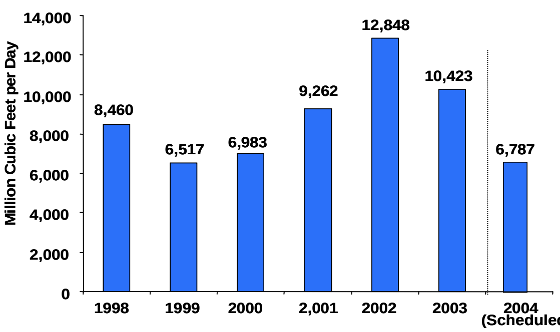
U.S. Natural Gas Pipeline and Underground Storage Expansions in 2003

This special report examines developments in the national natural gas pipeline network and the underground natural gas storage segment of the industry during 2003. In addition, it includes a discussion and a comparative analysis of the recent level of growth in each of these areas and an examination of the amount of additional development proposed for completion over the next several years. It does not address abandonments (shutdowns) of existing capacity or changes in overall pipeline or gas storage capacity. Questions or comments on the contents of this article should be directed to James Tobin at james.tobin@eia.doe.gov or (202) 586-4835.

Pipeline transportation and underground storage are vital and complementary components of the U.S. natural gas system. While mainline gas transmission lines provide the crucial link between producing area and marketplace, underground gas storage facilities help maintain the system's reliability and its capability to transport gas supplies efficiently and without interruption. Natural gas storage capacity ensures supply availability in downstream markets during periods of heavy demand by allowing a more reliable flow of production and transmission flows. In some instances, development or expansion of the pipeline network is tied inexorably with storage and vice versa.

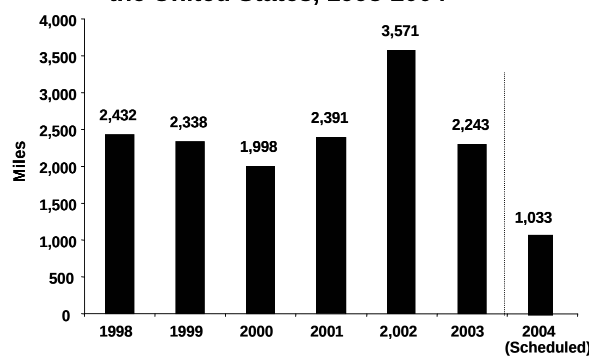
Figure 1. Natural Gas Pipeline Capacity Additions, 1998-2004



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity and Construction Databases.

Both natural gas pipeline and underground storage development decreased in 2003 compared with 2002 levels; pipeline capacity additions fell by 19 percent while additions to underground storage working gas capacity (see Box, "Underground Storage Operations and Operator Types," p. 3) fell by 27 percent.[1] Furthermore, while roughly 2,200 miles of pipeline and 10.4 billion cubic feet per day (Bcf/d) of natural gas pipeline capacity (see Box, "Pipeline Capacity Usage," p. 5) were added to the national transmission network during 2003, the current inventory of new pipeline capacity/mileage development projects indicates that pipeline capacity additions will drop once again in 2004 (Figures 1 and 2).[2]

Figure 2. Miles of Large Natural Gas Pipeline Added in the United States, 1998-2004



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity and Construction Databases.

In 2003, new and expanded underground gas storage fields added 18.6 Bcf of working gas with daily peak day withdrawal capability increasing by 2.0 Bcf/d (Table 1), compared with increases of 26 Bcf and 2.5 Bcf/d, respectively, in 2002. Reflecting the market's continuing demand for additional high-deliverability storage, more than 68 percent of new working gas capacity (19 Bcf) and 83 percent of added withdrawal capability (2.0 Bcf/d) in 2003 was new salt cavern development or its expansion.

Overall, at least 49 natural gas pipeline projects and 9 storage projects were completed during 2003 (Table 1). Of the former, 31 were expansions of existing pipeline systems or segments (Table 2). The other 18 included 3 new pipeline systems, 3 new gathering systems, and 12 new extensions or laterals[3] associated with existing

[1] In this article, additions to pipeline capacity, underground gas storage working gas capacity and daily peak day withdrawal capability (daily deliverability) levels, are based upon volumes quoted in application filings with the Federal Energy Regulatory Commission (FERC) or State agencies, or cited in company press releases or trade press sources. Because capacity and/or deliverability levels may be revised and/or adjusted as a project progresses, any volumes cited herein may not agree with final certification levels, or with volumes eventually reported on survey reports such as those filed with the Energy Information Administration (EIA).

[2] Gas pipeline development activity peaked in 2002 when more than 12 Bcf of new gas pipeline capacity and 3,571 miles of pipe were added. Energy Information Administration, *Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002*, May 2003, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/ngpipenet03.pdf

[3] Often it may be necessary for a mainline pipeline to build an extension, or lateral, off its existing system to serve a single new customer or to penetrate a new service area. Although the "lateral" will be a smaller diameter pipeline than that of the mainline, its design capacity may or

Table 1. Recent and Proposed Regional Natural Gas Pipeline and Underground Storage Additions to Capacity

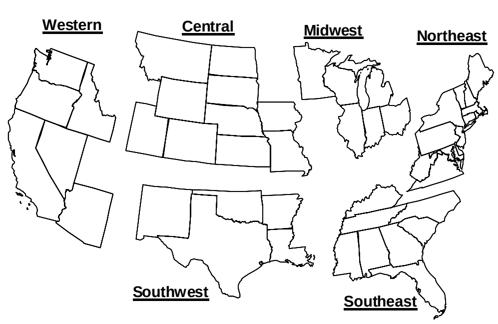
Regions (see Figure 3)	Pipeline Projects: Completed in 2003				Pipeline Projects: Scheduled for 2004 (Estimated)				Underground Storage Projects: Completed in 2003			Underground Storage Projects: Scheduled for 2004 (Estimated)		
	Projects	Added Capacity (MMcf/d)	Cost ($Millions)	Miles	Projects	Added Capacity (MMcf/d)	Cost ($Millions)	Miles	Projects	Added Working Gas Capacity (MMcf)	Added Withdrawal Capability (MMcf/d)	Projects	Added Working Gas Capacity (MMcf)	Added Withdrawal Capability (MMcf/d)
Central	12	1,162	182	409	6	560	104	34	1[a]	0	0	1	3,500	68
Midwest	4	651	132	129	3	1,063	90	51	1	5,000	300	5	42,200	1,005
Northeast	8	1,318	346	82	9	862	547	122	1	1,000	200	2	500	140
Southeast	9	1,532	905	463	2	195	122	53	1	3,910	870	0	0	0
Southwest	6	2,480	266	264	11	2,999	465	667	3	7,658	600	5	17,700	439
Western	6	2,368	1,693	885	6	1,083	315	97	2	1,008	45	3	11,669	370
To Mexico /Canada	4	912	41	11	1	25	2	9	NA	NA	NA	NA	NA	NA
U.S. Total	49	10,423	3,564	2,243	38	6,787	1,645	1,033	9	18,576	2,015	16	75,569	2,022

[a] Storage project consisted of an expansion of daily injection capability only.
Note: MMcf/d = Million cubic feet per day. Excludes projects on hold as of December 2003. In the table, a project that crosses interregional boundaries is included in the region in which it terminates. Offshore projects are included in the Southwest region.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Construction and Natural Gas Underground Storage Projects Databases.

pipeline systems. Expenditures for gas pipeline development amounted to more than $3.6 billion in 2003, well below the $4.4 billion spent in 2002.

Of the nine storage projects completed during 2003, only one salt cavern site was a new facility, compared with three new facilities completed in 2002. Of the remaining eight projects, six were expansions to high-deliverability salt cavern facilities, one a depleted reservoir type storage field, and the other an aquifer storage field.

Figure 3. U.S. Geographic Regions Used in Report



Source: Energy Information Administration, Office of Oil and Gas

may not impact the mainline itself. If there is sufficient unused capacity existing on the mainline system to accommodate the needed "new" capacity of the lateral, then the mainline system will be unaffected. On the other hand, if enough unused capacity is not available, all or part of the mainline system itself may need to be expanded as well.

Overview

Overall, the U.S. gas transportation network continued to grow in 2003, although at a slower pace than in 2002. For instance:

- **Following smaller increases in 2002, pipeline transportation capacity in the deepwater Gulf of Mexico increased by more than 1,825 million cubic feet per day (MMcf/d) in 2003.** In fact, capacity additions in the Gulf represented 74 percent of all new gas pipeline capacity in the Southwest region in 2003, and 18 percent of new capacity in the United States (Table 2). Continued deepwater gas and oil development in the Gulf of Mexico could also result in more than 1,700 MMcf/d of new gas pipeline capacity being installed in the Gulf in 2004 (if all currently approved 2004 offshore scheduled projects are actually completed in 2004).

- **Pipeline capacity constraints exiting Wyoming production fields eased considerably with completion of the Kern River Transmission Pipeline expansion (900 MMcf/d) in May 2003.** Completion of this project doubled the capability of the Kern River Transmission Pipeline to transport natural gas from Wyoming to California and Nevada. Because of a lack of sufficient take-away capacity on the interstate pipeline system serving the Wyoming area over the past 5 years, spot prices in the region had been much lower on average than, for instance, prices at the Henry Hub. Soon after the project's startup in May, spot prices in the Rocky Mountain trading area rose significantly, to levels more comparable to those at other major gas trading points in U.S. production areas.

- **Export capacity to Canada increased by 216 MMcf/d or about 6 percent in 2003, although gas pipeline import capacity between the United States and Canada grew by only 44 MMcf/d, the smallest annual increase since 1994.** The export capacity increase occurred when the Portland Natural Gas Transportation System, which was originally designed only to import gas (into New Hampshire), was reconfigured to provide bidirectional service to its customers. The objective of the reconfiguration was to provide shippers of Canadian Sable Island gas, using the Maritimes & Northeast Pipeline, with an opportunity to redirect some of their gas to markets located in Quebec, which previously had access only to western Canadian gas supplies.

- **Export capacity to Mexico increased by 24 percent, or 696 MMcf/d, in 2003, reflecting the increasing demand for U.S gas along the border with Mexico, particularly by electric generation customers.** It is the second year in a row that natural gas pipeline export capacity increased by more than 600 MMcf/d. Since 1998, export capacity to Mexico has almost tripled. Moreover, as export capacity to Mexico has grown, the average annual load factor on exporting pipelines also has grown significantly, from an average 15 percent in 1998 to 32 percent in 2002.[4]

- **Most storage development has occurred in the Southwest/Gulf Coast area.** Over the past 6 years, the existence of a large gas pipeline infrastructure and the presence of a rich salt formation geology on the gulf coast of east Texas, southern Louisiana, Mississippi, and Alabama have supported significant development of new salt cavern storage sites, expansions to existing storage, and the installation of new, or the expansion of existing, pipelines tied to these sites. In 2003 alone, this area of the United States accounted for 26 percent of the new pipeline capacity, and 55 percent of the combined working gas storage capacity additions installed in the Southeast and Southwest regions.

- **Environmental and/or routing concerns in the New York metropolitan area have significantly delayed several major projects in the Northeast region.** For instance, the Millennium Pipeline project (714 MMcf/d), originally proposed in 1996 for completion in 2000, was delayed once again in 2003. Subsequently, in early 2004, the sponsor of the project divided the installation into two separate phases with the less environmentally sensitive portion slated for 2006 and the other with an "open-ended" completion date. Another Northeast project that is currently "on hold" is the Islander East Pipeline (250 MMcf/d), which was approved by the Federal Energy Regulatory Commission (FERC) in October 2002 for development in 2003. However, its construction has been halted by the State of Connecticut, also for environmental reasons.

Underground Storage Operations and Operator Types

Operations

An underground storage site is described by its total capacity (the total volume of gas that can be stored in the facility), its base gas or volume of gas that remains in the facility at all times, and its working gas capacity, which is the difference between the first two measures (total capacity minus base gas). Base gas is the amount of gas that supports the working gas by providing pressure to enable the working gas to be withdrawn at an acceptable rate. Working gas is the amount of gas in the site that is available for withdrawal to serve customer or system needs.

Each day gas may be injected into and/or withdrawn from an underground facility, either increasing or decreasing the working gas. In theory, the level of working gas cannot exceed the working gas capacity nor may it drop below zero. In practice however, it is possible to exceed the working gas capacity by overpressurization, and it is possible to go below zero by withdrawing base gas. The determination of base gas has some degree of flexibility, depending on what level is determined necessary to maintain a desired withdrawal rate.

Owner/Operator Types

Interstate pipeline companies: Underground storage is particularly important to interstate pipeline companies because they depend heavily on storage inventories to facilitate load balancing and system management on their long-haul transmission lines.

Local distribution companies (LDCs) and intrastate pipeline companies: LDCs generally use gas from storage to serve customer needs directly, whereas intrastate pipeline companies use underground storage for operational balancing and system supply as well as the energy needs of end-use customers.

Independent operators: Many of the salt formation and high-deliverability sites that are currently in use were developed by independent storage service operators.

[4]This average daily pipeline load factor is based upon an annual volume of gas moved between the U.S. and Mexico during the years 1998 through 2002. Being based on annual figures it does not reflect seasonal or daily variations in flow. See Energy Information Administration, *Natural Gas Annual 2002 (*February 2004), and previous editions.

Table 2. Natural Gas Pipeline Projects Completed in 2003

Ending Region & State	Begins in State	-- Region	Pipeline/Project Name	FERC Docket Number	Greenfield (New) or Expansion Project	In Service Date	Estimated Cost ($Millions)	Miles	Additional Capacity (MMcf/d)
Central									
CO	CO	Central	CIG Valley Line II Expansion	CP03-7	Expansion	01-Dec-03	13	*	42
CO	CO	Central	CIG Valley Line III Expansion	CP03-7	Expansion	01-Dec-03	10	*	50
CO	CO	Central	NWPL Ridges Basin Dam Project	CP02-423	Expansion	15-Dec-03	17	7	0
CO	CO	Central	Questar Southern System Expansion	CP02-59	Expansion	11-Jan-03	4	*	90
IA	IA	Central	MidAmerican Des Moines Lateral	NA	Greenfield	01-Jun-03	2	13	175
MT	**AB**	**Canada**	**Regent Border Station**	**CP03-8**	**Greenfield**	**01-Sep-03**	**	**4**	**20**
MT	**AB**	**Canada**	**Sierra Border Station**	**CP01-461**	**Greenfield**	**04-Oct-03**	**	**2**	**24**
MT	WY	Central	Shoshone Pipeline	CP03-2	Greenfield	01-Oct-03	**	34	14
ND	WY	Central	WBP Grasslands Project I	CP02-37	Greenfield	01-Dec-03	58	253	80
WY	UT	Central	Questar Overthrust Tie Line 112	CP03-36	Expansion	06-Oct-03	13	17	217
WY	WY	Central	Pinedale/Jonah 2003 Expansion	NA	Expansion	01-Nov-03	65	80	300
WY	WY	Central	Questar Kern Expansion	CP02-124	Expansion	01-May-03	1	*	150
						Subtotal	**182**	**409**	**1,162**
Midwest									
MN	MN	Midwest	Hutchinson Pipeline Project	NA	Greenfield	01-Oct-03	27	89	60
MN	MN	Midwest	NNG Project MAX Expansion	CP02-436	Expansion	01-Nov-03	6	5	34
OH	OH	Midwest	NCGT Compression Addition	NA	Expansion	01-May-03	2	*	42
WI	WI	Midwest	We Ixonia Lateral	NA	Greenfield	01-Dec-03	97	35	515
						Subtotal	**132**	**129**	**651**
Northeast									
DE	PA	Northeast	Eastern Shore Natural System Expansion	CP03-80	Expansion	01-Nov-03	1	*	4
MA	MA	Northeast	Algonquin HubLine	CP01-5	Greenfield	24-Nov-03	127	29	295
MA	MA	Northeast	Maritimes & Northeast Phase III	CP01-4	Greenfield	24-Nov-03	134	25	230
NY	NY	Northeast	Niagara Mohawk Expansion	NA	Expansion	01-Nov-03	2	9	200
PA	PA	Northeast	CGT Rock Springs Expansion	CP02-142	Expansion	10-Dec-03	29	9	263
PA	PA	Northeast	DTI Ellisburg-Liedy Expansion	CP02-44	Expansion	15-Nov-02	10	*	127
PA	PA	Northeast	Tenneco Can-East/Leidy Expansion	CP02-46	Expansion	15-May-03	10	*	150
PA	NJ	Northeast	Transco Trenton-Woodbury Loop	CP02-204	Expansion	01-Nov-03	33	10	49
						Subtotal	**346**	**82**	**1,318**
Southeast									
AL	AL	Southeast	SONAT North System Expansion	CP01-161	Expansion	01-Nov-03	25	5	33
FL	AL	Southeast	FGT Phase VI Expansion	CP02-27	Expansion	01-Dec-03	105	33	121
FL	MS	Southeast	FGT Phase V Stage 4 Expansion	CP00-40	Expansion	01-May-03	132	136	130
GA	MS	Southeast	SONAT South Sys Expansion I Phase 2	CP00-233	Expansion	01-Jun-03	86	41	196
GA	**LA**	**Southwest**	**SONAT South System Expansion II Phase 1***	**CP02-1**	**Expansion**	**01-Oct-03**	**70**	**68**	**192**
MS	**AL**	**Southwest**	**SONAT South System Expansion II Phase 1A***	**CP02-1**	**Expansion**	**05-Nov-03**	**62**	**24**	**98**
NC	**VA**	**Northeast**	**ETenn Patriot Extension I**	**CP01-415**	**Expansion**	**19-Nov-03**	**225**	**95**	**315**
NC	**LA**	**Southwest**	**Transco Momentum Phase I**	**CP01-388**	**Expansion**	**01-May-03**	**164**	**42**	**262**
SC	GA	Southeast	SCANA Elba Island Connection	CP02-57	Greenfield	01-Oct-03	36	18	185
						Subtotal	**905**	**463**	**1,532**
Southwest									
GM	GM	Offshore	Okeanos Deepwater PL Phase I	NA	Greenfield	30-Nov-03	100	74	1,200
GM	GM	Offshore	Triton Pipeline System	NA	Greenfield	01-Oct-03	40	41	275
GM	GM	Offshore	WFS Canyon Chief Pipeline	NA	Greenfield	01-Jun-03	94	126	350
OK	OK	Southwest	CEGT Line ACT-9	CP03-6	Expansion	01-Sep-03	2	1	240
TX	TX	Southwest	CrossTex Denton Pipeline	NA	Greenfield	01-Nov-03	**	14	40
TX	TX	Southwest	KM (MidCon) Texas Pipeline Expansion	CP96-140	Expansion	20-Mar-03	32	9	375
						Subtotal	**268**	**264**	**2,480**
Western									
CA	**WY**	**Central**	**KRT Mainline 2003 System Expansion**	**CP01-422**	**Expansion**	**01-May-03**	**1,260**	**716**	**900**
CA	CA	Western	Wild Goose Storage Lateral	NA	Greenfield	20-Nov-03	20	25	700
NV	NV	Western	Paiute Carson Lateral Upgrade	CP03-31	Expansion	01-Nov-03	11	15	6
OR	**WY**	**Central**	**NWPL Rockies Expansion**	**CP01-438**	**Expansion**	**01-Nov-03**	**139**	**91**	**175**
OR	OR	Western	Northwest Natural Mist Storage Lateral	NA	Greenfield	12-Dec-03	19	12	320
WA	WA	Western	NWPL Evergreen Expansion	CP02-4	Expansion	09-Oct-03	241	26	268
						Subtotal	**1,693**	**885**	**2,368**
Canada									
QB	**NH**	**Northeast**	**Portland Natural Gas Transmission Export**	**CP96-248-011**	**Expansion**	**1-Nov-03**	**	*	**216**
						Subtotal	**0**	**0**	**216**
Mexico									
MX	**TX**	**Southwest**	**KM (MidCon) Texas Roma Export Station**	**CP96-583**	**Greenfield**	**20-Mar-03**	**1**	*	**375**
MX	**TX**	**Southwest**	**Tenneco South Texas Export**	**CP02-116**	**Greenfield**	**01-Jul-03**	**40**	**9**	**312**
MX	**TX**	**Southwest**	**West Texas Gas Export Expansion**	**CP02-382**	**Expansion**	**14-Feb-03**	**1**	**1**	**9**
						Subtotal	**41**	**11**	**696**
					Total		**3,564**	**2,243**	**10,423**

CEGT=CenterPoint Energy Gas Transmission Co, CIG = Colorado Interstate Pipeline Co, CGT = Columbia Gas Transmission Co, DTI = Dominion Transmission Co, ETenn = East Tennessee Natural Gas Co, FGT = Florida Gas Transmission Co, KM= Kinder Morgan Energy Corp, KRT = Kern River Gas Transmission Co, NCGT = North Coast Gas Transmission Co, NNG = Northern Natural Gas Co, NWPL = Northwest Pipeline Co, SONAT = Southern Natural Gas Co, Tenneco=Tennessee Gas Pipeline Co, Transco = Transcontinental Gas Pipeline Co, We = We Energy Co, WBP = Williston Basin Interstate Pipeline Co, WFS = Williams Field Services Co.

* Less than one mile of pipeline/looping or compression expansion only.

** Less than $1 million.

Note: MMcf/d = Million cubic feet per day. NA = Not applicable. Interregional projects are in **bold print**. Excludes projects on hold as of December 2003. In the table, a project that crosses interregional boundaries is included in the region in which it terminates. Offshore projects are included in the Southwest region.

Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Construction Database.

Nationally

At the close of 2003, the U.S. natural gas transportation network included more than 226 gas pipeline systems, more than 306,000 miles of pipeline, and more than 178 Bcf/d of gas transportation capacity.[5] During 2003, total U.S. gas pipeline system mileage increased by about 1 percent while overall system capacity increased by slightly more than 5 percent. There are currently approximately 400 underground gas storage sites located in the United States, operated by 127 companies (see Box, "Underground Storage Operations and Operator Types," p. 3).

After record additions in 2002, the installation of new natural gas pipeline capacity fell by 19 percent in 2003, while added mileage fell by 37 percent (Figures 1 and 2). Similarly, pipeline construction expenditures fell, although by a lesser rate of 18 percent.[6] In part, this decline reflected the fewer number of larger-scale pipeline projects (200 MMcf/d or greater) completed during 2003 (Table 2) compared with those completed in 2002 (21 versus 26), and fewer new laterals (7 versus 17) serving new power generation plants. At least 10 proposed new laterals or expansions to existing systems originally scheduled for 2003 were canceled or downsized because a planned gas-fired power plant was not completed on schedule or was canceled.

The basic profile of pipeline projects completed in 2003 also differed significantly from that in 2002. For instance, the average gas pipeline project completed in 2003 averaged 46 miles, compared with 66 miles per project in 2002, while the average capacity addition per project was 21 MMcf/d (6 percent) less in 2003 than in 2002 (213 versus 227 MMcf/d).

Interregional Developments

Of the 49 natural gas pipeline projects completed in 2003, 12 crossed regional boundaries. A major portion of the regional increase, 43 percent, occurred on interstate pipeline systems transporting gas from the Southwest region to the Southeast region (552 MMcf/d) and to Mexico (696 MMcf/d). Additions to interregional capacity in 2003 totaled 2,898 MMcf/d overall, an increase of 75 percent over the 2002 level, which was the smallest annual interregional increase in a decade. The largest amount of interregional transport capacity still remains with the 13 interstate pipeline systems transporting gas between the Southwest and the Southeast regions, 23,264 MMcf/d.

Pipeline Capacity Usage

A natural gas pipeline measures its capability to transport gas by its design capacity, that is, the peak volume of gas that it can deliver at several different levels over a specific period of time, usually a day. For instance, a systemwide design day deliverability volume, or how much gas a pipeline system can deliver to all its customers on its peak day, is its measure of overall service capacity. At the operational level, pipelines often will also include measures of peak (design) day volumes that can be transported through, or at, a specific point on its system, such as at a compressor station, along a specific pipeline segment, or received or delivered at a specific point on its system.

In this report the emphasis is upon new capacity added through pipeline construction, which is examined singularly by project (Table 2) and in the aggregate (Table 1). Pipeline project capacity additions can apply to (1) a completely new pipeline, in which case the added capacity will be equal to the systemwide capacity, (2) the expansion or addition of only a pipeline segment, or (3) upgrades to or addition of one or more compressor stations within a system.

Interregional capacity, shown on Figures 5, and 7 through 11, represents an EIA estimate of the design throughput capability of pipelines at regional border crossings. These estimates are based partially on "System Flow Diagrams" data (FERC Form 567) filed with the Federal Energy Regulatory Commission (FERC) by interstate pipeline companies, and partially on capacity additions from completion of construction projects. It provides an aggregate measure of the potential pipeline flow capability between regions and a view of how and where the interstate pipeline system has directed its growth.

Because the design and capacity of a specific pipeline or expansion project might not alter the overall capacity of the full pipeline system or cross regional boundaries, e.g., added capacity on a localized segment of a pipeline system, their respective additions would not necessarily affect the systemwide or interregional measures. Rather, their additional capacity is more specific and has impact on local production or the pipeline's ability to deliver gas for shippers.

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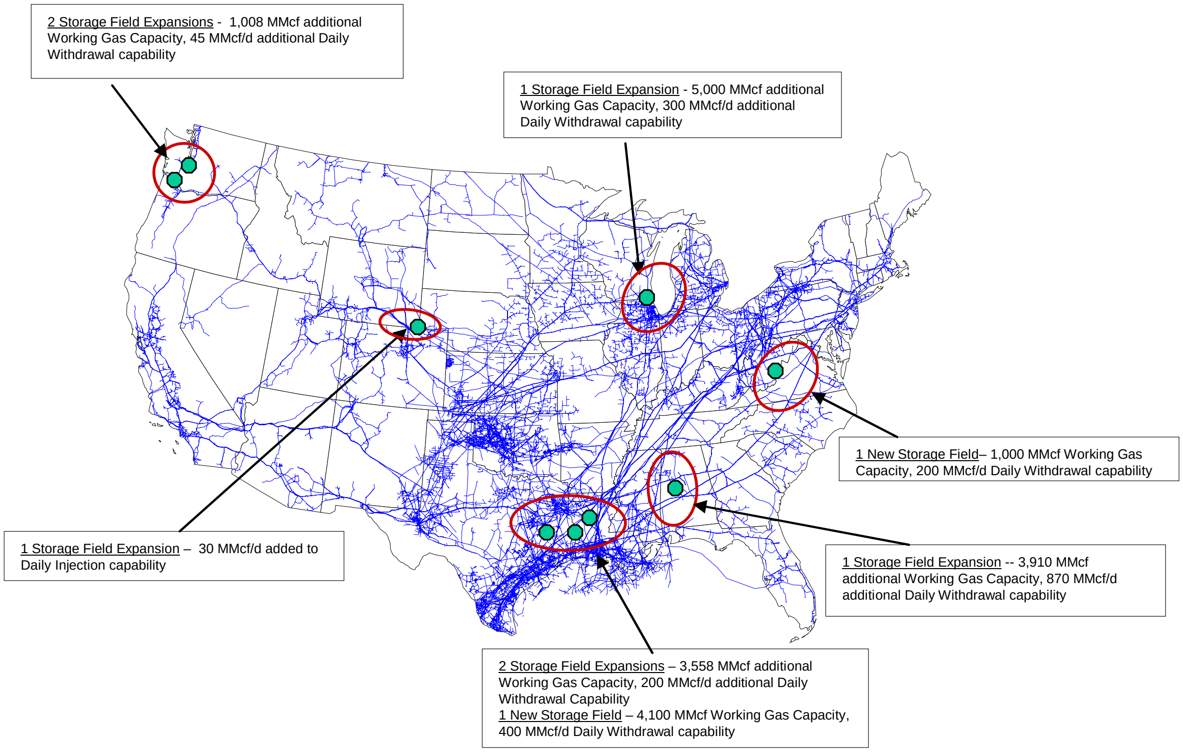
[5] Includes the large-diameter mainline portion of 97 interstate systems, 89 intrastate systems, and 40 gas gathering systems (about half offshore in the Gulf of Mexico). Source: Energy Information Administration, Office of Oil and Gas, U.S. Natural Gas Pipeline Profile Database.

[6] Energy Information Administration, *Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002*, May 2003, Table 1, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/ngpipenet03.pdf.

Figure 4. Areas with Major Underground Working Gas Storage Additions in 2003



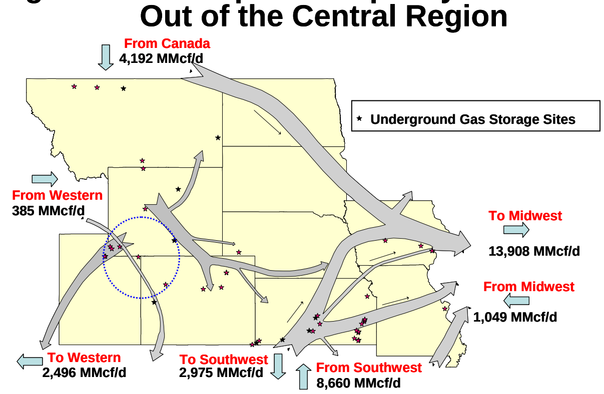
Note: MMcf/d = million cubic feet per day.
Source:Energy Information Administration, Office of Oil and Gas, Natural Gas Storage Projects Database.

Central Region

Gas pipeline capacity expansion in the Central region (Figure 5) in 2003 was primarily concentrated in Colorado and Wyoming, reflecting the continued expansion of conventional gas production in the western areas of these states and the ongoing development of coalbed methane in the Powder River Basin of northern Wyoming/southern Montana (Figure 6). Fully 81 percent of the 1,162 MMcf/d of new capacity added in the region came from 9 (of 12) projects completed, in part, or wholly within Wyoming and Colorado (Table 2).

Two of these projects represent new (often referred to as greenfield) pipelines designed to transport coalbed methane production from the Powder River area in northern Wyoming to delivery points in eastern Montana and North Dakota. The largest of the two, the Williston Basin Interstate Pipeline (WBP) Company's Grasslands Project,[7] was designed to transport up to 80 MMcf/d, in its initial phase, from Wyoming to an interconnection with the Northern Border Pipeline in western North Dakota (Figure 6). The Grasslands Pipeline provides gas shippers the opportunity to move Wyoming gas to the Midwest via an alternative to the Trailblazer Pipeline, which flows Wyoming production on a southern route to the Midwest. Subsequently, however, WBI was not able to find enough shipper support to justify developing additional capacity along the route and placed a planned Phase II on-hold in February 2004.

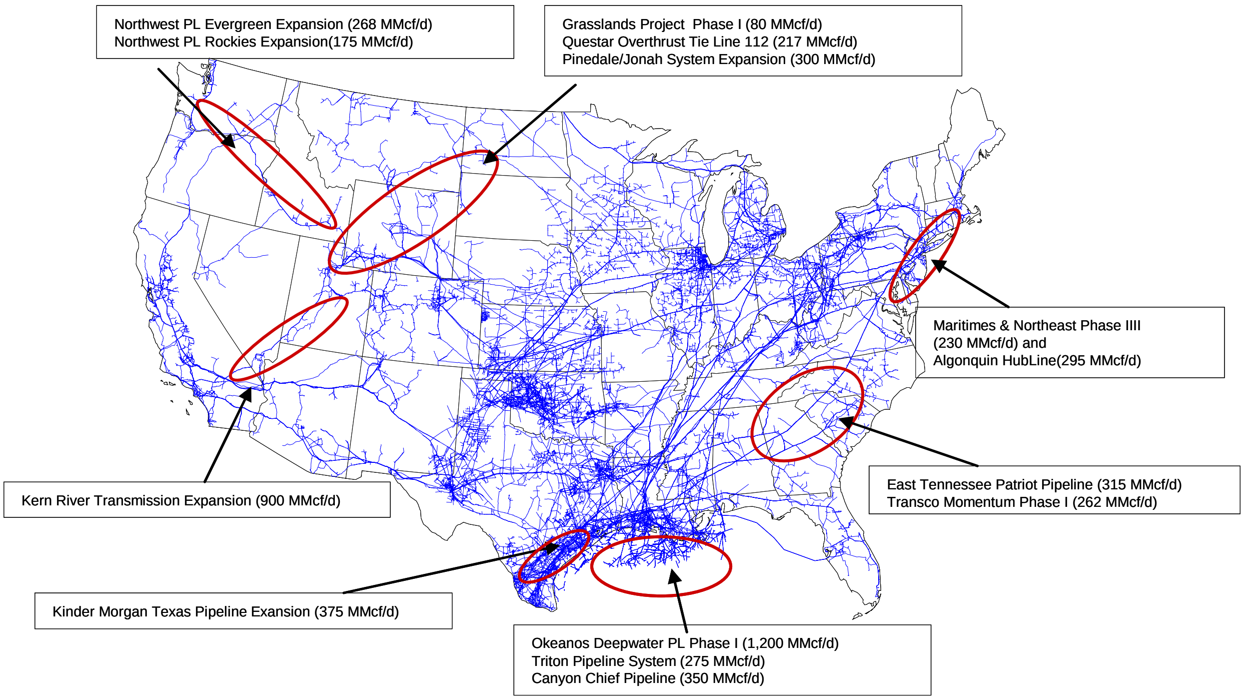
Figure 5. Gas Pipeline Capacity Into and Out of the Central Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity Database.

[7]The other was the Shoshone Pipeline, a short-distance (34 miles), small capacity (14 MMcf/d), unused oil pipeline converted to transport Wyoming gas to endusers in southeast Montana.

Figure 6. Areas with Major Natural Gas Pipeline Capacity Additions in 2003



Note: MMcf/d = million cubic feet per day.
Source:Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity and Construction Databases, as of December 2003.

The most active area within the Central region for gas pipeline development and expansion in 2003 included the adjoining southwest portion of Wyoming, northwestern Colorado, and northeastern Utah (Figure 5, Circle). During the year, the expanding production of the Jonah and Pinedale fields in southwest Wyoming was partially accommodated by the expansion of the Jonah Gas Gathering header system by 300 MMcf/d. This lateral expansion increased gas flows to the area's Opal gas processing plant and to interconnections with several interstate pipeline systems serving the area.

The Questar Pipeline, which is already widespread in this tri-state area, expanded its system by more than 450 MMcf/d in 2003, including the completion of a tie-line to transport Utah-produced gas to the Overthrust Pipeline in Wyoming for transshipment to markets in the Midwest and Central regions (Table 2). As part of this effort Questar completed a 150 MMcf/d supply lateral, which provided an additional interconnection to the expanded Kern River Gas Transmission Pipeline in western Wyoming.

The Kern River Transmission Pipeline, which begins in the Green River Basin of southwest Wyoming and terminates in California (Figure 6), increased its capacity by 900 MMcf/d (to 1,865 MMcf/d at its northern end). With the completion of this expansion in May 2003, the largest amount of new gas pipeline capacity in a decade was made available to Wyoming gas producers and rapidly relieved a capacity constraint situation that had built up over time as gas production rapidly expanded in the area. In fact, within days of placing the expansion in service, the Kern River Transmission Pipeline was reported as still operating at near full capacity.

The new capacity also had a dramatic effect on gas spot prices in the Rocky Mountain area.[8] After several years of relatively low prices because of insufficient interstate pipeline capacity exiting the Central region, particularly in Wyoming, prices rose rapidly. Between January 1 and April 30, 2003, spot prices in the Cheyenne/Opal area averaged about $2.21 less per MMBtu than prices at the Henry Hub. During the 4 months following the Kern expansion, the price differential narrowed to about 88 cents.

Market support upgrades in the region occurred primarily in the Denver, Colorado, metropolitan area with the Colorado Interstate Pipeline Company's (CIG) completion

[8]Intelligence Press Inc, *NGI Daily Price Index*, January 2003-August 2003.

of its Valley Line projects and the upgrade to its storage facilities located in the Denver area (Figure 4). The Valley Line projects upgraded compression and added looping,[9] allowing improved and expanded local service, while the storage upgrade enhanced the end-of-season injection capability in the service area. The upgrade increased storage flexibility and system responsiveness to changing summertime usage patterns, especially in major population areas.

Following several years of substantial capacity growth in the region, only six natural gas pipeline projects, representing less than 560 MMcf/d of new capacity, have been scheduled for completion during 2004 (Table 1). And, while eight gas pipeline projects, with a combined capacity of 3,970 MMcf/d, have been proposed for 2005, only three of these have gotten past the concept/planning stage. Only one of those, CIG's Cheyenne Plains Pipeline (560 MMcf/d initially), has been approved by regulatory authorities (as of May 2004).

Yet, several major energy companies believe that a large potential demand still exists for new pipeline capacity out of the Piceance Basin area of western Colorado to the Cheyenne Hub and beyond (to serve Midwest markets). In addition to the three projects for 2005 directed primarily at improving gas transportation between the Piceance Basin in northwestern Colorado and the Cheyenne Hub in northeastern Colorado, several projects (1,330 MMcf/d) have been announced for 2006-2008 that would extend from the vicinity of the Cheyenne Hub to markets in the Midwest. For instance, the Wyoming Interstate Gas, Kinder Morgan, EnCana, Questar, and TransColorado interstate pipeline companies have separate proposals to expand takeaway capacity from the Piceance Basin. All but TransColorado's project would terminate at the Cheyenne Hub.

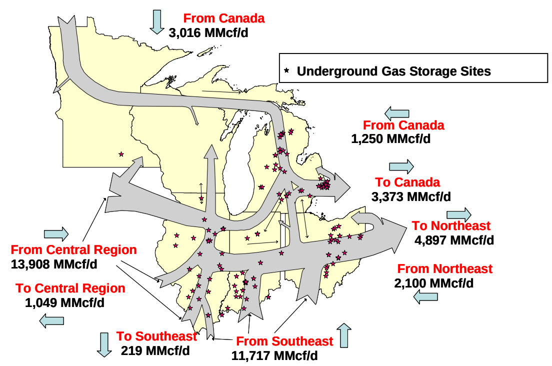
TransColorado's proposal is to expand capacity directed toward several new proposed pipelines and local markets in the Western region. Like CIG's approved Cheyenne Plains Pipeline project, Kinder Morgan Energy's Advantage and Wheatland Project proposals are predicated upon developing interconnections in the vicinity of an expanded Cheyenne Hub, and transporting that gas to Midwest markets. To some degree, the success of the Cheyenne-to-Midwest projects will depend upon the viability of the Piceance Basin expansions and whether the FERC believes there is going to be enough new take-away capacity from the general vicinity of the Cheyenne Hub when these projects are scheduled to be placed in service.

Most of the recent and proposed expansion of underground storage in the Central region has also targeted shippers that need to transport gas out of the expanding Powder River Basin.

Midwest

Only four gas pipeline projects, with a combined additional capacity of about 651 MMcf/d, were completed in the Midwest region (Table 2) in 2003, the lowest level since 1996. Moreover, none of these projects increased interstate natural gas pipeline capacity into and out of the Midwest region (Figure 7). In fact, only one of the four projects added any capacity to the interstate pipeline network, Northern Natural Gas Company's Project MAX, an expansion of 34 MMcf/d in Minnesota.

Figure 7. Gas Pipeline Capacity Into and Out of the Midwest Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity Database.

The only significant addition to gas pipeline capacity in the region in 2003 was the completion of the WeEnergy's 515 MMcf/d Ixonia lateral in southern Wisconsin. The 35-mile Ixonia lateral linked the Milwaukee metropolitan area to the Guardian Pipeline (750 MMcf/d, Chicago area to southern Wisconsin), which was completed in 2002.

Indeed, after the relatively heavy increases in gas pipeline capacity into and within the Midwest region over the past 10 years, gas pipeline expansion in the region appears to have leveled off, at least in the near term. To date (May 2004), only three proposed projects are scheduled for installation in 2004, four in 2005, and two in 2006. All are short-distance and/or small incremental capacity projects.

The extensive underground gas storage support found in the Midwest region was improved somewhat in 2003 with the 5 Bcf expansion of NICOR Gas' storage system located in northeast Illinois (Figure 4). Expansion of its storage infrastructure not only improved service to the

[9] Looping refers to the installation of another segment of pipeline parallel to an existing pipeline segment as a means of increasing overall pipeline capacity on part or all of an existing pipeline system.

NICOR system itself, it also indirectly supports NICOR's services provided at its Chicago Hub.[10]

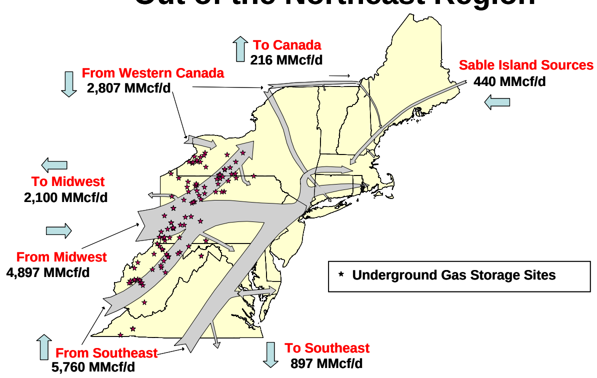
More significant increases in underground storage working gas capacity and deliverability are slated for 2004, with five new storage facilities scheduled for completion (Table 1). One, the Bluewater Pipeline's facilities, also includes the building of several short-distance laterals, which will interconnect with four nearby interstate and intrastate pipelines.

In contrast to the slow growth in the near term for pipelines, if all storage projects planned for 2004 in the Midwest region are completed as scheduled, working gas capacity will increase by 42.2 Bcf, more than in any of the other regions. Indeed, the increase will further extend the region's status as the location for the largest portion of U.S. underground storage capacity and deliverability, about 30 percent of the U.S. total.

Northeast

Eight pipeline projects were completed in the Northeast region in 2003 (Figure 8). The most notable installation of new gas pipeline capacity in the region occurred with the extension of service from Dracut, Massachusetts, to the Boston metropolitan area on the Maritimes & Northeast (M&N) Pipeline. Completion of the M&N Phase III extension provided shippers, for the first time, with the ability to transport up to 230 MMcf/d of Canadian Offshore (Sable Island) gas as far south as the Boston area (Table 2).

Figure 8. Gas Pipeline Capacity Into and Out of the Northeast Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity Database.

[10]Energy Information Administration, "Natural Gas Market Centers and Hubs: A 2003 Update" (Washington, DC, October 2003), Table 1.

An interconnection with the M&N Phase III project and Algonquin Gas Transmission Company's new Hub Line (295 MMcf/d), completed in tandem with the Phase III project, provides transport services into Boston proper. Both pipelines are owned in whole or in part by the Duke Energy Company. Since 2000, pipeline capacity into the Boston metropolitan area has increased by 12 percent.

The remaining 793 MMcf/d of gas pipeline capacity added in the Northeast region resulted from additions and expansions of existing pipeline systems, mostly concentrated in central and eastern Pennsylvania. Four of the largest interstate pipelines in the region (Columbia Gas Transmission Company (CGT), Dominion Transmission Company (DTI), Tennessee Gas Pipeline Company (Tenneco) and Transcontinental Gas Pipeline Company (Transco), each completed projects, although all involved relatively small mileage and capacity.

Two of the projects, in part, supported new electric power generation plants. The CGT Rock Springs project (263 MMcf/d) included replacement of an existing 9-mile pipeline segment with a larger diameter pipeline between southeastern Pennsylvania and a power plant located in northeastern Maryland. The Transco Trenton-Woodbury project, in addition to expanding the south New Jersey portion of the system by 49 MMcf/d, included building a 2.5 mile lateral to supply up to 21 MMcf/d to an electric power plant located across the state line in southeastern Pennsylvania. Completion of the DTI Ellisburg-Leidy (127 MMcf/d) and Tenneco Can-East/Leidy (150 MMcf/d) projects provided both pipelines with improved service capabilities on their respective systems in the vicinity of the Leidy Hub, which is located in northcentral Pennsylvania.

In the near term, estimated future increases in gas pipeline capacity in the Northeast region range between 0.86 and 2.3 Bcf/d per year. Several of the proposed expansions announced for 2004 through 2008, however, are uncertain with respect to their realization. For instance, the Duke Energy/KeySpan Islander East (250 MMcf/d) project, currently scheduled for completion in 2005, was stalled by the State of Connecticut in 2003 for environmental reasons and may yet be canceled. The fate of the Islander East also affects a proposed 2005 expansion of a section of the Algonquin Transmission Pipeline in Connecticut. Completion of the Algonquin expansion, which is designed to provide up to 280 MMcf/d of incremental capacity to support deliveries to the new Islander East Pipeline, is predicated upon the successful completion of that pipeline.

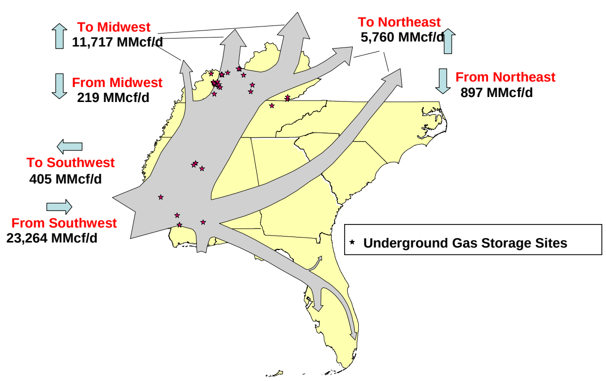
In another instance, the Millennium Pipeline project was originally scheduled to deliver up to 714 MMcf/d of Canadian gas to New York City by 2000, but it was halted by state officials because of the potential environmental impact of its Hudson River crossing. The Millennium project was split into two projects in February 2004. The project sponsor hopes that the phase 1 portion, which would serve the southeastern part of New York State and would not cross the Hudson, could be put in service by 2006. Meanwhile, the completion date for the second phase of the project has been left open-ended.

Nevertheless, even with the delays on such large projects, new gas pipeline capacity is being steadily added to the Northeast region’s pipeline grid. A substantial portion of the remaining scheduled incremental capacity (2004-2006) will come from projects designed to improve local service throughout the region. Of the 28 projects that could be completed (announced, under review, or approved) between 2004 and 2008, 18 involve less than 35 miles of pipeline construction. Only one underground gas storage project was completed in the region in 2003.

Southeast

Nine gas pipeline projects, totaling more than 1,500 MMcf/d of new gas pipeline capacity and terminating in the Southeast region (Figure 9), were completed in 2003. The largest was the 225-mile, 315-MMcf/d East Tennessee Patriot Pipeline project (Figure 6). Beginning in southwestern Virginia, where it interconnects with the East Tennessee Gas Pipeline and Saltville storage facility, the Patriot Pipeline provides gas transportation to points in the immediate Virginia area and extends into northwestern North Carolina, where it also interconnects with the Transcontinental Gas Pipeline. Patriot was completed despite the delay of one, and cancellation of another, gas-fired power plant along its route.

Figure 9. Gas Pipeline Capacity Into and Out of the Southeast Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas

One-third (519 MMcf/d) of the gas pipeline capacity added in the Southeast region in 2003 was installed on the Southern Natural Gas Pipeline (SONAT) in Alabama, Mississippi, and Georgia (Table 2) through four separate projects. The added capacity is the largest annual increase to the Southern Natural Gas Pipeline in the past 7 years and is in response to the growing demand for natural gas in the Southeast region. Southern Natural also plans on installing 138 MMcf/d of additional capacity on its system in 2004.

Also in 2003, Florida Gas Transmission Company (FGT) completed the final phase of a 4-year expansion strategy that saw its gas pipeline capacity into the State of Florida grow by 51 percent since 2000. Indeed, as gas demand increased rapidly along its service route, that is, between Mississippi and Florida, the FGT Pipeline has increased capacity by an additional 150 percent since 1990. In fact, gas pipeline capacity into Florida on the FGT Pipeline stood at only 820 MMcf/d in 1990, but had increased to 2,224 MMcf/d by the end of 2003.[11]

In the Southeast region’s midsection, Transcontinental Gas Pipeline Company’s Momentum project increased interstate pipeline service to South and North Carolina by 262 MMcf/d. The Momentum expansion is being constructed in two phases, increasing capacity on the Transcontinental Gas Pipeline in the region by a total of approximately 315 MMcf/d over 2 years. Phase two of the expansion, 53 MMcf/d, is scheduled to be ready for service by mid 2004. The original project design, however, was downsized in 2002 after two large potential customers canceled their commitment to the project. Nevertheless, increasing gas demand in the region is reflected in a more than 20-percent growth in pipeline capacity since 1996 on the portion of the Transcontinental Gas Pipeline traversing the region.

Commensurate with the reopening of the Elba Island LNG import facility in Georgia, the SCG Pipeline Company in early 2003 installed an 18.4-mile, 185-MMcf/d pipeline from an interconnection with Southern Natural Gas Company’s existing twin pipelines, which exit the Elba Island facility, to Port Wentworth, Georgia, in Chatham County. The SCG pipeline transports gas from the interconnection to an 875 MW electric power generating plant located in southeastern South Carolina. The SCG interconnection at Port Wentworth also provides the capability to receive up to 93 MMcf/d of system supply from Southern Natural’s Savannah Lateral in the event that Elba Island LNG supply becomes unavailable.

Looking to the future, 19 pipeline expansion projects have been proposed that could tentatively add as much as 11,840 MMcf/d to gas pipeline capacity into and within the Southeast region between 2004 and 2008. However, a large portion of this potential capacity represents volumes

[11] For 1990 pipeline capacity levels for 1990 see: Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, Appendix A, Table A4 (Washington, DC, May 1998).

from competing proposals for several large new pipelines and several major expansion projects that remain in the planning stage.

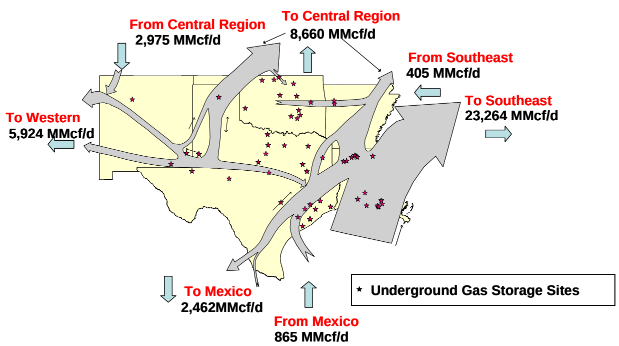
Several proposals, such as the AES Ocean Express Pipeline, the Tractebel Calypso Pipeline LLC, and the El Paso Seafarer Pipeline projects, represent separate 750-850 MMcf/d capacity pipelines that would extend between LNG vaporization facilities located in the Bahama Islands and south Florida. The likelihood that all three projects will be built is marginal. All are competing for similar markets and predicated upon the future development of new gas-fired power plants in south Florida. While the first two pipelines have been tentatively approved by FERC, the Seafarer pipeline application was not submitted to FERC until April 2004.[12]

As demand for natural gas in the region continues to grow, additional proposals for storage access and capacity also continue to grow. At least four storage-related pipeline expansion projects are currently active, two approved and two pending. Moreover, several high-deliverability (salt cavern) underground gas storage facilities are being built in the region to support the growing variable load needs of regional customers. Two of these proposed salt cavern facilities will interconnect with the interstate pipeline system via three 600 MMcf/d laterals.

Southwest and Gulf of Mexico

While only six pipeline projects were completed in the Southwest region (Figure 10) in 2003, the 2,480 MMcf/d of additional capacity was a substantial increase over the 882 MMcf/d installed in the region in 2002. The completion of three major deepwater offshore gas pipeline systems accounted for 74 percent of the region's added capacity (Table 2).

Figure 10. Gas Pipeline Capacity Into and Out of the Southwest Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity Database.

In 2003, only two interstate pipeline systems, Southern Natural Gas Company (SONAT) and Transcontinental Pipeline Company (Transco), had expansions that extended beyond the Southwest region (Table 2). Combined, they added 552 MMcf/d of capacity between the Southwest and Southeast regions. Otherwise, there has not been any significant increase in pipeline capacity on the other major interstate pipeline systems out of the Southwest in several years.

Among the newly completed offshore pipelines, the largest was the Okeanos Deepwater Pipeline (Phase 1), which consists of a 74-mile, 24-inch, 1,200 MMcf/d pipeline serving the NaKika field complex 150 miles southeast of New Orleans. In fact, it accounted for about half of the total capacity added in the Southwest region. The second phase, which will be completed in 2005, will consist of a 26-mile, 1,000 MMcf/d segment serving the Thunder Horse field.

The two other offshore pipeline completed in the region in 2003 were the Williams Field Services Company's Canyon Chief Pipeline (350 MMcf/d) and Shell's Triton Pipeline System (275 MMcf/d). The former, though completed in 2003, System was not placed in service until May 2004, when its gas source, the Devil's Tower production platform, was completed. It now transports gas from the deepwater Mississippi Canyon area to an interconnection with Transcontinental Gas Pipeline's Mobile Bay Lateral on the coast of Alabama. The Triton Pipeline System is a 275 MMcf/d, 41-mile gathering system extending from the deepwater Garden Banks area to an interconnection with the existing Stingray Pipeline.

Onshore, only three relatively small projects were completed in the Southwest region in 2003 (Table 2). Only the 9-mile, 375 MMcf/d extension of the KM Midcon Texas Pipeline, which provided southeast Texas gas shippers with additional pipeline access to Mexico, cost more than $1 million. The CenterPoint Energy Gas (CEGT) Transmission's Line ACT-9 project, however, did complete a link between it and the Ozark Gas Transmission Pipeline and subsequent service to a new gas-fired electric generation plant located in southeast Oklahoma. Lastly, completion of the CrossTex Denton Pipeline provided initial intrastate access to new gas production emanating from the Barnett Shale formation in the Denton county area of Northeast Texas.

Offshore pipeline development, primarily to serve new deepwater platforms, also predominates in the Southwest region for 2004. Indeed, more than 58 percent of the 2,999 MMcf/d capacity additions in the region (Table 1)

[12]In March 2004 the Environmental Protection Agency recommended that the sponsors consider that Ocean Express and Calypso projects be consolidated to some degree, to minimize the environmental impact of two projects.

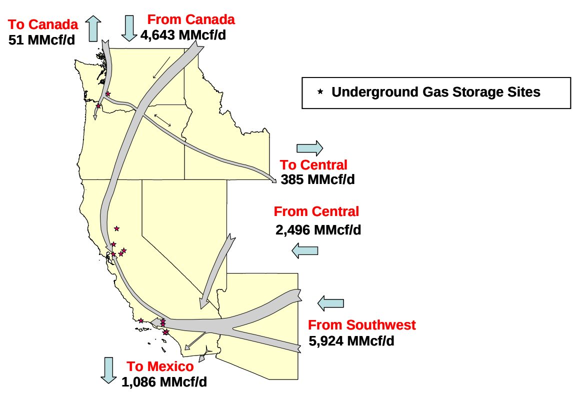
tentatively scheduled for 2004 completion will reside on four new systems to be constructed in the Gulf of Mexico. Beyond 2004, however, only 4 of the 13 proposed pipeline projects announced to date for the region represent offshore projects, 2 of which are tied in with proposed offshore LNG import facilities. Interestingly, 7 of 13 pipeline projects associated with proposed LNG import facilities, account for 83 percent of the 11,670 MMcf/d that has been proposed for development in the region between 2005 and 2007.

The largest amount of high-deliverability, salt cavern underground gas storage in the United States is located in the Southwest region, in Texas and Louisiana.[13] Salt cavern storage capacity in the region represents approximately 75 percent of total U.S. salt cavern gas storage capacity. Moreover, that is expected to grow substantially between 2004 and 2007, as at least 15 salt cavern gas storage projects (7 new, 8 expansions) have been proposed over the period. For 2004, three of the five proposed projects are expansions of salt cavern gas storage facilities (Table 1).

Western

In 2003, 2,368 MMcf/d of gas pipeline capacity (15 percent less than in 2002) was added in the Western region (Figure 11) with the completion of six gas pipeline projects (Table 2). Incremental pipeline capacity in the Western region accounted for about 23 percent of all gas pipeline capacity additions in the Lower 48 States in 2003. The largest contributor to regional capacity growth (and second largest in the United States) was the 900 MMcf/d Kern River Transmission Pipeline expansion that went into service in May 2003 between Wyoming and California. Completion of this project doubled previously existing capacity on the Kern River Transmission Pipeline, substantially enhancing deliverability to customers in southern California and the Las Vegas area in Nevada.

Figure 11. Gas Pipeline Capacity Into and Out of the Western Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity Database.

Northwest Pipeline Company, which is one of the major owners of interstate natural gas pipeline capacity in the Pacific Northwest, completed two key projects in 2003. Its two projects accounted for almost 20 percent of the incremental pipeline capacity added in the Western region during the year. The most significant project for the pipeline, its Rockies Expansion, eliminated bidirectional flow constraints that previously occurred on the system between Wyoming and Oregon when Wyoming spot gas prices fell below the price of imported gas at Sumas, Washington. When this happened, scheduled volumes flowing north through the Kemmerer station (located in southwest Wyoming) often exceeded physical and/or contractual displacement capacity availability. The Rockies expansion provides enough new physical capacity, 175 MMcf/d, to offset the need to contract for displacement volumes on the northern part of the system.

Although larger than the Rockies expansion, 268 MMcf/d versus 175 MMcf/d, Northwest's Evergreen expansion confined its improvements primarily to service within Washington State. The expansion provides additional natural gas to new gas-fired electric generation facilities in the state, with the installation of additional compression and almost 30 miles of mainline looping. The added compression will also reduce system reliance on displacement gas to accommodate flows from Stanfield, Oregon, north to Washougal, Washington, during peak periods.

Although the California energy crisis of 2000-2001 helped bring about major additions of gas pipeline capacity within, and into, the state in 2002, the current slate of pipeline proposals for the region still contains significant capacity additions directed toward the state. Indeed, almost one-half of the proposed additions to capacity announced for 2004-2007 (4,173 MMcf/d) are destined for the California market. A large portion of the remaining additions are slated for Arizona (29 percent), the rest for the States of Oregon and Washington (23 percent).

Half of the 12 gas pipeline projects proposed through 2007 are slated for completion in 2004. Of the remaining 6 projects, however, only 2 have been submitted to, or approved by regulatory authorities. The approved projects amount to only 1,203 MMcf/d of new gas pipeline capacity for the region through 2007, a relatively low figure compared with 2,368 MMcf/d installed in 2003.

Vying for an opportunity to enter the growing Arizona and California gas marketplaces, two major energy companies have proposed to develop new large-scale pipeline systems

[13] See Energy Information Administration, *Natural Gas Annual 2002,* Table 14 (Washington, DC, January 2004).

in the region by the end of 2006. Kinder Morgan's 525-mile Silver Canyon Pipeline would be able to transport up to 750 MMcf/d from the San Juan Basin located in northern New Mexico and southern Colorado, while the Pacific Texas Pipeline's 825-mile Picacho Pipeline would provide Permian Basin producers (in southwest Texas) the capability to transport 1,000 MMcf/d to the California border. While both sponsors are actively marketing their projects, they have not yet (May 2004) developed sufficient shipper commitments to support submission of a final project design to regulatory authorities for review and approval.

In fact, the 300-mile, 500 MMcf/d Coronado Pipeline, which would have extended from the San Juan Basin to the Phoenix/Tucson area of Arizona, could not garner sufficient shipper interest to further its cause. TransColorado Gas Pipeline Company also had proposed to extend its system from its terminus in the San Juan Basin to an interconnection with the Silver Canyon Project, which originally was planned to begin in northeast Arizona, but it too could not find enough potential shipper interest. Consequently, it canceled its proposed project, while the Silver Canyon Pipeline conceptual design was changed to incorporate the TransColorado proposed extension into its marketing strategy.

As gas pipeline capacity (service) demand in the Western region continues to expand, the need for underground storage facilities to provide supply backup and transportation customer support for this growth also is being addressed. In California, the expansion of the Wild Goose storage facility in early 2004 was preceded by the installation of a 25-mile, 700 MMcf/d pipeline that interconnects with Pacific Gas and Electric Company's mainline transmission system.

All of the increases to underground storage capacity and deliverability in 2003 in the Western region occurred in Washington State and Oregon, where an additional 1,008 MMcf of working gas capacity and 45 MMcf/d of deliverability were added at two sites (Figure 4). Both sites have been undergoing annual expansions since 1998 in response to a steady increase in demand for storage services. Moreover, working gas capacity increases of over 30 percent are also scheduled between 2004 and 2008. These increases in working gas capacity will provide vital system load support to the northern portion of the Northwest Pipeline system and access to storage services by Northwest's shipper/customers, and are critical to future expansions of the Northwest Pipeline system itself.

Also linked to these sites is the Northwest Natural Gas Company, the largest local natural gas distributor in the Oregon/Washington area. It needs the additional seasonal storage capacity to meet an expanding customer base. In conjunction with the expansion of these facilities, Northwest Natural Gas is also building a 61-mile pipeline extension (in two phases, 2004 and 2005) from one of the facilities, to provide expanded service to the south and west of the city of Portland, Oregon.

Import/Export Pipeline Capacity

Canada

Mexico

Growth in gas pipeline import capacity between the United States and Canada was practically nonexistent in 2003 as only 44 MMcf/d of new gas pipeline capacity was added.[14] Indeed, 2003 accounted for the smallest annual increase in Canadian import capacity since 1994 as only two small localized import points for natural gas were built between Alberta, Canada, and Montana (Table 2).

In contrast, export capacity to Canada and Mexico increased substantially. Export capacity to Canada increased by 216 MMcf/d, or about 6 percent, as the Portland Natural Gas Transportation System reconfigured its previously single-direction import system to a bidirectional system. Consequently, Canadian Sable Island (off the east coast of Canada) gas shippers now have the opportunity to redirect supplies off the Maritimes & Northeast Pipeline in Maine northwestward toward Quebec. Previously, Quebec only had access to western Canadian gas supplies, via the TransCanada Gas Pipeline.

Export capacity to Mexico increased by 696 MMcf/d in 2003 (Table 2), the second year in a row that export capacity grew by more than 25 percent. While in the late 1990's industrial gas users and new gas-fired power plants along the northern border area of Mexico supported most of the growth in export capacity, in recent years the demand for natural gas by local distribution companies in northern Mexico became a principal motivating force for developing additional export capacity.[15] Two of the three export projects completed in 2003 were, in part, directed to serving Mexican utilities in Reynosa and Monterrey, Mexico. No further expansion projects have been announced, or applied for, beyond 2004, other than a small (25 MMcf/d) export point scheduled for completion in

[14] Compare that to the 2.3 Bcf/d that came on line at the turn of the century. In 2000, the Alliance Pipeline System (1.7 Bcf/d) began service, while in 1999 the Maritimes & Northeast Pipeline (440 MMcf/d) and the Portland Natural Gas Transportation System (178 MMcf/d) began service.

[15] Since 1995, and the creation of the CRE (Comision Reguladora de Energia) in Mexico, the relaxation of gas regulations in the northern region of the country has stimulated the expanded development of local gas distribution companies in the country and altered their relationship with U.S. pipeline exporters and marketers.

Natural Gas Pipeline/Storage Project Development Process

After first detecting that enough potential need may exist in a particular area to support construction of new pipeline or storage capacity, the sponsors of the project, be it a new system or an expansion of an existing one, publicly announce their belief that a project of particular magnitude and location could be built if there is enough interest. To gauge the level of market interest, an **open season** is held (1 to 2 months), giving potential customers an opportunity to enter into a nonbinding commitment and sign on for a portion of potential capacity rights. If enough interest is shown during the open- season, the sponsors will arrive at a **preliminary project design** and move forward.

New or additional pipeline/storage capacity can be implemented in several ways. Project designers have various options open to them, each with particular physical and/or financial advantages and disadvantages. Some of the alternatives available for installing new pipeline capacity include building an entirely new line, conversion of an oil or product pipeline, or expansion or extension of an existing pipeline system. The least expensive option, often the quickest and easiest, and usually the one with the least impact environmentally, 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. New underground storage facilities, and sometimes the expansion of existing ones, also may require the designing and building of a pipeline lateral to and from the facility and an interconnection with a local major pipeline or local distribution company (LDC) mainline.

The **development of the final project design** and obtaining firm financial commitments from customers may take from 2 to 3 months, after which project specifications and environmental impact statement are filed with the appropriate regulatory agency. While there are no data available on the average length of time a project may require to receive a final determination from a State agency, generally a FERC review takes from 5 to 18 months. Usually, **approval by the regulating authority** is conditional, but most often the conditions are minor. Regardless, it is then up to the project sponsor to accept or reject the conditions or refile with an alternative plan. The Federal Energy Regulatory Commission (FERC) usually issues a certificate that is valid for 1 to 3 years, during which time construction on the project must begin. If it does not, the projects sponsors may request an extension of time, which is usually granted.

In most instances, **construction** typically is completed within 18 months following final regulatory approval, and at times in as little as 6 months for smaller projects. Sometimes construction of an approved project is delayed because of the extended time required to acquire local permits from the numerous towns and land use agencies located along the proposed construction route (Figure 12).

Commissioning and testing of the completed pipeline project usually takes about 1 to 3 weeks and involves subjecting the completed segments of the projects to hydrostatic and other required testing of the facilities in place. Line packing, or filling the line with the initial baseload gas volumes, is usually needed only on new pipelines or larger expansion projects. A new storage facility also requires the injection of needed base gas (to develop and maintain reservoir pressure) and initial customer storage gas before service can commence.

2004, which may indicate that demand for additional import capacity from the United States has peaked, at least temporarily.

Also, for the near term, it appears that the need for Canadian export capacity to the United States has reached an apex. To date, no new cross-border projects have been proposed for implementation through 2008. Of the several proposals that had been announced, all were subsequently put on hold or postponed. The 140 MMcf/d Sumas Energy 2 Pipeline project, intended to support a new gas-fired electric power plant in northern Washington, has been postponed indefinitely. In addition, a major expansion of the Maritimes & Northeast Pipeline, from Sable Island to the Northeastern United States, scheduled for 2005, has been put on hold pending future development (postponed) of gas fields located offshore eastern Canada.

A similar fate may also face El Paso Energy's Blue Atlantic subsea pipeline project, which is a 1,000 MMcf/d, 750-mile, 36-inch pipeline that would run from Nova Scotia to New York. Originally slated for 2005 service, and now tentatively scheduled for 2007, the project has yet to be filed with Canada's National Energy Board (NEB) or the U.S. FERC.

There are several possible reasons for the current absence of further Canadian gas import capacity development. For instance, it appears that in the areas of the United States served by imported Canadian gas, installed gas pipeline capacity has come into balance with demand. Also, in the opinion of various gas industry prognosticators,[16]

[16]Bank of Montreal Financial Group, *Sectoral Analysis*, *Review of Major Sectors, Oil & Ga*s, February 2003. Also, in early 2003 EnCana Corp. shelved its plans to develop its proposed 400 MMcf/d Deep Panuke

Canadian gas production and new development likely will stall over the next decade as less new gas resources are currently being discovered throughout Canada.[17] For example, offshore Sable Island (Scotian Shelf) development slowed in 2003. Ongoing exploratory studies have indicated that gas reserves in the area may be much less than previously estimated. Similarly, production in the Ladyfern area of northern Alberta and British Columbia, once considered a large potential source of long-term supply,[18] has declined much more rapidly than once predicted.[19]

Observations and Outlook

A large natural gas pipeline[20] or underground storage development project may take about 3 to 4 years from the time it is first announced until it is placed in service, or even longer if it encounters major environmental obstacles or public opposition. The life cycle for both pipeline and storage projects is long and complex (see Box, "Natural Gas Pipeline/Storage Project Development Process," p. 16) and includes numerous potential obstacles. Often the initial step, the "open season" process, is as far as a project progresses. Besides not enough market interest (demand) to justify proceeding to the planning stage, one of the major problems that has developed in recent years has been the more stringent credit/collateral approval requirements demanded of potential customers.

The recent financial difficulties of a number of companies in the energy industry and the overall slowdown in the economy have made it more difficult for sponsors to develop and maintain firm customer commitments for their projects. This situation has not only resulted in the cancellation of a number of announced projects, it has also caused significant delays in project timelines. In addition, creditworthiness problems continue to affect some projects during the latter stages of development, with some potential customers backing out as late as the construction phase of a project because of financial difficulties or even bankruptcy. Such actions by clients have resulted in the downsizing of some projects, often delaying the scheduled completion of the project or causing outright cancellation.

Several project sponsors have also cited the recent higher prices for steel pipe as a potential impediment to the successful development of their projects, especially those in the early planning stages. Since late 2003 steel pipe prices have increased by 20 to 40 percent,[21] depending upon the pipe diameter. The resulting increased costs on some marginal projects may necessitate a project design revision and/or delay, and in some cases, project termination. Compression-only expansion projects will be less affected by these cost increases. Even faced with such obstacles, however, a substantial number of pipeline and storage projects, with proposed in-service dates between 2004 and 2008, remain on the books.

The current inventory (May 2004) of pending gas pipeline projects consists of 122 natural gas pipeline expansion projects in various stages of development. For the same period, 73 underground storage projects have been announced, 15 of which are multi-phase projects applicable to single storage facilities.

Pipeline Development

Of the 38 pipeline projects proposed for construction in 2004, 33 have reached the final regulatory stage, that is, received approval to proceed with construction. As of May 2004, most of these are either under construction or already completed. Although the other five proposals are still under review by regulators, approval and construction are expected by the end of the year. The 38 projects represent 6,787 MMcf/d of additional pipeline capacity and about 1,033 miles of new pipeline or looping (Table 1), a substantial decline from that placed in service in 2003.

A key factor in the relatively low level of additional gas pipeline capacity in 2003 was the reduced demand for new pipelines and laterals to feed gas-fired electric generation plants. At least 10 pipeline projects, originally slated for development in 2003, were postponed or canceled because a planned power plant customer decided not to go forward with construction. And, although these cancellations appear to have reached a peak as the power generation market has stabilized, the 2005-2008 pipeline projects inventory contains many fewer pipeline projects linked directly to power plant development than in previous years.

project located under the Scotian Shelf after disappointing exploration in the area.

[17] A recent National Energy Board of Canada (NEB) assessment of potential gas reserves in Alberta Province, which accounts for more than 40 percent of Canadian natural gas reserves, indicates that in spite of very high drilling activity levels and the exploration success over the 10-year period from 1990 to 2000, the total resource base did not increase substantially in the region. See National Energy Board of Canada, *Canada's Conventional Natural Gas Resources, A Status Report: An Energy Market Assessment* (Calgary, Alberta Canada, April 2004).

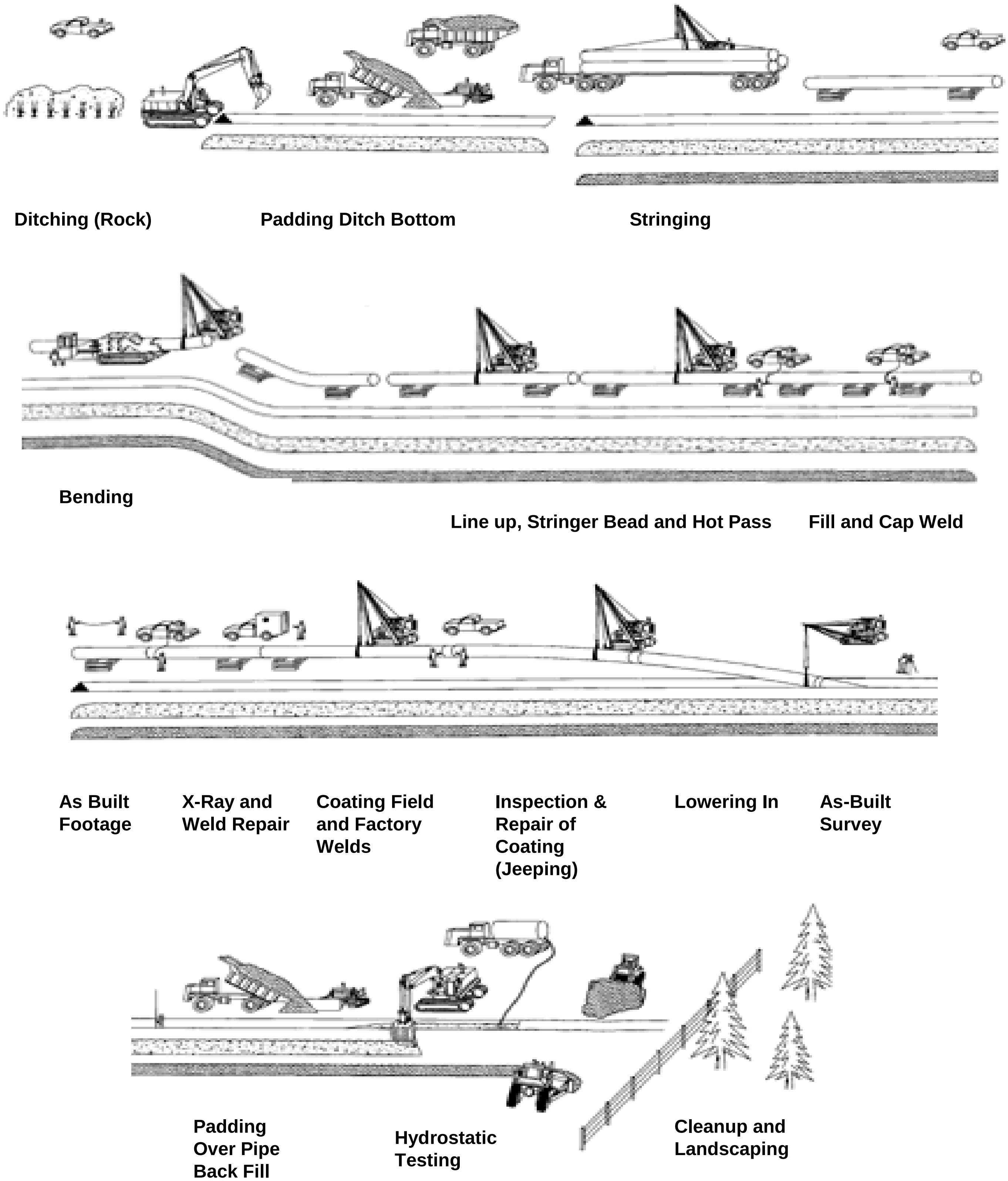
[18] *Oil and Gas Investor*, "Ladyfern," Chemical Week Publishing L.L.C. (June 2002).

[19] *Natural Gas Intelligence Press*, Daily Gas Price Index, "Analyst: Canadian Gas Exports to U.S. Could Fall 10% This Year" (November 10, 2003).

[20] Relatively small projects can be implemented under a "Blanket Certificate" authorization. A blanket certificate approves a series of similar actions in one authorization, provided the total cost does not exceed some threshold level and other eligibility criteria are met. In recent years, FERC has issued blanket certification to expedite and facilitate needed upgrades and minor expansion projects.

[21] Based upon informal price solicitation information provided by several pipeline project managers currently involved in pre-construction contracting, or preparing the design of proposed gas pipeline projects.

Figure 12. Typical Natural Gas Pipeline Construction Process



Source: Courtesy of Gulfstream Natural Gas System LLC

Underground Storage Development

For the period between 2004 and 2008, more than 73 underground natural gas storage projects have been proposed; 26 are new facilities and 47 are expansions to existing facilities.[22] These projects have the potential to add as much as 346 Bcf to existing working gas capacity and 17 Bcf/d to daily deliverability (withdrawal capability).

Continued emphasis on the development and expansion of high-deliverability, salt cavern storage is especially reflected in the inventory of proposed storage projects. Proposed salt cavern (31) storage projects represent 46 percent of all additional working gas capacity (158 Bcf) and 69 percent (11.5 Bcf/d) of additional deliverability which could be installed over the next 5 years. The rapid cycling capability of salt cavern storage, coupled with its ability to respond quickly to daily, even hourly, variations in customer needs, has made it very attractive to storage developers, whose profitability is often dependent upon their capability to maximize turnover volumes.

The attractiveness of high-deliverability storage is also reflected in the fact that horizontal well-drilling techniques have been increasingly incorporated into the development and expansion proposals for "depleted reservoir" storage sites. Horizontal drilling through a reservoir increases the exposure surface of the well bore, thus increasing the rate and the amount of gas that can be withdrawn from a well over a specific time period, i.e., higher deliverability rates.

High-deliverability storage sites have also become closely associated with, or become the reason for, many of the natural gas market centers and hubs located in the United States and Canada.[23] These storage sites can attract interconnections with many pipeline systems that find access to high-deliverability storage beneficial to them and their shipper/customers. They are especially useful for the temporary storage of shipper gas that is not immediately marketable, and/or as a tool for mitigating transportation imbalance situations.

Storage operators in particular are finding that in today's marketplace the one factor that is having the greatest impact on their project plans is the credit/collateral issue. Several storage project sponsors have reported that the original time schedule for their project has been delayed by a year or more as a result of having to reinitiate their marketing efforts because one or more potential customers dropped out for financial reasons or were unable or unwilling to enter into a long-term contract owing to more stringent credit tests or collateral requirements.

Conclusion

Overall, the U.S. gas transportation network continued to grow in 2003, although at a slower pace than in 2002. Pipeline additions were 19 percent less than in 2002 and storage additions were 27 percent less than 2002 levels. Still, at least 49 pipeline projects and 9 storage projects were completed during the year, adding 10 Bcf/d of pipeline capacity and 19 Bcf of underground gas storage working gas capacity. Another 38 pipeline projects are expected to be completed in 2004, adding 6,787 MMcf/d of capacity and about 1,033 miles of pipe, substantially less than placed in service in 2003 and 2002.

The current slowdown in capacity development can be attributed in part to customer creditworthiness issues, increasing prices for steel pipe, and a slowdown in the development of gas-fired power generation plants. To what degree these factors will influence the current inventory of proposed gas pipeline and underground storage is difficult to foretell. Certainly, they will have a depressing effect on short-term pipeline and storage development in the United States. But their full impact will depend upon how well gas market participants adapt to the changed business environment, and whether higher material costs are temporary or permanent, and, if they are permanent, can they be absorbed without a major negative impact on new pipeline and storage development.

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[22]Beyond 2004, 17 storage projects have a tentative 2005 completion year; for 2006, it is 18 storage projects; for 2007, 8 storage, and 2008, 4 storage projects (4/04).

[23] See Energy Information Administration, "Natural Gas Market Centers and Hubs: A 2003 Update," October 2003 (Washington, DC, October 2003).