5. Natural Gas Pipeline Network: Changing and Growing

Natural gas consumption is expected to grow steadily into the next century, with demand forecasted to reach 32 trillion cubic feet by 2020. The likelihood of a substantial increase in demand has significant implications for the interstate natural gas pipeline system. A key issue is what kinds of infrastructure changes will be required to meet this demand and what the costs will be of expanding the pipeline network, both financial and environmental. Significant changes have already occurred on the pipeline grid. During the past decade, for example, interstate pipeline capacity has increased by more than 16 percent (on an interregional basis). Average daily use of the network was 72 percent in 1997, compared with 68 percent in 1990. More than 15 new interstate pipelines were constructed, as well as numerous expansion projects. From January 1996 through August 1998 alone, at least 78 projects were completed adding approximately 11.7 billion cubic feet per day of capacity. By the end of 1998, another 8.4 billion cubic feet of daily capacity is expected to be in service (Figure 36). Moreover:

- In the next 2 years (1999 and 2000), proposals for new pipelines or pipeline expansions call for the potential expenditure of nearly $9.5 billion and an increase of 16.0 billion cubic feet per day of capacity. The proposed capacity additions would be less than what was installed in 1997 and 1998 but represent a 122-percent increase in expenditures (Table 11).

- The Energy Information Administration projects that interregional pipeline capacity (including imports) will grow at an annual rate of only about 0.7 percent between 2001 and 2020, compared with 3.3 percent between 1990 and 2000. But natural gas consumption will grow at more than twice that rate, 1.8 percent per year, reaching an additional 25 billion cubic feet per day by 2020. The majority of the growth in consumption is expected to come from the electric generation sector, which will tend to level out overall system load during the year, i.e., greater utilization, and result in less need for capacity expansion

- While many of the current expansion plans are associated with growing demand for Canadian supplies (15 percent of proposed capacity through 2000), several recent proposals also reflect a growing demand for outlets for Rocky Mountain area (Wyoming/Montana) gas development, which is steadily expanding.

- Although the Henry Hub in Louisiana remains the major natural gas market center in North America, the Chicago Hub can be expected to grow significantly as new Canadian import capacity targets the area as a final destination or transshipment point.

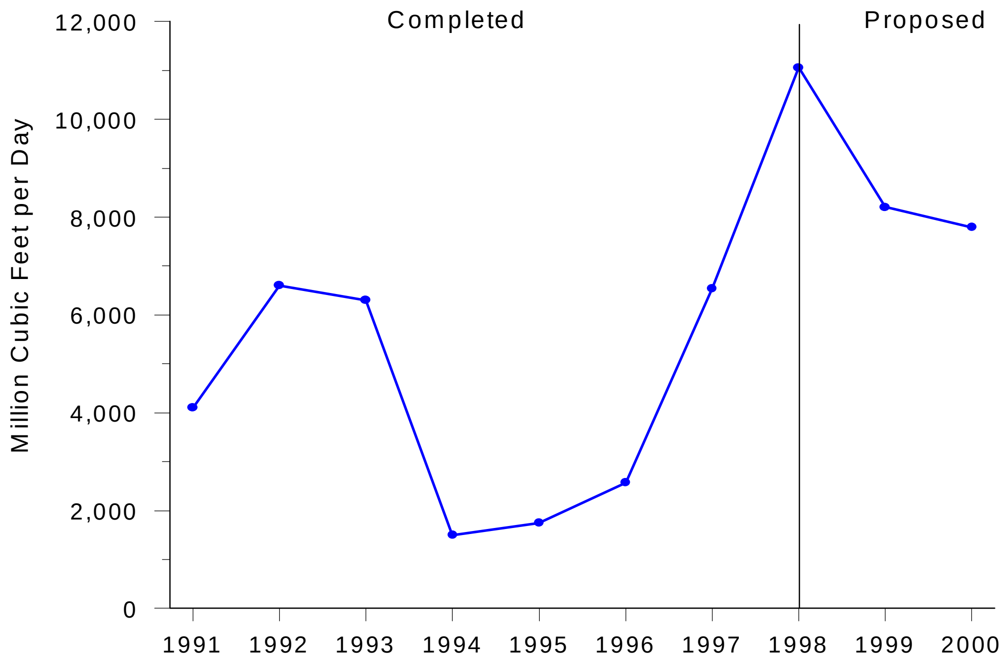
- Expanding development in the Gulf of Mexico (particularly deep water gas drilling) is competing heavily with Canadian imports to maintain markets in the Midwest and Northeast regions but is also finding a major market in its own neighborhood, that is, in the Southeast Region. Greater natural gas use for electric generation and to address environmental concerns is fueling a growing demand for natural gas in the region.

This chapter focuses upon the capabilities of the national natural gas pipeline network, examining how it has expanded during this decade and how it may expand further over the coming years. It also looks at some of the costs of this expansion, including the environmental costs which may be extensive. Changes in the network as a result of recent regional market shifts are also discussed.

Prior to the 1990s, nearly all natural gas flowing in the interstate market was owned by the major pipeline companies, which transported and sold the gas to their customers. The regulatory changes by the Federal Energy Regulatory Commission (FERC) in the 1980s, culminating in Order 636 in 1993, changed all that. These initiatives and emerging market forces created open access transportation on the interstate pipeline system and provided increasing flexibility in the way the industry operates. Now, almost all natural gas is purchased directly from producers in an open market with the pipeline companies principally providing transportation services for their customers.

The combination of wellhead price deregulation in the 1980s, greater access to transportation services, a growth

Figure 36. Major Additions to U.S. Interstate Natural Gas Pipeline Capacity, 1991-2000



Note: 1998 includes 10 projects completed through August.

Sources: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas Pipeline Construction Database, as of August 1998; Natural Gas State Border Capacity Database.

Table 11. Summary Profile of Completed and Proposed Natural Gas Pipeline Projects, 1996-2000

Year	All Type Projects						New Pipelines[a]		Expansions	
	Number of Projects	System Mileage[b]	New Capacity (MMcf/d)	Project Costs (million $)	Average Cost per Mile ($1,000)[c]	Costs per Cubic Foot Capacity (cents)	Average Cost per Mile ($1,000)[c]	Costs per Cubic Foot Capacity (cents)	Average Cost per Mile ($1,000)[c]	Costs per Cubic Foot Capacity (cents)
1996	26	1,029	2,574	552	448	21	983	17	288	27
1997	42	3,124	6,542	1,397	415	21	554	22	360	21
1998	54	3,388	11,060	2,861	1,257	30	1,301	31	622	22
1999	36	3,753	8,205	3,135	727	37	805	46	527	31
2000	19	4,364	7,795	6,339	1,450	81	1,455	91	940	57
Total	**177**	**15,660**	**36,178**	**14,285**	**862**	**39**	**1,157**	**48**	**542**	**29**

[a]New pipelines include completely new systems and smaller system additions to existing pipelines, i.e., a lateral longer than 5 miles or an addition that extends an existing system substantially beyond its traditional terminus.

[b]Includes looped segments, replacement pipe, laterals, and overall mileage of new pipeline systems.

[c]Average cost per mile is based upon only those projects for which mileage was reported. For instance, a new compressor station addition would not involve added pipe mileage. In other cases final mileage for a project in its initial phases may not yet be final and not available. In the latter case, cost estimates may also not be available or be very tentative.

MMcf/d = Million cubic feet per day.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database through August 1998.

in new services and pipeline routings, and greater participation in the market by end users, marketers, and others has resulted in a much more competitive pipeline transportation network than existed a decade ago.

Changes in Production and Market Links

The cumulative effect of market changes and regulatory reforms has, among other things, brought on shifts in North American production patterns and regional market demands. As producers and shippers alike have sought greater access to new and expanding production areas, pipeline companies have been quick to improve their receipt facilities to retain their position in the face of current or potential competition. Pipeline companies have also enhanced their regional facilities and increased capacity to maintain and expand their markets in the face of changes in customer demand profiles. Overall, this has resulted in some shifts in long-haul transport patterns, with gas flow decreasing along some traditional transportation corridors while increasing in others as new or modified production/market links have been established.

Between 1990 and the end of 1997, capacity additions on the long-haul corridors alone, which link production and market areas, totaled approximately 12.4 billion cubic feet per day, an increase of about 17 percent.[1] Capacity and deliverability additions during the period fall into several categories:

- New pipeline systems built either to transport gas from expanding production areas or to serve new market areas
- Expansion of existing systems to accommodate growing customer demand but accessing supplies already linked to the network
- Expansion of an existing system to accommodate shipper supplies transported via other pipeline systems
- Expansions of short-haul local delivery lines to link with new customers who bypass local natural gas distribution companies
- Expansions of pipeline systems in areas where productive capacity was greater than existing transportation capacity.

This pipeline network expansion activity was also augmented by the development of the natural gas market center, greater (open-) access to interstate underground storage capacity (see box, below), the development of a release market for pipeline capacity in which unused firm capacity can be sublet by others, and increased use of computer-based electronic trading. These changes have helped improve the operational flexibility of the interstate pipeline system.

Market Centers and Improved Storage Access

Since 1990, 39 natural gas market centers have been established in the United States and Canada. They have become a key factor in the growing competitiveness within the natural gas transportation market, providing locations where many natural gas shippers and marketers can transact trades and receive value-added services. Among other features, they provide numerous interconnections and routes to enhance transfers and movements of gas from production areas to markets. In addition, many provide short- term gas loans to shippers who have insufficient (receipt) volumes to meet the contractual balancing requirements of the transporting pipeline. Conversely, temporary gas parking is often available when shippers find they are delivering too much gas to the pipeline. Market centers also offer transportation (wheeling) services, balancing, title transfer, gas trading, electronic trading, and administrative services needed to complete transactions on behalf of the parties.

Many of the services offered by market centers are supported by access to underground storage facilities. More than 229 underground storage sites (out of 410 total) in the United States currently offer open-access services to shippers and others through market centers or interstate pipeline companies. These services are essential in today's transportation market—without them pipeline system operations would be much less flexible and seasonal demand would be more difficult to meet.

[1]Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity.

The greatest increase in capacity since 1990 occurred on those routes between Canada and the U.S. Northeast, 1.9 billion cubic feet (Bcf) per day, or 412 percent (Table 12). This was brought about with the completion of several new pipelines and expansions to several import stations, almost exclusively in New York State. The largest increase in solely domestic capacity, however, was between the Southwestern and Southeastern States, 1.1 Bcf per day. This increase was driven primarily by the growth in electric power and industrial demand for natural gas in the Southeast, particularly in Florida.[2]

The magnitude of pipeline expansion since 1990 can best be illustrated in conjunction with the natural gas pipeline transportation patterns that have emerged in North America over the years (Figure 37). In the early 1990s, three geographic regions were the primary focus of capacity expansion: the Western, Midwest, and Northeast regions. All three regions shared one common element, greater access to Canadian supplies. In addition, the Western Region was the target of expansions out of the Southwest Region, as new production sources were developed in the San Juan Basin of New Mexico and demand for natural gas in California was expected to grow substantially during the decade.

Through the year 2000, U.S. access to Canadian production is expected to continue to expand but at a rate never before seen, while major service expansion to the Western Region appears to have ended (Figure 38). During the next several years, the emphasis will shift to expanding natural gas transportation capabilities from the Rocky Mountain, New Mexico, and West Texas areas eastward to link with pipeline systems reaching the Midwest and Northeast markets. With the completion of this effort, the interstate natural gas pipeline network will come closer to being a national grid where production from almost any part of the country can find a route to customers in almost any area. It will fill the gap in the national network that to some extent has left the Rocky Mountain and Western natural gas producers isolated from certain markets.

Environmental issues related to the emission reductions mandated by the Clean Air Act Amendments (CAAA) of 1990 are also providing opportunities for increasing the use of natural gas, particularly in the generation of electricity. For instance, regulatory agencies in several States have instituted initiatives that encourage reductions in consumption of residual fuel oil and coal as a utility boiler fuel, resulting in the increased use of natural gas in this area. Throughout the country, natural gas will figure as an option in the powering of utility boilers to meet the emission reduction requirements under Phases I and II of the CAAA. Natural gas will also figure prominently in any implementation of the Kyoto Protocol, which specifies a reduction in greenhouse gas emissions. One of the main ways to reduce these emissions is to replace coal- and oil-fired boilers with gas-fired or renewable facilities or to improve energy efficiency.

Interregional Growth

Since 1990, approximately 11.7 billion cubic feet per day of additional interregional capacity has been constructed, principally to expand service to the West and Northeast. While the current utilization rates into the Northeast remain high and, in fact, have grown since the expansions began (83 versus 79 percent), the average daily usage rate into the Western Region fell as an excess capacity situation developed with the completion of its expansion program (Table 12). Capacity into the Midwest and Southeast increased substantially as well, adding 2.3 and 1.6 billion cubic feet per day, respectively. The average pipeline usage rate into the Midwest increased by 10 percentage points, rising to 75 percent, between 1990 and 1997. This increase occurred primarily because of increased demand and utilization of pipeline capacity out of Canada.

On an average day during 1997, utilization of interregional pipeline capacity varied from 50 to 96 percent (Table 12). (This excludes capacity into the Southwest, which is principally an exporting region.) These figures indicate that a substantial amount of unused off-peak pipeline capacity still remains on some interregional pipeline routes, although the usage-rate range itself is up somewhat from the 45-to-90-percent range in 1990. This increased capacity usage, in part, reflects the demand growth in some markets and also the growth in the capacity release market, which has helped improve the use and viability of some previously underutilized pipeline systems.

These increases in the average pipeline usage rates and the steady growth in natural gas consumption have brought about the need for expanded capacity and service in some areas. More than 11,500 miles of pipeline (109 projects)[3]

[2]Only a small part of this additional capacity, 342 million cubic feet per day, represented capacity that continued on to the Northeast or Midwest regions.

[3]Excludes minor looping and minor extension projects.

Table 12. Interregional Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1997

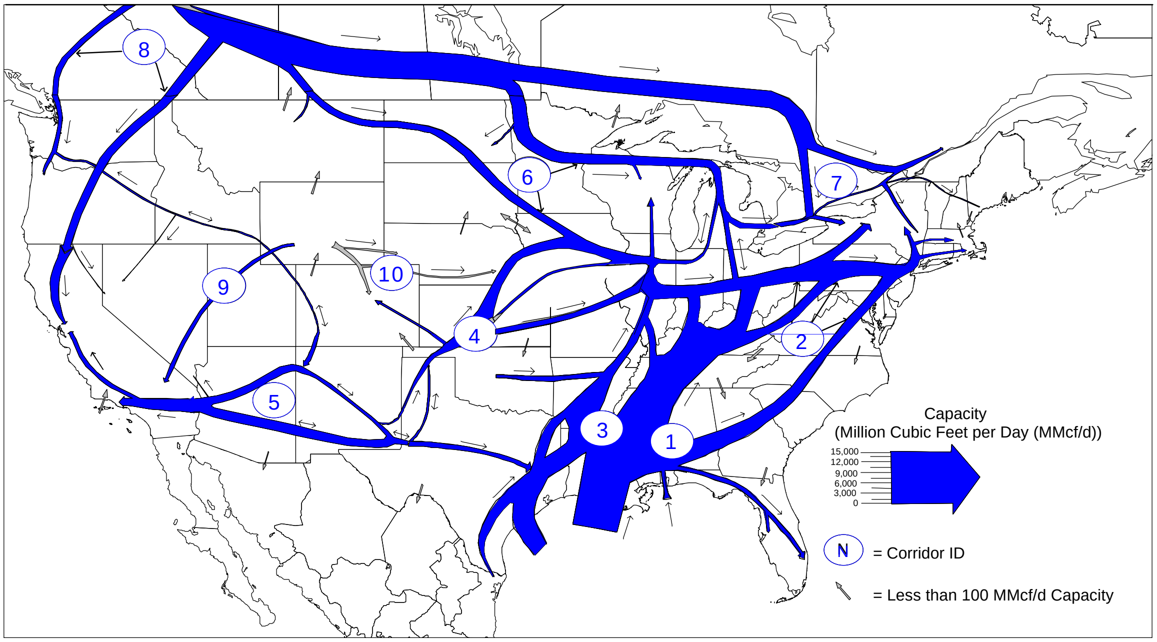
Regions		Capacity (MMcf per day)			Average Flow (MMcf per day)			Usage Rate[1] (percent)		
		1990	1997	Percent Change	1990	1997	Percent Change	1990	1997	Percentage Point Change
To Market Areas										
Receiving	**Sending**									
Midwest	Canada	2,161	3,111	44	1,733	2,647	53	84	85	1
	Central	8,888	10,069	13	5,754	7,514	31	65	75	10
	Northeast	2,054	2,068	1	729	1,045	43	45	51	6
	Southeast	9,645	9,821	2	6,134	7,199	17	64	78	14
Total to Midwest		**22,748**	**25,070**	**10**	**14,350**	**18,405**	**28**	**65**	**75**	**10**
Northeast	Canada	467	2,393	412	309	2,007	549	66	84	18
	Midwest	4,584	4,887	7	3,474	4,072	17	76	84	8
	Southeast	4,971	5,173	4	4,091	4,232	3	82	83	1
Total to Northeast		**10,022**	**12,453**	**24**	**7,875**	**10,311**	**31**	**79**	**83**	**4**
Southeast	Northeast	100	521	417	63	15	-77	63	58	-5
	Southwest	19,801	20,946	6	14,613	15,508	6	74	74	0
Total to Southeast		**19,901**	**21,467**	**8**	**14,676**	**15,523**	**6**	**74**	**74**	**0**
Western	Canada	2,631	4,336	65	1,874	3,222	72	71	77	6
	Central	365	1,194	227	196	747	260	54	96	42
	Southwest	4,340	5,351	23	3,910	2,655	-32	90	50	-40
Total to Western		**7,336**	**10,881**	**48**	**5,784**	**6,624**	**15**	**83**	**64**	**-19**
Total to Central		**12,093**	**13,096**	**8**	**6,248**	**8,183**	**31**	**56**	**68**	**12**
Total to Southwest		**2,058**	**2,879**	**40**	**651**	**1,240**	**91**	**69**	**55**	**-14**
U.S. Interregional Total		**74,158**	**85,847**	**16**	**49,584**	**60,286**	**22**	**68**	**72**	**4**
From Export Regions										
Sending	**Receiving**									
Canada	Central	1,254	1,566	25	941	1,592	69	75	99	24
	Midwest	2,161	3,111	44	1,733	2,647	53	84	85	1
	Northeast	467	2,393	412	309	2,007	549	66	84	18
	Western	2,631	4,336	65	1,874	3,222	72	71	77	6
Total from Canada		**6,514**	**11,406**	**75**	**4,857**	**9,468**	**95**	**76**	**84**	**8**
Central	Canada	66	66	0	44	44	0	67	66	-1
	Midwest	8,888	10,069	13	5,754	7,514	31	65	75	10
	Southwest	1,303	2,114	63	575	1,181	105	68	65	-3
	Western	365	1,194	227	196	747	260	54	96	42
Total from Central		**10,622**	**13,453**	**27**	**6,373**	**9,442**	**48**	**63**	**78**	**15**
Southwest	Central	8,824	8,878	1	4,137	4,950	20	48	58	10
	Mexico	354	1,056	198	38	140	265	11	13	3
	Southeast	19,801	20,946	6	14,613	15,508	6	74	74	0
	Western	4,340	5,351	23	3,910	2,656	-32	90	50	-40
Total from Southwest		**33,319**	**36,231**	**9**	**22,698**	**23,254**	**2**	**69**	**65**	**-4**

[1]Usage rate shown may not equal the average daily flows divided by capacity because in some cases no throughput volumes were reported for known border crossings. This capacity was not included in the computation of usage rate.

MMcf = Million cubic feet.

Sources: Energy Information Administration (EIA). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1997. **Average Flow:** Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." **Usage Rate:** Office of Oil and Gas, derived from Pipeline Capacity and Average Flow.

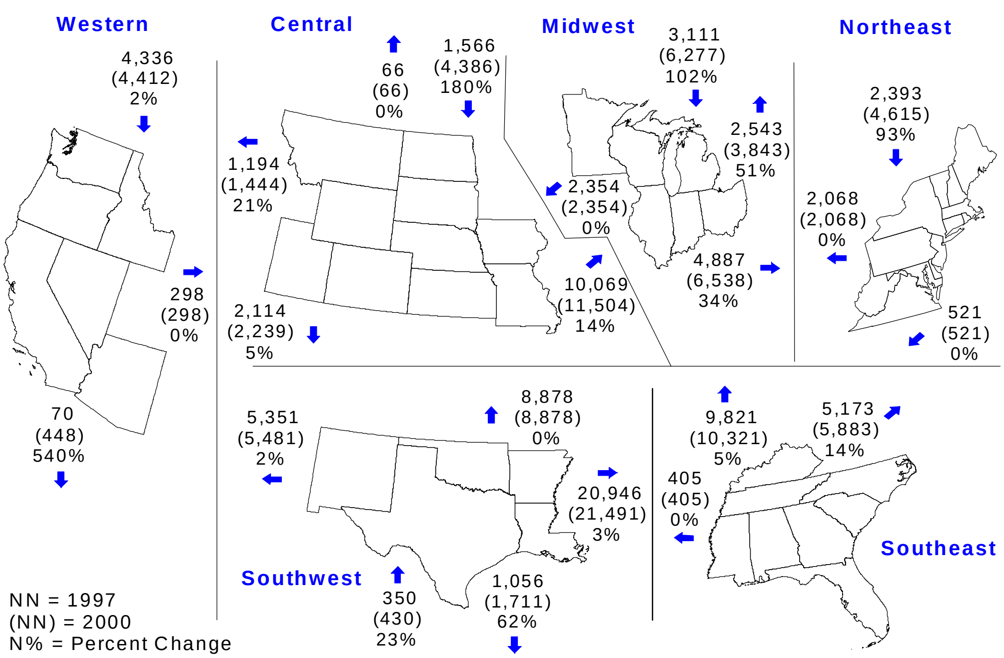
Figure 37. Major Natural Gas Transportation Corridors in the United States and Canada, 1997



Note: The 10 transportation corridors are: (1) Southwest–Southeast, (2) Southwest–Northeast, (3) Southwest–Midwest, (4) Southwest Panhandle–Midwest, (5) Southwest–Western, (6) Canada–Midwest, (7) Canada–Northeast, (8) Canada–Western, (9) Rocky Mountains–Western, and (10) Rocky Mountains–Midwest.

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1997.

Figure 38. Region-to-Region Natural Gas Pipeline Capacity, 1997 and Proposed by 2000
(Volumes in Million Cubic Feet per Day)



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas Proposed Pipeline Construction Database, as of August 1998, and Natural Gas Pipeline State Border Capacity Database.

are scheduled to be added between 1998 and 2000 within the United States. Even if only half of these projects are eventually built, the level of proposed activity is a dramatic change from the slow growth in the mid-1980s when only 200 to 800 miles of pipeline were added each year,[4] and more recently in 1994 and 1995 when only 550 and 325 miles, respectively, were installed as part of 12 projects.

Regional Trends

The increased deliverability and utilization of the U.S. natural gas system reflect recent regional trends in supply access as well as in market demand. The natural gas transmission and delivery network within the different U.S. regional markets has evolved over time to meet particular requirements (Table 13). Each region differs in climate, underground storage capacity, number of pipeline companies, and availability of local production. Additionally, the varying demographics of each region dictate different patterns of gas use and potential for growth. Since 1990, some changes have occurred in each region and, thus, so has the level of natural gas deliverability within the respective regional markets. Further changes surely will occur during the next two decades as the demand for natural gas grows to a projected 32 trillion cubic feet annually by 2020 and a 28-percent share of the total U.S. energy market (Figure 39). The following section highlights some of the major regional trends that have affected deliverability during the past decade and are likely to affect the whole network over the next several years.

Increased Demand for Access to Canadian Supplies

Growing U.S. demand for Canadian natural gas has been a dominant factor underlying many of the pipeline expansion projects this decade. As a consequence, Canadian natural gas has become an increasingly important component of the total gas supply for the United States. In 1997, more than 2.9 trillion cubic feet of gas was imported from Canada, an increase of 100 percent from the level in 1990.[5] This trend is expected to continue as Canadian production expands rapidly in the western provinces of British Columbia and Alberta and is developed off the east coast of Nova Scotia. Consequently, more pipeline projects are expected to be built to gain greater access to these Canadian supplies.[6] Among these projects is a proposed expansion of the NOVA system in Alberta, Canada, by up to 2.3 billion cubic feet (Bcf) per day. This in turn will link with the TransCanada Pipeline system expansion and its connections with existing and new U.S. pipelines feeding into the expanding markets in the Midwest and Northeast regions. In addition, two totally new pipeline systems, the Alliance and the Maritime & Northeast, are scheduled to be in service by the end of 2000. The former will link British Columbia/Alberta, Canada production sources with U.S. Midwestern and Northeastern markets, while the latter will bring Sable Island gas supplies from off the east coast of Canada to the New England marketplace.

While pipeline capacity and U.S. access to Canadian supplies increased by 75 percent (11.4 versus 6.5 Bcf per day) between 1990 and 1997 (Table 12), an additional 6.0 Bcf per day capacity could be in place by the end of 2000 if the planned projects are completed (see Chapter 1). This would amount to a 168-percent increase in import capacity between 1990 and 2000. Put another way, in 1990, Canadian import capacity was only 20 percent as large as export capacity from the U.S. Southwest, the major-producing region in the United States. By 2000, Canadian import capacity could be as much as 53 percent of the Southwest's export capacity (Figure 38).

Southwest Producers Seek Greater Access to Eastern Markets

Natural gas pipeline export capacity from the Southwest Region has continued to grow, by 9 percent since 1990 (Table 12), but the rate has slowed as production and new reserve additions continued on a downward trend.[7] The Southwest Region now accounts for 68 percent of the natural gas reserves in the Lower 48 States, down from 72 percent in 1990. The bright spot in the region is the increased exploration and development activity in the Gulf of Mexico. Annual production levels in the Gulf remained relatively steady throughout much of the 1980s but have increased significantly since 1996. A number of deep-

[4]Federal Energy Regulatory Commission, Office of Pipeline Regulation, Staff Report, *Cost of Pipeline and Compressor Station Construction Under Natural Gas Act Section 7(c), for the Years 1984 Through 1987* (Washington, DC, June 1989) and subsequent issues.

[5]Energy Information Administration, "U.S. Natural Gas Imports and Exports—1997," *Natural Gas Monthly*, DOE/EIA-0130(98/09) (Washington, DC, September 1998).

[6]Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of September 1998.

[7]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves, 1997 Annual Report*, DOE/EIA-0216(97), Advance Summary (Washington, DC, September 1998) and *1990 Annual Report*, DOE/EIA-0216(90) (Washington, DC, September 1991)

Table 13. Principal Interstate Natural Gas Pipeline Companies Operating in the United States, 1997

Destination/ Pipeline Name	Major Supply Source(s)	Begin-ning Region	Beginning State	Intermediate States	Ending State(s)	System Capacity (MMcf/d)	Miles of Mainline Transmis-sion[a]
Central Region							
Colorado Interstate Gas Co	WY,N TX/OK	Central	Wyoming	TX,OK,KS	Colorado	2,218[b]	4,199
KN Interstate Gas Co	WY,N TX/OK	Central	Wyoming	TX,OK,CO,NE,MT	Kansas	906	6,268
KN Wattenberg LL Co	WY,CO	Central	Wyoming	None	Colorado	171[b]	64
Mississippi River TransCorp	N TX/OK/AR	Southwest	Texas	OK,AR,LA,IL	Missouri	1,670[b]	1,976
Northern Border PL Co	Canada	Central	Montana	ND,SD,MN	Iowa	1,760	971
Northern NG Co	N TX,OK,KS	Southwest	Texas	NM,OK,KS,NE,IA,IL,WI,SD	Minnesota	3,800	16,424
Questar Pipeline Co	WY,CO	Central	Wyoming	CO	Utah	1,362[b]	1,712
Trailblazer Pipeline Co	WY	Central	Colorado	WY	Nebraska	508[b]	436
Williams NG Co	N TX,OK,KS,WY	Central	Wyoming	CO,NE,KS,OK,TX	Missouri	1,850[b]	5,837
Williston Basin Interstate PL Co	WY	Central	Montana	WY,SD	North Dakota	460[b]	3,067
Wyoming Interstate Gas Co	WY	Central	Wyoming	None	Colorado	732	269
Midwest Region							
ANR Pipeline Co (WL)	N TX,OK,KS	Southwest	Texas	OK,KS,NE,MO,IA,IL,IN,WI	Michigan	5,846[b]	9,565
ANR Pipeline Co (EL)	LA,MS	Southwest	Louisiana	AR,MS,TN,KY,IN,OH	Michigan	©	©
Bluewater PL Co	MI, Other Pipelines	Midwest	Michigan	None	Canada	225	95
Crossroads Pipeline Co	Other Pipelines	Midwest	Indiana	None	Ohio	250	205
Great Lakes Gas Trans Co	Canada	Midwest	Minnesota	WI	Michigan	2,483[b]	2,005
Midwestern Gas Trans Co	Tennessee Gas PL	Southeast	Tennessee	KY,IN	Illinois	785	350
Natural Gas PL Co of Am (WL)	N TX,OK,KS	Southwest	Texas	OK,KS,NE,IA,	Illinois	5,011[b]	9,856
Natural Gas PL Co of Am (EL)	S TX,LA,	Southwest	Texas	LA,AR,MO	Illinois	©	©
Panhandle Eastern PL Co	N TX,OK,KS	Southwest	Texas	OK,KS,MO,IL,IN,OH	Michigan	2,765[b]	6,334
Texas Gas Trans Corp	LA	Southwest	Louisiana	AR,MS,TN,KY,OH	Indiana	2,787[b]	5,736
Trunkline Gas Co	S TX,LA	Southwest	Texas	LA,AR,MS,TN,KY,IL	Indiana	1,884[b]	4,143
Viking Gas Trans Co	Canada	Midwest	Minnesota	ND	Wisconsin	513[b]	609
Northeast Region							
Algonquin Gas Trans Co	Other Pipelines	Northeast	New Jersey	NY,CT,RI	Massachusetts	1,586[b]	1,064
CNG Trans Corp	LA,WV,PA	Northeast	Pennsylvania	WV,MD,VA	New York/Ohio	6,275	3,851
Columbia Gas Trans Co	LA,WV/PA	Northeast	West Virginia	PA,MD,VA,NJ,DE,NC	New York/Ohio	7,276[b]	11,249
Eastern Shore NG Co	Other Pipelines	Northeast	Pennsylvania	DE	Maryland	58[b]	270
Empire PL Co	Canada	Northeast	New York	None	New York	503	155
Equitrans Inc	WV	Northeast	West Virginia	None	Pennsylvania	800[b]	492
Granite State Gas Trans Co	Canada	Northeast	Vermont	NH	Maine	49[b]	105
Iroquois Gas Trans Co	Canada	Northeast	New York	CT,MA	New York	829	378
National Fuel Gas Supply Co	OP, Canada	Northeast	New York	None	Pennsylvania	2,133[b]	1,613
Tennessee Gas PL Co	S TX,LA, Canada	Southwest	Texas	LA,AR,KY,TN,WV,OH,PA,NY,MA	Massachusetts	5,939	15,257
Texas Eastern Trans (WL)	S TX,LA	Southwest	Texas	LA,AR,MO,IL,IN,OH,WV,PA,NJ	New York	5,587[b]	9,270
Texas Eastern Trans (EL)	S TX,LA	Southwest	Texas	LA,MS,AL,TN,KY,OH	Pennsylvania	©	©
Transcontinental Gas PL Co	S TX,LA	Southwest	Texas	LA,MS,AL,GA,SC,NC,VA,MD	New York	6,556	10,245
Vermont Gas Systems Inc	Canada	Northeast	Vermont	None	Vermont	40	165
Southeast Region							
Chandeleur PL CO	Gulf of Mexico	Offshore	–	None	Mississipi	280	172
Columbia Gulf Trans Co	SE TX,LA	Southwest	Texas	LA,MS,TN	Kentucky	2,063	4,190
East Tennessee NG Co	Tennessee Gas PL	Southeast	Tennessee	None	Virginia	675	1,110
Florida Gas Trans Co	S TX,LA,MS	Southwest	Texas	LA,MS,AL	Florida	1,405[b]	4,843
Mobile Bay PL Co	Gulf of Mexico	Offshore	–	None	Alabama	600	29
Midcoast Pipeline Co	Other Pipelines	Southeast	Alabama	None	Tennessee	136[b]	288
South Georgia NG Co	Southern NG PL	Southeast	Georgia	AL	Florida	129	909
Southern NG Co	SE TX,LA,MS	Southwest	Texas	LA,MS,AL,GA,TN	South Carolina	2,536	7,394
Southwest Region							
Discovery PL Co	Gulf of Mexico	Offshore	–	None	Louisiana	600	147
High Island Offshore System	Gulf of Mexico	Offshore	–	None	Louisiana	1,800	203
Koch Gateway PL Co	SE TX,LA	Southwest	Texas	LA,MS,AL	Florida	3,476	7,781
Noram Gas Trans Co	AR,TX,KS,OK	Southwest	Texas	KS,AR,LA	Missouri	2,797[b]	6,222
Mid-Louisiana Gas Co	LA	Southwest	Louisiana	MS	Louisiana	193[b]	412
Nautilus Pl Co	Gulf of Mexico	Offshore	–	None	Louisiana	600	101
Ozark Gas Trans Co	OK	Southwest	Oklahoma	None	Arkansas	166[b]	436
Sabine Pipeline Co	TX	Southwest	LA	None	Louisiana	1,348[b]	190
Sea Robin PL Co	Gulf of Mexico	Offshore	–	None	Louisiana	1,241	470
Shell Gas PL Co	Gulf of Mexico	Offshore	–	None	Louisiana	600	45
Stingray PL System	Gulf of Mexico	Offshore	–	None	Louisiana	1,132[b]	318
Valero Interstate Trans Co	TX	Southwest	Texas	None	Texas	–	–
Western Region							
El Paso NG Co	S CO,NM	Southwest	New Mexico	AZ	California/TX	4,744	9,838
Kern River Trans Co	WY	Central	Wyoming	UT,NV	California	714	925
Mojave PL Co	Transwestern PL	Western	Arizona	None	California	407	362
Northwest PL Co	Canada	Western	Washington	ID,OR,WY,UT	Colorado	3,300	2,943
PG&E Trans Co - Northwest	Canada	Western	Idaho	OR	California	2,568[b]	1,336
TransColorado PL Co	CO	Central	Colorado	None	New Mexico	135	28
Transwestern Gas PL Co	CO,NM,W TX	Southwest	New Mexico	AZ	California/TX	2,640	2,487
Tuscarora Gas Trans Co	PG&E-Northwest	Western	Oregon	CA	Nevada	110[b]	229

[a]Includes miles of looped (parallel) pipeline.

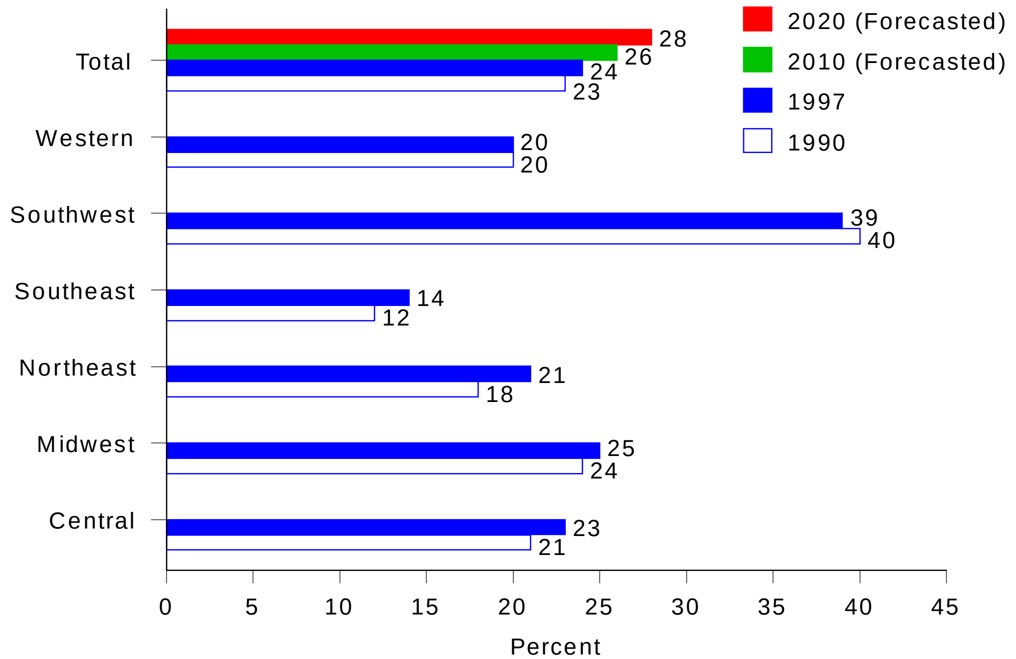
[b]Reported in thousand decatherms per day (Mdth/d). Converted to million cubic feet per day (MMcf/d) using 1.027 conversion factor, e.g., 113 Mdth/d / 1.027 = 110 MMcf/d.

[c]Included in above figure.

– = Not applicable; WL = West Leg; EL = East Leg, NG = Natural Gas; PL = Pipeline; Trans = Transmission. OP = Other Pipelines.

Sources: **Capacity:** Federal Energy Regulatory Commission, FERC 567 Capacity Report, "System Flow Diagram" and Annual Capacity Report (18 CFR §284.12); Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity. **Transmission Line Mileage:** Federal Energy Regulatory Commission, FERC Form 2, "Annual Report of Major Natural Gas Companies" and FERC Form 2A, "Annual Report of Minor Natural Gas Companies."

Figure 39. Percent of Total Energy Fueled by Natural Gas in the United States



Source: **1990-1997:** Energy Information Administration (EIA), *State Energy Data Report, Consumption Estimates 1980-1996* (December 1996) and *Annual Energy Review 1997* (July 1998). **Projected:** EIA, *Annual Energy Outlook 1999* (December 1998).

water oil and gas development projects and corollary pipeline expansions are slated to become operational over the next several years. While much of this development in the Gulf replaces reduced production in older areas, some will also serve expanding customer demand in the Southeast Region for access to additional sources of supply.

Nevertheless, only a limited amount of new pipeline capacity onshore is being added to accommodate the new production. Currently, existing capacity within and exiting the region is not being fully utilized throughout the year. Thus until overall demand for space on those lines rises substantially, any major expansion possibilities will be held in abeyance. A sizeable portion of the new offshore capacity is supporting specific developmental project locations. The few onshore expansion proposals that have been announced (or are under study) will most likely support new interconnections and links to expanding offshore production.

A growing part of the production from the San Juan Basin (New Mexico) and pipeline capacity from the general area has been redirected eastward into the West Texas Waha trading area. This change in orientation was due primarily to greater price competition and sluggish growth in older markets. During 1998, however, the traditional California market has begun to demand a greater portion of San Juan production, and thus the growth in eastward gas flow from the basin has slowed somewhat. Nevertheless, since 1993, several projects have been completed and several more are planned that in total could increase pipeline capacity in this new direction by as much as 715 million cubic feet per day by 2000. This amounts to almost a 30-percent increase in available pipeline capacity flowing eastward to the West Texas trading points since 1990.

Supporting the increased flow of gas eastward has been the growing development of new pipeline capacity on the Texas intrastate system, as well as on several interstate pipelines that operate within Texas. These expansions support the movement of greater quantities of gas across the State from West to East Texas. These actions have given regional traders increased access to Eastern and Midwestern customers who traditionally trade in East Texas and Louisiana. Since 1990, at least 600 million cubic feet per day of new capacity has been added along this corridor.

Despite the increased capacity from the Southwest to the Southeast, customers in the Midwest and Northeast regions are currently opting for increased access to Canadian supplies rather than Southwestern supply. Only a limited amount of pipeline expansion from the Southwest Region (via the Central and Southeast regions) to the Midwest and Northeast regions (2- and 4-percent increases, respectively) occurred between 1990 and 1997 (Table 12). Nor has much been proposed for installation over the next several years. Customers in the Western Region have also come to rely less upon access to Southwestern supply sources and more on Canadian. Between 1993 and 1996, pipeline usage out of the Southwest production areas into the Western Region decreased significantly (more than 30 percent) while usage of those pipelines supplying Canadian gas increased significantly, despite a general economic downturn in the region during the period.

Increased Interest in Moving Rocky Mountain Supply Eastward

The Rocky Mountain area now accounts for 15 percent of gas reserves in the Lower 48 States, up from 10 percent in 1990. Yet, with the exception of the startup of the Kern River Pipeline system in 1993, little or no new pipeline capacity has been developed exiting the area. As a result, natural gas producers in the southern Montana, Wyoming, Utah, and Colorado area (which accounts for 9 percent of Lower 48 production) have sometimes encountered significant capacity bottlenecks, limiting their access to potential customers, especially to the east. This situation has been alleviated somewhat with the expansion of the Trailblazer, Pony Express and Colorado Interstate Gas Company systems in recent years. These systems carry gas out of the area to interconnections with regional pipeline systems and major interstate pipelines serving the Midwest Region.

With their traditional Western regional market growing at a slower rate than their production is expanding, Rocky Mountain producers are concentrating upon gaining greater access not only to Midwest markets but to growing metropolitan areas within the Central Region itself. As a result, the existing systems that exit the area eastward are operating at full capacity throughout most of the year.

Additional pipeline capacity out of this production area is scheduled to become available over the next several years, which will more than double 1997 levels. In addition, during 1998, several regional expansion proposals were announced or approved by regulatory authorities which would expand local market access out of the Powder River Basin with more than 750 million cubic feet per day of new capacity. Several proposals were also announced that would extend additional service to the Western Region, primarily to the northern Nevada area.

Chicago Area Becoming a Major Hub for Expanding Canadian Supplies

Because of its strategic position and extensive system infrastructure, the Chicago Market Center, which began operations in 1993, has become a major hub for the trading of natural gas in the Midwest Region. Among the regions, the Midwest is capable of receiving the highest level of supplies during peak periods, about 25.1 Bcf per day, up from 22.7 Bcf per day in 1990 (Table 12). Traders and shippers using the center can readily trade and gain access to gas from the Southwest Region, in particular at the Henry Hub (Louisiana), and arrange to transship the gas to any number of alternative points within the Midwest and Northeast.

This ability to accommodate shippers and traders has made the hub an attractive destination for several Canadian-proposed pipeline projects designed to bring western Canadian supplies into U.S. markets. Moreover, several other pipeline proposals, seeking to increase deliverability to the Northeast using potential excess capacity from these Canadian proposals, are targeting the Chicago hub as a receipt point for their systems. The flexibility of hub operations and the Chicago center's relationship to the Henry Hub also allow some of these expansion projects to the Northeast to offer shippers access to Southwestern supplies as an alternative to Canadian supplies.

The region has a relatively mature gas market but demand for natural gas continues to grow steadily. Between 1990 and 1997, regional natural gas use grew at an annual rate of 2.4 percent, while total energy use increased at only a 1.1-percent rate.[8] As a result, natural gas's share of the regional energy market increased by 1 percentage point during the period. Moreover, the average daily usage rates on all natural gas pipeline routes into the region, with the exception of some of the recently added Canadian import capacity, increased as well. Overall the usage rate into the region increased from 65 percent in 1990 to 75 percent in 1997. Much of this increase occurred on existing pipelines bringing supplies from the Southwest Region (via the Central and Southeast regions). In part, this increase can be attributed to greater trading activity owing to the links between the Chicago market center, the Henry Hub in Louisiana, and several East Texas market centers.

[8]Energy Information Administration, *State Energy Data Report, Consumption Estimates, 1980-1996*, DOE/EIA-0214(96) (Washington, DC, December 1997); and *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998).

Greater Deliverability from Canada Expected for the U.S. Northeast

Natural gas still represents only about 21 percent of overall energy consumption in the Northeast (Figure 39), but it has made steady inroads into the region's total energy consumption picture (up 3 percentage points since 1990). This growth is expected to continue into the next century.

In 1997, the interstate pipeline system had the capability to move about 12.5 Bcf of gas per day into the region (Table 12), up 24 percent since 1990. The largest increase, 1.9 Bcf per day, occurred in import capacity from Canada, which grew by 412 percent over the period. By the end of 1998, capacity from Canada is estimated to have increased by 213 million cubic feet per day.

The Northeast Region displayed the most robust growth in natural gas usage with an average annual increase of 4.3 percent between 1990 and 1997 (Figure 40). So it is not surprising that the area has been targeted for the most development of new pipeline capacity of any region over the next several years, about 5 Bcf per day. A key factor in this growth has been the 4.1-percent average annual increase in gas-powered electric generating capacity placed in operation since 1990, which is reflected in an average annual growth in gas usage for electric generation of 3.7 percent during the same period. Future growth is also anticipated as several nuclear plants in the region are expected to be replaced over the next several years by gas-fired units.

Natural gas demand in the region is predicted to grow about 2.8 percent annually through 2010. To meet these added requirements, the trend that began in 1991, to expand access to Canadian imports, is expected to continue and grow. However, while almost all of the previous additional capacity came directly from Canada, about half (1.9 Bcf per day) of the current proposals (3.8 Bcf per day) to bring Canadian supplies into the Northeast Region have routes that will carry these supplies via the Midwest Region. Additional Canadian supplies, directed from the Sable Island area off Canada's east coast, will begin arriving in the region in late 1999, at the rate of up to 440 million cubic feet per day. Further growth along this route is expected after the turn of the century as Newfoundland/Nova Scotia coastal natural gas resources are scheduled to be developed to a greater degree.

Growing Electric Utility Demand for Natural Gas in the Southeast

Of all the regions, the Southeast uses natural gas the least in the overall energy mix: 14 percent versus the national average of 24 percent (Figure 39). However, several of its coastal States have been experiencing double-digit population growth, and as a result, growth in overall energy consumption in this portion of the region has risen at an annual rate of about 2 to 3 percent in recent years, while residential natural gas consumption has grown by 5.6 percent per year.[9]

The largest growth is expected in the electric utility sector. Indeed, between 1990 and 1997, natural gas use for electric power generation increased at an annual rate of 8.5 percent (Figure 40). During the same period, that sector's share of the region's natural gas market grew by 2 percentage points, accounting for 16 percent in 1997.[10] Since 1990, the region has also shown substantial growth in the industrial sector overall, with natural gas usage increasing at an annual rate of about 3.0 percent per year as the number of new industrial customers also grew.[11]

Increasing development of new natural gas reserves within the region and the Gulf of Mexico and expanding regional production are meeting the needs of the region's growing markets. For instance, regional production in 1997 satisfied 33 percent of regional natural gas needs compared with only 17 percent in 1990.[12] The outlook for additional regional production over the next decade is also bright. In particular, it is anticipated that production will be forthcoming from new platforms in Mobile Bay (Alabama) and planned offshore development of the Destin area south of the Florida Panhandle.

Natural Gas Has Lost Market Share in the Southwest and West

During the first half of the 1990s, population levels in the Southwest and Western regions grew at an estimated

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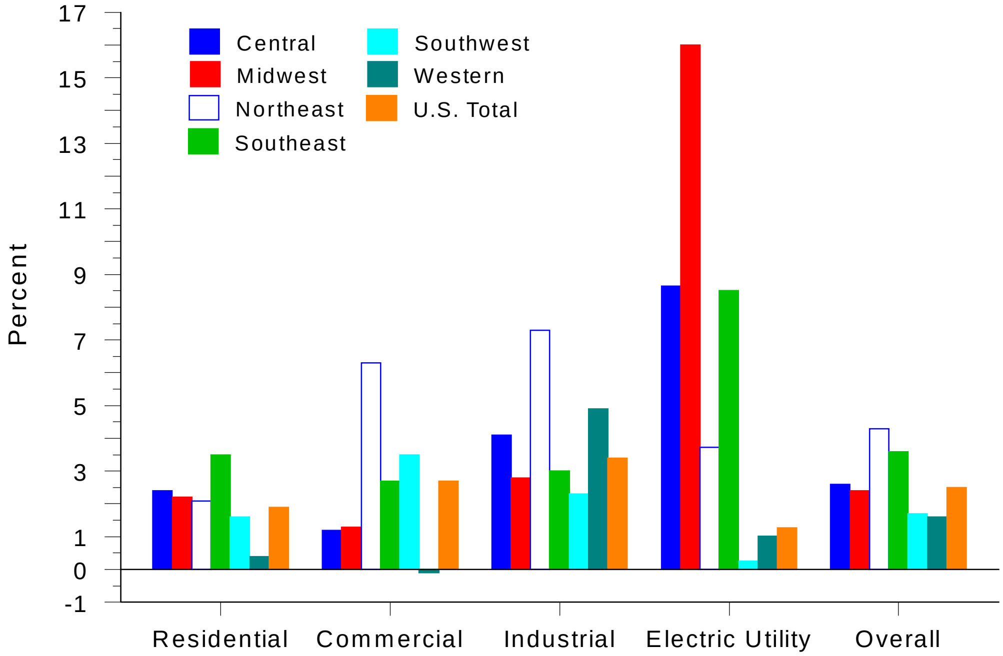
[9]Energy Information Administration, *State Energy Data Report, Consumption Estimates, 1980-1996*, DOE/EIA-0214(96) (Washington, DC, December 1997); and *Annual Energy Review* 1997, DOE/EIA-0384(97) (Washington, DC, July 1998).

[10]More than 90 percent of the expansion capacity on the Florida Gas Transmission system occurring in 1994 and 1995 was to satisfy demand by electric utilities.

[11]Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998).

[12]Energy Information Administration, *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998) and earlier issues.

Figure 40. Average Annual Rate of Change in Natural Gas Use by Sector, 1990-1997



Note: "Overall" excludes gas for vehicles, lease and plant fuel, and pipeline use.
Source: Energy Information Administration, *Natural Gas Annual 1997* and earlier issues.

average annual rate of 2.7 percent, while the total U.S. population grew at a rate of only 1.9 percent. Yet, since 1990, natural gas has lost market share in these regions. Both are non-weather-sensitive regions with comparatively low residential/commercial market shares. Industrial and electric utility customers constitute the largest users, and they are often able to switch to alternative fuels if the economics dictate. Nevertheless, in the case of the Southwest Region, which saw the largest regional drop in natural gas's share of the energy market, the use of natural gas for industrial purposes had the largest increase of any customer category on a volumetric basis (almost 500 Bcf since 1990), although at an annual rate of only 2.3 percent.

For both the interstate and intrastate pipeline companies in these two regions, this loss of market share has meant a drop in capacity utilization rates overall. However, there are signs that the situation was only temporary. Although the use of natural gas in California for power generation fell during the first half of the decade, primarily owing to a return of hydro power following a severe drought period, demand in other sectors appears to be picking up. During 1998, for instance, two projects were proposed that would increase natural gas supply to the southern California marketplace. One, Questar Pipeline Company's Four Corners project, would bring 130 million cubic feet per day to the Long Beach area from the northern Arizona/New Mexico area. Kern River Transmission Company has also proposed to expand its service to the California coast by building a lateral (300 million cubic feet per day) from its existing system, which now ends in Kern county.

Increased purchasing of Canadian gas by shippers in the West has returned the utilization rates of most of the regional pipelines to relatively high levels. Even the pipeline systems that transport supplies from the Southwest Region, Transwestern Pipeline and El Paso Natural Gas, who experienced a major drop in utilization rates as several major shippers turned backed capacity rights, are now attracting new customers eager to compete in the regional market.

In the Southwest Region, where a number of pipeline systems have experienced some falloff in pipeline usage in local markets, expansions in several major supply areas and increased demand for regional export capacity have somewhat compensated for the decline. Expansions on several intrastate systems in recent years, principally those that connect West Texas to East Texas markets, have also been a positive note.

Cost of Pipeline Development

All of this pipeline development requires significant capital investment.[13] In 1996, investment in pipeline developments amounted to about $0.6 billion (Table 11). From 1997 through August 1998, an estimated $2.1 billion was invested. And for the next several years at least, the amount of additional capital investment slated for natural gas pipeline expansion is expected to grow significantly, reflecting the anticipated development of several large (new) pipeline systems, mainly from Canada.

The cost of a pipeline construction project varies with the type of facilities being built and the distance involved (see box, p. 122, and Figure 41). Typically, a new pipeline, for which right-of-way land must be purchased and all new pipeline laid and operating facilities installed, will cost much more than an expansion of an existing route. For instance, a new pipeline, such as the proposed long-distance Alliance Pipeline system, is expected to cost as much as $1.81 per added cubic foot of daily capacity. In contrast, the relatively short-distance Texas Eastern Lebanon expansion project is expected to cost about $0.25 per added cubic foot of daily capacity. When recently completed and proposed projects are categorized by project type, new pipeline projects averaged about $0.48 per added cubic foot; a major expansion, about $0.33; and a small expansion, i.e., compression-only, about $0.15 (Figure 42).

During 1996 and 1997, the costs per added cubic foot of capacity averaged about $0.21 over 68 projects (Table 11). The majority of these projects (42) were expansions to existing pipelines systems. However, based on the projects currently scheduled for completion in 1998 and through 2000, average costs will increase as a number of new pipelines and large expansions projects are implemented. The high average cost per mile in 2000 reflects the magnitude of both expansion and new projects slated for development during that year.

The cost of a project also varies according to the region of the country in which it is located or traverses. For instance, projects that must go through major population areas, such as found in the Northeast or Midwest regions, on average cost more than those developed in the more sparsely populated and open Central and Southwest regions. Furthermore, while many of the projects completed in the Northeast and Midwest in recent years have tended to be expansions to existing systems, which are less expensive overall, future development in these regions will include many of the large new and expansion projects, which, on average, are much more expensive. For instance, in the Northeast Region, where 13 projects were completed during 1996 and 1997, the average cost per cubic foot of added daily capacity was about $0.22,[14] while over the next 3 years the average cost in the region is estimated to rise to about $0.37. On the other hand, in the Southwest Region, where much less long-haul pipeline development is slated to be installed, the average cost per project is estimated to fall into the range of $0.20 to $0.23 per cubic foot of capacity.

Although the least populated of the regions, the Central Region has relatively high average costs per planned project, reflecting the prevalence of new pipelines and large expansion projects scheduled for development over the next several years. For instance, of the 18 projects proposed for the region, average costs range between $0.35 and $0.43 per cubic foot of daily capacity, in the high range among the regions. Of the projects primarily located in the Central Region, a number are high-mileage trunkline expansions and new pipe laid to reach expanding supply areas, such as the Powder River area of Wyoming.

The differences between the estimates of project cost provided prior to construction and the actual costs are usually not large. Computer programs and extensive databases have improved estimation techniques substantially during the past several decades. According to one report that compared the actual cost of pipeline projects (filed with FERC between July 1, 1996, and June 30, 1997) with the original estimates,[15] the difference was only about 4 percent: the largest difference being in the estimated/actual cost of materials (7 percent) and the lowest being in labor costs (2 percent). Most of the differences between the two figures can usually be attributed to revisions in construction plans because of routing changes and/or pipeline-diameter changes on specific pipeline segments (often for environmental or safety reasons, see box, p. 124).

On average, construction/expansion projects completed in 1996 or 1997 took about 3 years from the time they were first announced until they were placed in service. Construction itself typically was completed within

[13] In 1997, according to filings with the Federal Energy Regulatory Commission, total capital (gas plant) investment in place by the major interstate pipeline companies amounted to close to $60 billion.

[14] One of the reasons for this was that almost all of the projects were low-mileage or compression additions rather than long-haul new pipelines.

[15] Warren R. True, "Construction Plans Jump: Operations Skid in 1996," Pipeline Economics OGJ Special, *Oil and Gas Journal* (Tulsa, OK: Pennwell Publishing Co., August 4, 1997).

Natural Gas Pipeline Development Options and Costs

Stages of Natural Gas Pipeline Development

The need for new or additional pipeline capacity to meet the growing demand for natural gas can be implemented in several ways. Pipeline designers have various options open to them, each with particular physical and/or financial advantages and disadvantages. The least expensive option, often the quickest and easiest, and usually the one with the least environmental impact is to upgrade facilities on an existing route. But that may not be feasible, especially if the market to be served is not currently accessible to the pipeline company. Some of the alternatives available, along with the various steps involved in completing the effort (besides the mandatory regulatory approval), include the following.

- **Build an Entirely New Pipeline**
  - — Survey potential routes and assess environmental/historical impact
  - — Acquire rights-of-way (new land or along routes of existing utility services)
  - — Build access roads and clear/grade/fence construction pathways
  - — Dig/explode pipe ditches (padding bottom and soil upgrades)
  - — Lay pipe (string, bending, hot pass, fill/cap weld, wrapping, inspection)
  - — Build compressor stations, pipeline interconnections, and receipt and delivery metering points
  - — Pad/backfill/testing and final survey
  - — Restore construction site(s).

- **Convert an Oil or Product Pipeline**
  - — Acquire pipeline and assess upgrade requirements
  - — Upgrade some pipe segments (for example, larger diameters to meet code standards in populated areas)
  - — Install compressor stations at 50- to 100-mile intervals
  - — Build laterals to reach natural gas customers and install metering points
  - — May have to build bypass routes (to avoid certain oil related areas such as tank farms).

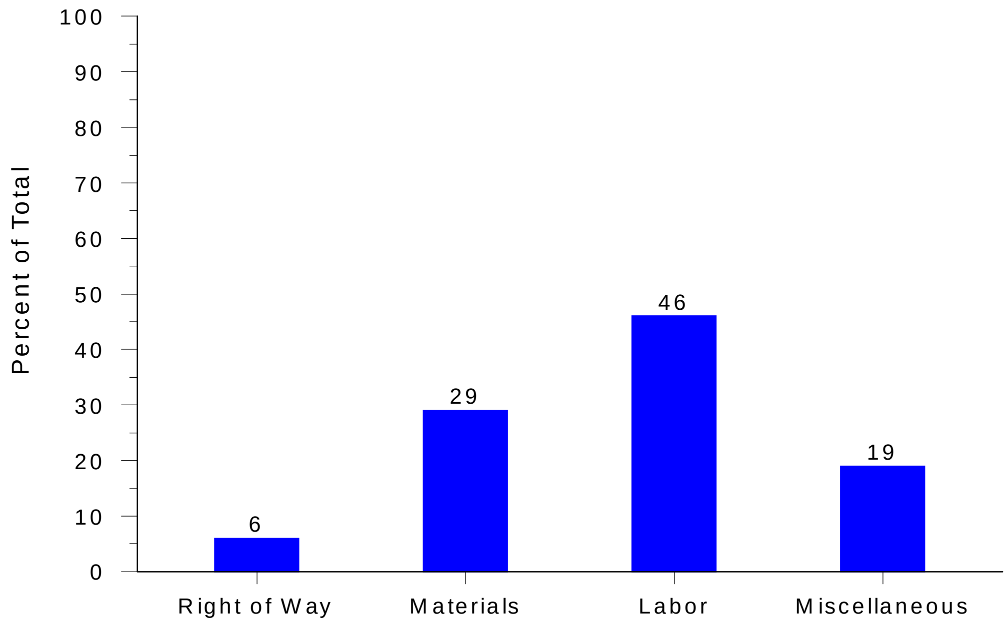
- **Expand an Existing Pipeline System**
  - — Add new laterals and metering points
  - — Install pipeline parallel to existing pipeline line (looping)
  - — Install new compressors
  - — Build interconnections with other pipeline systems.

Expanding an existing pipeline or converting an oil pipeline also include many of the same construction tasks as building a new pipeline but usually to a much lesser degree. When an expansion project includes building a lateral, then all the new-pipeline procedures apply to installing the new section. When pipeline looping is installed, digging/laying/testing and site restoration are necessary.

Component Costs of Pipeline Development

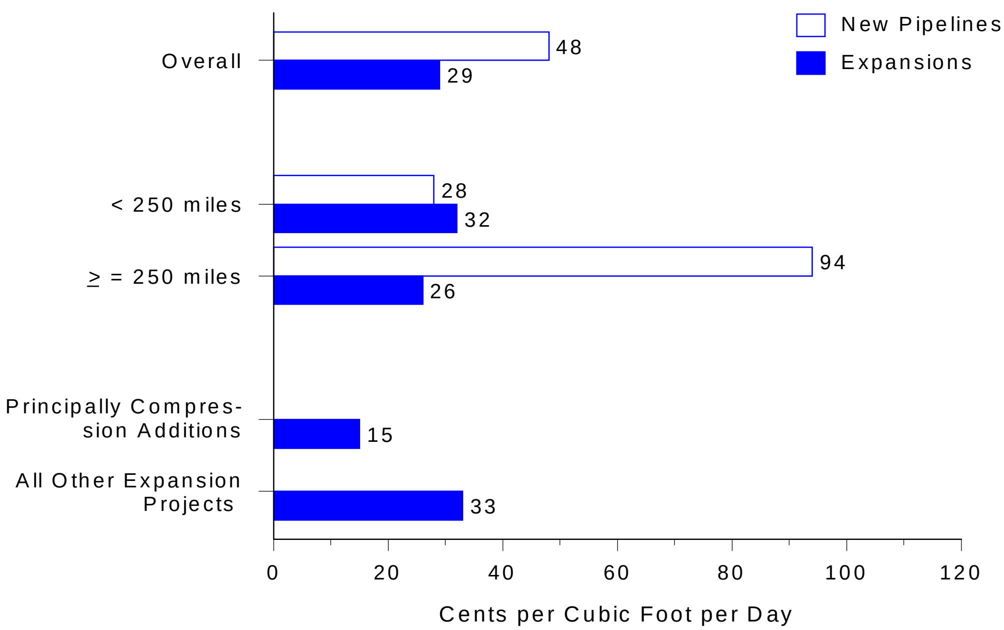
The major cost components associated with the building or expansion of a natural gas pipeline are usually placed under the following categories: labor (including survey and mapping), right-of-way acquisition, facilities (compressor stations, meter stations, etc.), materials (compressors, pipe, wrapping), and miscellaneous (administration, supervision, interest, Federal Energy Regulatory Commission fees, allowances for funds during construction, and contingencies). Generally, labor costs represent the largest component (Figure 41), although on new, long-distance pipeline projects, with pipe diameters greater than or equal to 36 inches, material costs approach labor costs. Right-of-way costs also represent a larger proportion of costs in the latter case.

Figure 41. Proportion of Costs by Category for Completed Natural Gas Pipeline Projects, 1991-1997



Note: Based on average cost per mile of onshore natural gas projects in the Lower 48 States of 16-inch or greater pipe diameter.
Source: Pennwell Publishing, *Oil and Gas Journal* (OGJ), Pipeline Economics OGJ Special (August 4, 1997).

Figure 42. Average Costs for New Capacity on Completed and Proposed Natural Gas Pipeline Projects, 1996-2000



Note: Data for each category were not available on all projects. For example, estimated/actual project cost or miles of pipeline were not announced or not available until filed with the Federal Energy Regulatory Commission. In some cases, where profiles of projects were similar but for which one cost was unavailable, an estimated cost was derived and assigned to the project based on known data.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of August 1998.

Environmental Impact of Natural Gas Pipeline Expansions

The extent of the environmental impact brought about by natural gas pipeline construction depends upon the size of the project, its length, and its design. A large new pipeline route, built from scratch, will necessitate a good deal of environmentally sensitive actions compared with a project that only involves the upgrading of existing facilities to expand capacity. For instance, planning of a new route has to include an evaluation of its need (perhaps to be economically viable) to cross wetlands, wildlife-sensitive areas, or potential archaeological sites, and its trespass minimized before being presented to regulatory authorities. Alternative routings must also be available, since the regulatory authorities may withhold approval even if passage through these lands has the potential to create only a minimal intrusion. Upgrades and expansion projects, since they usually involve less development of new rights-of-way (other than building relatively short laterals), generate much less of a potential impact in these types of environmentally sensitive areas. Some other types of impacts that must be evaluated include the effects of:

- Clearing construction routes and building access roads
- Possible redirection (oftentimes temporary) of waterways or other natural formations
- Possible oil-residue discharge (when converting an oil line)
- Hydrostatic test water discharge (when leaks are detected).

The proposed expansion also must be evaluated in regard to its potential environmental impact once it is completed and placed in operation. For instance, it must be examined for:

- Emissions from compressor station operations
- Noise from compressor stations.

Land-clearing affects indigenous vegetation to the extent that it must be removed; however, in most instances only a narrow layer of soil is usually scraped off (of the nonditch section of the construction right-of-way) leaving most root systems intact. Grading is required when the topography is not level enough to establish a stable work area or when conditions, such as steep slopes or side slopes, exist.

When natural gas is used for fuel, a sample compressor station unit will emit approximately 50 tons per year of nitrogen oxide, 75 tons of carbon monoxide, and 50 tons of volatile organic compounds. This estimate is based on continuous year-round operation (8,760 hours) of a unit with a 3,300 horsepower (HP) rating. The typical level of compressor station emissions will vary depending upon actual hours of annual operation, HP rating, number of individual units, and other factors. Some compressor stations use electric-powered units rather then natural-gas-fueled units. Their on-site direct emission levels are zero.

Environmental Review of Pipeline Construction

The National Environmental Policy Act (NEPA, 1969) requires that anyone proposing to undertake a major interstate-related project, such as construction of a pipeline, LNG import terminal, gas storage field, or other major project that may have a significant impact on the environment, first produce an environmental impact study (EIS) that examines the types of environment-sensitive features involved in their project. The EIS must also describe the actions that are to be taken to mitigate potential damage. The Federal Energy Regulatory Commission must evaluate and approve any EIS associated with a pipeline construction related activity within its jurisdiction.

Depending upon the project profile and its proposed route, the preparation of the EIS itself can be a major undertaking, the approval process lengthy, and the cost of implementing remedial actions significant. However, in many instances, approval delays occur because the initial study does not address the environmental aspects of the project thoroughly and is not complete enough to permit a proper evaluation. As a result, regulators often have to ask for additional data and more time is needed before environmental approval can be granted. In some instances, when only conditional environmental approval is granted, the project’s economic viability may be affected because of unanticipated extra costs and schedule delays. Most proposed pipeline projects, however, encounter little or no delay as a result of environmental review.

18 months following FERC approval, sometimes in as little as 6 months. The remainder of the period was consumed with the initial open-season (2 months), plan development prior to filing (3 months), and FERC review and reaction to FERC revisions, if any. Generally FERC review takes from 5 to 18 months, with the average time being about 15 months.[16]

Future Development

From 1998 through 2000, more than 100 pipeline projects have been proposed for development in the Lower 48 States (Table 11). While a number of these projects are only in their initial planning stage with no firm cost estimates yet available, 70 projects have preliminary estimates associated with them.[17] Based upon these projects,[18] at least $12.3 billion could be spent on natural gas pipeline expansions from 1998 through 2000 (Figure 36). The largest expenditures, about $6.3 billion, would be for the several large projects scheduled for completion in 2000, such as the Alliance Pipeline ($2.9 billion), the Independence Pipeline ($680 million), and the Columbia Gas System's Millennium project ($678 million).

Between 2000 and 2020, EIA forecasts that the largest growth in demand,[19] 2.4 trillion cubic feet (Tcf), will occur in the Southeastern United States (the East South Central and South Atlantic Census regions)—an annual growth rate of 3.0 percent.[20] The next largest demand growth, 1.9 Tcf (2.3 percent annual growth rate), is expected in the Northeast (the New England and Middle Atlantic Census regions). The Southwestern area (West South Central) is also expected to have substantial growth, with demand increasing 1.2 Tcf (1.3 percent annual growth rate) between 2000 and 2020.

The projected demand growth in the Southeastern region is expected to be driven by greater electric utility demand and increased residential/commercial usage. A major portion of this growth will be supplied by increased natural gas production within the region (from coalbed methane sources in southern Appalachia and in the Black Warrior Basin in northern Alabama). The pipeline capacity additions to meet the transportation demands can be expected to be developed within the region itself. EIA forecasts that capacity into the region will increase at an annual rate of only about 0.1 percent between 2001 and 2020 and capacity exiting the region will increase at a 0.3 percent rate. A sizable portion of the additions is destined to meet demand in the Northeast, although some is also targeted for the Midwest market.

Overall, interregional pipeline capacity (including imports) is projected to grow at an annual rate of only about 0.7 percent between 2001 and 2020 (compared with 3.7 percent between 1997 and 2000 and 3.8 percent between 1990 and 2000). However, EIA also forecasts that consumption will grow at a rate of 27 Bcf per day (1.8 percent annually) during the same period. The difference between these two growth estimates is predicated upon the assumption that capacity additions to support increased demand will be local expansions of facilities within regions (through added compression and pipeline looping) rather than through new long-haul (interregional) systems or large-scale expansions.

It can be expected that additions to new capacity to the Midwest and Northeast from Canadian sources will slow after 2000. The EIA forecast projects that little new import capacity will be built between 2001 and 2006 (about 0.2 percent per year). From 2007 through 2020, import capacity is expected to grow only 0.7 Tcf, compared with the 1.8 Tcf (an estimated 4.8 Bcf per day) projected to be added between 1997 and 2000 alone. However, as demand continues to expand in the Midwest and Northeast during the period,[21] additional capacity on those pipelines extending from the Southeast Region (Texas, Louisiana, and especially out of the Gulf of Mexico) to these regions can be expected to grow. Several factors could influence this potential shift. First, as Canadian supplies expand their access to U.S. markets, growth in western Canadian production may slow. And, as a result, price competition between domestic and imported natural gas could narrow the price differential between them, and thus allow U.S. supply sources to attract new customers.

[16]Federal Energy Regulatory Commission, Office of Pipeline Regulation, Case Tracking System.

[17]Most projects that have yet to be filed with regulatory authorities do not provide cost estimates. Cost estimates given at the time of filing will certainly change by the time the project is completed. The Federal Energy Regulatory Commission requires that an actual cost figure must be filed within 6 months of the time a project is placed in service (CFR Section 157.20).

[18]Including derived estimates for an additional 15 projects without preliminary estimates. Estimates for these were developed based on proposed project profiles similar to completed or proposed projects for which estimates were given.

[19]Excluding lease, pipeline, or plant fuel usage, which varies per region but constitutes about 10 percent of total annual U.S. consumption.

[20]The geographic makeup of the Census regions discussed in this section differs slightly from the regions discussed elsewhere in this chapter and shown in Figure 38.

[21]Some Canadian expansion capacity into the Northeast (New England) will occur primarily to accommodate increased production from the Sable Island area off Canada's east coast.

Investment Estimates

The amount of new pipeline capacity that is projected to be added to the national network between 2001 and 2020 represents a very large potential investment in new resources. After 2000 and the completion of several "new" systems, such as the Alliance, TriState, and Vector pipelines, it is likely that few, if any, new long-distance trunklines would be needed to improve the scope and reach of the national network.[22] By then, most potential sources of production and markets will be in relatively close proximity to some part of the grid, necessitating only short pipeline extensions or expansion of an existing route to meet new demand. As a result, it might be reasonable to assume that most of the expansion projects during the next 20 to 25 years will be additions to existing systems (through looping and added compression) and therefore in total should cost less (in real terms) to implement than the typical project built during the 1990s.

Based on the EIA-projected increase in natural gas consumption by 2020 of 24.9 Bcf per day (9.1 trillion cubic feet per year)[23] (half the rate projected to occur in the 1990s) and applying the current estimated average cost of $0.39 per cubic foot per day per unit of added capacity (Table 11), a minimum investment of $9.7 billion would be needed between 2001 and 2020 to match capacity, one for one, with growth in demand.[24] However, a greater amount of pipeline capacity must be placed in service over time to accommodate an anticipated increase in demand. Indeed, a comparison of the amount of completed and proposed capacity additions between 1996 and 2000 (36.2 Bcf per day) with projected demand growth during the same period (4.5 Bcf per day) shows an 8-to-1 ratio between the two.

Several factors account for this. First, pipeline capacity must be designed to meet peak-day demands, not simply average daily requirements. As a result, demands on a pipeline system during peak periods can be several times those occurring during offpeak periods. Second, while pipeline capacity, especially for a large project, becomes immediately available and accounted for upon completion of the project, the level of anticipated new demand may not immediately match the level of new capacity. Rather, for the first year or so after the project is completed, usage of the new capacity is expected to grow until the line is fully utilized (that is, peak-period demand nears capacity levels). As a consequence, and temporarily at least, the incremental increase in capacity will exceed demand needs.

Lastly, to move supplies to end-use markets from production areas, several discrete though complementary projects, each with its own capacity level and customer delivery requirements, are usually necessary. As a result, several units of new capacity may be tallied even though only one unit of gas flow (incremental demand) will be accommodated.[25] However, the need for multiple discrete, but related, projects will diminish if, as assumed, most new capacity beyond 2001 is from expansions to existing regional systems and short-haul lines rather than new pipelines and major interregional expansions. For instance, a review of projects completed or proposed within the 1996-through-2000 time frame indicates that the ratio between singular capacity additions and actual/projected demand might be closer to about 4 to 1 if related projects were consolidated and/or complementary ones eliminated.

Assuming then that the need for a certain level of new capacity relative to a specified level of demand-increase might range from 4-to-1 to 8-to-1, between $39 billion and $78 billion in capital investments (at $0.39 per added cubic foot)[26] could be required of the natural gas pipeline industry to meet the increase in demand (24.9 Bcf per day) projected to occur by 2020. The high investment estimate could also result if there is a need for one or more large, new pipeline systems during the period (2001 through 2020). More likely, much of the new capacity beyond 2000 will come from expansions to existing systems rather than new pipelines, in which case the total investment required will be at the lower end of the range, perhaps in the vicinity of about $45 billion.

[22]Unless, perhaps, a source of supply in southern Mexico was tapped and a new pipeline system built in Texas to interconnect with the interstate system.

[23]Includes lease, pipeline, or plant usage of natural gas. Energy Information Administration (EIA), *Annual Energy Outlook 1999*, DOE/EIA-0383(98) (Washington, DC, December 1998).

[24]The investment figures are based on broad estimates of future pipeline expansion requirements and simplifying assumptions regarding how and where additional investments may be required. As such, they reflect, at best, rough estimates of future potential natural gas pipeline investment needs.

[25]For instance, the Alliance Pipeline project, starting from British Columbia, Canada, and ending in Chicago, Illinois, would deliver a portion of its flows to the TriState and/or Vector pipelines for eventual delivery to Ontario, Canada, and the Eastern United States. They, in turn, would redeliver to other new and expansion projects in the Northeast such as Columbia's Millennium and Tenneco's Eastern Express. Several other proposed new pipelines and expansions also anticipate redelivering some of Alliance's capacity to the eastern United States. These same projects would also be set up to accommodate shipments from other expansion pipelines bringing supplies to Chicago from other areas as well.

[26]And using a base of $9.7 billion for a 1-to-1 demand /capacity ratio.

Outlook

The natural gas pipeline network in Canada and the United States has grown substantially since 1990. Meanwhile, its numerous parts have become more interconnected, its routings more complex, and its business operations more fluid. New types of facilities, such as market centers, and established operations, such as underground storage facilities, have become further interwoven into the fabric of the network and have made the system operate in a much smoother manner.

While a major amount of new pipeline capacity is scheduled to be built over the next several years, just as important will be the types of complementary facilities and services that are installed or developed to support it. Although it is likely that only a few new market centers will become operational during the next few years, the services and flexibility offered at existing sites can be expected to be expanded and improved. The Chicago market center, for example, should grow as Canadian import and Southwest supplies (via the Henry Hub) expand into the area and some of this gas is redirected to the Northeast Region. The Leidy Hub in northcentral Pennsylvania is the transaction and transfer point for several major pipelines and market centers serving the Northeast and can be expected to become key to moving gas from the Midwest to New England markets and other parts of the region.

Underground storage operations, which facilitate both market center services and efficient pipeline operations, will also be expanding over the next several years in support of market center or pipeline expansions (Chapter 1).[27] For instance, the proposed Millennium (Columbia Gas Transmission Company) and Independence (ANR and Transcontinental Pipeline Company joint venture) pipeline systems to transport supplies from the Chicago, Illinois area[28] to the Northeast will require the expansion of several storage facilities in Ontario, Michigan, New York, and Pennsylvania to handle the additional load. Likewise, in the southern States of Texas, Louisiana, and Mississippi, where a number of market centers are located (including the Henry Hub), several high-deliverability salt cavern storage facilities are being expanded to handle growing production out of the Gulf of Mexico. They are also expected to handle increasing business among regional hubs, such as those located in the Midwest (Chicago) and the Northeast (Pennsylvania and New York). In these States alone, proposed increases in daily deliverability (through 2001) from storage sites that directly or indirectly support market or trading centers total 2,200 million cubic feet per day, or 5 percent more than current levels.

Given the forecasted growth in natural gas demand in the Midwest and Northeast, it seems certain that a good proportion of the proposed additional capacity will be built. However, a few of the projects might encounter later contract abandonments by customers because current estimates of near-term demand requirements could be overly optimistic. In some cases, where there is an obvious duplication of service, it is likely that some projects will be abandoned, downsized, or consolidated into a single effort.

EIA projects that natural gas consumption will move above the historical peak of 22 trillion cubic feet (Tcf) (reached in 1972) in 1999, increase by another 5 Tcf by 2010, and reach more than 32 Tcf by 2020. This growth is largely expected to come about as a result of increased use of natural gas for electricity generation in the electric utility sector and for cogeneration in the industrial sector.

The current extensive list of planned capacity additions and expansion projects indicates that substantial activity is underway to address these potential increases in demand. If all the projects currently proposed were built, interregional capacity would increase by as much as 12.8 billion cubic feet (Bcf) per day or about 15 percent from the level in 1997. Additional projects that are limited to providing service within a specific region comprise an additional 14.3 Bcf per day of capacity (see Chapter 1).

The current interregional and State-to-State capacity levels, in most instances, appear adequate to meet current customer demands, although in a few cases, the average daily pipeline utilization rates rose significantly between 1990 and 1997. This rise in usage is a good indicator that instances of peak-period capacity constraint could occur if demand for natural gas in some markets increases faster than expected. On the other hand, while the amount of new capacity proposed for the next several years is consistent with forecasted demand, there probably will be some local areas where available pipeline capacity may not always match demand.

[27] Also see Energy Information Administration, "U.S. Underground Storage of Natural Gas in 1997: Existing and Proposed," *Natural Gas Monthly*, DOE/EIA-0130(97/09) (Washington, DC, September 1997).

[28] Much of it is Canadian gas shipped from Emerson, Manitoba, through Ontario, Canada, via the U.S. Midwest.