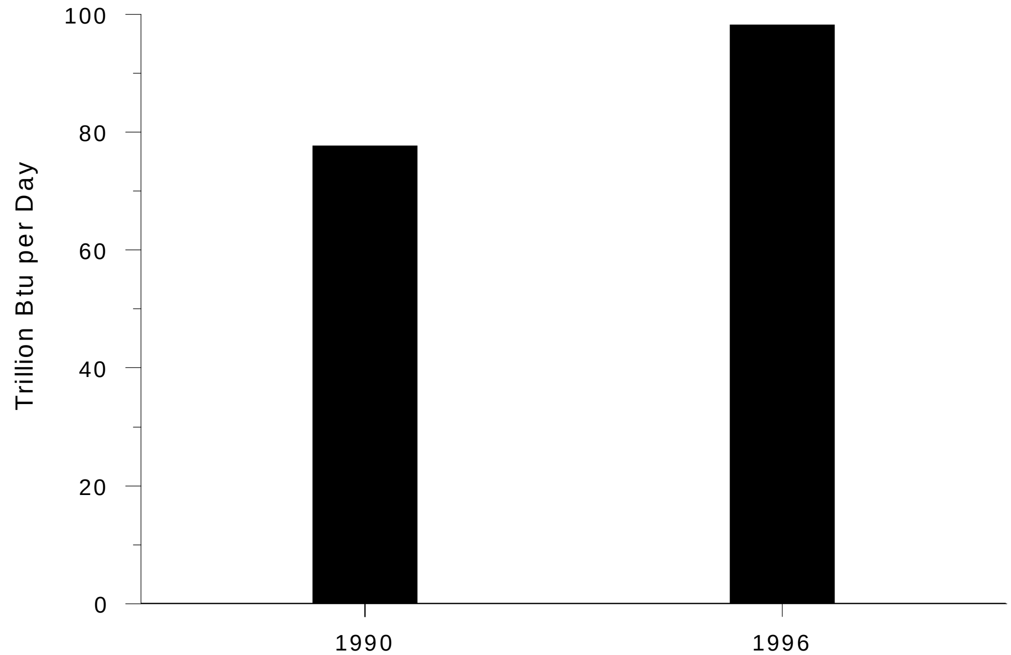
Not surprisingly, two of the geographic regions that posted significant increases in pipeline capacity over the period, the Northeast and the West, also showed the largest increase in reservations for the companies included in the sample. Pipeline company commitments for firm service in the Northeast showed the largest increase, 8.6 trillion Btu per day, followed by the Western Region, which increased 4.0 trillion Btu per day or 46 percent since 1990 (Table 6). Also noteworthy is the 31-percent increase in firm commitments in the Southeast between 1990 and 1996. The regional estimates were developed by assigning each pipeline company's contracts to the geographic region corresponding to its principal service area as indicated by historical delivery patterns.[30] (See Appendix G for definition of the regions used and more information on capacity commitments.)

[28]Derived by Energy Information Administration, Office of Oil and Gas from: Interstate Natural Gas Association of America, *Gas Transportation Through 1995* (Washington, DC, September 1996), Tables A-1 and A-4. Total delivered for market (21.765 quadrillion Btu times percentage firm services (52 percent plus 17 percent plus 17 percent) equals 18.7 quadrillion Btu for 1995.

[29]Derived by Energy Information Administration, Office of Oil and Gas from: *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-0556 (Washington, DC, June 1992); and Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

[30]These regional estimates are approximate because of the lack of contract information on service location.

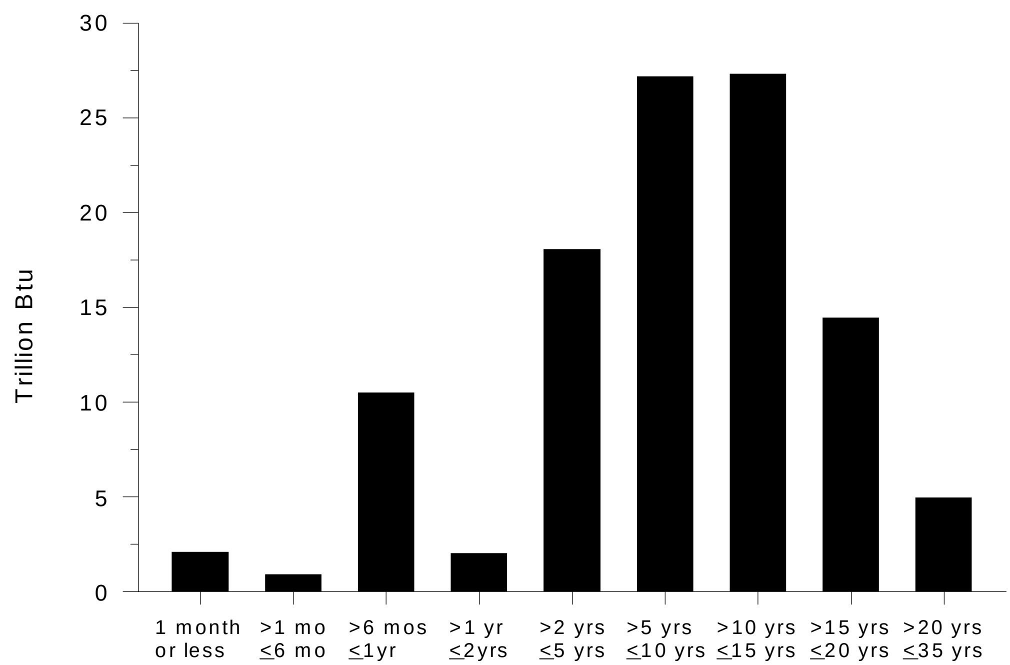
Figure 20. Pipeline Capacity Under Firm Contract in 1990 and 1996 for a Sample of Interstate Pipeline Companies



Note: See Appendix D for a list of the pipeline companies and commitments included in the sample.

Sources: Energy Information Administration (EIA), Office of Oil and Gas, derived from: **1990:** EIA, *Capacity and Service on the Interstate Natural Gas Pipeline System 1990* (June 1992); **1996:** Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

Figure 21. Firm Transportation Capacity as of April 1, 1996, Grouped by Length of Contract



Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

Table 6. Transportation Capacity Under Contract in 1990 and 1996 for a Sample of Interstate Pipeline Companies, by Region
(Million Btu per Day)

Region	Firm Capacity Commitments	
	1990	1996
Central	12,211,680	14,209,661
Midwest	21,313,790	24,453,615
Northeast	27,910,940	36,482,322
Southeast	3,766,710	4,935,744
Southwest	3,646,200	5,224,234
West	8,850,790	12,895,685
Total	**77,700,110**	**98,201,261**

Note: See Appendix D for a list of the pipeline companies and commitments included in the sample.
Sources: Energy Information Administration (EIA), Office of Oil and Gas, derived from: **1990:** EIA, Capacity and Service on the Interstate Natural Gas Pipeline System 1990 (June 1992); **1996:** Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

Contracts Representing 89 Percent of Currently Reserved Capacity Will Be Up for Renewal Between 1996 and 2010

Between 1996 and 2010, transportation contracts representing a total of 89 percent of currently[31] reserved capacity in the United States will come up for renegotiation or expiration (Table 4). The pace of those expirations varies over time (Figure 22). For most years, expirations account for less than 5 percent of current reservations. However, the years 1996, 2000, and 2004 will be particularly active, when 16, 12, and 12 percent, respectively, of currently contracted capacity will expire (Figure 23). The short-term period, through 1997, will be active as almost one-fourth of contracted capacity will be up for renewal, including rollovers and short-term (less than 1 year) contracts each of which account for approximately 5 percent of current reservations. An additional 27 percent of currently contracted capacity will expire in the mid-term period 1998 through 2001, which will bring cumulative expirations to just over one-half of current commitments. Between 2002 and 2010, contracts covering an additional 39 percent of current capacity reservations will be up for renewal. Finally, although most contracts will expire before 2010, 11 percent of capacity is under contracts that continue after 2010 and in some cases through 2025.

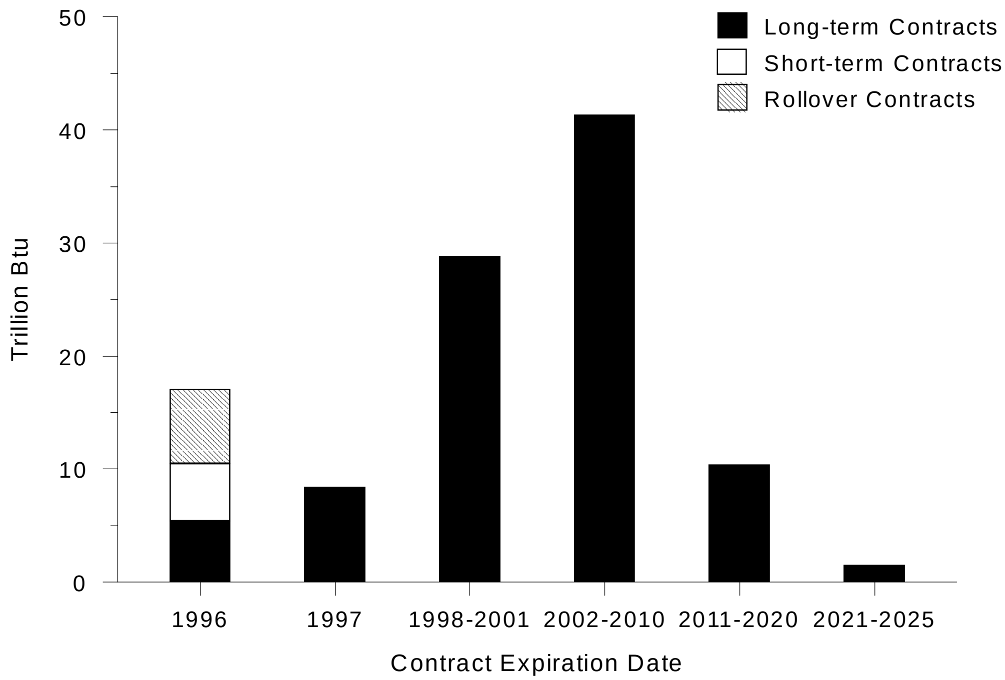
Over the Mid Term, Contract Expirations Vary Considerably by Region, but the Long-Term (2010) Outlook Is Similar for Each Region

The schedule (or profile) of contract expirations over time also varies by region (Figure 24). Although there is considerable variation in the quantity of cumulative capacity expirations in the short and mid term (through 2001), for each region the pattern of extensive contract turnovers or expirations by 2010 is similar and in the range of 85 to 100 percent of existing contracts (Figure 25). In the short term, shippers on pipelines that principally serve the Central and Southwest regions will see the most expirations, over 40 percent of capacity under existing contracts. In contrast, pipeline companies in the Northeast and Southeast will have contracts covering only about 9 percent of their current reservations expire while companies in the Midwest and West expect between 27 to 32 percent of their capacity reservations to expire over the short term. As an aside, it should be noted that these expirations are based on contracts that were in effect as of April 1, 1996, and therefore would include any capacity reductions, changes, rollovers, or renegotiations made prior to that date. As noted earlier, pipeline company information is the basis for these regional totals, which show enormous variation. For instance, at least 11 pipeline companies, such as Northern Border (Central Region), Granite State Gas Transmission, Inc. (Northeast Region), and several pipeline companies in the West, have no contracts expiring through 1997.[32] In contrast, almost a dozen companies principally in the Central and Midwest regions, including Michigan Gas Storage, K N Interstate Gas Transmission, and Williston Basin Interstate Pipeline

[31]As of April 1, 1996.

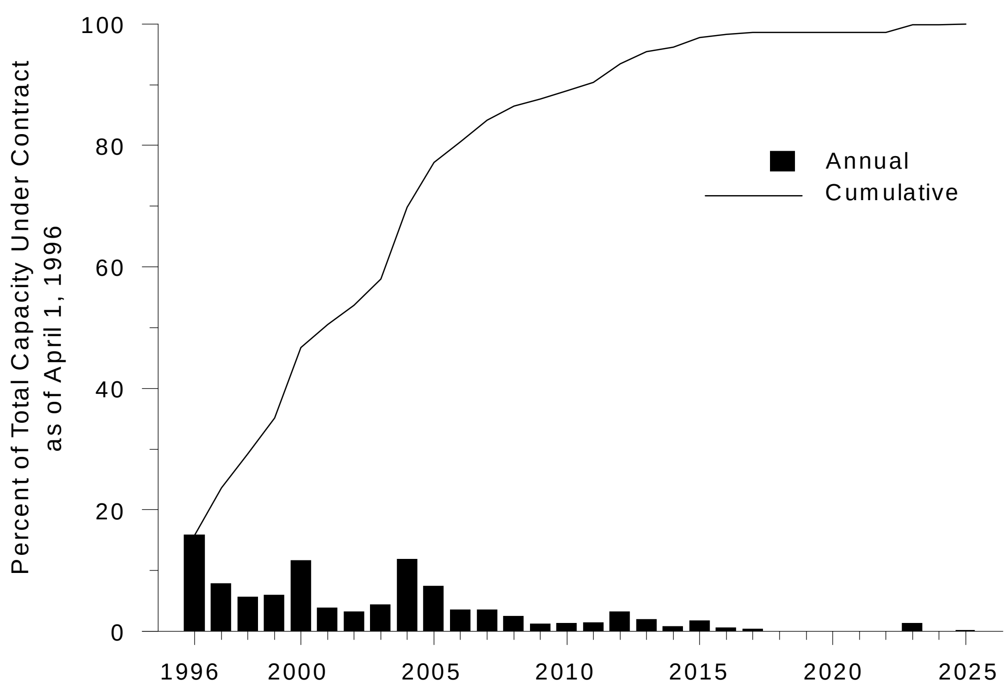
[32]Including Cove Point LNG, MIGC, Inc., Mobile Bay Pipeline, OKTex Pipeline, Pacific Gas Transmission Company, Pacific Interstate Offshore Company, Paiute Company, Riverside Pipeline, and Tuscarora Gas Transmission Company.

Figure 22. Expiration of Firm Transportation Capacity Under Contract as of April 1, 1996



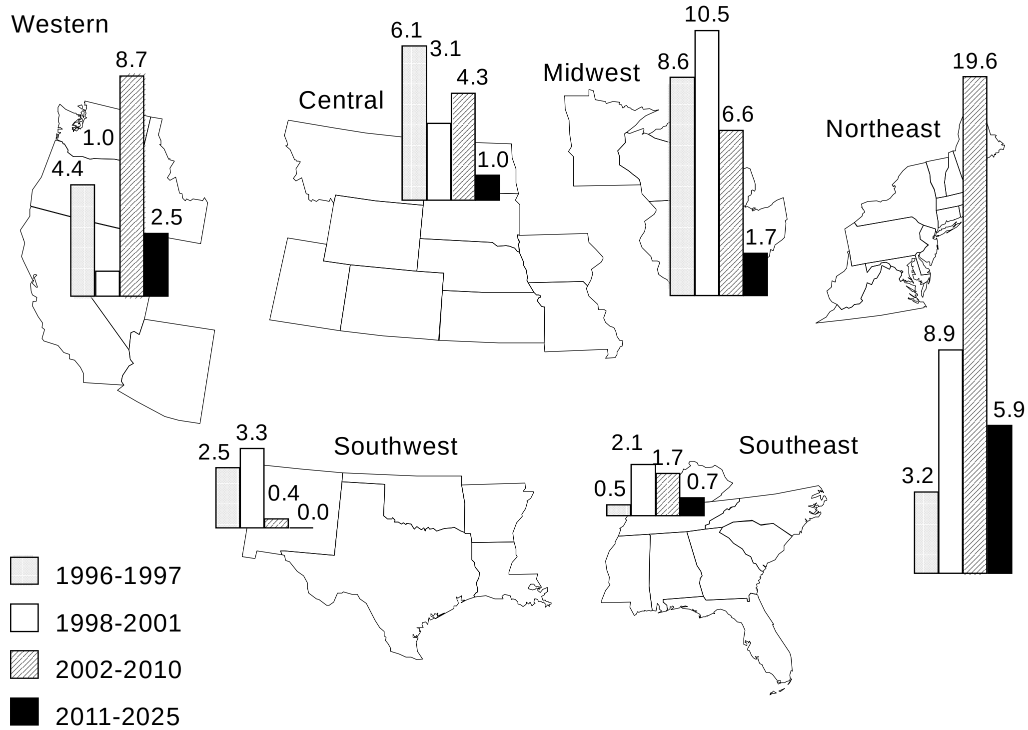
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

Figure 23. Annual and Cumulative Expirations of Firm Transportation Capacity, 1996-2025



Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

Figure 24. Regional Exposure to Capacity Expirations, 1996-2025
(Trillion Btu)



Capacity Associated with Expiring Firm Transportation Contracts by Region (Million Btu)

Region	1996-1997	1998-2001	2002-2010	2011-2025
Central	6,111,633	3,067,964	4,263,969	1,003,859
Midwest	8,640,978	10,491,173	6,552,234	1,691,382
Northeast	3,248,228	8,875,327	19,646,885	5,871,170
Southeast	465,373	2,054,247	1,694,176	749,833
Southwest	2,523,256	3,304,974	392,403	14,500
West	4,442,041	1,015,271	8,737,494	2,522,509

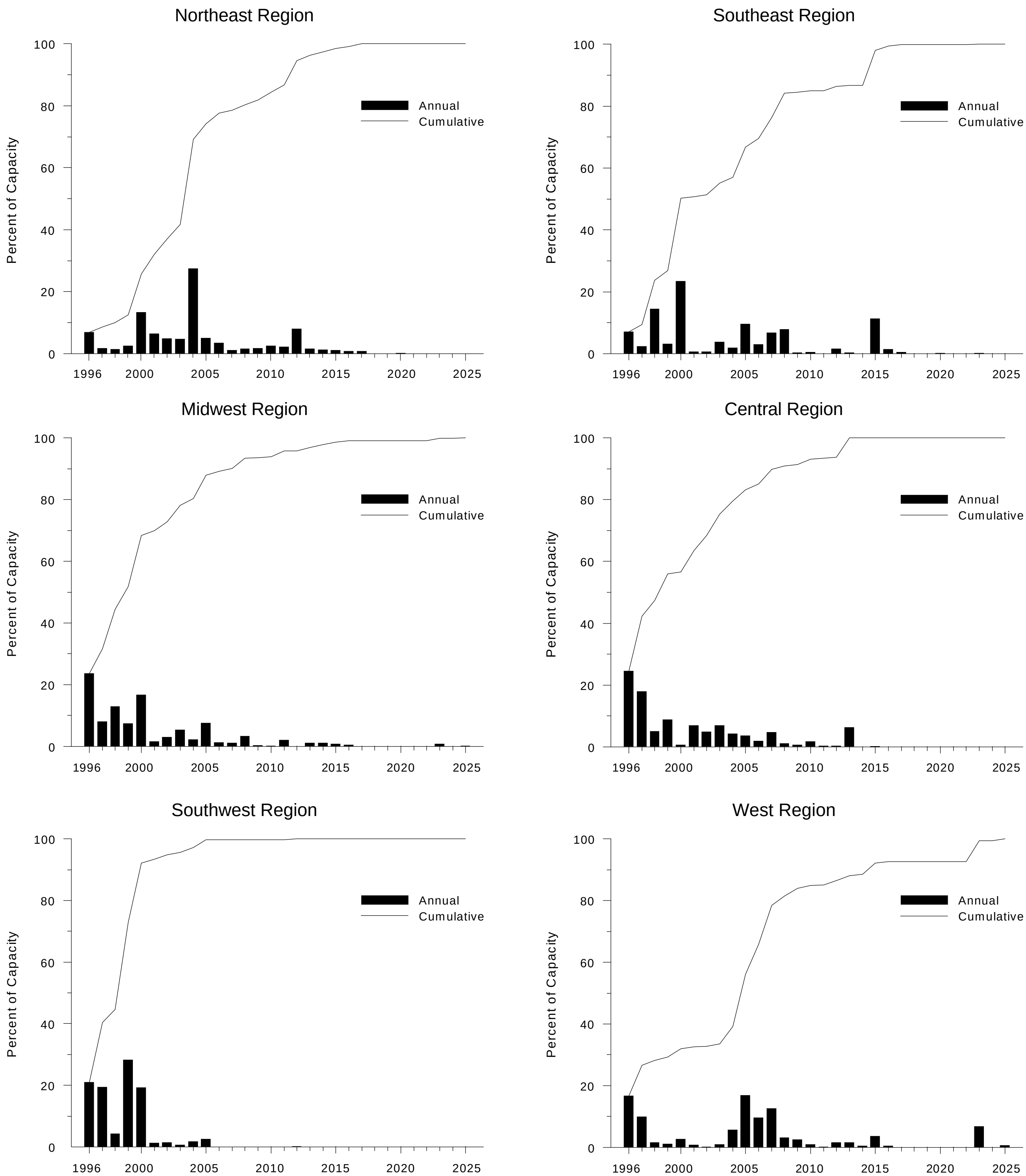
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

Company, have more than three-fourths of existing contracts expiring by the end of 1997.[33]

Based solely on contract expirations, the Southwest, Central and Midwest regions have the greatest potential for significant capacity turnbacks between 1996 and 2001 (Table 5, Figure 25). By 2001, the cumulative expirations since April 1, 1996, will total a substantial 93 percent in the Southwest, 64 to 70 percent in the Midwest and Central regions, 51 percent in the Southeast, and only 33 percent in the Northeast and West. Expirations of contracts in the West are lower than in other regions because a significant number of contracts to transport gas from the Southwest to California were renegotiated in 1995 and 1996 and are not due to expire

[33]Additional pipeline companies with three quarters or more of existing contracts expiring by the end of 1997 include: Trailblazer Pipeline Company, Crossroads Pipeline Company, Carnegie Interstate Pipeline Company, Kentucky West Virginia Gas Company, NORA Transmission Company, High Island Offshore System, Ozark Gas Transmission System, and Sabine Pipeline Company.

Figure 25. Expirations of Firm Transportation Capacity Under Contract as of April 1, 1996, by Region



Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for April 1, 1996, FERC Bulletin Board (August 28, 1996).

for several years.[34] Incidentally, in the years from January 1998 through December 2001, the Southeast is the region with the largest share of contract expirations, with over 40 percent of its contracts with pipeline companies serving the region due to expire. Between 2001 and 2010, expirations in the Northeast and West exceed 50 percent of current reservations, bringing cumulative expirations up to approximately 85 percent of 1996 reservations in those regions—this is comparable to the levels in other regions.

Between 1996 and 2001, over half[35] of the interstate pipeline companies will have more than three-fourths of their current contracts expire. For example,all firm contracts with Koch Gateway, which serves the Southwest Region, will expire by 1999. Additional companies with a significant portion of their contracts expiring between 1997 and 2001 include Questar, Company of America, which had capacity turned back when some contracts expired in 1996, will see a significant amount of additional expirations in 1998 and again in 2000. This will bring the company's total expirations in 2001 up to 94 percent of the 1996 capacity reservation levels. In contrast, for approximately one-third of the companies with contracts that generally exceed 10 years in duration, significant expirations are postponed until 2001 or later.[36] In addition, several companies that together serve a broad geographic area will have limited vulnerability to capacity turnback until after 2010 compared with other pipeline companies. For example, 60 percent of capacity currently reserved on Algonquin Gas Transmission Company is under contracts that are not due to expire until after 2010.[37] Pacific Gas Transmission Company will have 40 percent of its transportation contracts expiring after 2020. ANR Pipeline Company holds the current record for the longest contract term; it has one small-volume transportation contract that will expire in 2025.

Industry Expectations for Capacity Turnback

Two surveys were conducted by the industry to assess expectations about capacity turnback. The Interstate Natural Gas Association of America survey in March 1995 examined the expectations of a sample of 31 interstate pipeline companies regarding the amount of capacity likely to be turned back.[38] In August 1995, the LDC Caucus survey looked into the expectations of a sample of 75 LDC shippers for future capacity reservations.[39]

Pipeline companies anticipate that 75 percent of capacity expiring under long-term contracts through 2002 will lead to long-term resubscriptions, although for a lesser term than under the expiring contract. Further, based on market characteristics, peak-day requirements, and communication with shippers, pipeline companies expect only a moderate decline in the demand for long-term firm transportation contracts during this period. This decline is expected to result in an increase in uncommitted capacity to 13 percent of capacity in 2002, up from 4 percent in 1994. Regionally, pipeline companies that serve the West expect to see the most significant increase in uncommitted capacity, from 1 percent in 1994 to 25 percent in 2002. All other regions, except the Rockies, also are expected to have increased levels of uncommitted capacity that will reach between 6 and 15 percent of current capacity in 2002.

The survey of local distribution companies, almost a third of which have connections to four or more interstate pipelines, presents a somewhat different outlook about the levels and locations of future capacity reservations. Whereas almost 30 percent of LDCs in the survey expect to increase their capacity reservations, approximately 45 percent expect to reduce their reservations by 5 percent to over 25 percent from 1995 levels. It is difficult to gauge the amount of capacity that could be affected, because the survey did not collect volumetric information. The survey also did not ask LDCs about the price at which they would renew their reservations. Nevertheless, it appears that LDCs expect to turn back more capacity than pipeline companies anticipate. Approximately two-thirds of large-volume LDCs (with throughput exceeding 300 million cubic feet per day) expect to reduce their capacity reservations.

Competition among pipeline companies may be a factor in future reductions in capacity reservations by LDCs. Almost two-thirds of the LDCs in the survey connected to four or more interstate pipelines (one-third of the sample) expect to reduce their capacity reservations and to enter into contracts

[34]To date, the Western Region, which includes California, has led the other regions in terms of potential for capacity turnback. However, a number of large capacity contracts have already expired or have been renegotiated, with extended terms. These expired contracts were not in place on April 1, 1996, and therefore are not included in FERC's Index of Customers data, which present a snapshot of active contracts as of April 1, 1996.

[35]Represents 33 of the 64 interstate pipeline companies included in the Index of Customers data.

[36]Companies with a significant amount of capacity expirations between 2001 and 2005 include National Fuel Gas Supply Corporation and Columbia Gas Transmission Corporation. Pipeline companies with significant capacity expirations between 2006 and 2010 include Kern River Gas Transmission Company, Northwest Pipeline Corporation, and Transcontinental Gas Pipeline Corporation.

[37]Additional companies include Pacific Gas Transmission Company, Williams Natural Gas Company, Texas Eastern Transmission Corporation, and Florida Gas Transmission Corporation.

[38]The Interstate Natural Gas Association of America published the survey results in its September 1995 report, *The Effect of Restructuring on Long-Term Contract For Interstate Pipeline Capacity*.

[39]The LDC Caucus is a national organization of almost 200 local distribution companies that are members of the American Gas Association. The results of the survey as well as an analysis of other issues relating to unsubscribed pipeline capacity were published in the December 1995 report *Future Unsubscribed Pipeline Capacity*.

with shorter terms. When the survey was conducted in August 1995, the potential problem of unsubscribed capacity during the next 5 years appeared to be most significant in the West, followed by the Middle Atlantic and North Central East regions. The results for the Middle Atlantic States are in contrast to the pipeline company survey, which found that no significant reductions were anticipated by the pipeline companies serving that region.

A comparison of the two surveys with the contract expiration data presented in this chapter indicate that the Midwest and Central regions may be particularly vulnerable to capacity turnback through 2001.[40] The industry surveys indicate that both pipelines and local distribution companies expect a significant reduction in the long-term capacity commitments needed in the future. There will be ample opportunity to turn back capacity in the Midwest, as approximately 70 percent of currently reserved capacity is under contracts that will expire by 2001.

Future Challenges

The changes that shippers are making to their long-term firm capacity contracts indicate a general shift in operating procedures for the transportation industry. The movement to tightly controlled, short-term capacity contracts will have an impact on interruptible transportation service, the secondary market for capacity, rates for firm capacity, and the perceived risk of pipeline company investments.

As shippers align their firm capacity contracts with their system requirements, interruptible transportation (IT) will be affected in two basic ways. First, if the pipeline company's system contains excess capacity as a result of shippers' turnbacks of firm capacity, interruptible transportation may become very reliable. If the pipeline company is unable to market the turned-back capacity, its system may operate below its potential during peak periods. Therefore, it is unlikely that interruptible service will need to be suspended because of capacity constraints. This could result in interruptible service that is essentially as reliable as firm service, making IT more valuable to shippers than it is now. Second, future tariff rates for transportation service, including IT, may increase as some fixed costs that previously were recovered from capacity that now has been turned back are collected from remaining customers.[41] However, depending on the competitive environment, some companies may be forced to discount IT rates.

Capacity turnbacks could affect the secondary market in one of several ways. First, the reduction in firm capacity held may reduce the quantity of capacity that is offered for release. However, turned-back capacity might not have been highly marketable to replacement shippers to begin with. Unless the turnback provides space on a desired segment of the pipeline, it may not materially affect the release market. Also, as discussed above, the excess system capacity could result in highly reliable interruptible transportation service that could compete with the secondary market.

The change in firm transportation contracting will challenge the current rate design practice for firm capacity charges. As discussed earlier, Order 636 mandated the use of the straight fixed-variable (SFV) method of rate design, which recovers all fixed costs in the reservation charge of firm transportation rates. On some systems, the SFV rate design may have created charges that exceed the shipper's valuation of the firm capacity.[42] FERC recognizes that, in some cases, departure from SFV may be appropriate to make unsubscribed capacity more marketable.[43] Nevertheless, this does not address the price of the capacity that remains under contract to captive customers. In some cases, the alternative rate design methods described in FERC's January 31, 1996 Order (Chapter 1) can alleviate the value and price disparity of capacity. As pipeline companies develop innovative pricing methods, practices that charge varying rates for essentially the same services may need to be evaluated.

Further turnback of long-term firm transportation (FT) capacity by LDCs can be expected as the trend toward unbundling of LDC services to smaller customers gains momentum (see Chapter 6). As part of retail unbundling, some State regulators are requiring LDCs to assign the capacity they hold on pipelines to their customers. This will reduce LDC requirements for firm capacity and give LDCs less reason to renew their FT contracts when they come up for

[40]There are a number of limitations with this comparison. First, the industry surveys were done 1 to 2 years ago and may have become outdated. Second, because each of the studies uses different region classifications, aggregate regions (for the East, West, and Midwest/Central) were developed as part of this analysis to allow comparisons. In some cases, the mapping to aggregate regions required analyst judgment, and is therefore somewhat uncertain. Third, coverage of the three data sources varies. The contract information (Index of Customers) represents all existing contracts, whereas the other two studies are based on industry surveys of a sample of either LDCs or pipeline companies. In spite of these limitations, the comparison may be broadly indicative of industry expectations.

[41]In the Transwestern and El Paso turnback examples, customers who were parties to the settlement are charged negotiated rates for the next 10 years. However, customers who were not parties to the settlement may face rate increases associated with the capacity turnback.

[42]The fact that, on average, rates for most released capacity are discounted at about 31 percent of the maximum rate level (Interstate Natural Gas Association of America, *Capacity Release Activity in the First Three Quarters of 1994* (December 1994)) may also be an indication that reservation rates exceed the shipper's valuation of firm capacity.

[43]Federal Energy Regulatory Commission, Order Following Technical Conference, Natural Gas Pipeline Company of America, Docket Nos. RP95-326, et al. (October 11, 1995), p. 11.

renewal. Moreover, as more LDCs exit the business of providing bundled sales service, they will have less need for long-term FT capacity. Competitive pressures may make long-term FT pipeline capacity an expensive option compared with other services offered to LDC transportation customers. The challenge for pipeline companies is to market capacity to existing customers as well as to other shippers who possibly have expanding markets.

The current changes in gas pipeline capacity contracting somewhat parallel the changes in gas supply contracting that occurred over a decade ago (see Chapter 4). Previously, the norm in gas supply contracting was the use of fixed-price, long-term contracts. The upstream deliverability surplus of the early 1980's, along with open access in transmission and the development of the spot market in gas, contributed to the demise of this system. Specifically, industrial consumers could save hundreds of millions of dollars by purchasing gas on the spot market. Pipeline companies, however, who at the time were both sellers and transporters of the gas, were contractually obligated to pay for what were now largely unmarketable supplies of gas. The pipeline companies ultimately sought to free themselves from their contractual obligations by declaring *force majeure* and even bankruptcy. Since then, long-term fixed-price supply contracts have been largely abandoned by the industry.

In today's market for pipeline capacity, long-term contracts are not flexible enough to keep pace with changing market conditions. Instead of a gas productivity surplus (the gas bubble from the 1980's), there is now a pipeline capacity surplus in some areas. Shippers are now seeking to free themselves from inflexible long-term capacity contracts just as pipeline companies once sought relief from inflexible long-term gas purchase contracts. Some shippers are reducing the length of their contracts and expect that new contracts will have shorter terms than current contracts to enable them to respond better to market changes.[44]

As in the supply industry of a decade ago, the role of the spot market is a key factor in the changing market for pipeline capacity. In the case of gas supply, the emergence of spot supplies at prices below the previously established contracted prices effectively doomed the use of fixed-price long-term contracts. While it may be too early to predict with confidence, the emerging secondary or spot market for pipeline capacity may seriously undermine the practice of contracting for pipeline capacity for long periods of time at fixed prices. What could emerge is a system of rates that are based on market conditions as opposed to historical costs. Such a system may promote more options for shippers and provide opportunitites for pipeline companies. However, the increased opportunities may be accompanied by increased risk since market-driven pricing does not assure a profit.

[44]LDC Caucus of the American Gas Association, *Future Unsubscribed Pipeline Capacity* (December 1995), p. 19.