NATURAL GAS COMPRESSORS AND PROCESSORS – OVERVIEW AND POTENTIAL IMPACT ON POWER SYSTEM RELIABILITY

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Disclaimer

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ACRONYMS AND ABBREVIATIONS

Bcf	Billion cubic feet
Bscf	Billion standard cubic feet
Btu	British thermal unit
CC	Combined cycle
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
ESPA	Energy Sector Planning and Analysis
ft/sec	Feet per second
GE	General Electric
H_2O	Water
H_2S	Hydrogen sulfide
HHV	Higher heating value
hp	Horsepower
hr	Hour
HRSG	Heat recovery steam generators
kWh	Kilo-watt hour (electric)
lb/ft	Pound per foot
LDC	Local distribution company
MAOP	Maximum Allowable Operating Pressure
Mcf	Thousand cubic feet
MESA	Mission Execution and Strategic Analysis
MHI	Mitsubishi Heavy Industries
MMBtu	Million British thermal units
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MPa	Megapascal
MW	Mega-watt (electric)
MWh	Mega-watt hour (electric)
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
PHMSA	Pipeline and Hazardous Materials Safety Administration
psi	Pounds per square inch
psig	Pounds per square inch gauge
SC	Simple cycle
SCADA	Supervisory control and data acquisition
STG	Steam turbine generator
U.S.	United States

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EXECUTIVE SUMMARY

Natural gas compressor stations and processing plants are critical components of the natural gas transmission network. Gas compressor stations are located periodically along the transmission pipeline to boost the pressure of the gas to make up for lost pressure due to pipeline friction and changes in pipeline elevation. Processing plants act in the recovery/fractionation of natural gas liquids (NGLs) (e.g., ethane, propane, butane), and remove contaminants (e.g., H_2S, CO_2, H_2O, etc.) from the produced natural gas at or near the wellpad, and at multiple points along the supply chain. This report evaluates the impact natural gas transmission compressors and processing plants have on the natural gas system in terms of its ability to supply sufficient natural gas for electrical generation.

ABB Velocity Suite lists 2,304 compressor stations and 717 natural gas processing plants in the United States; however, only 1,197 of the compressor stations in the database have detailed information. Of those, over 79 percent (1,007) of the compressor stations report having more than one compressor unit, while only 6.5 percent (83) of stations report having more than 10 units. Most compressor stations typically have total installed power of several thousand horsepower (hp), while 15.7 percent (206) of stations report having over 30,000 hp.

Compression and processing stations are typically automated and are serviced by regional technicians who travel between stations performing periodic and corrective maintenance. Equipment in the stations is protected from major damage by sensors that detect abnormal conditions and control systems that can automatically shut down equipment when preset limits are exceeded.

An analysis of the potential impact of a compressor station failure on an electrical generating plant was evaluated using a simplified model of a transmission pipeline. In this model, it was assumed that the compression station provided a 250 pounds per square inch gauge (psig) boost (the average boost pressure reported by the Energy Information Administration (EIA)) to a natural gas transmission pipeline carrying 800 million standard cubic feet (MMscf) of gas. [1]

The analysis showed that for most power plants, this pressure drop would not affect operations. For power plants using more modern, fuel efficient gas turbines that require higher fuel injection pressures[a], operations may be affected if the turbine does not have an integrated fuel boost pump. Analysis showed that there is sufficient latent pressure and gas volume in a large transmission pipe to support operation of most gas-fired

[a] Older conventional gas turbines require inlet gas pressures between 250 – 300 psig, newer industrial gas turbines require 500 – 600 psig, while the latest aeroderivative types require pressures as high as 700 – 1,000 psig. [11]

power plants with fuel boost pumps for several hours in the event of a complete transmission pipeline shutdown.

If a single compressor at a station unexpectedly shuts down, the system is typically unaffected because most stations have multiple backup compressors. The total flow through the station may be reduced by an amount equivalent to the capacity of that compressor if a single compressor is lost and no backup compressor is available. If an entire compressor station becomes incapacitated, the transmission pipeline may experience a pressure drop along the line until the next compressor station. However, the natural gas transmission system network also provides multiple delivery paths to ensure gas delivery to the end customer.

Overall, the natural gas transmission system is very robust. Individual compressor stations are designed with multiple redundant systems and the integrated pipeline system typically provides multiple redundant pathways for delivery. The more likely scenario causing electrical generation to be curtailed would be an extended duration failure (in excess of several hours depending on pipeline size) during an extremely high demand period at a location with limited supply and/or pipeline infrastructure.

1 INTRODUCTION

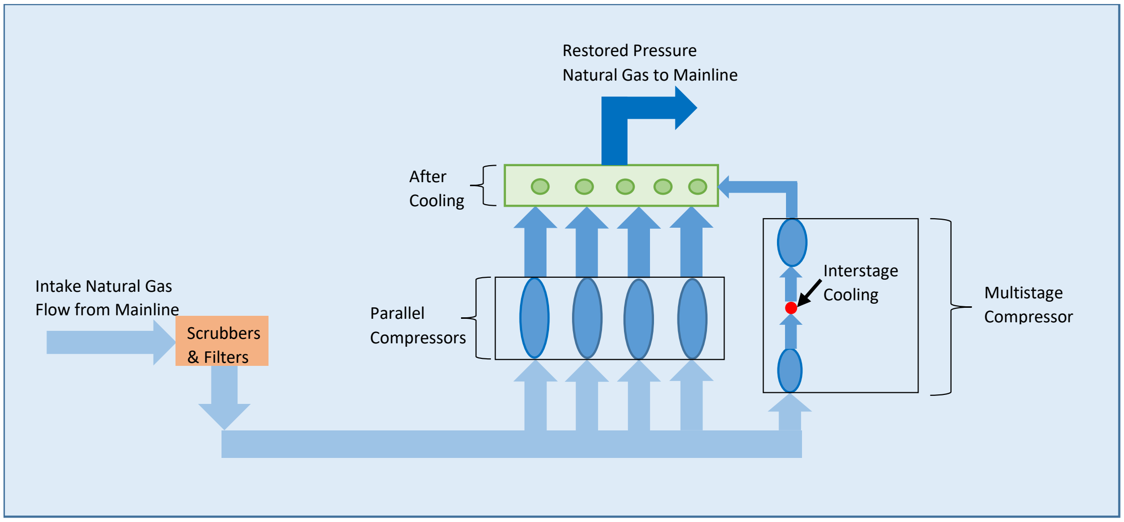
Natural gas compressor stations and processing plants are an important part of the natural gas transmission network. Compressor stations along a mainline natural gas transmission pipeline are used to boost the pressure of the gas as it travels down the pipe. Typically, these compressors are either centrifugal or piston types and can be rated at over 1,000 horsepower (hp). These compressors use natural gas-fired engines/turbines or electric motors for power. Compressor stations typically have more than one compressor with some stations having between 10 and 16 units with a total rating between 50,000 and 80,000 hp and have a throughput of over 3 billion standard cubic feet (Bscf) per day. [1]

Processing plants allow the natural gas transmission grid to provide pipeline-quality dry natural gas. These plants house processes to remove oil, water, natural gas liquids (NGLs), and other impurities such as sulfur, helium, nitrogen, hydrogen sulfide, and carbon dioxide from gas out of a wellhead or from storage. [2]

2 NATURAL GAS TRANSMISSION COMPRESSORS AND PROCESSING FACILITIES

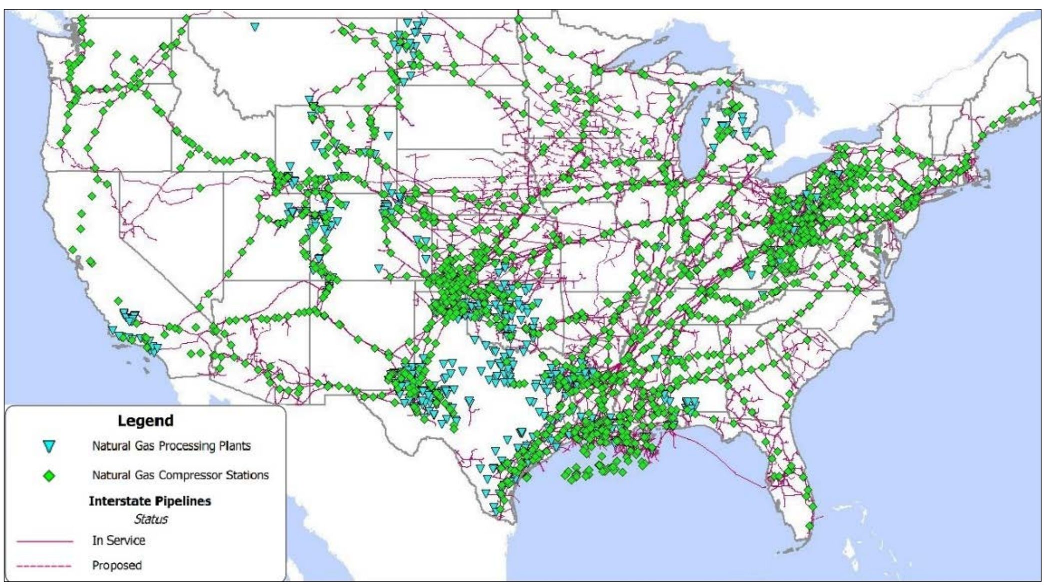
Compressors increase the pressure in a natural gas transmission pipeline system to maintain pipeline pressure, compensating for pressure lost due to pipeline friction and changes in pipeline elevation. Exhibit 2-1 shows a simplified schematic of compressor station configurations. Most stations are configured with a series of compressors operating in parallel. The compressors can be single stage or multistage depending on the desired pressure boost and flowrate. Exhibit 2-2 shows the location of compressor stations and processing plants in the continental United States, as well as the interstate pipeline system in those states. Exhibit 2-3 shows the breakdown of compressor stations and processing plants by state. ABB Velocity Suite lists 2,304 compressor stations, and 717 processing plants. [3]

Exhibit 2-1 Schematic of natural gas compressor station



Source: EIA [4]

Exhibit 2-2 Compressor stations and processing plants on interstate pipelines [3]



As can be seen in Exhibit 2-2, there are clusters of compressor stations near the gas producing regions of the Gulf Coast, Oklahoma, West Texas, and the Marcellus shale gas region of Ohio, Pennsylvania, and West Virginia.

Exhibit 2-3 Compressor stations and processing plants by state [3]

State	Compressor Stations	Processing Plants	State	Compressor Stations	Processing Plants
Texas	231	200	Michigan	28	14
Louisiana	184	57	Oregon	27	0

State	Compressor Stations	Processing Plants	State	Compressor Stations	Processing Plants
Pennsylvania	169	12	Utah	26	0
Kansas	161	8	Virginia	25	0
Oklahoma	139	80	Indiana	24	0
West Virginia	127	17	Nebraska	20	0
Wyoming	104	37	North Dakota	20	0
Colorado	99	51	New Jersey	17	0
Washington	87	0	Florida	16	0
Ohio	67	7	Missouri	16	0
Mississippi	62	6	Georgia	15	0
New Mexico	50	30	Wisconsin	11	0
Idaho	46	0	Massachusetts	8	0
Tennessee	46	1	Maine	7	0
Kentucky	39	3	South Dakota	7	0
Illinois	38	2	Connecticut	6	0
New York	38	0	South Carolina	6	0
Alabama	35	15	North Carolina	5	0
Iowa	33	0	Maryland	4	0
Montana	33	0	Nevada	3	0
Arkansas	32	2	Various States	3	0
Arizona	32	0	Rhode Island	2	0
Minnesota	32	0	Total	**2,304**	**567**
California	28	25			

2.1 Typical Size and Capacity of Compressors and Processors

Most compressor stations have multiple compressor units to provide the necessary redundancy and capacity to support the natural gas transmission pipeline system. Some stations have 10 or more compressor units, with some stations totaling over 30,000 hp. Exhibit 2-4 shows compressor station details by state, including station horsepower and number of units. The exhibit shows a high average number of units at a station in the mid-west and lower mid-Atlantic areas. Areas with a higher average horsepower seem correlated to areas with fewer compressor stations, as shown in Exhibit 2-5. Exhibit 2-6 shows the breakdown of compressor units at stations reported by Velocity Suite. Approximately 20.8 percent (264) of the 1,271 stations in the database reported having only 1 compressor at the station, while 6.5 percent (83) of stations reported having 10 or more compressor units. [3]

Exhibit 2-4 Compressor station details

State	Compressor Stations	Average Number of Units	Average Certificated Horsepower	State	Compressor Stations	Average Number of Units	Average Certificated Horsepower
AL	35	5	15,079	NE	20	3	12,696
CA	28	3	12,240	NY	38	2	20,620
CO	99	3	12,144	OK	139	4	9,187
CT	6	2	16,697	OR	27	2	39,722
FL	16	3	62,296	PA	169	3	3,647
KS	161	4	5,853	SC	6	11	8,925
KY	39	4	10,820	TX	231	5	20,028
MA	8	3	29,546	UT	26	3	13,380
MD	4	3	13,250	VA	25	3	7,613
MI	28	2	29,366	WV	127	3	7,251
ND	20	3	4,082				

Exhibit 2-5 Compressor stations and average horsepower

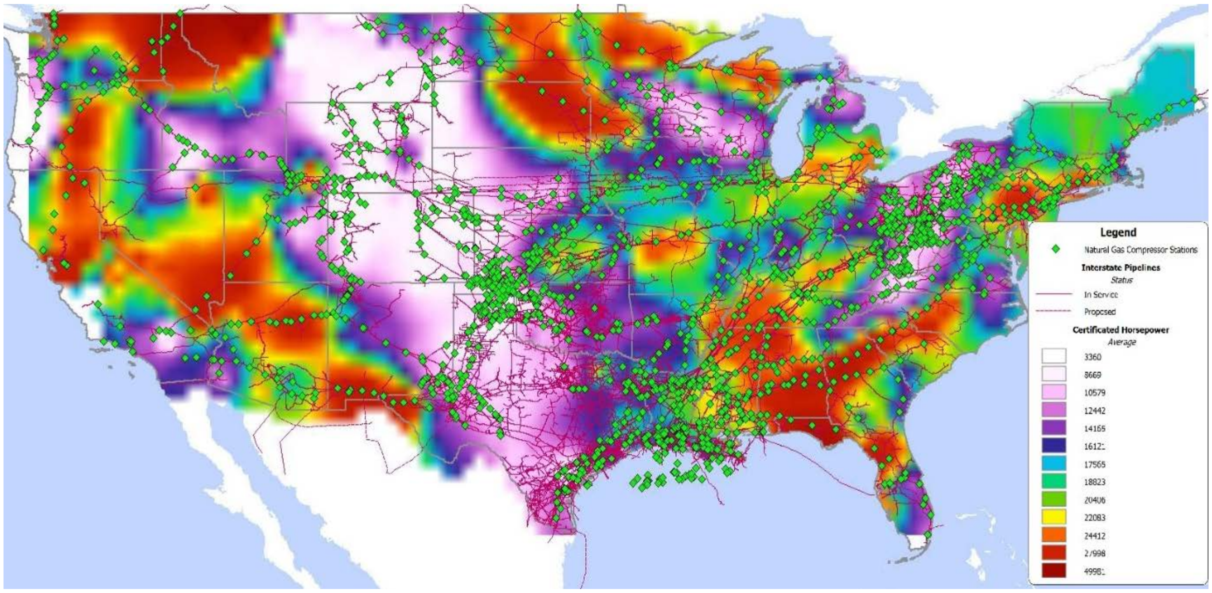


Exhibit 2-6 Number of compressors at each station

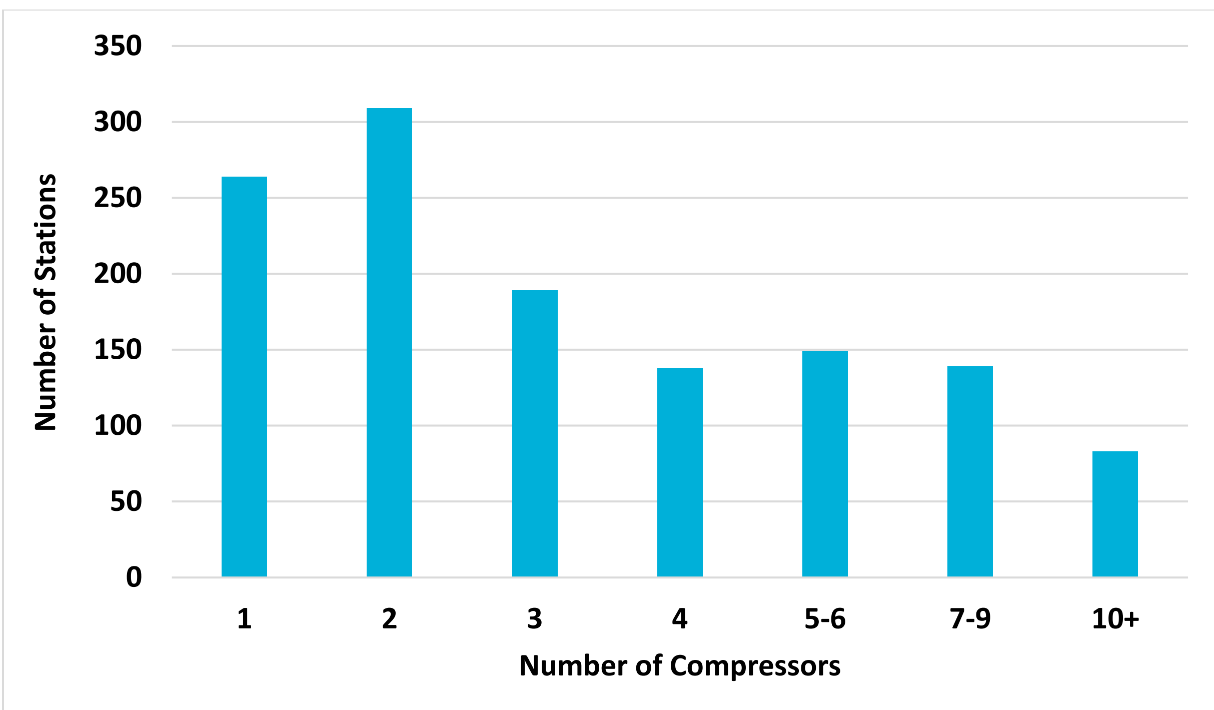
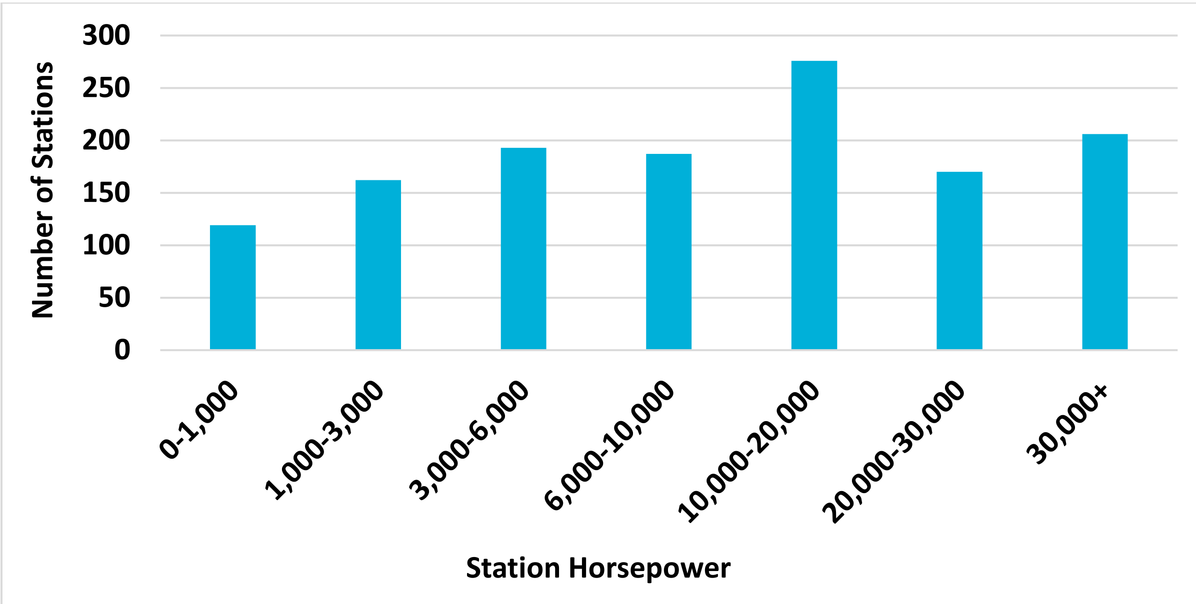


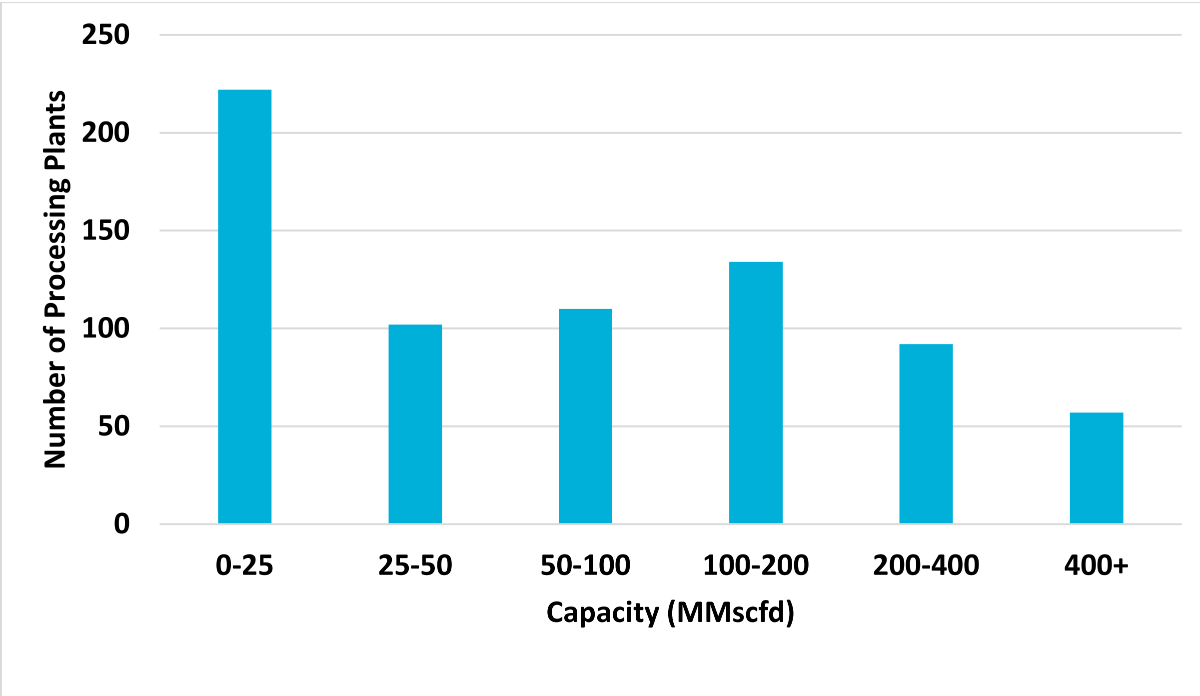
Exhibit 2-7 shows the total compressor station horsepower. This data is per station, so a station with several compressor units will likely report a higher total station horsepower than a station with only one unit. The highest percentage, 276 stations (21 percent), falls into the 10,000 to 20,000 hp range, with 206 (16 percent) units reporting 30,000 hp or more. The highest hp compressor stations correlate to areas with greater distances between stations. [3]

Exhibit 2-7 Natural gas station horsepower



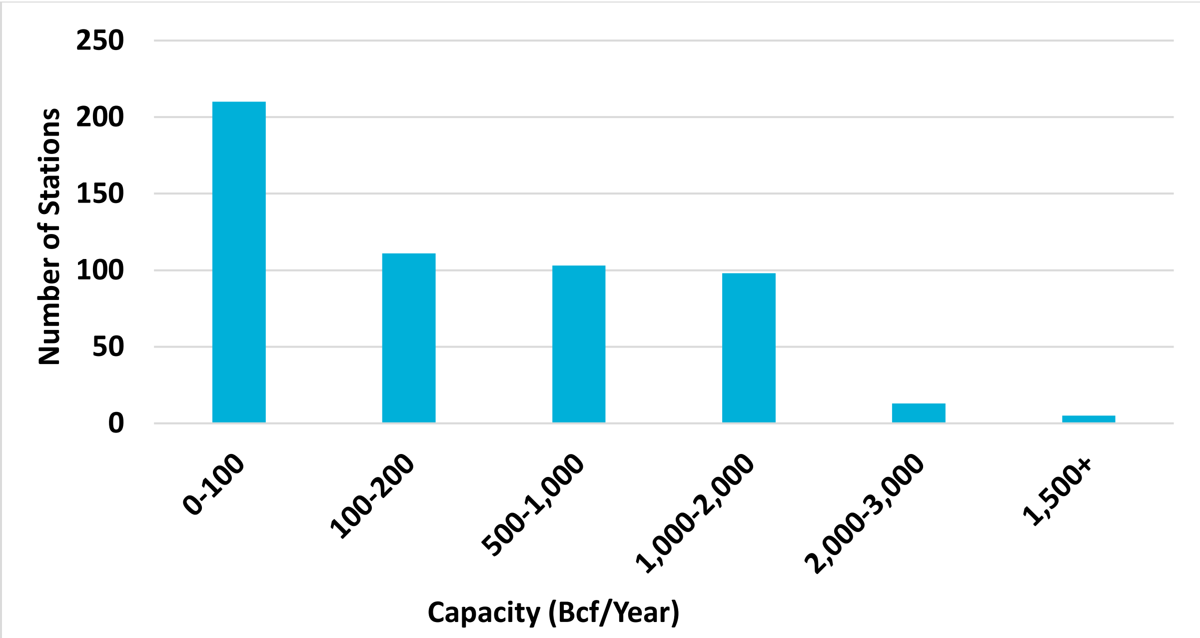
Velocity Suite provides detailed data on processing plants. Exhibit 2-8 shows the processing capacity in million standard cubic feet per day (MMscfd) for the 717 processing plants reported. Approximately 31 percent (222) of those plants process between 0 and 25 MMscfd, while 57 produce 400 or more. [3]

Exhibit 2-8 Processing plant capacity



The operational capacity data set in Velocity Suite provides capacity data for processors and compressors in 2016. For the year 2016, 540 of the 2,304 compressor stations have detailed operational capacity data. Exhibit 2-9 shows how many stations fall into each capacity interval. A total of 210 of the reported units (39 percent) have a less than a 100 billion cubic feet (Bcf) annual capacity, with only 5 having a capacity of over 1,500 Bcf per year. [3]

Exhibit 2-9 Capacity breakdown for compressors [3]

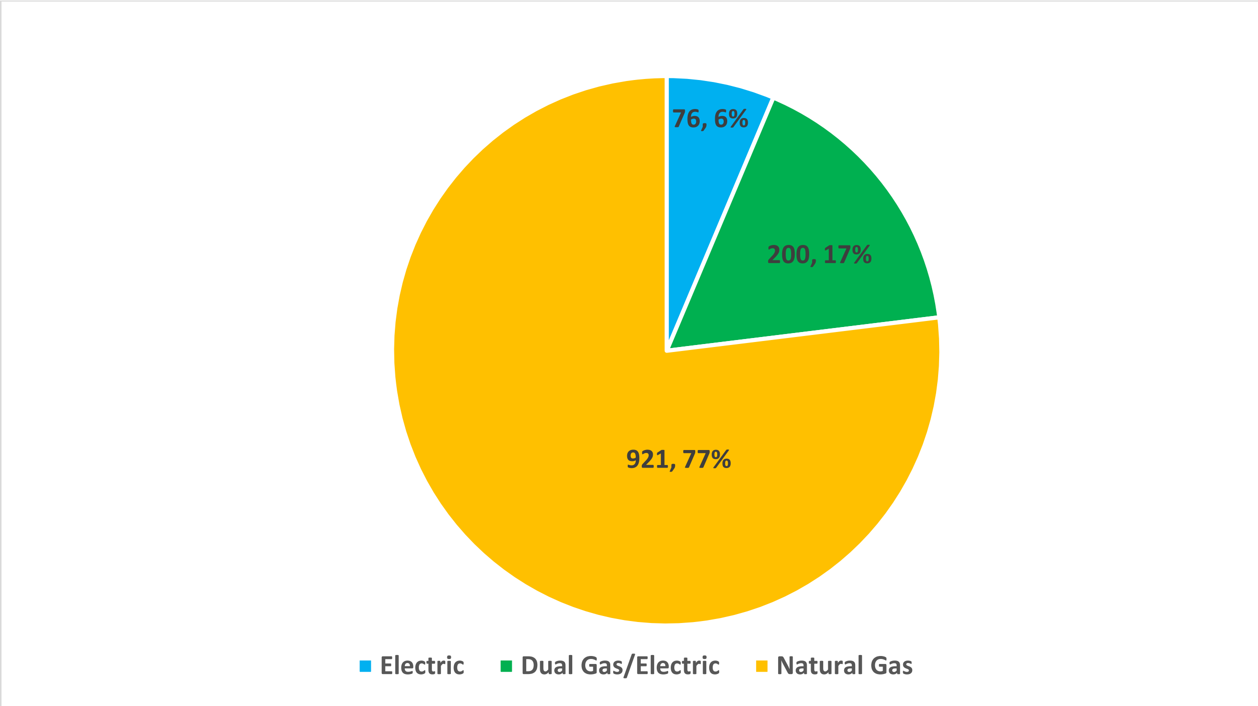


The data provided by Velocity Suite shows that while there are large processing plants, and compressor stations with many units, horsepower, and capacity, there are many smaller processing plants and compressor stations with only 1 unit and a smaller capacity.

2.2 Configurations of Compressor and Processor Power Sources

Compressor stations on the interstate pipeline system are typically spaced every 50 – 100 miles, to maintain adequate pressure on the pipeline network. [4] These compressor stations may be configured to be powered by natural gas and/or electricity. Exhibit 2-10 shows the breakdown of these power sources for compressor stations as reported by Velocity Suite. Seventy-seven percent of compressors stations are powered solely by natural gas; 6 percent are powered solely by electricity; and 17 percent are capable of dual power operation on natural gas and/or electricity. Compressor station operational demand varies, averaging 119,500 thousand cubic feet (Mcf)/mega-watt hour (MWh) for electric compressor stations. Some compressor stations near suburban areas are operated on electricity due to convenience or pollution concerns.

Exhibit 2-10 Compressor stations by fuel type [3]



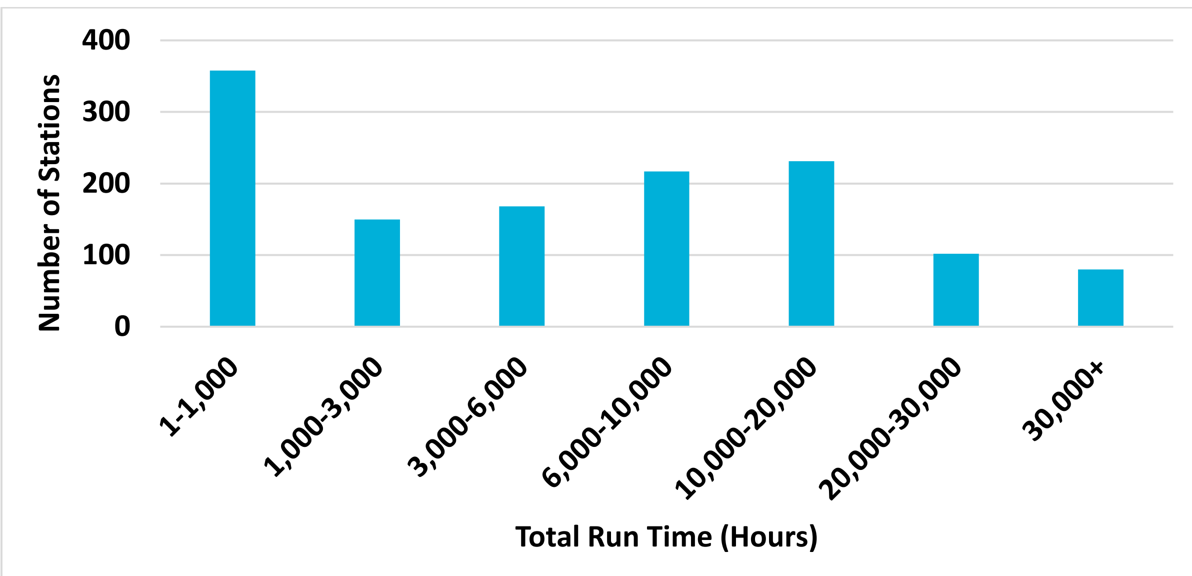
For the most part, natural gas processing plants are heavily reliant on the power system for operation. Not all plants are fully reliant upon the grid, with some plants utilizing process gases and low pressure gas turbines as a means of self-supplying power, this is particularly true with plants that are removing large quantities of flammable contaminants from the gas stream. [5]

3 COMPRESSORS/PROCESSORS OPERATION

3.1 OPERATIONAL TIME

Most compressor stations are designed for continuous operation to maintain pipeline pressure and flow volumes to customers. Exhibit 3-1 shows compressor operation hours reported on FERC Form 2 and aggregated in Velocity Suite. Operational hours are summed per unit, and added for the station total. Therefore, a station with 5 compressors can report 17,000 hours, and have compressors operating at different levels of utilization, while a station with only one unit can report 8,200 hours, and be running nearly full time. If running full time, for one year, a compressor station would report 8,760 hours, not accounting for downtime for any reason. The breakdown in Exhibit 3-1 shows that there are some stations that are not running full time. There could be multiple reasons for this observation, such as spare compression capacity, low demand periods, or maintenance operations; however, the run time data is insufficient to provide those answers. [3]

Exhibit 3-1 Compressor station run time in 2016 [3]



The capacity utilization reported in Velocity Suite for compressor stations and processing plants is shown in Exhibit 3-2 and Exhibit 3-3. Most of these units are not at capacity, with the largest percentage being in the 0 – 20 range. For both compressors and processors, this data is calculated as the fraction of the scheduled throughput for the year divided by the reported annual operating capacity. For compressor stations, this fraction likely reflects installed compressor units not being utilized at maximum flow capacity. For processing plants, capacity utilization depends on plant design capacity and wellhead production.

Exhibit 3-2 Capacity utilization of processors [3]

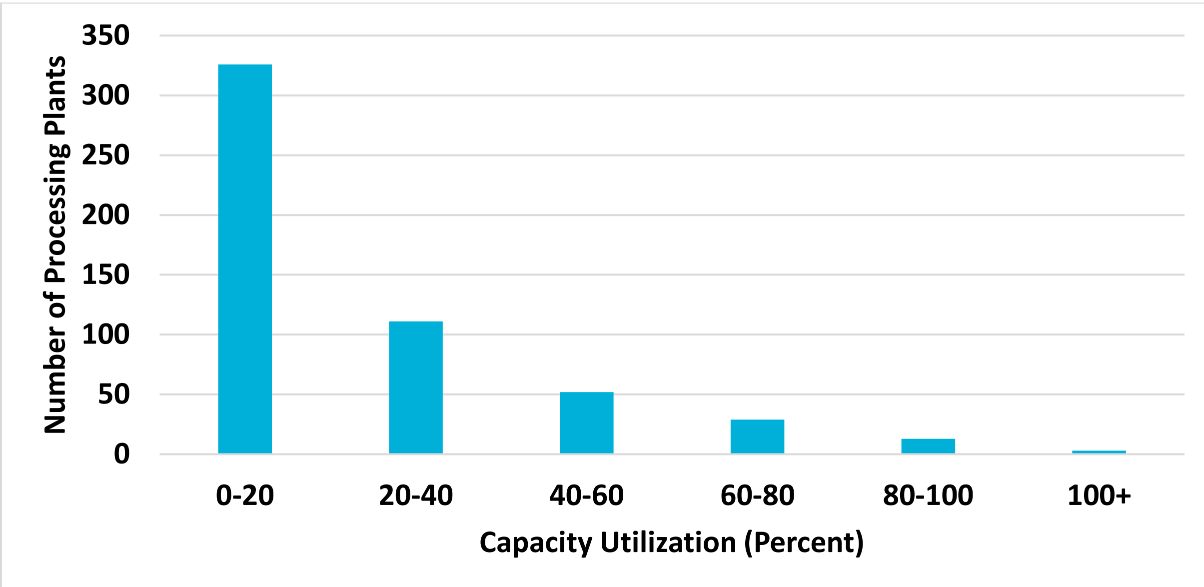
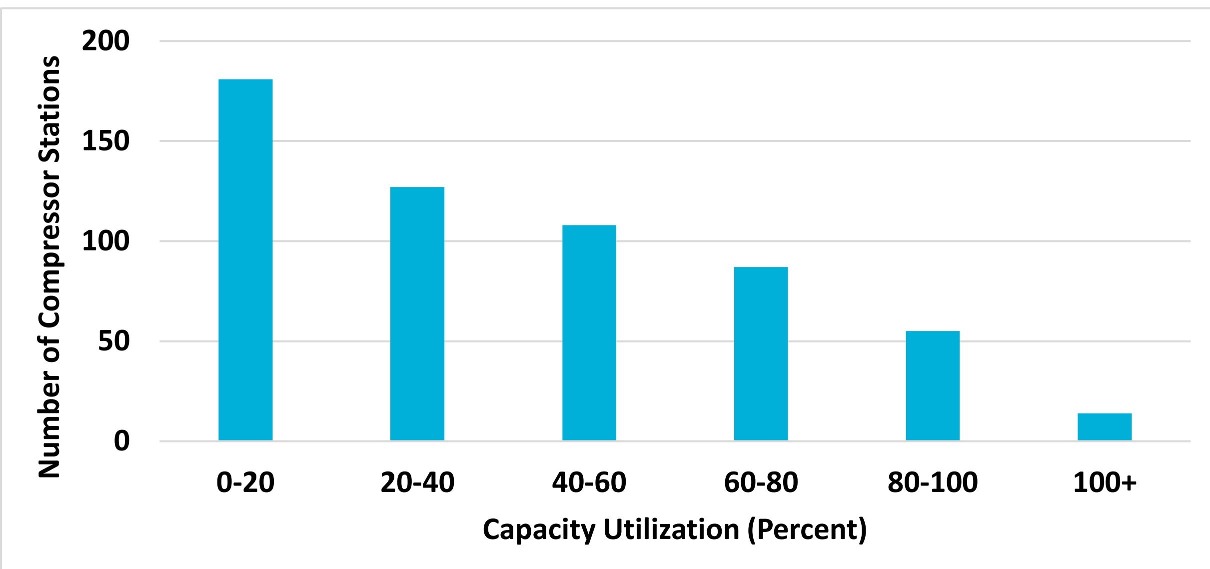


Exhibit 3-3 Capacity utilization of compressors [3]



3.2 Operational Reliability

Typically, compressor stations operate reliably due to their relatively simple operation. Single unit or entire station shutdowns are most commonly caused by any of the number of safety systems designed to protect the compressor units and the station.

Inclusion of these systems is mandated by federal regulations detailed under Title 49 Part 192 of the Code of Federal Regulations (CFR). These systems ensure safe operation, and prevent damage to the compressor units and station components in the event of equipment failure or abnormal operating conditions. These include, but are not limited to, systems that monitor station operating conditions, such as vessel liquid levels, station inlet and discharge flows and pressures, and gas leak detection at critical points within the station. Each of these systems report conditions back to a supervisory control and data acquisition (SCADA) system. If SCADA detects a condition exceeding designed limits, an automatic system shutdown is initiated. Depending on the station design and the cause, these shutdowns may be limited to a single compressor unit or the include the entire compressor station.

Gas detection systems, for instance, must be sensitive enough to detect a gas leak, which could cause a fire or explosion in presence of an ignition source. One incident noted [6] was the shutdown of an entire compressor station due to activation of the station leak detection system. In this example, the leak detection system activation occurred during the station run-in period after start-up.

Another common problem that can result in compressor unit shutdowns is high liquid levels in gas/liquid separator vessels within the station. To assure safe compressor operation, liquids entering the station entrained in the gas or by routine pipeline pigging operations must be removed from the gas stream before reaching the compressor. Liquids entering a compressor can cause significant physical damage to the units as they are not designed to handle incompressible liquids. Automatic shutdowns can occur if separator automatic dump valves fail or bottlenecks exist in the station, which prohibit adequate liquid separation during pipeline pigging.

Compressor units are also monitored for suction/discharge pressure, flow rate, and adequate lubrication. Sensors monitoring these parameters will alarm when a preset limit is exceeded and will initiate a unit shutdown if the condition can potentially cause damage or injury.

When an abnormal condition results in a compressor shutdown, an alarm is sent to the SCADA system, which alerts operating personnel. These unplanned shutdowns typically require little maintenance to correct; however, design changes to the station are sometimes required. The operating philosophy of some compressor operators allow for automatic unit restarts after shutdowns. Other companies require that the site be visited by a maintenance technician to manually take corrective action and physically ensure that the issue has been corrected prior to restart. The SCADA system will typically dispatch the on-shift maintenance technician to the affected compressor or processing station. The technician will identify and correct the problem to return the station to normal operation.

3.3 Failure Rate

Shutdowns of individual compressors are relatively common due to system upsets like those identified above. [6] However, most compressors stations have multiple individual compressors that limit the impact of any single compressor outage or failure. These individual compressor shutdowns may result in a reduction in pipeline pressure or flow. In cases of a full station shutdown, the pipeline network typically will be able to compensate for the loss of one station. A more detailed discussion of the impact of a compressor station shutdown is provided in Section 4 of this report.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) maintains a record, accessible to the public, of natural gas transmission, distribution, and gathering system incident reports. [7] This record includes incident reports flagged involving compressor stations. There has been an average of 30 incidents per year involving compressor stations reported in the PHMSA records. An incident is flagged as serious (a fatality) or significant if it meets one of the following criteria:

1. A death, or personal injury necessitating in-patient hospitalization
2. Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost
3. Unintentional estimated gas loss of three million cubic feet or more
4. An event that results in an emergency shutdown of a liquefied natural gas facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident
5. An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition

In 2014, there were 32 incidents involving compressor stations, 11 of which were significant incidents, one of which was a serious incident. There were 35 incidents in 2015 as of December 14, eight being significant incidents and one serious incident. [7]

4 Impact of a Compressor Failure on the Pressure and Throughput of a Natural Gas Transmission Pipeline

Natural gas transmission pipelines are typically large diameter pipes with operating pressures of 200 – 1,500 psig. As improved fabrication methods and materials have been developed, the maximum size and operating pressure of these pipelines have increased as shown in Exhibit 4-1, increasing the efficiency of the system. Typically, natural gas compressors are spaced approximately 50 – 100 miles apart along a transmission pipeline providing an average pressure increase of 250 psig. [4]

Exhibit 4-1 Historic natural gas transmission pipeline sizes and pressures [9]

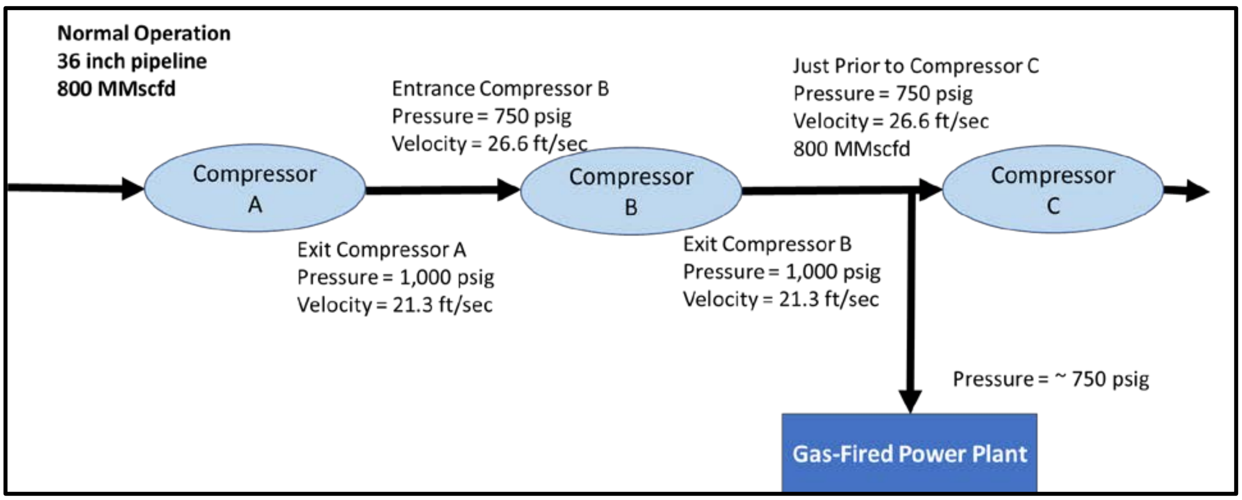
Decade of Construction	Available Maximum Diameter (inch)	Maximum Allowable Operating Pressure (MAOP) (psig)[b]
<1940	24	720
1940 – 1949	28	720
1950 – 1959	30	860
1960 – 1969	36	860
1970 – 1979	36	1,020
1980 – 1989	42	1,440
1990 – 1999	42	1,440
2000 – 2009	48	1,600
2010 +	48	1,750

To evaluate the hypothetical impact of a complete compressor station failure on a representative natural gas transmission pipeline, a simplified transmission pipeline system was created, as shown in Exhibit 4-2. For this system, it is assumed that a nominal 36-inch transmission pipeline operating at 1,000 psig is transporting 800 MMscfd of natural gas. In a real-world setting, the transmission pipeline would likely have multiple incoming and outgoing branches off a main trunk line, some of whom, such as local distribution companies (LDC), are designated firm service and guaranteed first right to pipeline volumes, while other customers, such as power plants, are

[b] Pre-1970s pipelines were allowed an exemption grandfathering them from establishing MAOP under the federal safety rules of 1970. This allows natural gas transmission lines installed before July 1, 1970, to be operated, in some cases, without material records, having been pressure tested in the field, or at higher MAOPs than allowed for pipelines constructed after implementation of the regulations. Approximately 50 percent of onshore natural gas transmission lines were constructed prior to 1970 and operate under this exemption. [13]

designated at various levels of interruptibility. For this hypothetical analysis, however, these considerations are ignored and the system configuration only considers one outflow—to a gas-fired power plant. For this evaluation, 800 MMscfd enters and is compressed to 1,000 psig in Compressor (Station) A. The gas exits each compressor station and travels an assumed distance (50 – 100 miles), where the pressure in the pipe decreases 250 psig due to pipeline frictional and elevation changes. Each compressor station along the pipeline recompresses the gas to 1,000 psig. Just prior to entering Compressor Station C, a portion of the gas is diverted to a gas-fired powered electrical generator.

Exhibit 4-2 Simplified NG transmission system (normal operation)



In a transmission pipeline, the mass flow in the pipeline is conserved, i.e., the mass entering the pipe is the same as the mass exiting the pipe if no gas is removed from the pipe.[c] For this example, the gas flow through the pipeline remains 800 MMscfd until a portion of the gas is removed just prior to Compressor Station C.

As the pressure in the pipe decreases, the velocity of the gas must increase to maintain a constant mass flow. Transmission pipelines are typically designed to operate at 20 – 50 feet per second (ft/sec) to prevent excessive pipeline erosion corrosion[d]. For this evaluation, velocities were calculated[e] at each point throughout the simplified system. During normal operation (Exhibit 4-2), the gas exiting Compressor Station A has a

[c] In reality, pipelines often suffer from small volumes of lost and unaccounted gas along with additional small volumes for post-market operational consumption – gas used to operate the pipeline system, processing facilities, and in well, field, and production operations. These volumes are negligible in this analysis, as analysis of historical FERC *Form 2/2A - Major and Non-Major Natural Gas Pipeline Annual Report*s indicates that they represent less than 5 percent of annual gas volumes passed through the system. [14]

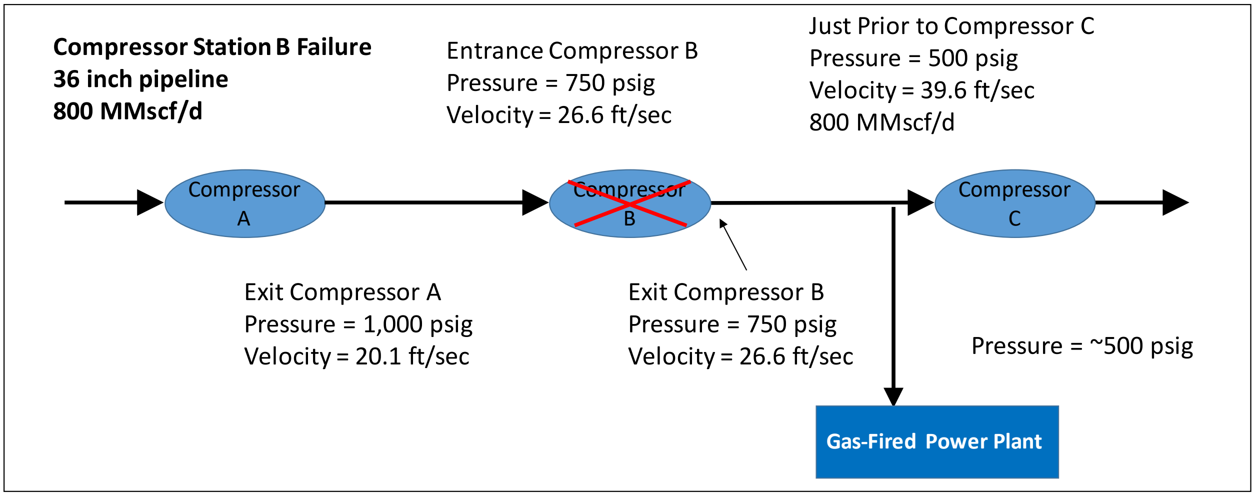
[d] Erosion corrosion is an increase in corrosion caused by the turbulent corrosive fluid against the pipeline surface. [15]

[e] Calculations were performed using natural gas pipeline velocity equations found in Oil and Gas Pipeline Design, Maintenance and Repair - Part 2: Steady State Flow of Gas through Pipelines. [12]

pipeline velocity of 21.3 ft/sec. As the pressure decreases, the velocity increases to a maximum of 26.6 ft/sec at a pressure of 750 psig just prior to entering Compressor Station B. The gas exits Compressor Station B at 1,000 psig, the pressure again drops along the pipeline and the velocity again increases to 26.6 ft/sec at 750 psig.

In the abnormal operation case (Exhibit 4-3), there is a complete failure of all compressors at Compressor (Station) B and no pressure boosting is available. Compressor stations can be designed to "shut-in" and cut off all flow through the station, or they can be designed to shut-in and the gas flow is bypassed around the station. In this case, the gas flow bypasses the station and the pipeline pressures will continue to decrease along the pipeline until the gas reaches the next operable compressors at Compressor (Station) C. For this example, the gas-fired power plant would experience an inlet gas pressure that is 250 psig lower than it normally experiences. However, the quantity of available gas would remain the same and, barring any additional plant limitations (inlet pressure regulator requirement, etc.) the plant should be capable of normal operations. A more detailed discussion of potential plant operational problems is discussed in the following section.

Exhibit 4-3 Simplified NG transmission system (abnormal operation)



The worst-case impact of a compressor station loss along a natural gas transmission line is a maximum pipeline pressure loss of approximately 250 psig, assuming no additional offtake. There may be some rare exceptions to this case in areas that have limited gas transmission infrastructure and/or during periods of extreme natural gas demand.

However, natural gas transmission pipeline owners can face significant legal and financial concerns if they do not meet their contracted delivery requirements, particularly to firm customers.[f] Therefore, they expend significant resources to make certain that they have a robust system, with multiple preventative measures, to ensure that they can meet their commitments. These measures include:

- Multiple compressors at each compressor station to ensure that there is additional compressive capacity available to substitute for an out-of-service compressor and allow continued normal flow.
- Robust pipeline networks to ensure that if a compressor station does go down there are multiple alternate routes to guarantee gas delivery to downstream customers.
- Preventative maintenance programs and traveling maintenance technicians that can respond quickly to address any issues.
- Significant sensors and controls to identify potential problems that could cause significant compressor damage and shut the system down before the damage occurs.

[f] The pipeline owner could face significant financial penalities if they cannot deliver the quantity of natural gas on the prescribe schedule. If the failure could not have been foreseeable, they could avoid the penalities by declaring "Force Majeure". However, an equipment failure would be considered forseeable and therefore force majeure would not be applicable.

5 Impacts of the Loss of a Natural Gas Compressor(s) on Electricity Generation

There are three types of natural gas plants currently used to generate electricity:

- Steam turbine generator (STG) plants that use natural gas to heat water in a boiler and create steam that spins a turbine to generate electricity.
- Simple cycle (SC) plants that burn natural gas to spin a gas turbine. They are relatively inefficient in their ability to convert heat into electricity so their use is often limited to periods of high demand.
- Combined cycle (CC) plants that incorporate simple cycle turbines and a heat recovery steam generator (HRSG). As gas is burned to spin a gas turbine, the waste heat from that process is captured and used to generate steam to spin a steam turbine.

To determine the gas pressure and flow requirements for each of these types of natural gas-fired power plants, nominal heat rates were collected from a variety of sources as shown in Exhibit 5-1.

Exhibit 5-1 Nominal heat rate sources

Simple Cycle	Combined Cycle	Subcritical Steam Turbine Generator	Supercritical Steam Turbine Generator[9]
Nominal heat rates from Gas Turbine World Simple Cycle Specs for the following turbines: • GE LM1800e (2011), Net Plant Output 17.9 MW • GE LMs100PB (2010), Net Plant Output 98.4 MW • GE 7FA (2009), Net Plant Output 213.8 MW	Nominal heat rates from Gas Turbine World Combined Cycle Specs for the following turbines: • GE LM6000PF (2006), Net Plant Output 61.4 MW • GE S109E (2008), Net Plant Output 193.2 MW • GE 107FA (2008), Net Plant Output 277.3 MW • MHI MPCP1 (M501GAC) (2011), Net Plant Output 404.0 MW • GE 207FA (2008), Net Plant Output 559.7 MW	Nominal heat rates from GE Steam Turbine Generators, 100 MW and Larger, 1,800 – 2400 psig, single reheat: • 125.0 MW • 200.0 MW • 301.7 MW • 401.6 MW • 502.0 MW	Nominal heat rates from GE Steam Turbine Generators, 100 MW and Larger, 3,500 psig, single reheat: • 402.2 MW • 502.8 MW • 604.7 MW • 800 MW

[9] Supercritical steam turbines operate with steam conditions above water's critical pressure of 3,208 psi (22 MPa), which can provide a 3.5 percent improvement over sub-critical units. [16]

Simple Cycle	Combined Cycle	Subcritical Steam Turbine Generator	Supercritical Steam Turbine Generator[9]
• MHI M501J (2011), Net Plant Output 323.7 MW	• GE 207FA (2009), Net Plant Output 647.8 MW • MHI MPCP2 (M501J) (2011), Net Plant Output 942.9 MW	• 602.3 MW • 800.0 MW	

Using the data from the sources identified in Exhibit 5-1, heat rates were plotted for each of the cycle types (SC, CC, and sub- and supercritical STGs) for a range of plant outputs as shown in Exhibit 5-2. This data allowed the calculation of linear approximations of the heat rates across the entire range of plant sizes. Using these heat rates, the natural gas requirements for each type of generator were calculated for each plant size and are presented in Exhibit 5-3. The information presented in Exhibit 5-3 assumes that the plant is running at 100 percent capacity for the entire 24-hour period.

Exhibit 5-2 Heat rate of natural gas-fired generating facilities

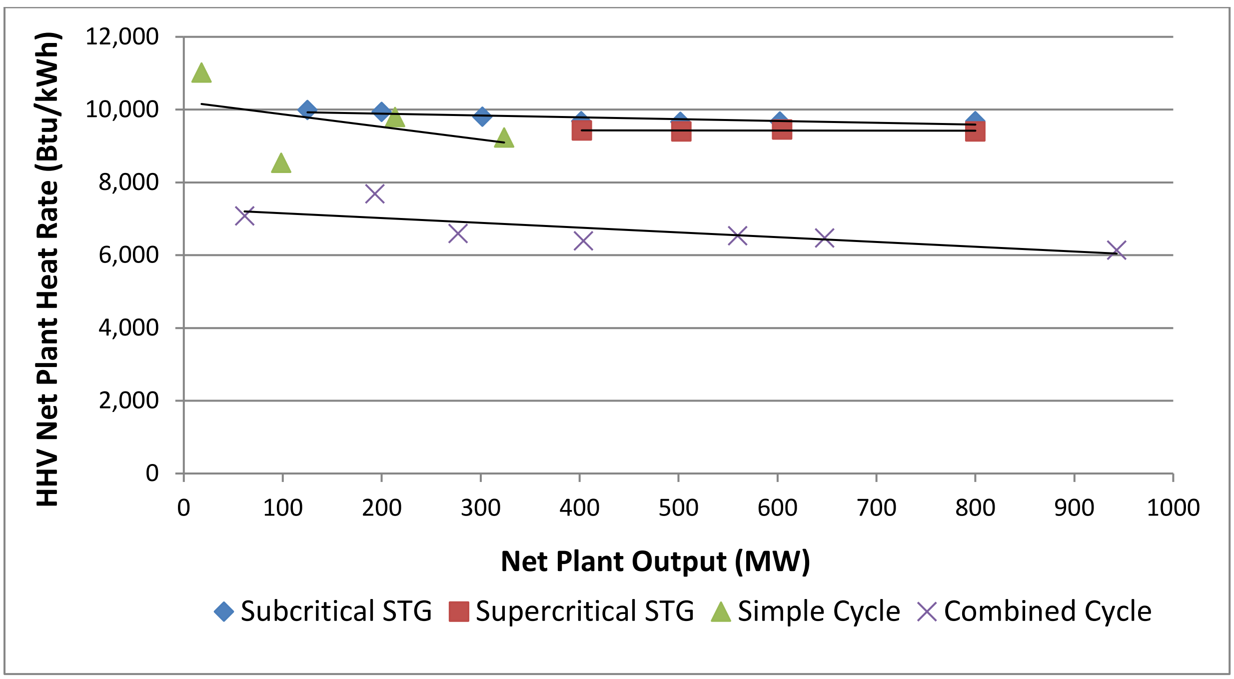
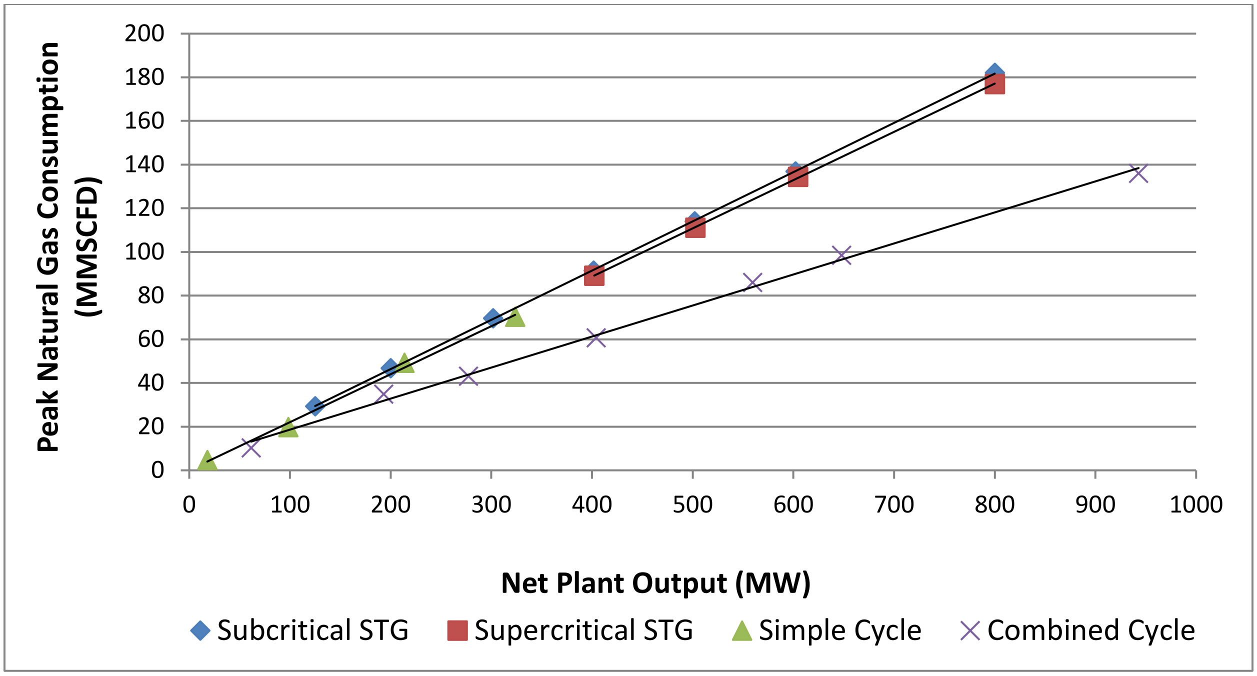


Exhibit 5-3 Natural gas consumption by generating facilities



As discussed in the previous section, the loss of a single compressor at a natural gas transmission facility would have minimal impact on the operation of a downstream electrical generator due to the redundancies built into the compressor station. It has also been shown that a catastrophic failure at an entire compressor station would typically result in a pipeline pressure decrease of approximately 250 psig before the inlet on the next downstream compressor station. Therefore, the impact to electrical plant operation would be dependent on supply pressure requirements at each individual plant and pipeline operator limitations.

The required combustor supply pressures are highest for gas turbines (both SC and CC) because the gas is injected into the highest-pressure portion of the turbine and must, therefore, be at a higher pressure than the combustion air exiting the turbine compressor section. The gas pressure must also be high enough to exceed the maximum fuel nozzle pressure drop and minimum control valve pressure drop necessary to maintain sonic velocity in the control valve throat. [10] The required combustor inlet pressures for General Electric (GE) turbines are presented in Exhibit 5-4.

Exhibit 5-4 Required minimum natural gas supply pressures

Model Series	Standard Combustor Supply Pressures (psig)
3002J	115
5001 P	200
5002 C	175
6001 B	240
6001 FA	310
7001 EA	260
7001 FA	310
9001E	250
9001FA	315
LM6000	655

Historically, in the North American market, mainline gas pressure has been sufficient to provide the fuel to the turbine without any pressure boosting. However, as gas turbine technology has evolved and turbines have become increasingly efficient, the gas pressure requirements have also increased. As shown in Exhibit 5-4, typical inlet gas pressures are between 200 and 315 psig, while the newer, more efficient turbines like the LM6000 require pressures in excess of 650 psig. Some of the latest aeroderative gas turbines now require gas pressures from 700 to 1,000 psig. [11]

Power plants with the newer higher efficiency gas turbines typically employ a high-pressure fuel boosting compressor. These fuel boosting compressors ensure high pressure delivery of natural gas with no pulsation regardless of the incoming pipeline pressure. [11]

Therefore, a combination of conditions must exist for the loss of a natural gas transmission pipeline compressor to impact the operation of a gas-fired electric generator. These conditions include:

- A generation plant that is on a relatively small, low pressure transmission line with no alternate pipeline infrastructure may not have sufficient pressure if it is located a significant distance from the last operational compressor station.
- A generation plant with a high efficiency turbine that does not have a fuel boosting compressor may not have sufficient pressure for operation.

A typical plant is more likely to be impacted by a potential shortage of gas supply during high demand periods. For this reason, many transmission pipelines are installing "looped" systems where multiple pipelines are laid parallel to one another along the same right-of-way. In some cases, looped systems may extend the distance between compressor stations and/or act as a storage device to ensure a sufficient quantity of gas for delivery during peak periods. These large high-pressure pipelines have the potential to store large quantities of gas as shown in Exhibit 5-5. One mile of 48-inch pipe at 1,750 psig can store almost 9,000 MMBtu, which is enough gas to operate a 500 MW CC plant for over 2 hours[h].

Exhibit 5-5 Transmission pipeline storage capacity

Decade of Construction	Pipe Diameter (inches)	Maximum Pressure (psig) [9]	Natural Gas Mass[i] (lb/ft of pipe)	Natural Gas Heating Value[j] (MMBtu/ft of Pipe)	Natural Gas Heating Value (MMBtu/mile of Pipe)
<1940	24	720	7.6	0.15	810
1940 – 1949	28	720	10.3	0.21	1,102
1950 – 1959	30	860	14.5	0.29	1,544
1960 – 1969	36	860	20.9	0.42	2,224
1970 – 1979	36	1,020	25.4	0.51	2,700
1980 – 1999	42	1,440	51.5	1.0	5,485
2000 – 2009	48	1,600	76.1	1.5	8,100
Present	48	1,750	84.4	1.7	8,980

6 KEY FINDINGS

In most areas of the U.S., the natural gas supply system is robust and is designed with multiple redundant systems to ensure natural gas deliveries. In these areas, a single compressor failure will not impact the delivery capabilities of the gas transmission system, but the failure of an entire compressor station has the potential to decrease transmission line pressure by approximately 250 psig based on the reported average compressor boost pressure.

[h] Based on a 500 MW CC plant with a heat rate of 6,400 Btu/kWh using 3,200 MMBtu/hr.

[i] International Organization for Standardization created ISO 2213-2, which is the standard for calculating natural gas compressibility using the AGA8-92DC equation. The values calculated in the table were based on 15°C and 96.5 percent methane with minor specie of ethane, propane, butane, pentane, and hexane.

[j] Based on a natural gas heating value of 20,160 Btu/lb.

Natural gas-fired power plants require a significant amount of high pressure gas for operation. In most cases, a minimum supply pressure of approximately 300 psig is required. This means an entire compressor station can go off line and a typical downstream power plant can remain operational, assuming offtakes between the failed compressor station and the power plant do not result in lower supply pressures. The larger, more efficient gas turbines may be affected by the lower supply pressure from a lost compressor station, but they typically have an integrated fuel boost pump that would allow them to continue operation. Even in the event of a catastrophic pipeline failure, the network of transmission pipelines in most regions would limit the impact on power generation.

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