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Pipelines to Power Lines: Gas Transportation for Electricity Generation

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R E P O R T   S U M M A R Y

Pipelines to Power Lines: Gas Transportation for Electricity Generation

Gas-fired power generation represents a major growth market for the natural gas industry; but the large, high pressure, highly variable loads required for individual power generators can be difficult to serve. This report, cosponsored by the Gas Research Institute and EPRI, is a design stage assessment of the engineering and costs of the pipelines needed to handle these types of loads.

INTEREST CATEGORIES

Utility planning studies
Power system planning & engineering
Combustion turbines & combined cycles

KEYWORDS

Natural gas transportation
Natural gas pipelines
Pipeline engineering and operations
Combustion turbines and combined cycles
Fuel management
Transient flow modeling

BACKGROUND Despite the significant growth potential of gas-fired power generation, information on the interface between the natural gas and electric industries is limited. EPRI report TR-101239 provided a comprehensive introduction to the topic, and EPRI report TR-102948 examined gas and electric coordination in New England. The current report, using state-of-the-art tools and the terminology of the gas industry, provides a more quantitative treatment of pipeline engineering and design options. Future collaboration in this area between the Gas Research Institute (GRI) and EPRI will likely turn to the operational issues of serving new power generation loads.

OBJECTIVES
To provide a quantitative assessment of the pipeline engineering and costs involved in serving the load requirements of gas-fired power generators; to describe the principals and processes of pipeline design, construction, and operation.

APPROACH The research had three components. In the first, a multidisciplinary team with skills in pipeline engineering, modeling, and electric utility planning analyzed hypothetical, but realistic pipeline configurations using transient flow analysis. They examined major factors influencing pipeline design and operations, including the amount, type, and timing of power generation load; delivery pressures, ramping times; load patterns; and pipeline geometry. In the second phase, the team, with the assistance of project advisors, compiled a series of industry examples of recent approaches to meeting new power generation loads. Finally, the team drew on its experience to prepare background information on pipeline design, construction, and operations.

KEYPOINTS Quantitative simulations and industry examples indicate that pipeline designers can design systems flexible enough to accommodate the large, highly variable loads needed for power generation. Serving these loads requires additional facilities, with costs estimated to range from $8 to 180/kW. The cost of pipeline facility additions are calculated for specific electric generation requirements and take into account the current condition of the pipeline, for example, whether it is an under powered or a fully powered pipeline. Local gas storage can greatly reduce the need for additional pipeline facilities. In some circumstances, power generators can enhance the interface between the pipeline and the power generating facility by using local compression or automatic switchover capability to an alternative fuel. Intra-day changes in load requirements can be met if the total design load requirements are unchanged. Variations in total daily load, however, can require up to a 40% increase in pipeline capacity. Because of the special characteristics of power generation loads, transient flow modeling, a powerful analytical technique developed within the last decade, is especially helpful in designing and costing pipelines.

EPRI PERSPECTIVE This report represents the first systematic collaboration between GRI and EPRI on pipeline engineering and operations. It deals primarily with the design phase of the interface between the two industries and provides essential technical understanding of the engineering and costs required to handle new loads for power generation. Through its use of the latest techniques of analysis, its discussions of recent pipeline projects, and its explanation of basic concepts, the report gives utility readers insight into the pipeline business and how gas pipeline engineers think.

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Pipelines to Power Lines: Gas Transportation for Electricity Generation

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ABSTRACT

Gas-fired power generation represents a major growth market for the natural gas industry. However, the large, high pressure, highly variable loads required for individual power generators can be difficult to serve, particularly for natural gas pipelines. This report assesses the flexibility and costs, at the design stage, of pipelines to handle these types of loads. The report is organized into three components. The first presents the results of a quantitative pipeline simulation modeling effort using transient flow analysis techniques. Hypothetical, but realistic, pipeline configurations are described, representative of conditions in the southeast, the northeast, and the mid-Atlantic and eastern midwest. The simulations illustrate major factors influencing pipeline design and operations, including the amount, type and timing of power generation load, delivery pressures, ramping times, load patterns and pipeline geometry. The second component presents a series of industry examples of recent approaches to new power generation loads. The third component is a primer on basic concepts and considerations of pipeline design, construction and operations.

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1

EXECUTIVE SUMMARY

Even though gas-fired generation represents one of the major growth markets for the natural gas industry, a broad understanding of the interface between pipelines and this growing load for gas-fired generation is limited, particularly when it involves high pressure combustion turbine or combined cycle units. A major contributing factor to this lack of understanding is that the loads for individual power generators can be difficult to serve, due to the fact that they are often very large, high pressure loads that can be subject to considerable variation. This is particularly true for the pipeline segment of the gas industry.

To date, most of the published industry data and information on this subject have been limited to qualitative research efforts, such as the 1992 Electric Power Research Institute (EPRI) report entitled "Natural Gas and Electric Generation: The Challenge of Gas and Electric Industry Coordination."[1] Quantitative analysis on this subject, in general, has been performed on a case by case basis by the pipeline, LDC, or power generator directly involved.

This report represents one of the first systematic efforts to quantitatively examine the flexibility, and associated costs, of pipelines to handle these new loads for power generation. Its scope is limited primarily to examining the design phase of the interface between the two industries, in which case it is assumed that full knowledge of the load requirements of the new power generator is known to both parties. Additional research is planned to build upon this initial quantitative effort to examine the day-to-day operational aspects of these new loads, which are usually subject to considerable variation and are very difficult to predict, and thus, place the pipeline in the position of having to serve these loads without full knowledge of the load requirements. The combination of this design-oriented report and the future research on the day-to-day operations should provide significant technical insight into the flexibility, and associated costs, of pipelines to handle the load requirements of this new and growing load for power generation.

The approach used for this report was to model and analyze hypothetical, but realistic, scenarios for several pipelines configurations. The model uses transient flow analysis for the simulations, since it is the best tool for analyzing the impact of large, high pressure loads that are subject to considerable variation. Major factors which influence pipeline design and operations were examined in these simulations, including the

[1] EPRI, *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination,* (EPRI TR-101239), September 1992.

amount, type and timing of power generation load, delivery pressures, ramping times, load patterns and pipeline geometry.

Accompanying the material presented on pipeline simulations (Section 2) is a series of recent industry examples involving new power generation loads, which are briefly reviewed to provide the reader with further tangible information on the interface between the gas and electric industries (Section 3). In addition, in order to increase the familiarity of those in the electric utility industry with pipeline design, the report's contents have been broadened to include a primer on the basic elements of pipeline design, construction and operations (Section 4). Thus, readers from the electric utility industry might consider reading Section 4 first, while their counterparts in the gas industry may desire to skip over this primer material. The last section of this report identifies areas where further research on the subject would be beneficial (Section 5).

Simulations of Pipeline - Power Generation Interface

Overview

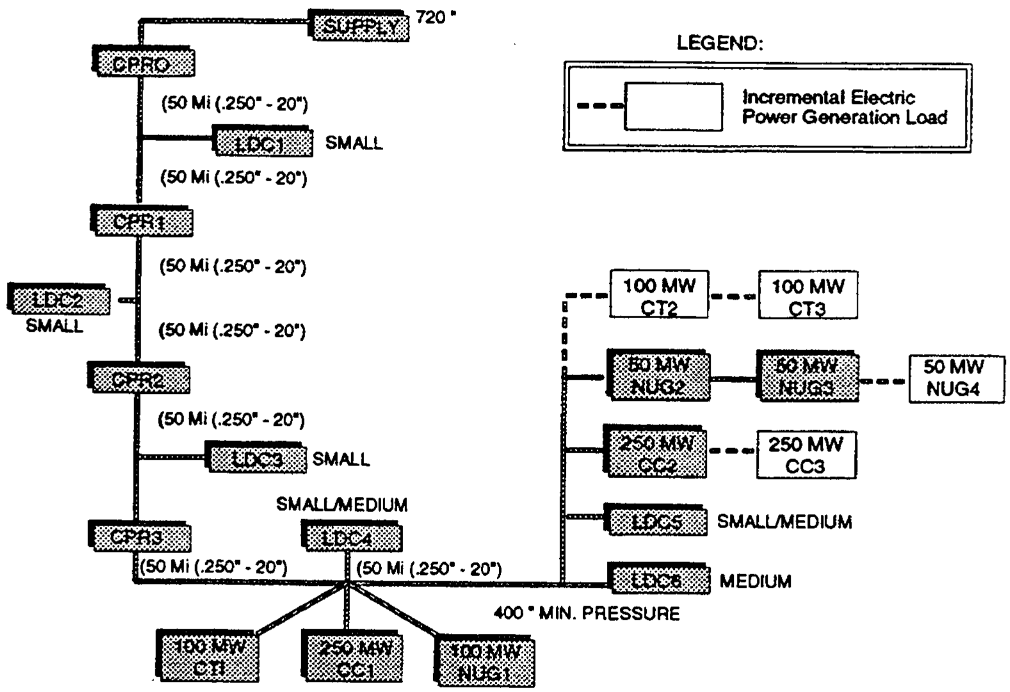
Three different pipeline systems were modeled in order to provide further insight into the interface between natural gas pipelines and large power generation loads. For each of these systems the impact on pipeline facilities and operations for a series of parameters, such as increasing power generation load requirements or changing delivery pressure and altering pipeline geometry, were simulated using transient flow analysis. An outline of the characteristics of the three pipeline systems modeled is presented in Exhibit 1-1. Exhibit 1-2 illustrates one of the pipeline configurations that was modeled. Local distribution company (LDC) and power generations loads, as well as pipeline characteristics, used in the model are representative of a variety of actual industry conditions.

Exhibit 1-1
PIPELINE SYSTEM CHARACTERISTICS

Characteristic	System 1	System 2	System 3
General Location	Southeast	Northeast	Midwest
MAOP[1] - psig	1,200	720	720
Size - diameter in inches	20	30	24 and 20
Length - miles	400	400	600
Storage	No	No	Yes
Dominant Existing Load	Electric Utility	LDC	LDC
Incremental Load	CC,CT,NUG	CC, NUG	CT

1 MAOP = maximum allowable operating pressure.

Exhibit 1-2
PIPELINE DIAGRAM SYSTEM 1



General Modeling Conclusions

The general conclusions from the combination of all the simulations done for the systems are noted below. While some of these conclusions will seem intuitively obvious to those well versed in the gas pipeline industry, a full summary is presented in order to ensure that the broader audience of this report is educated on the basic principles of pipeline design and operations involving large, variable loads.

Pipeline Flexibility: Pipeline designers have the flexibility to accommodate the large, highly variable loads for power generation, however, serving these loads requires additional facilities. The cost of these additional facilities varies depending upon the requirements of the electric utility and the current condition of the pipeline (e.g. an under powered versus a fully powered pipeline). In addition, the presence of local gas storage reduced the need for these additional facilities. Quantification of these conclusions is as follows:

- *Additional Facilities:* The facility additions necessary to support incremental power generation loads varied between 12 and 41 HP per MW, but a significant amount of this variation was dependent on the pipeline system that was analyzed. Assuming an average capital cost of $1,500 per HP, that equals a range of $18,000 to $62,000 per MW.

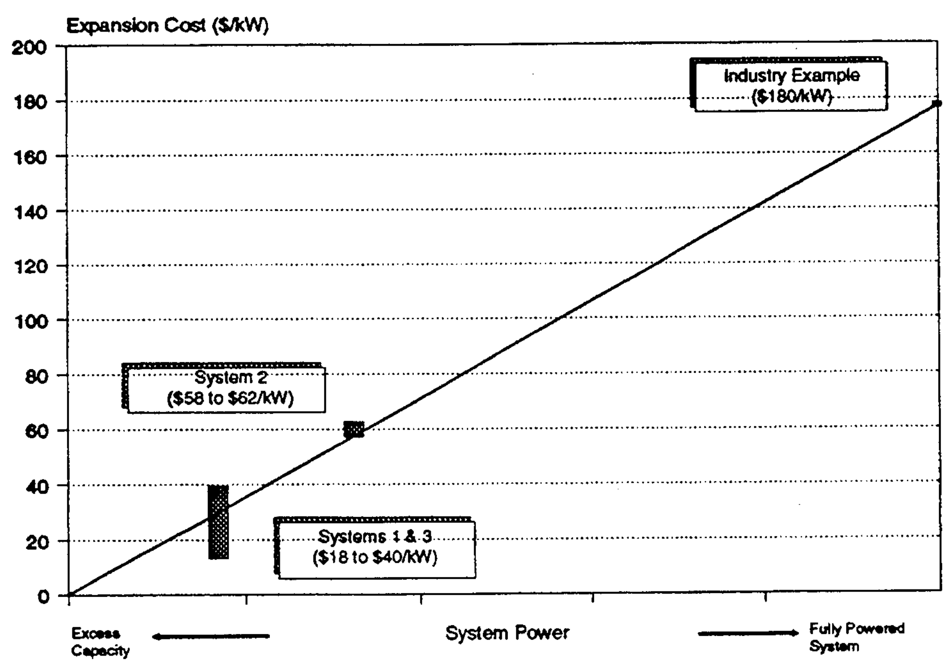
Electric Utility Options: Exhibit 1-3 compares and contrasts the amount of facility additions required to support incremental power generation for the three pipeline systems analyzed in this report.

- It is important to note, however, that these three systems were not fully developed or powered under base case conditions and could therefore be expanded to satisfy the incremental power loads with the addition of relatively inexpensive compression. In contrast to these examples of inexpensive expansion, Tenneco Gas spent approximately $180,000/MW to expand and extend its mature, fully powered 200 system in New England to provide transportation service to the initial 250 MW Ocean State Power Facility (see Exhibit 1-3.)

- In addition, the cost data presented in Exhibit 1-3 represents only a summary of the pipeline systems analyzed for this report as well as industry examples reviewed in the report. While this data is informative, it by no means represents the continuum of potential facility costs of new power generation loads. Industry participants will be required to analyze the additional facility requirements, if any, on a case-by-case basis, as site and pipeline specific factors will have a significant impact on these requirements.

- *Storage:* Local gas storage reduced or eliminated significant pipeline facilities that would have otherwise been required to support incremental power generation load operations.

Exhibit 1-3
COST OF POWER GENERATION LOAD ADDITIONS



Operational Considerations: As noted below, intra-day changes in load requirements can be met if the total load requirements are unchanged. However, variations in total daily load may require additional facilities.

- *Varying Timing of Load: Varying* the number of power generation load burn periods per day did not affect facility requirements, provided that the total burn time remained constant. For example, increasing combustion turbine loads from one 4-hour burn period per day to four 1-hour burn periods per day had no significant impact on the amount of facilities required.

- *Varying Amount of Load:* Varying the total amount of combustion turbine burn time per day had a significant effect on facilities required. For example, in one case tested the additional facilities associated with increasing the daily combustion turbine burn time from four hours to 12 hours totaled 20 HP per MW (i.e., approximately a 40% increase).

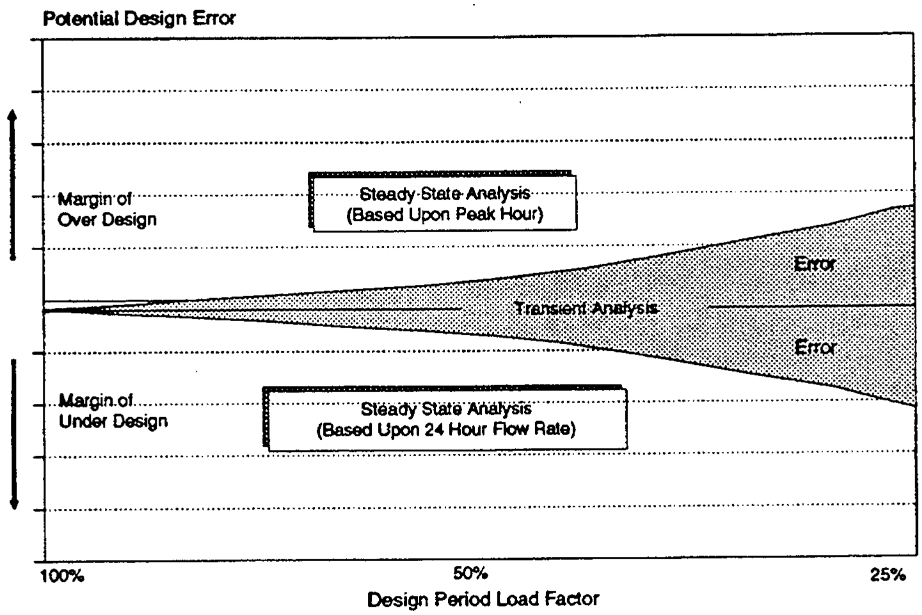
Electric Utility Options: Electric utilities and non-utility generators can enhance the interface between the pipeline and power generation facility in certain applications by considering the use of local compression or automatic switchover capability to an alternative fuel. For example,

- *Local Compression:* Generally, it was less costly to use "local" booster compression to satisfy power generation minimum pressure requirements than to increase pressure on the entire pipeline system, provided that the power generation load was localized and not distributed along the entire pipeline.

- *Alternative Fuels:* The use of distillate or other alternate fuels to fuel power generation loads (when pipeline delivery pressure drops below power turbine minimums) may be more cost effective than paying for and utilizing fuel gas booster compression, since the need for this horsepower was very limited, in terms of "on line" time, in all cases tested.

Transient Flow Analyses: Although standard practice for most major pipelines, it bears mentioning that the use of transient flow analysis rather than a steady state analysis is required for the analyses of these large, highly variable loads in order to ensure the optimium pipeline design. While steady state analysis is still used for less variable loads, the modeling work performed for this report confirmed the need for transient flow analyses for the large, highly variable loads associated with power generation, when such loads represent a significant component of the pipeline's throughput. As conceptually illustrated in Exhibit 1-4, the use of steady state analysis for these loads may result in (1) significant over design if that design is based upon maximum hourly flow conditions or, conversely, (2) significant under design if that design is based upon the average 24 hour flow rate. Furthermore, this potential design error increases disproportionately as the design period load factor decreases.

Exhibit 1-4
COMPARISON OF STEADY STATE AND
TRANSIENT FLOW ANALYSIS



Other Items: Other noteworthy findings of this modeling effort are:

- *CT Ramping:* While power generation ramping rates may affect operations, particularly if communications between pipeline and power generation operating personnel are inadequate, ramping time had little impact on the basic facility design (e.g., decreasing combustion turbine ramping rates from five minutes to 30 minutes did not affect facilities).

- *Pipeline Design Alternatives:* Larger diameter pipe operating at lower pressure (e.g., 30" @ 720 psig) was slightly less costly to expand for power generation loads than smaller diameter line operating at higher pressure (e.g., 24" @ 1,200 psig), provided that minimum line pressure was 200 psig and that "local" compression was used to satisfy the power generation pressure requirements.

Industry Examples

To further illustrate the variety of commercial circumstances for accommodating large power generation loads, a series of recent industry examples are presented on how the interfaces between the pipeline and power generator have been resolved. These examples cover a variety of situations that include: (a) the design of new pipelines that are heavily dependent upon power generation loads, (b) the ability of a specific pipeline to use idle compression capability during the summer to meet additional power generation load requirements and (c) the use of booster compression at a specific electric utility.

With one exception, the pipeline in each of these examples used transient flow analysis to determine the proper means of serving the power generator's load requirements. Furthermore, these examples reemphasize that two of the most important parameters for a transient flow analysis are the pressure requirements at the delivery point, which is heavily influenced by the hardware selected by the power generator, and the hourly gas requirements.

Primer on Pipeline Design, Construction and Operation

The primer on natural gas pipelines (i.e., Section 4) is presented as an educational item, primarily for those in the electric utility industry desiring greater familiarity with the principles of pipeline design, construction and operation. It may also be informative to those in the natural gas industry who do not have a background in pipeline design or operations. Furthermore, this primer may fall short for some readers in that it doesn't cover everything concerning pipeline design, construction and operations, but instead presents a broad overview of the subject.

Key elements in the primer include:

- *Major Steps in the Delivery of Natural Gas:* Each of the major steps in the delivery of natural gas from the wellhead to the burner trip are reviewed in order to clearly illustrate where the natural gas pipeline is positioned in the overall delivery process. In addition, the various processes used at gas treatment facilities (e.g., absorption and cryogenic extraction processes) are discussed.

- *Pipeline Construction:* Each of the numerous steps involved in the construction of a pipeline is reviewed. Numerous illustrations are provided to depict more clearly the various elements involved in constructing a pipeline.

- *Pipeline Operations:* The basic operating procedures of a major interstate pipeline are reviewed, along with a compilation of operational issues common to the electric utilities.

Future Research

Additional research on this subject would be useful in the following three areas with the highest priority being given to the initial area for research (i.e., impact on pipelines to handle daily variations in load requirements for power generation).

- *Analysis of Daily Variations in Load Requirements:* The information contained in this report represents a significant step in examining on a quantitative basis the flexibility, and associated costs, of pipelines to handle the large, highly variable loads of power generation. However, the scope of the research summarized in this report was limited primarily to the design phase of pipeline operations. In order to provide a more complete picture, additional research should be conducted on the flexibility, and associated costs, of pipelines to handle, under a variety of scenarios, the daily variations in load requirements of power generators. This research on day-to-day operations would examine scenarios where full knowledge of load requirements is not available, which is reflective of many current operations and distinctly different from the design-oriented project contained in this report, which assumes full knowledge of all load requirements by both the power generator and the pipeline. This research on day-to-day operations would examine the impact of variations from nominated loads, multiple day variations, location, weather and pressure requirements.

- *Expand Scope of Design - Oriented Analysis:* It would be useful to expand the scope of the design - oriented research in order to provide additional breath and depth on the subject. Key areas to be examined include (1) detailed analysis of specific variables on pipeline costs, such as CT and/or CC load requirements, pressure requirements, compressor spacing and location; (2) detailed examination of pipeline cost alternatives, which would include a complete discussion of the use of the J-curve analysis; and (3) an analysis of other system configurations, such as a telescoped system.

- *Analysis of Implications of Current Research:* A series of regional workshops could be held as a means for management and planners in both the gas transportation and electric utility industries to assess the scope and implications of the combination of the design-oriented research in this report and the research on day-to-day operations discussed above. This assessment could be augmented with an analysis of existing and projected gas demands within a region, along with an overview of the gas transportation infrastructure within the region. The applicable industry examples in Section 3 to a specific region, along with others, could be used to promote discussion. These workshops could have as a central objective increasing the understanding of project tradeoffs and uncertainties for both industries.

2

PIPELINE - POWER GENERATION INTERFACE SIMULATIONS

Overview

Although combustion turbine (CT) and combined cycle (CC) power generation loads represent a significant future transportation market for domestic natural gas pipelines, little gas or electric industry analytical work has addressed the interface between pipelines and this growing load for gas-fired generation. Generally, this type of pipeline flow simulation work has been performed on a case by case basis by the pipeline, LDC or the power generator directly involved.

Published industry data and information on this subject have, until recently, been limited to qualitative research efforts such as the 1992 Electric Power Research Institute (EPRI) report *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination*, (TR-101239).

The principal purpose of this current pipeline simulation and modeling effort was to develop quantitative insights into these dynamic interface issues so that both the natural gas and electric power industries might have a more specific understanding of each other's capabilities and limitations. A specific objective was to identify and evaluate major factors that influence pipeline design and operations, such as power generation load and facility start-up times, delivery pressures, and pipeline system geometry. In identifying and evaluating these major factors it is assumed that the reader is already well versed in pipeline design and operation. For those readers not familiar with the fundamentals of pipeline design and operation it is recommended that they review Section 4 of this report, which is a primer on pipeline design, construction and operation, before reading the remainder of the report.

Assumptions and Conditions

Systems Modeled

Three hypothetical pipelines models were created which, in general terms, approximate typical pipeline systems in the Southeast (System 1), the Northeast (System 2) and the eastern portion of the Midwest (System 3). These are areas where most additions in gas-fired power generation loads are forecasted to occur. The basic modeling approach for each of these systems was to: (1) establish a base case for each system that would be representative of current local distribution company (LDC) and power generation market conditions; (2) superimpose upon that base case incremental power generation loads generally representative of the type, size and density forecast for that geographic region, and then (3) assess the facility and operational implications associated with servicing these new power generation markets. It is important to note that the base case developed for each of these three systems was without measurable excess capacity under base design conditions and facilities which is typical of many, but not all, major pipeline systems. Exhibit 2-1 summarizes the primary characteristics of each system, and Exhibits 2-2 through 2-3 provide schematic diagrams for each system considered.

Exhibit 2-1
PIPELINE SYSTEM CHARACTERISTICS

Characteristic	System 1	System 2	System 3
General Location (USA)	Southeast	Northeast	Midwest
MAOP[1] - psig	1,200	720	720
Size - diameter in inches	20	30	24 and 20
Length - miles	400	400	600
Storage	No	No	Yes
Dominant Existing Load	Electric Utility	LDC	LDC
Incremental Load	CC,CT,NUG	CC, NUG	CT

1 MAOP = maximum allowable operating pressure.

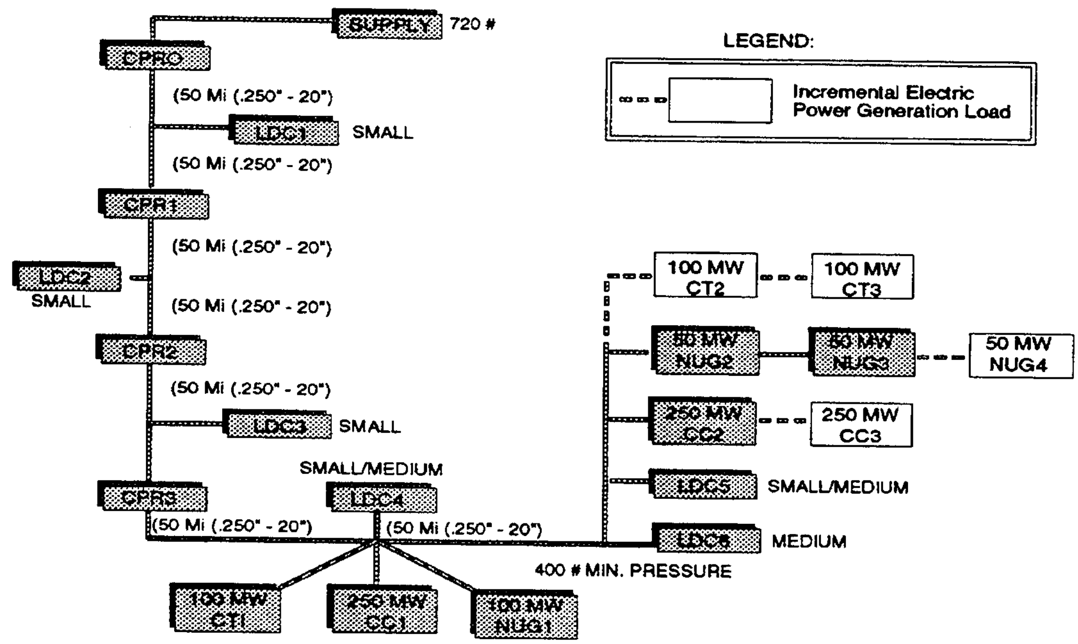
LDC Loads

Although assumptions regarding LDC load size and density vary among the three systems, there were certain common LDC characteristics. Exhibit 2-4 summarizes key LDC design characteristics by class or size of the LDC. Note that the peak hour rate is 125% of the peak day rate, the average winter day rate is two-thirds of the peak day rate and the average summer day rate is one-third of the peak day rate. Based upon discussions with a number of pipelines and LDC's, these relationships are believed to be reasonably representative of residential and commercial LDC loads. Also, note that all of these loads, including the peak hour, are expressed as 24 hour volumes.

While the design criteria varied among cases (e.g., System 1, the Southeast case, was based on a summer day design while Systems 2 and 3, the Northeast and Midwest cases, were based on three consecutive winter peak design days), the relationships as shown in the top of Exhibit 2-5 were held constant in all cases tested. In addition, a minimum contract LDC delivery pressure requirement of 200 psig was assumed in all system base cases. This minimum was established after informally surveying a number of gas pipeline operators. Furthermore, the peak day load profile and the three consecutive winter days peak period load profile illustrated in Exhibit 2-5 was common to both Systems 2 and 3.

Exhibit 2-2

PIPELINE DIAGRAM SYSTEM 1



PIPELINE DIAGRAM SYSTEM 2

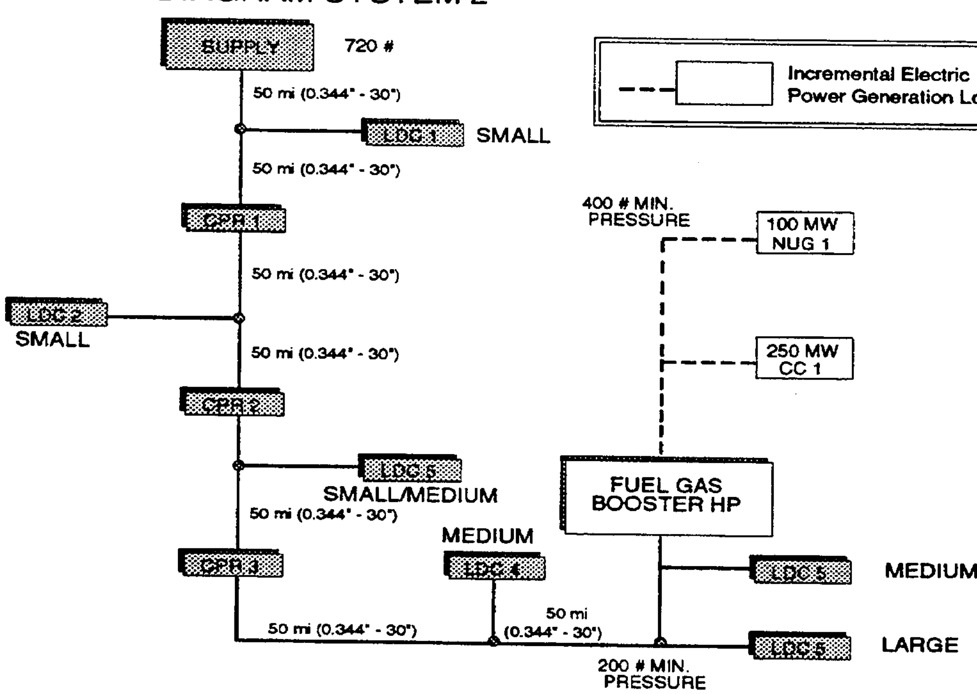
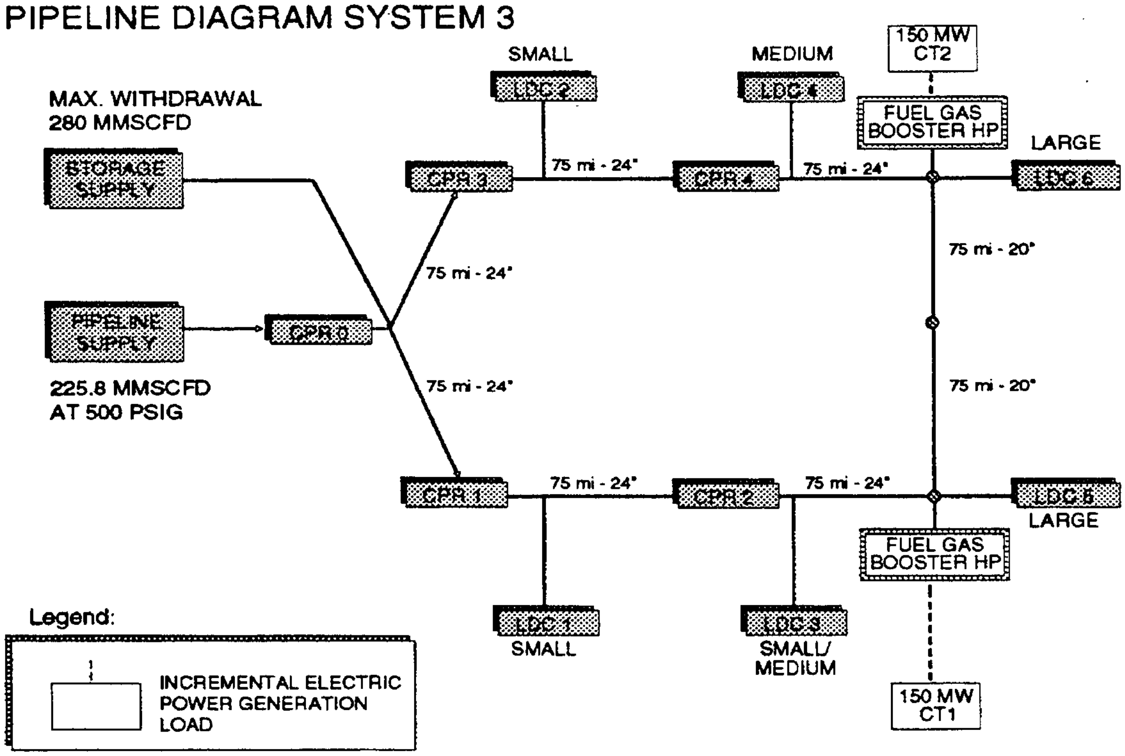


Exhibit 2-3

PIPELINE DIAGRAM SYSTEM 3



PIPELINE DIAGRAM SYSTEM 3 (ALTERNATIVE)

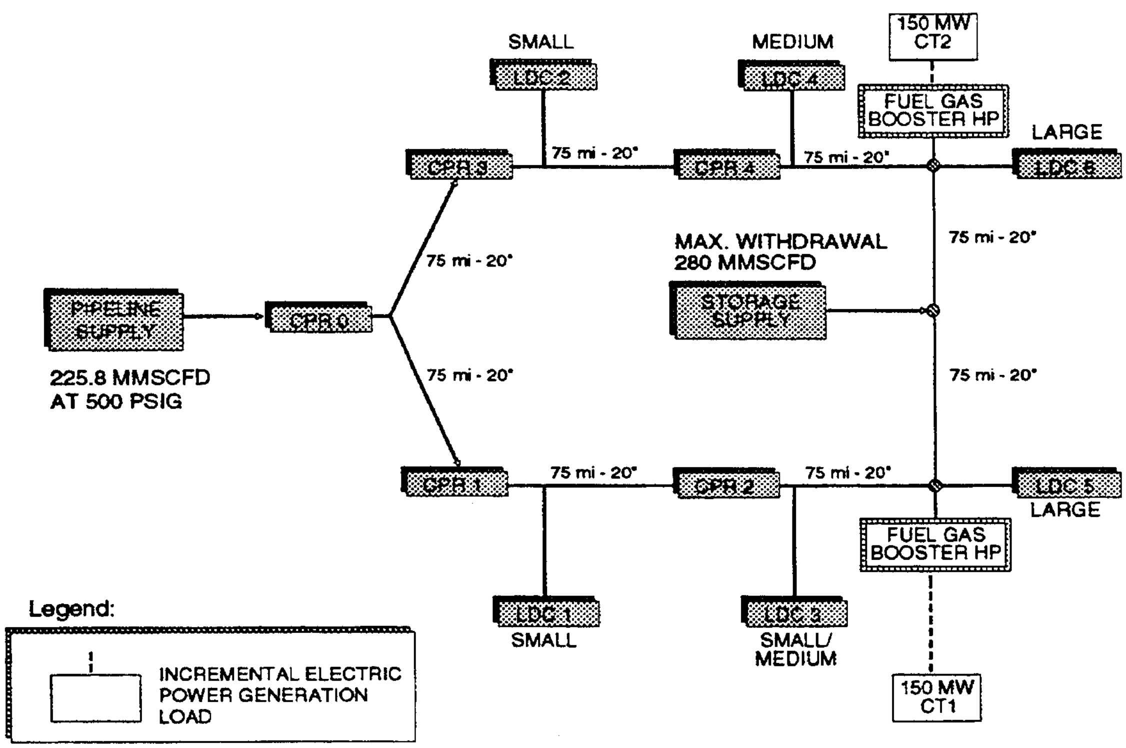


Exhibit 2-4
LDC CHARACTERISTICS
(Volumes in MMCFD)

LDC Class	Peak Day Peak Hour	Peak Day Avg Hour	Avg Winter Day 24 Hour Avg	Avg Summer Day 24 Hour Avg
Small	25.0	20.0	13.3	6.7
Small-Medium	50.0	40.0	26.6	13.3
Medium	100.0	80.0	53.2	26.6
Large	200.0	160.0	106.4	53.2

Power Generation Loads

Three types of power generation plant loads - combustion turbine, combined cycle and non-utility generators (NUG's) - were incorporated in the model. Assumed unit sizes for these power loads were (1) 50 MW to 100 MW for NUG combined cycle plants, (2) 100 MW to 150 MW for combustion turbine plants, and (3) 250 MW for combined cycle plants.

The amount of incremental power load additions utilized in the three system models was generally a function of: (1) anticipated power generation load growth by type and geographic region, (2) pipeline mileage by region and (3) pipeline mileage for the applicable system being modeled [i.e., (power load additions by type and by geographic region ÷ pipeline mileage in geographic region) X pipeline mileage in modeled system] and was obtained from a variety of sources.[1]

The load pattern for the various gas-fired generation units used in this study are summarized briefly below and illustrated in the bottom of Exhibit 2-5:

- *Electric utility CC units* were assumed to come on line at 7 a.m., ramping up to full load by noon, stay at full load for 8 hours, until 8 p.m., then ramp down and go off line at 11 p.m.[2] Heat rates were assumed to be 7,700 BTU/kwh.

- *NUG CC units* were assumed to be baseload plants and operate at 100% load factors. Similarly, heat rates were assumed also to be 7,700 BTU/kwh.

- *CT units* (i.e., "peakers") were assumed in the base case to be on line four hours each day between 2 p.m. and 6 p.m. Furthermore, load start-up time was approximately five minutes.

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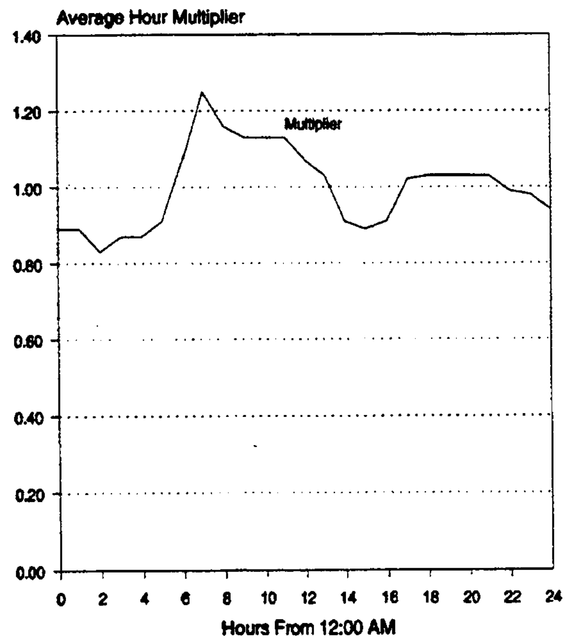
[1] See AGA, *1992 Gas Facts*, 1992 for pipeline mileage data by region; EPRI, *A Thousand Pieces - How Non-Utility Fossil Fuel Generation Adds Up*, (EPRI TR-102944), 1993 for NUG data by region and NERC, *Electricity Supply and Demand 1993-2002*, June 1993 for electric utility capacity additions by region.

[2] EPRI, *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination*, (EPRI TR-101239), September 1992.

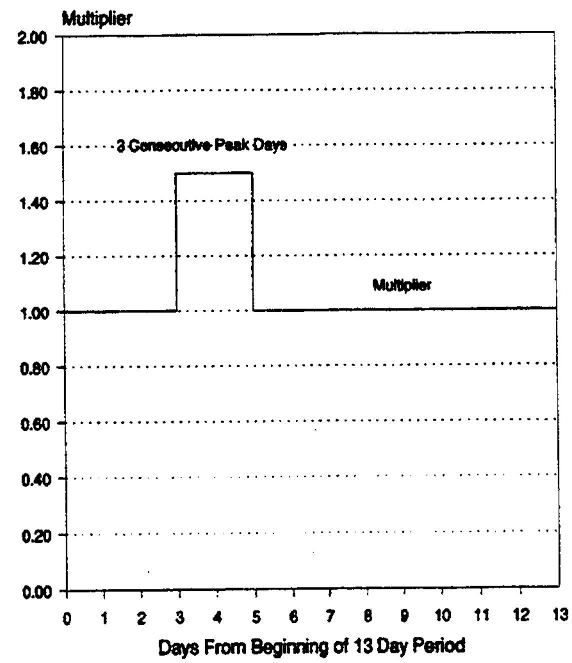
Exhibit: 2-5
LOAD PROFILES

LDC WINTER DAILY AVERAGE LOAD MULTIPLIER

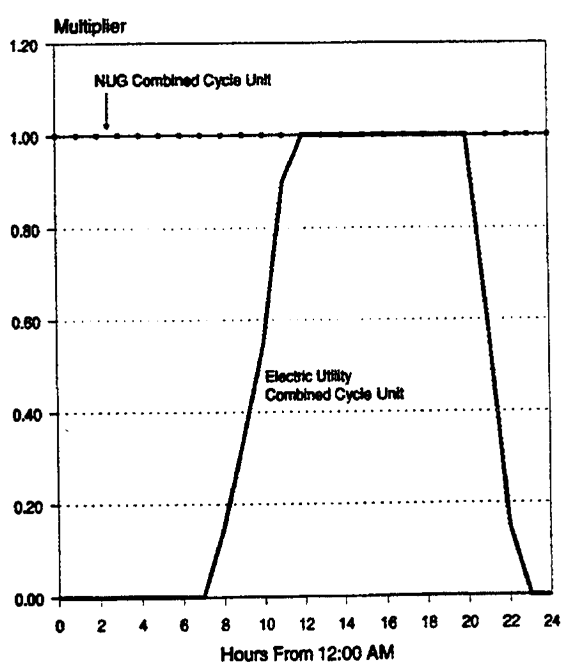


Note: 1.0 = Average Hour

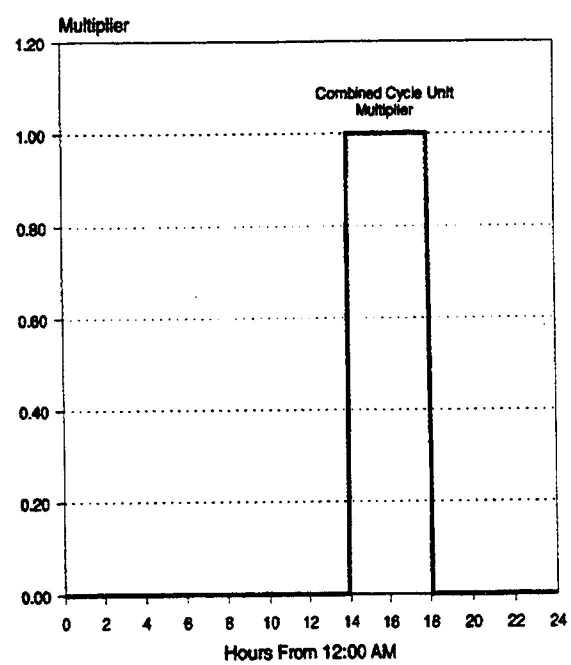
LDC AVERAGE WINTER DAY LOAD MULTIPLIER



MAXIMUM BURN RATE MULTIPLIER FOR ELECTRIC UTILITY AND NUG UNITS



MAXIMUM BURN RATE MULTIPLIER FOR COMBUSTION TURBINES



Alternative CT load profiles of four 1-hour periods and three 4-hour periods per 24 hours were also modeled. CT heat rates were assumed to be 10,000 BTU/kwh.

As to delivery pressure assumptions for these power generation loads, a minimum pressure of 400 psig at the pipeline delivery point was established for base case purposes. This pressure, even allowing for some 50 PSI of pressure drop between the pipeline and the power generation load, should be adequate to satisfy most industrial turbine applications currently under consideration. To evaluate the effect of delivery pressure on required facilities, several alternative cases were run incorporating a delivery pressure of only 325 psig.

Pipeline Design

The basic pipeline design objective for all three systems was to establish base system designs which would result in little excess capacity under the assumed peak day design conditions. This was done so that the maximum facility impact of adding incremental power generation loads could be uniformly assessed for each of the cases tested. Basic facility design for all systems assumed a realistic mix of pipeline and compression facilities; however, no system is represented as being optimally designed.

Maximum allowable operating pressure (MAOP) for the three systems varied from a low of 720 psig to a high of 1200 psig. This range covers the majority of U.S. gas transmission pipelines. Nominal pipeline size varied from 20 inches in diameter to 30 inches. Pipeline systems varied in length from a low of 400 miles in Systems 1 and 2 to 600 miles in System 3. For the purpose of calculating pipeline flows, pipe internal diameters were determined by assuming the use of high strength steel (i.e., Grade X-60 pipe) and a DOT Class I location factor, which is 72%.

Compressor station spacing generally varied from 75 to 100 miles and the minimum station size was set at 2,000 HP. Because all incremental power generation load additions were relatively small in size, requisite facility additions were limited to compression (i.e., no pipeline loops (i.e., parallel lines) were considered) and such incremental horsepower additions were limited to amounts of no less than 1,000 HP.

Storage

Storage was utilized as a load balancing tool in System 3. Simply put, it was assumed that System 3 pipeline had a storage pool or storage service which enabled it to purchase gas at a constant daily rate 365 days per year. During the summer period, excess supply would be stored and during the winter period storage withdrawals would be used to supplement the pipeline flowing supply, so that over the winter season the withdrawal of the top gas inventory plus the total pipeline flowing supply exactly equaled the winter season market requirements. Further, storage withdrawals, up to a maximum of 2% of storage top gas capacity, were used to help satisfy peak day and peak hour market requirements.

In the base case, storage was located at the beginning of the grid system where the upstream supplier or production provides gas to the grid system. From an operating perspective, this is equivalent to having no storage and simply purchasing supply on a "full requirements" basis. In the alternative grid system case, the storage pool or storage service delivery point was positioned at the downstream end of the grid. This alternative case illustrates the significant impact and support that local storage can provide to required facilities and pipeline operations.

Transient Modeling

While Section 4 of this report includes a discussion of pipeline modeling considerations and a detailed discussion of transient flow modeling for pipelines, the subject is reviewed again in very brief terms because of its overall importance. Pipeline flow analysis or modeling on a steady state basis typically involves mathematical solutions to historically developed steady state pipeline flow/pressure loss equations in which the pressure, flow and temperature are assumed to be independent of time. That is, steady state always implies that mass flow into the upstream end of a pipe section is the same as the mass flow out the downstream end with no increase or decrease of pipe section mass inventory as a function of time.

While such a steady state analysis is useful for true steady state situations wherein pipeline system loads and supplies are relatively constant over long periods of time, this type of analysis is not valid, and sometimes can be very misleading for those pipeline systems that do experience highly variable loads and supplies. For example, in the case of a pipeline system that has significant, very weather dependent LDC loads, should the steady state analysis be based upon loads representing the average winter day, the peak day, or the peak hour of the peak day? If the peak hour is chosen as the representative flow condition and required facilities, in turn, are designed to accommodate this maximum flow condition without system inventory, or line pack, draw down, then those facilities are likely over designed. Conversely, the use of average winter day or even peak day flow conditions may result in an under designed system in that available system inventory draw down may not be sufficient to cover the difference between the peak day average hour load and the peak hour load.

Before the advent of computers, it was common practice in the gas industry to use some modified forms of steady state analysis for verifying the adequacy of system facilities for future load and supply conditions as well as for designing new facilities. A common method of modifying the steady state analysis was to use some representative period flow condition and then impose an additional pressure requirement on top of the known or desired allowable minimum pressure. That is, facilities were designed to meet some estimated representative system flow condition, which was statistically typical of the system's design operating period (e.g., average hour of the peak day), while meeting a minimum pressure condition some arbitrary amount in excess of the contract minimum. This method, when successful, allowed the pipeline to meet its volume and pressure obligations under moderately variable load and supply conditions.

With the advent of transient hydraulic analysis capabilities, pipelines, engineering companies and others are now routinely simulating, modeling, planning, and designing pipeline facilities using computers when dealing with highly variable load situations. Such computer simulation for transient analysis basically consists of numerical solutions in space and time of the simultaneous partial differential equations that govern the physics of pipe flow and frictional pressure loss. The four basic equations solved in the computer by numerical solution techniques are:

- Equation of State;
- Continuity Equation;
- Momentum Equation, and
- Flow Area Equation.

The time dependent partial differential equations derived from these four equations can also be solved for the special case of time independent variables to yield many of the well known steady state gas flow equations. See Primer, Section 2, for a more detailed discussion of both steady state and transient pipeline flow formulae.

In summary, when dealing with a low load factor pipeline operating situation, the use of transient analysis allows the engineer to plan, design and operate facilities which meet the system's inherent variable flow and pressure conditions without the need for excess plant capital. Most major pipelines currently use transient flow analysis for these types of operating situations, but will use steady state analysis for most high load factor situations, because the additional sophistication and expense for transient flow analysis is not required.

Due to the inherent cyclic nature of electric utility combined cycle units and the low load factors for combustion turbine units which were the principal subjects of this research work, transient analyses were employed exclusively in the modeling done for this report. All such modeling was performed by Stoner Associates, Inc. utilizing its Drem Pipeline Simulator (DPS) software.

Discussion - System 1

Base Case Description

System 1, a 400 mile high pressure 20" pipeline system, was intended to be representative of a regional pipeline serving predominantly power generation markets in the southeastern U.S. This system is illustrated schematically in Exhibit 2-2. The initial modeling objective was to establish a realistic (but not necessarily optimum) combination of pipeline size, compression and load so that there was little, if any, excess capacity available under design conditions. Supply to this system was via a single source with the delivery point at the system's upstream terminus. MAOP of the pipeline was set at 1200 psig and a minimum delivery pressure of 400 psig was established.

The load requirements for this pipeline system consist of 800 MW of gas-fired power generation equipment and six LDC's and are summarized in Exhibit 2-6. The system 24 hour throughput for these loads totaled approximately 160 MMCF/D with peak hour throughput reaching the equivalent rate of some 227 MMCF/D.

Exhibit 2-6
SYSTEM 1 BASE LOAD REQUIREMENTS

Base Load	Size	Location by Milepost	Maximum Burn Rate (MMCF/D)
Electric Utility-CC	500 MW	350 & 400	92.4
NUG-CC	200 MW	350 & 400	36.8
Electric Utility-CT	100 MW	350	24.0
LDC	6 small-medium[1]	50,100,250,350 & 400	73.3
Total			226.5

1See Exhibit 2-4.

Mainline compression was provided for at mileposts 0, 100, 200 and 300. The amount of horsepower required, by station, was determined by running a seven day summer period simulation using the DPS model. Hourly load profiles or multipliers for the combustion turbine, combined cycle and NUG base case loads used during this seven day summer design modeling period are illustrated in Exhibit 2-5. Like the NUG's, the LDC loads were assumed to be at 100% load factor for this summer period base case design. Compression was adjusted by station until the lowest observed delivery pressure was at, or just above, the established 400 psig minimum.

The results of this base modeling for System 1 are summarized in Exhibit 2-7, which illustrates that the timed use of system inventory, or line pack, was fully utilized.

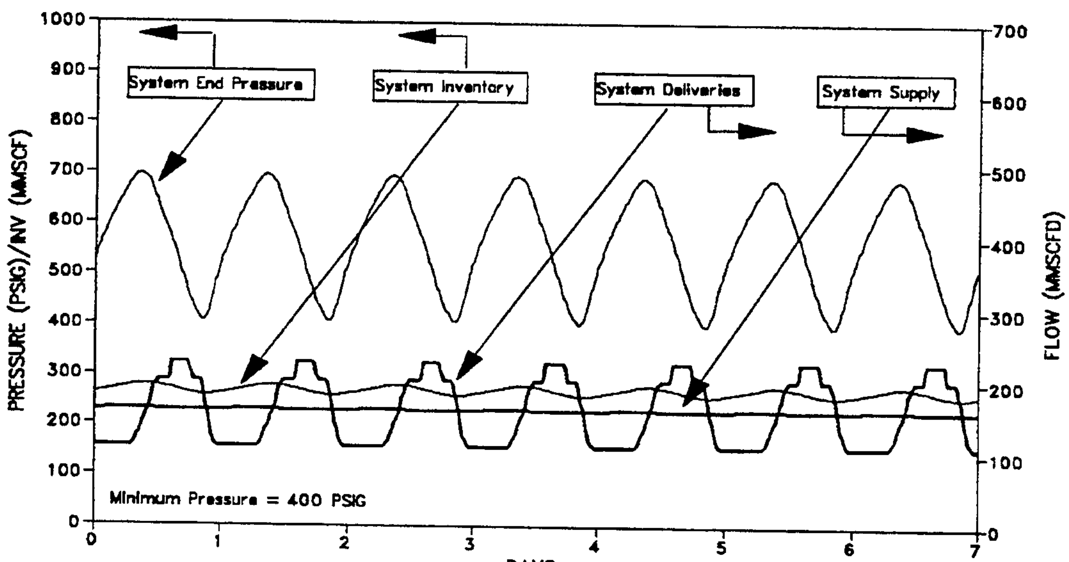
That is any further use or reduction in line pack would have resulted in the pipeline pressure dropping measurably below the 400 psig minimum. In order to obtain this result, 5,000 HP of compression was required at Station 0 and 2,000 HP was required at Station 3. Also, system supply at Station 0 was held constant throughout the period.

Exhibit 2-7, which is typical of several exhibits used in this report to describe system characteristics, includes the following information: (1) the change in system pressure (PSIG) which is presented on the left axis; (2) system inventory (MMSCF), or line peak, which is also presented on the left axis; (3) system deliveries (MMSCFD) which is the amount of gas supplied to the pipeline customers and is presented on the right axis; (4) system supply (MMSCFD) which is the amount of gas received by the pipeline, which is constant in this example, and is presented on the right axis; and (5) the minimum operating pressure for the pipeline (PSIG), which is the top straight line and is 400 PSIG in this example, and is presented on the left axis.

It should be noted that this base case configuration is far from optimum in that substantial future expansion could be effected by adding relatively low cost compression rather than adding more expensive pipeline loops. This situation would be representative of a relatively new pipeline that had been built to provide for future

Exhibit: 2-7

SYSTEM 1 SUMMARY



Footnote: System 1 (A.1)

Source: GRI/EPRI Project Team

expansion in a growing market area. Needless to say, such a system could be a good candidate for load growth such as power generation - certainly better than a "mature" system already fully powered.

Incremental Power Generation Load Additions

Several variations of this base configuration were modeled in order to assess the impact on facilities design and pipeline operations. Initially, incremental power generation loads were added to the base case system to assess the impact on facilities. One 250 MW combined cycle plant with a maximum burn rate of 46.2 MMCF/D, two 100 MW combustion turbines, each with a maximum burn rate of 24 MMCF/D, and one 50 MW NUG with a maximum burn rate of 9.2 MMCF/D were all added at milepost 400, the downstream terminus of the system, as illustrated in Exhibit 2-2. The hourly load patterns employed were the same as the those in the base case.

A seven day simulation was then rerun to determine the compression requirements with these additional power generation loads. To transport both the base case and incremental volumes (an average of 200 MMCF over each 24 hour period) and sustain the minimum pipeline pressure of 400 psig, an additional 7,000 HP was required, as depicted in Exhibit 2-8.

Exhibit 2-8
SYSTEM 1: COMPRESSION REQUIREMENTS FOR INCREMENTAL LOADS

Location	Base Case	Base Case + Incremental Loads	Incremental Compression
Station 0	5,000 HP	6,000 HP	1,000 HP
Station 1	None	3,000 HP	3,000 HP
Station 2	None	2,000 HP	2,000 HP
Station 3	2,000 HP	3,000 HP	1,000 HP
Total	7,000 HP	14,000 HP	7,000 HP

The graphic results of this supplemental modeling run are illustrated in Exhibit 2-9. These results appear similar to those depicted for the base case (i.e., Exhibit 2-7) except for amplitude of pressure and volume swings and, of course, the indicated amounts and location of compression.

Additional Design and Operational Variations

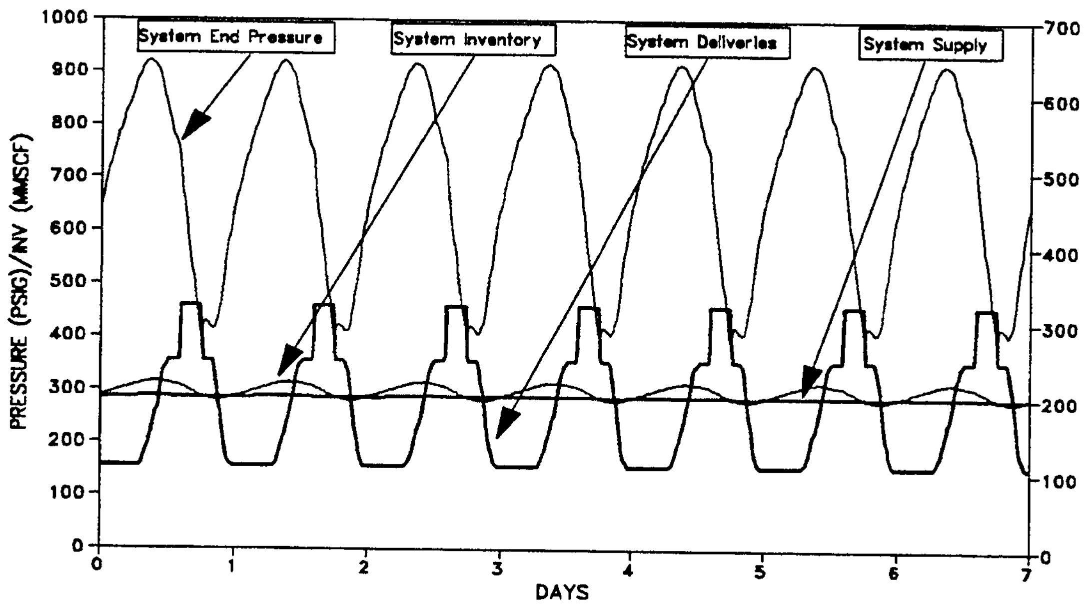
Other load characteristics, such as combustion turbine load profiles, combustion turbine start-up times, and power generation load delivery pressures were altered to further evaluate the facility impact of such operational and design variations. Each of these variations is briefly discussed below. Furthermore, in most instances the accompanying pressure and flow diagrams for each variation is also presented below; however in the interest of brevity some of these diagrams are included in the Appendix for completeness.

Alternative Combustion Turbine Load Profiles

Two alternative combustion turbine load profiles or multipliers, four - 1 hour periods per twenty four hours and three - 4 hour periods per twenty four hours, were tested to evaluate the facility sensitivity to such changes in load demand, as illustrated in Exhibit 2-10. All other load conditions remained as described above under Base Case Description and Incremental Power Generation Load Addition.

The results of changing the combustion turbine load profiles from one - 4 hour period to four - 1 hour periods did require a small change in system facilities. The top portion of Exhibit 2-11 illustrates the results of this test. In this case the compression requirements were slightly less than those developed in the original case with the one - 4 hour load pattern (i.e., 13,000 HP versus 14,000 HP). However, changing the CT load profile to multiple periods may make pipeline operations more difficult for the gas controllers, particularly if there is a lack of effective communication between the power generator and the pipeline.

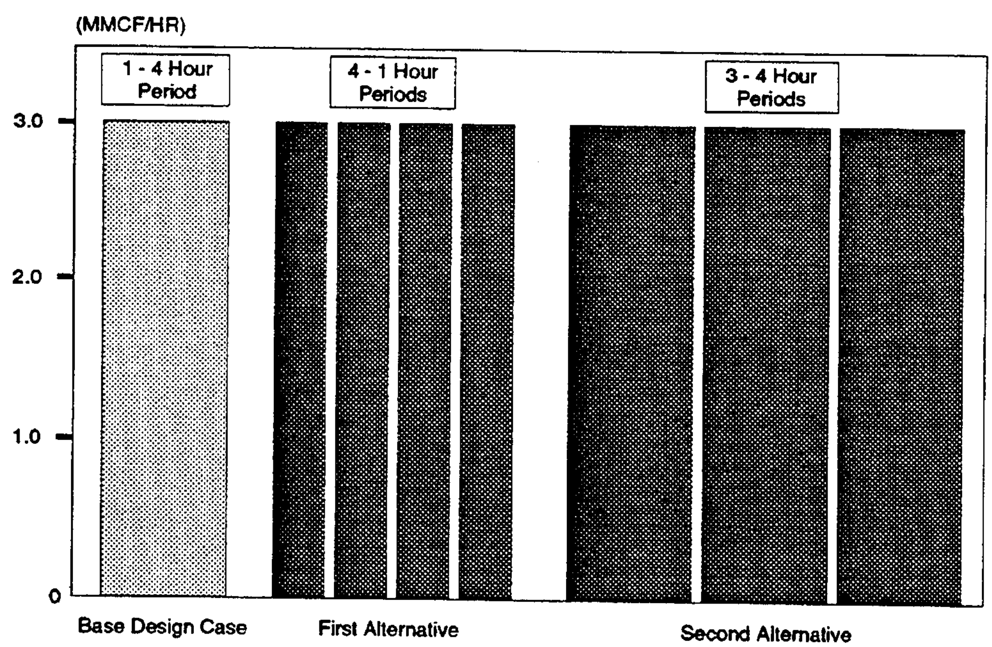
Exhibit: 2–9
ADD NEW LOADS TO SYSTEM 1



Footnote: System 1 (B.1)

Source: GRI/EPRI Project Team

Exhibit 2-10
ALTERNATIVE COMBUSTION TURBINE [(1)]
LOAD PROFILES



(1) 300 MW of gas-fired combustion turbines

Source: GRI/EPRI Project Team

The bottom portion of Exhibit 2-11 shows the results of increasing the 300 MW of combustion turbine load from one - 4 hour burn period to three - 4 hour burns each 24 hours during the seven day modeling period. In this case the facility impact is significant. Compression requirements increase from 14,000 HP to 20,000 HP, some 43%, as indicated in Exhibit 2-12.

Exhibit 2-12
SYSTEM 1: COMPRESSION REQUIREMENTS FOR CHANGING TURBINE LOADS

Location	One-4 Hour Burn	Three-4 Hour Burn	Incremental Compression
Station 0	6,000 HP	7,000 HP	1,000 HP
Station 1	3,000 HP	5,000 HP	2,000 HP
Station 2	2,000 HP	4,000 HP	2,000 HP
Station 3	3,000 HP	4,000 HP	1,000 HP
Total	14,000 HP	20,000 HP	6,000 HP

Reduction of Power Generation Load Delivery Pressure From 400 psig to 325 psig. There is a considerable variation within the industry with respect to the fuel gas pressure requirements of the newer more efficient turbine units. Some units require 445 psig, while others appear to have pressure requirements in the low 300 psig range. Furthermore, use of some of the newer aircraft derivative turbines could require 600 psig or more. In order to gain some insight into the impact of turbine fuel gas pressure requirements on pipeline facilities, the delivery pressure to the power generators was reduced from 400 to 325 psig under two conditions - first, where the combustion turbine loads were operating under the one - 4 hour burn time scenario and secondly, where these same loads were operating under the three - 4 hour burn time scenario.

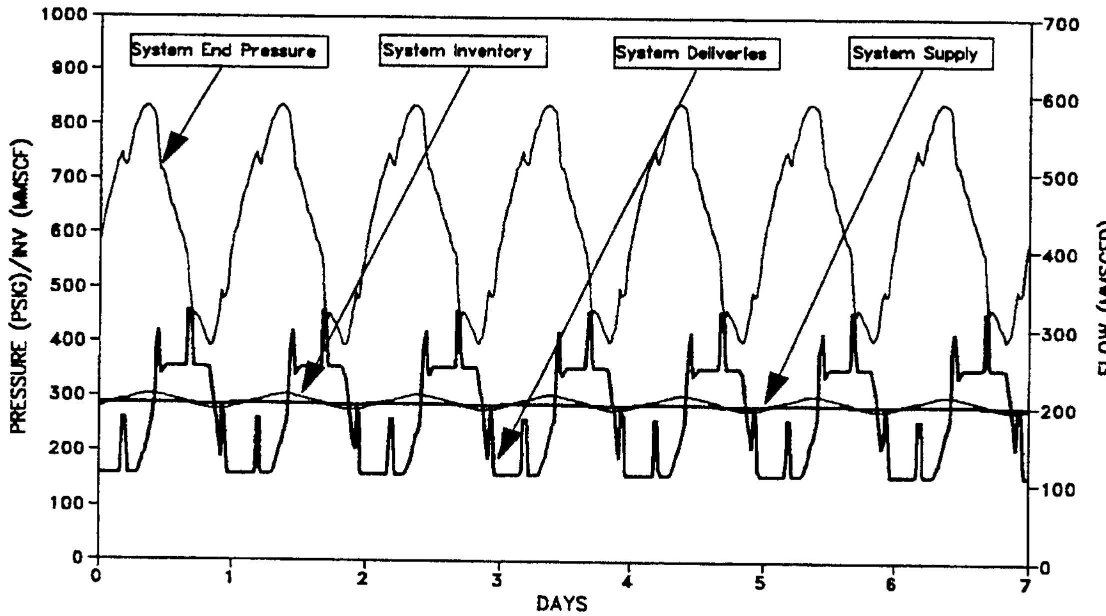
In the first instance, reducing the minimum delivery pressure from 400 to 325 psig dropped the compression requirement from 14,000 HP to 13,000 HP. Similarly, there was little difference in compression requirements using the scenario that incorporated the three - 4 hour burn times for the combustion turbines. In this case the required compression dropped from 20,000 HP to 19,000 HP when the minimum pressure was reduced to 325 psig. Exhibit 2-13 below summarizes these results, while Exhibits A-1 and A-2 in the Appendix illustrates the corresponding pressure and flow data.

Increase Combustion Turbine Start-Up Time to 30 Minutes

As was previously noted, the start-up time required for the combustion turbines can be very small. In actual fact, five minute start-up, both on line and off line, were utilized in the model runs. To test the effect of a moderately longer start-up period, a thirty minute alternative was tested.

Exhibit 2-11

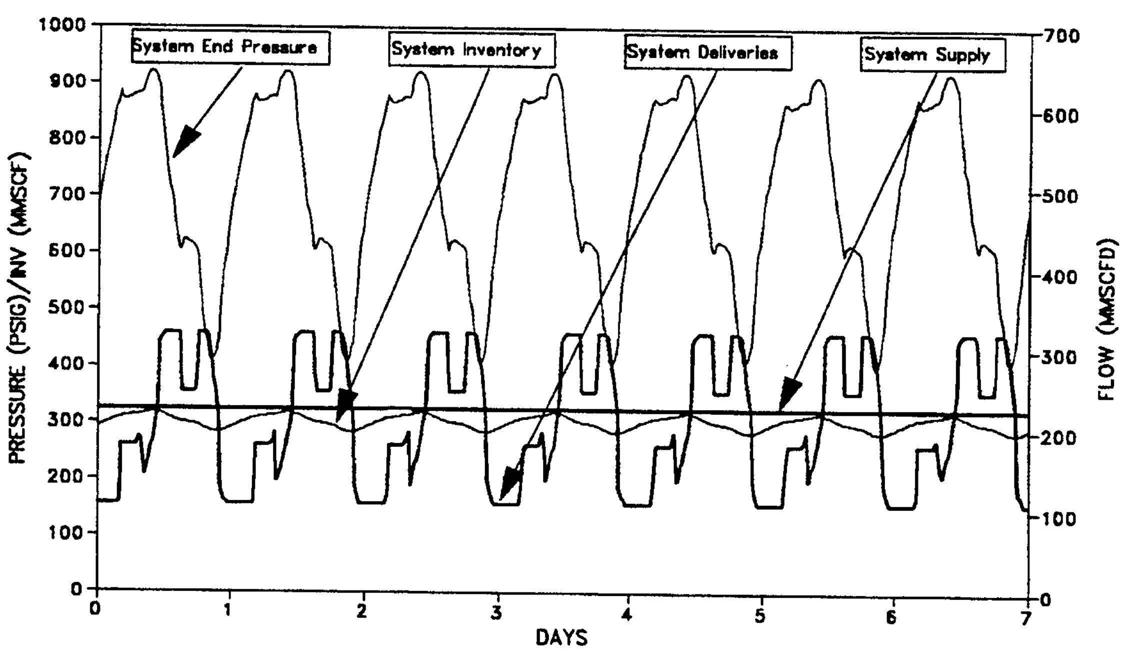
REDISTRIBUTE LOAD



Footnote: System 1 (B.2)

Source: GRI/EPRI Project Team

INCREASED CT LOAD FACTOR



Footnote: System 1 (B.3)

Source: GRI/EPRI Project Team

Exhibit 2-13
SYSTEM 1: COMPRESSION REQUIREMENTS AS A RESULT OF CHANGING PRESSURE REQUIREMENTS

CT Burn Time	Delivery Pressure		Difference
	400 psig	325 psig	
1-4 Hour Period 3-4 Hour Period	14,000 HP 20,000 HP	13,000 HP 19,000 HP	1,000 HP 1,000 HP

For comparison purposes, the base case plus incremental power generation load addition with the combustion turbines at one - 4 hour burn period was rerun employing the 30 minute start-up schedule. Even though the ramping time was increased six fold the impact on pipeline facilities was relatively minor, as compression requirements only declined from 14,000 to 13,000 HP. (See Exhibit A-3 in the Appendix for additional detail.)

Conclusions - System 1

The major conclusions from this analysis of several load characteristics of the single pipeline system represented in System 1 are as follows:

- *Load Profiles for Combustion Turbines.* To properly assess the facility impact of combustion turbine loads, accurate knowledge of the load profile is essential. While a change in load profile from one - 4 hour burn period per 24 hours to four - 1 hour burn periods per 24 hours caused no significant effect on facility requirements, increasing the combustion turbine burn time from one - 4 hour to three - 4 hour periods per 24 hours did indeed have a pronounced impact on facility requirements. This three fold increase in burn time for 300 MW of combustion turbine load caused the system compression requirements to increase more than 40%.

- *Impact of Reducing Minimum Delivery Pressure.* For the subject 1200 psig system, reducing the minimum delivery pressure from 400 to 325 psig did not have a significant effect on facility requirements regardless of the combustion turbine load pattern.

- *Impact of Reducing Combustion Turbine Start-Up Time.* Combustion turbine start-up schedules appeared to have little impact on facilities. Even when start-up time was increased six fold (from 5 minutes to 30 minutes), there was no significant reduction in compression requirements.

- *Compression Required for Incremental Power Generation Loads.* The addition of 500 MW of combustion turbine, combined cycle and NUG power generation loads required 7,000 HP of additional compression, an average of 14 HP per MW, for this 20" - 1,200 psig system (where the combustion turbine burn rate was limited to four hours per day).

Discussion - System 2

Base Case Description

As illustrated in Exhibit 2-2, System 2, a 400 mile 30" 720 psig pipeline system, was intended to be representative of a regional pipeline located downstream of storage and serving predominantly LDC markets in the northeastern United States. The initial modeling objective was to establish a realistic (but not necessarily optimum) combination of pipeline size, compression and load so that there was little, if any, excess capacity available under design conditions. Supply to this system was via a single variable or "full requirements" source with the delivery point at the upstream terminus. MAOP of the pipeline was set at 720 psig. Six LDC loads, varying in size from "Small" to "Large" (i.e., see Exhibit 2-4) were located at mileposts 50, 150, 250, 350 and 400. The peak day load totaled 400 MMCFD for this base case market.

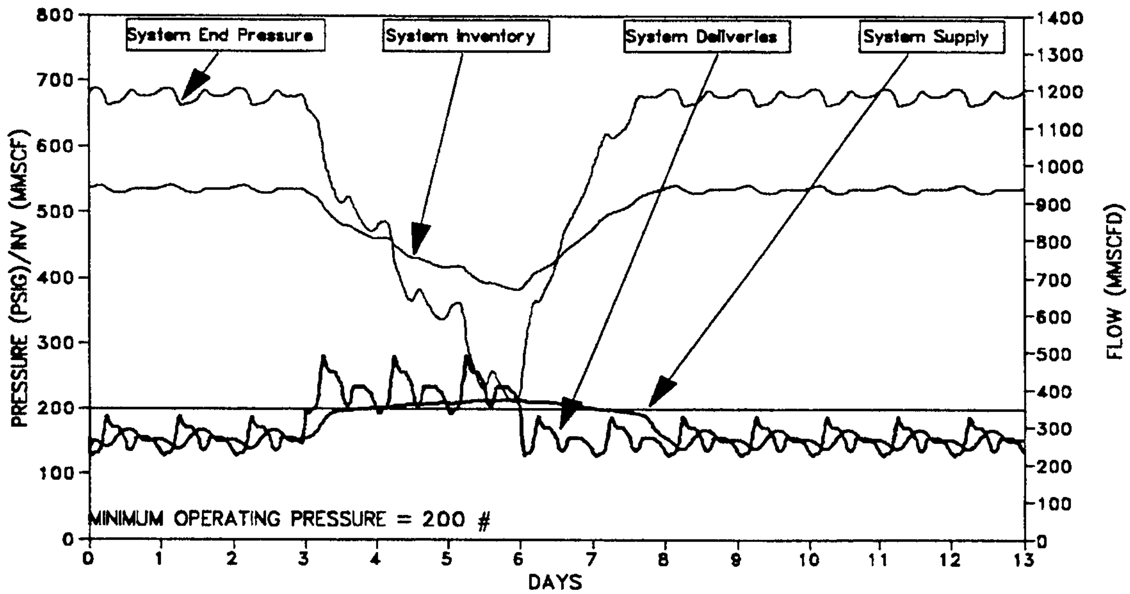
Mainline compression was provided for at mileposts 100, 200, and 300. The amount of compression required by each station was determined by running a 13 day winter period simulation listing the DPS software. This 13 day period included three consecutive peak days, a typical pipeline design criteria for a Northeast U.S. pipeline, and each peak day exhibited the hourly load profile or multiplier, as shown in Exhibit 2-5. Compression requirements were then adjusted until the lowest observed pipeline pressure was at, or just above, the 200 psig minimum under this design load condition.

The results of this base case modeling for System 2 are illustrated in Exhibit 2-14. For this system line pack, or system inventory, was fully utilized, i.e., any further reduction in line pack would have caused the pipeline pressure to drop below the 200 psig minimum. Furthermore, while the three consecutive peak days occurred during the fourth through the sixth days, the pipeline inventory and pressure did not recover until the end of the eighth day, or two days later. Finally 9,000 HP of compression was required to effect this modeling solution (i.e., Station 1-4,000 HP, Station 2-3,000 HP and Station 3-2,000 HP).

Like the System 1 base case, the System 2 base case configuration is far from optimum, in that substantial future expansion could be effected by adding relatively low cost compression, rather than adding more expensive pipeline loops. This situation would be representative of a relatively new pipeline that had been built to provide for future expansion in a growing market area. Such a system could also be a good candidate for load growth such as power generation - certainly better than a "mature" system already fully powered.

Exhibit: 2-14

SYSTEM 2 BASE CASE SUMMARY



Footnote: System 2 (2A.1)

Source: GRI/EPRI Project Team

Incremental Power Generation Load Addition

As was done for System 1, the impact of incremental power generation loads on system facilities was modeled for System 2. In this case, one 250 MW combined cycle unit with a maximum burn rate of 46.2 MMCFD and one 100 MW NUG with a burn rate of 18.4 MMCFD were added at milepost 400, the downstream terminus of the system, as illustrated in Exhibit 2-2. The hourly load patterns employed are the same as previously used for these types of units and are illustrated in Exhibit 2-4.

A thirteen day winter period simulation was then rerun to determine compression requirements with these added power generation loads. To transport the base case LDC volumes as well as the incremental power generation supply and sustain the minimum mainline pressure requirement of 200 psig under design conditions, 11,000 HP of additional mainline compression was required. Further, 2,500 HP of fuel gas booster compression was needed to effect a 400 psig fuel gas delivery to the power generators, as noted in Exhibit 2-15 below. The booster compression for the power generator, typically, automatically comes on line when the pipeline's system pressure declines below the required minimum delivery pressure for the power generator's units, which in this case is 400 psig - however, the minimum pressure of this pipeline system is 200 psig.

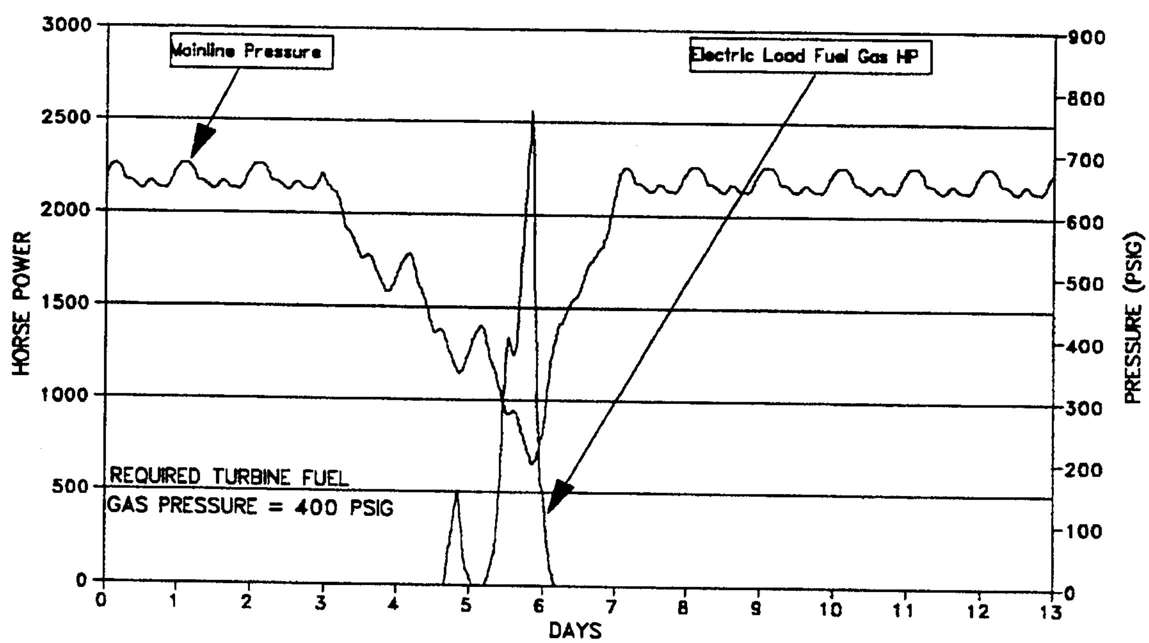
The pressure and flow diagram for this testing of additional new power generation loads, which is presented in Exhibit A-4 in the Appendix, is very similar to the similar diagram presented for the base case (i.e., Exhibit 2-14) except for the amplitude of the pressure and volume swings.

Exhibit 2-15
SYSTEM 2: COMPRESSION REQUIREMENTS FOR INCREMENTAL LOADS

Location	Base Case (LDC Only)	Power Gen Case (LDC + Power Gen)	Incremental Compression
Station 1	4,000 HP	8,000 HP	4,000 HP
Station 2	3,000 HP	6,000 HP	3,000 HP
Station 3	2,000 HP	6,000 HP	4,000 HP
Booster Station		2,500 HP	2,500 HP
Total	9,000 HP	22,500 HP	13,500 HP

The more interesting observation is the graphic illustration of the use of the booster compression at the electric utility site, which is presented in Exhibit 2-16. The use of the booster compression occurs for a very limited period of time and may or may not be cost effective, dependent upon the availability and cost of an alternate fuel, such as distillate.

Exhibit: 2-16
SYS. 2: USE OF BOOSTER COMPRESSOR FOR INCREMENTAL LOADS



Footnote: System 2 (2A.4)

Source: GRI/EPRI Project Team

This alternate fuel would be used when the gas pressure dips below the requisite turbine inlet pressure, which is assumed in this illustration to be equivalent to a mainline pressure of 400 psig. In a prior EPRI report,[3] it was noted that the total cost of alternative fuel capability for these units was $47 to $70 per kw.[4]

Design and Operational Variations

Increase Mainline Minimum Pressure to 400 psig. This alternative involved increasing the mainline minimum pressure from 200 psig to 400 psig in lieu of providing for "local" fuel gas booster compression to cover the power generation pressure requirements. No other changes in assumptions were made. Exhibit A-5 in the Appendix illustrates the pressure and flow diagram for this alternative. This diagram is similar to the one presented for the base case in many respects, except that a significant increase in mainline compression was required to effect this higher pressure for the entire system. Although increasing the mainline minimum pressure requirement to 400 psig eliminated the need for 2,500 HP of "local" or fuel gas booster compression, the price was costly in that 13,000 additional horsepower was required on the mainline, as indicated in Exhibit 2-17.

Exhibit 2-17
SYSTEM 2: COMPRESSION REQUIREMENTS FOR INCREASING MINIMUM OPERATING PRESSURE

Location	Minimum Mainline Pressure		Incremental Compression
	200 psig	400 psig	
Station 1	8,000 HP	12,000 HP	4,000 HP
Station 2	6,000 HP	11,000 HP	5,000 HP
Station 3	6,000 HP	10,000 HP	4,000 HP
Booster Station	2,500 HP		(2,500 HP)
Total	22,500 HP	33,000 HP	10,500 HP

[3] EPRI, *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination*, (EPRI TR-101239), September 1992.

[4] This cost consists of (a) unit dual-fuel capability at $6 to $15/kw; (b) automatic switching to oil at low pressure capability at $3 to $10/kw; (c) back-up oil storage system at $20/kw; and (d) back-up oil inventory at $18 to $25/kw.

Alternative 24" - 1,200 psig System. To evaluate the influence that line size and operating pressure can have on the rendering of service to power generators, an alternate case was prepared using a 24", 1,200 psig MAOP system with the same LDC and power loads and minimum 200 psig pressure condition as in the original 30" - 720 psig case. While the pressure and flow diagram for this alternative (i.e., see Exhibit A-6 in the Appendix) is similar to that for the base case (i.e., Exhibit 2-14), there was a substantial increase in compression requirements (i.e., an increase of 11,000 HP to 20,000 HP), as detailed in Exhibit 2-18.

Exhibit 2-18
SYSTEM 2: COMPRESSION REQUIREMENTS FOR ALTERNATIVE PIPELINE DIAMETER

Location	Original 30" Base Case (LDC Only)	Base Case (LDC Only)	Power Gen Case (LDC + Power Gen)	Incremental Compression
Station 0	4,000 HP	9,000 HP	12,000 HP	3,000 HP
Station 1	3,000 HP	6,000 HP	7,000 HP	1,000 HP
Station 2	2,000 HP	5,000 HP	7,000 HP	2,000 HP
Station 3			6,000 HP	6,000 HP
Booster Station			2,500 HP	2,500 HP
Total	9,000 HP	20,000 HP	34,500 HP	14,500 HP

In addition, the same incremental power generation loads that were previously discussed for System 2 were added, and the simulation was rerun. The mainline compression requirement increased from 20,000 HP to 32,000 HP as a result of adding the 350 MW of electric power load, plus 2,500 HP of fuel gas booster compression was also required, as presented in Exhibit 2-18. Pressure and flow diagrams for these alternatives are presented in Exhibits A-7 and A-8 in the Appendix.

The total incremental compression, 14,500 HP, required in this alternative 24"/1,200 psig case is not substantially different than the 13,500 HP of incremental compression required in the original 30"/720 psig scenario (i.e., Exhibit 2-15).

Finally, to obtain a second reading on the impact of changing the minimum mainline pressure from 200 psig to 400 psig (in lieu of using fuel gas booster compression), this alternative 24"/1,200 psig system was modified in a manner identical to that which was described previously. Unlike the 30"/720 psig scenario, only a limited increase in mainline compression was required to effect this higher minimum pressure for the entire system, as summarized in Exhibit 2-19. (Exhibit A-9 in the Appendix provides a pressure and flow diagram for this alternative.)

Although it still appears to be more cost effective to use local fuel gas booster compression, as opposed to use of distributed system wide compression, to achieve the

400 psig minimum pressure level, the difference in incremental compression required is much less significant with this higher MAOP 24" system.

Exhibit 2-19
SYSTEM 2: COMPRESSION REQUIREMENTS FOR INCREASING MINIMUM OPERATING PRESSURE ON A 24" SYSTEM

Location	Minimum Mainline Pressure		Incremental Compression
	200 psig	400 psig	
Station 0	12,000 HP	12,000 HP	
Station 1	7,000 HP	9,000 HP	2,000 HP
Station 2	7,000 HP	8,000 HP	1,000 HP
Station 3	6,000 HP	7,000 HP	1,000 HP
Booster Station	2,500 HP		(2,500 HP)
Total	34,500 HP	36,000 HP	1,500 HP

Conclusions - System 2

The major conclusions associated with the analysis of System 2 are as follows:

- *Fuel Gas Booster Versus Mainline Compression.* If power generation loads are localized, the use of fuel gas booster compression to satisfy the minimum pressure requirements of such loads appears to be more cost effective (i.e., requires less total compression) than increasing the minimum operating pressure of the entire system.

- *Compression Required for Power Generation Loads.* Assuming the use of fuel gas booster compression and a minimum mainline pressure of 200 psig, the additional compression required to satisfy the incremental power generation loads averaged 40 HP per MW (39 HP/MW for the 30" system and 41 HP/MW for the 24" system).

- *Fuel Gas Booster versus Alternate Fuel.* The use of distillate or other alternate fuels (when pipeline pressure drops below power turbine minimums) may be more cost effective than paying for and utilizing fuel gas booster compression, since the need for this horsepower was very limited in all cases tested.

Discussion - System 3

Base Case Description

As illustrated in Exhibit 2-3, System 3 is a 600 mile pipeline loop, or grid, consisting of 450 miles of 24" and 150 miles of 20" legs, or segments, and is intended to be representative of a moderately sized pipeline, with underground storage, serving predominantly low load factor LDC markets in the mid Atlantic region or midwestern region of the United States. The initial modeling objective was to establish a realistic combination of pipeline size, storage, compression and load so that there was little, if any, excess capacity remaining under design conditions.

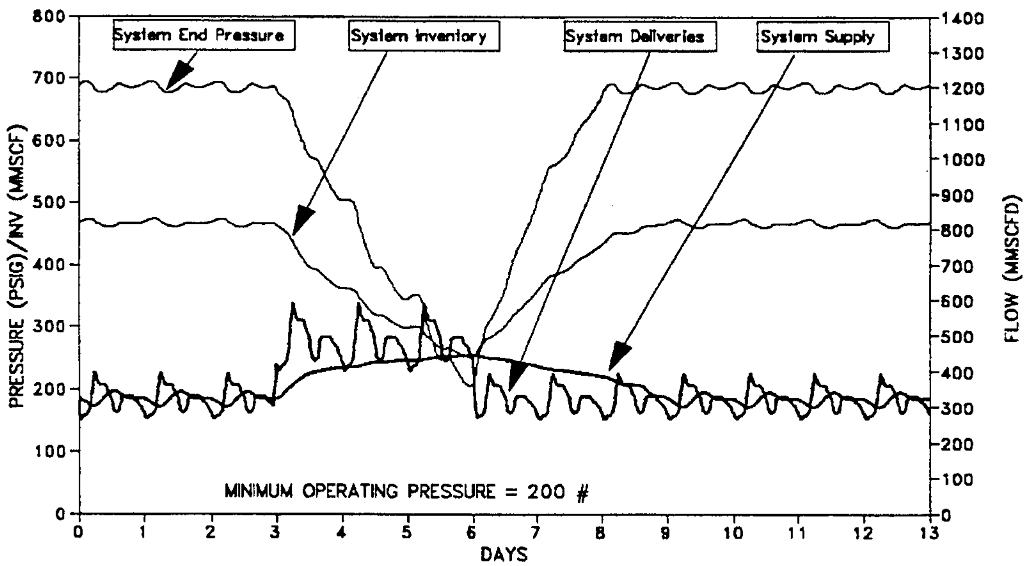
Supply to this System was assumed available via a single 100% load factor source, and deliverable at 500 psig at the upstream terminus. MAOP for this System was set at 720 psig and a minimum delivery pressure of 200 psig was also established. Additionally, 14 BCF of storage (or contracted storage service) capacity and up to 280 MMCF/D of peak day storage deliverability were also assumed available at this upstream point. The 14 BCF of top gas capacity was the amount required to balance the basic system on a seasonal basis and, in turn, allow the purchase of upstream pipeline supply, or production, on a 100% load factor basis. The 280 MMCF/D of peak day storage deliverability, some 2% of top gas capacity was utilized along with line pack and flowing supply to satisfy peaking requirements. The 2% of top gas capacity is considered reasonably representative of a storage pool developed from a depleted natural gas production reservoir in this geographic region of the U.S. While storage allowed this particular pipeline system to load balance, locating such storage at the upstream terminus of the system generated no direct downstream operational benefits. Simply put, coupling storage with a 100% load factor supply purchase at this point on the system is tantamount, operationally speaking, to purchasing supply on a "full requirements" basis. In an alternative case discussed below, the advantage of having this storage located downstream within the major market area is explored.

Six LDC loads, varying in size from "Small" to "Large" (i.e., see Exhibit 2-4), were located throughout the System every 75 to 150 miles. The peak day load for this LDC base case market totaled 480 MMCF/D. Furthermore, mainline compression was located every 75 miles on the 24" legs. As with System 2, the amount of compression required by station was determined by running a 13 day winter period simulation. This 13 day period included three consecutive peak days, a typical design criteria for a upper midwest U.S. pipeline. Further, each daily load, including the peak days, was profiled on the basis of the hourly multiplier shown in Exhibit 2-5. Horsepower was then adjusted until the lowest observed pipeline pressure was at, or just above, the 200 psig minimum under this design load condition.

The results of this base case modeling for System 3 are illustrated in Exhibit 2-20. For this system, line pack, or system inventory, was fully utilized. That is, any further reduction in line pack would have caused the pipeline pressure to drop below the 200 psig minimum. Furthermore, as was the case for System 2, while the three consecutive

Exhibit: 2-20

SYSTEM 3 BASE CASE SUMMARY



Footnote: System 3 (3A.1)

Source: GRI/EPRI Project Team

peak days occurred during the fourth through the sixth day, the pipeline inventory and pressure did not recover until the end of the eighth day, or two days later. Also, system supply in Exhibit 2-20 is a combination of flowing supply, which is fixed at 226 MMCF/ D, and storage deliverability. Finally, 15,000 HP of compression was required to effect this modeling solution (i.e., Station 0-6,000 HP, Station 1-2,000 HP, Station 2-2,000 HP and Station 3-3,000 HP), and Station 4-2,000 HP.

Like the base cases for both Systems 1 and 2, it should be noted that this System 3 base case configuration is far from optimum in that substantial future expansion could be effected by adding relatively low cost compression rather than adding more expensive pipeline loops. This situation would be representative of a relatively new pipeline that had been built to provide for future expansion in a growing market area.

Again, such a system could be a good candidate for load growth such as power generation - certainly better than a "mature" system already fully powered.

Incremental Power Generation Load Addition

As with the prior System 1 and 2 studies, several variations of this base configuration were subsequently modeled in order to assess the impact on facilities design and pipeline operations. Initially, incremental power generation loads were added to the base case market to test facility impact. In this instance, two 150 MW combustion turbines were added near the far "end" of the grid adjacent to the "Large" LDC's and at the ends of the 24" legs, (i.e., see Exhibit 2-3). Each of these incremental power loads had a maximum burn rate equivalent of 36 MMCF/D. The hourly load profile for these peakers is illustrated in Exhibit 2-5.

A thirteen day winter period simulation was then rerun to determine compression requirements with these incremental power generation loads. To transport the base case LDC volumes as well as the incremental power generation supply and sustain the minimum mainline pressure requirement of 200 psig under design conditions, 1,000 HP of additional mainline compression was required. Further, 3,000 HP of fuel gas booster compression was needed to effect a 400 psig delivery pressure to the power generators, as illustrated in Exhibit 2-21 below:

Exhibit 2-21
SYSTEM 3 (UPSTREAM STORAGE): COMPRESSION REQUIREMENTS FOR INCREMENTAL LOADS

Location	Base Case (LDC Only)	Power Gen Case (LDC + Power Gen)	Incremental Compression
Station 0	6,000 HP	7,000 HP	1,000 HP
Station 1	2,000 HP	2,000 HP	None
Station 2	2,000 HP	2,000 HP	None
Station 3	3,000 HP	3,000 HP	None
Station 4	2,000 HP	2,000 HP	None
Booster Station	None	3,000 HP	3,000 HP
Total	15,000 HP	19,000 HP	4,000 HP

The pressure and flow diagram for the addition of this new CT load, which is presented in the Appendix (i.e., Exhibit A-10), is very similar to the diagram presented for the base case (i.e., Exhibit 2-20), except for the amplitude of pressure and volume swings. The use of the fuel gas booster compression required in this analysis is very limited, as illustrated in Exhibit A-11 in the Appendix. Thus, it may be more cost effective when gas pressure dips below the requisite turbine inlet pressure (i.e., 400 psig) to use an alternate fuel depending on its availability.

Additional Design and Operational Variations

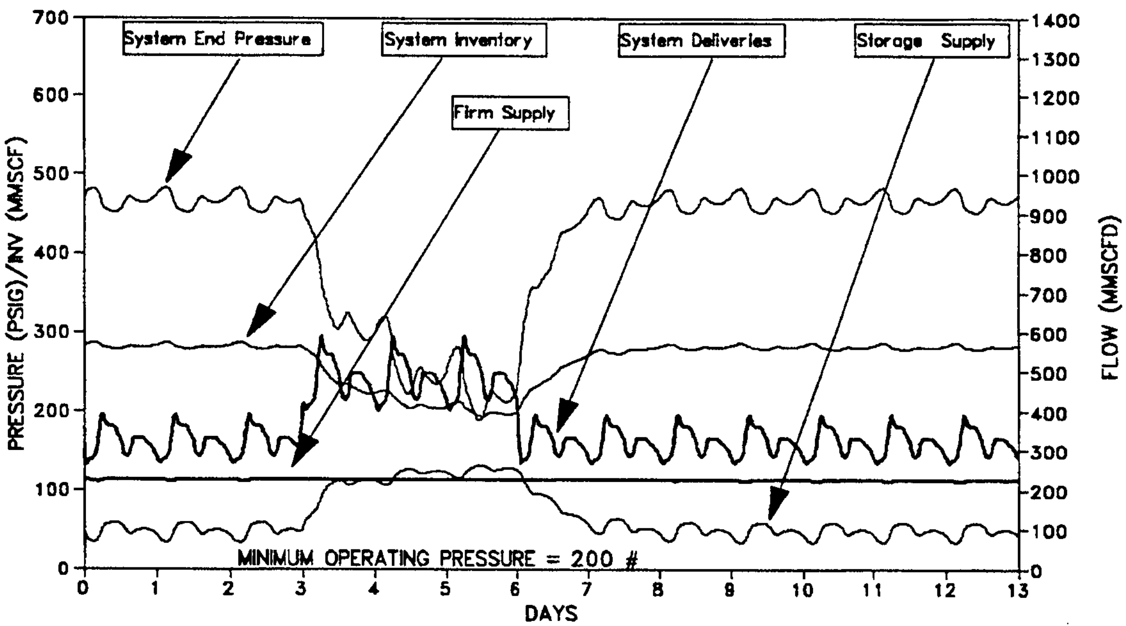
Three additional design and operational variations were tested. The first two of the three variations that were modeled were based upon an alternative grid system in which storage was assumed available in the downstream market area in lieu of being located at the upstream terminus. The final variation examines changes in CT load profiles using the base case for System 3 in which storage was located at the upstream terminus.

Downstream Storage Alternative. To evaluate the effect that storage location can have upon system design and operations, an alternative case was developed in which the 14 BCF of gas storage was assumed available in the downstream market area midway between the "Large" LDC loads (i.e., see Exhibit 2-3). By shifting the storage load balancing function downstream, it was possible to reduce the previous 24" legs to 20". Exhibit 2-22 illustrates the results of rerunning this base case with downstream storage.

In addition to reducing 450 miles of line pipe from 24" to 20", this alternative base case only required 5,000 HP of compression versus 15,000 HP in the original base case. In order to fully illustrate the impact of storage in this alternative, storage deliverability and 100% load factor pipeline or production flowing supply have been separated on the Exhibit 2-22.

Exhibit: 2-22

SYSTEM 3 ALTERNATE LOCATION FOR STORAGE



Footnote: System 3 (3B.1)

Source: GRI/EPRI Project Team

The impact of incremental power generation on this alternative system design was also tested. The results of this modeling exercise are presented in Exhibits A-12 and A-13 in the Appendix. As was the case previously, mainline compression requirements increased 1,000 HP as a result of adding the 300 MW of combustion turbine load, and 3,000 HP of booster compression was also required to effect the 400 psig minimum delivery pressure for the combustion turbines. This incremental increase of 4,000 horsepower was identical to that required in the former, upstream storage scenario, as illustrated in Exhibit 2-23.

Increase Mainline Minimum Pressure to 400 psig. As was done for System 2, the impact of increasing the mainline minimum pressure from 200 psig to 400 psig was tested using the System 3 pipeline model that incorporated the alternative, or downstream, location for storage and the incremental power generation load. Increasing

Exhibit 2-23
SYSTEM 3 (DOWNSTREAM STORAGE): COMPRESSION REQUIREMENTS

Storage Location	Base Case (LDC Only)	Power Gen Case (LDC + Power Gen)	Incremental Compression
Upstream	15,000 HP	19,000 HP	4,000 HP
Downstream	5,000 HP	9,000 HP	4,000 HP

the mainline minimum pressure requirements is an alternate to using local fuel gas booster compression to cover the power generation pressure requirements. While Exhibit A-14 in the Appendix illustrates the results of this design alternative, the key point of interest is that while mainline compression requirements increased from 6,000 HP to 8,000 HP, the need for 3,000 HP of booster compression was eliminated. The net result was an overall reduction in horsepower from 9,000 to 8,000 HP, which is attributable to the flexibility provided by the nearby storage.

Alternate Combustion Turbine Load Profiles. As with System 1, two alternative combustion turbine load profiles or multipliers, four - 1 hour periods per twenty four hours and three - 4 hour periods per twenty four hours, were tested to evaluate the facility sensitivity to such changes in load demand (i.e., see Exhibit 2-10). Furthermore, the base case System 3 in which storage was located at the upstream terminus, was used to test the impact of these alternative load profiles.

The results of changing the combustion turbine load pattern from one - 4 hour period to four - 1 hour periods had no effect on facilities, as illustrated in Exhibits A-15 and A-16 in the Appendix. The compression requirements are the same as those developed in the original case with the one - 4 hour load pattern (i.e., 19,000 HP). However, this does not suggest that pipeline operations will not be made more difficult for the gas controllers, particularly if there is a lack of effective communications between the power generator and the pipeline.

While there was no effect for the first alternate CT load profile tested, compression requirements increased substantially when the CT load profiles were changed from one - 4 hour period to three - 4 hour periods, as illustrated in Exhibit 2-24 below (also see Exhibit A-17 and A-18 in the Appendix).

To assess the potential impact that downstream storage might have when the combustion turbine burn times are altered, these same tests were rerun using the alternative design for System 3 where the storage was located downstream. As expected, shifting the combustion turbines burn times from one - 4 hour period per 24 hours to four - 1 hour periods per 24 hours had no effect on the compression requirements (i.e., see Exhibits A-19 and A-20 in the Appendix). However, when the burn times were increased to three - 4 hour burn periods per 24 hours, the compression requirements increased, but only from 9,000 HP to 10,000 HP, which may be a surprise to

Exhibit 2-24
SYSTEM 3 (UPSTREAM STORAGE): COMPRESSION REQUIREMENTS FOR ALTERNATIVE CT LOAD PROFILES

Location	One - 4 Hour Burn	Three - 4 Hour Burn	Incremental Compression
Station 0	7,000 HP	8,000 HP	1,000 HP
Station 1	2,000 HP	3,000 HP	1,000 HP
Station 2	2,000 HP	3,000 HP	1,000 HP
Station 3	3,000 HP	3,000 HP	None
Station 4	2,000 HP	3,000 HP	1,000 HP
Booster Stations	3,000 HP	3,000 HP	None
Total	19,000 HP	23,000 HP	4,000 HP

Exhibit 2-25
SYSTEM 3 (DOWNSTREAM STORAGE): COMPRESSION REQUIREMENTS FOR ALTERNATIVE CT LOAD PROFILES

Location	One - 4 Hour Burn	Three - 4 Hour Burns	Incremental Compression
Station 0	4,000 HP	4,000 HP	None
Station 1	None	None	None
Station 2	1,000 HP	2,000 HP	1,000 HP
Station 3	None	None	None
Station 4	1,000 HP	1,000 HP	None
Booster Stations	3,000 HP	3,000 HP	None
Total	9,000 HP	10,000 HP	1,000 HP

some readers (i.e., see Exhibit A-21 and A-22 in the Appendix). This clearly illustrates the significant impact that having nearby storage can play in providing operational flexibility. Compression requirements for these alternative load profiles are compared and contrasted in Exhibit 2-25 below.

Conclusions - System 3

The major conclusions associated with the analysis of System 3 are as follows:

- *Flexibility Provided by Storage.* Market area storage had a significant impact on facility requirements in cases with and without incremental power generation loads. For example in this System 3 case with both LDC and incremental power generation loads, the shift of storage to the downstream market area permitted the reduction in size of 450 miles of line pipe from 24" to 20" and a corresponding reduction in compression requirements from 19,000 to 9,000 HP.

- *Load Profiles for Combustion Turbines.* Although pipeline operations and communications may be adversely affected, one - 4 hour versus four - 1 hour combustion turbine operating cycles per day had no material effect on facility requirements. However, increasing the combustion turbine load patterns from one - 4 hour to three - 4 hour periods per day had a substantial impact on the facility requirements, except in the case where storage deliverability was locally available (i.e., downstream) to mitigate the impact of compression requirements.

- *Fuel Gas Booster versus Mainline Compression.* With gas storage deliverability available in the immediate market area, increasing the mainline grid system pressure from 200 psig to 400 psig, in lieu of utilizing booster compression to satisfy combustion turbine pressure requirements, did not significantly effect facility requirements.

- *Compression Required for Incremental Power Generation Loads.* The addition of 300 MW of combustion turbine loads required the addition of 4,000 HP of compression, some 13 HP per MW, when the burn rate was limited to four hours per day, regardless of the location of storage.

Transient Flow Versus Other Analyses

In a prior EPRI report concerning the challenge of gas and electric industry coordination, several examples were developed concerning the possible impact of large high pressure load requirements for power generation on pipelines. These examples illustrated that such power generation loads were more susceptible to cause pipeline operating problems than the traditional low pressure gas requirements for steam generators. Chief among these operating problems was the possibility of reducing pipeline pressure below minimum operating levels.

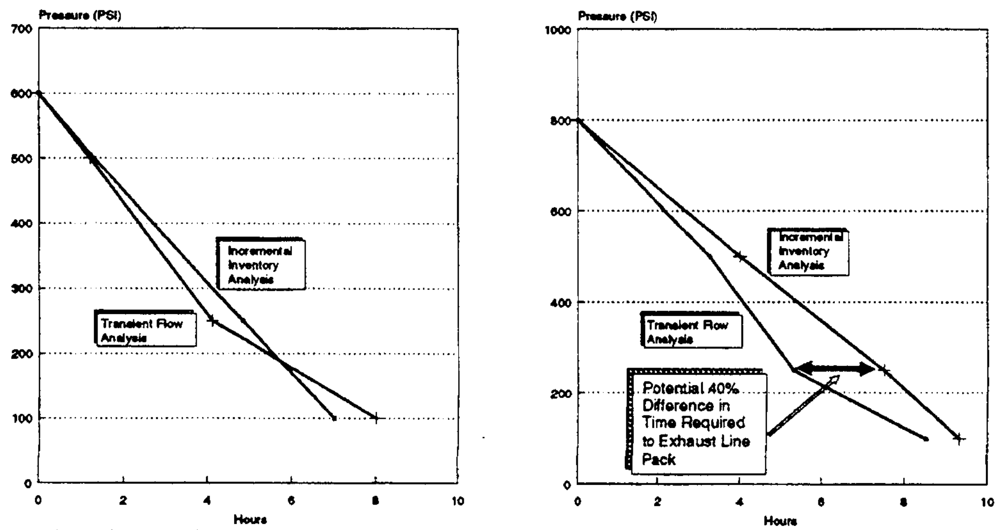
While the overall conclusion of this series of examples was that there was both a cost associated with the use of units with higher pressure requirements and a need for closer coordination between the two industries as a result of the use of the newer gas-fired units, the specific examples used an incremental inventory analysis rather than transient flow analysis.

Exhibit 2-26 compares the use of transient flow analysis to the incremental inventory analysis for two of the examples used in a prior EPRI report. For the example involving a low pressure pipeline system (e.g., a MAOP of 700 psi), the incremental inventory analysis provided a reasonable approximation of the correct transient flow analysis. However, for high pressure pipeline systems (e.g., a MAOP of 1,100 psi) the incremental inventory analysis overstated the results by up to 40%, which means that the available line pack would have been exhausted is less time than predicted using an incremental inventory analysis. While the general conclusion of these analyses is the same (i.e., the use of high pressure gas-fired units increases the need for the coordination between the gas and electric industries), the actual analysis of such situations should use transient flow analysis in order to provide a more rigorous solution, or perspective, in all cases.

Exhibit 2-26

TIME TO EXHAUST LINE PACK [3]

LOW PRESSURE SYSTEMS [1] HIGH PRESSURE SYSTEMS [2]



(1) 700 PSI MAOP (2) 1,100 PSI MAOP

(3) 500 MW Of Capacity, 36" Line, 40 Miles From Compressor Station

Source: GRI/EPRI Project Team

General Modeling Conclusions

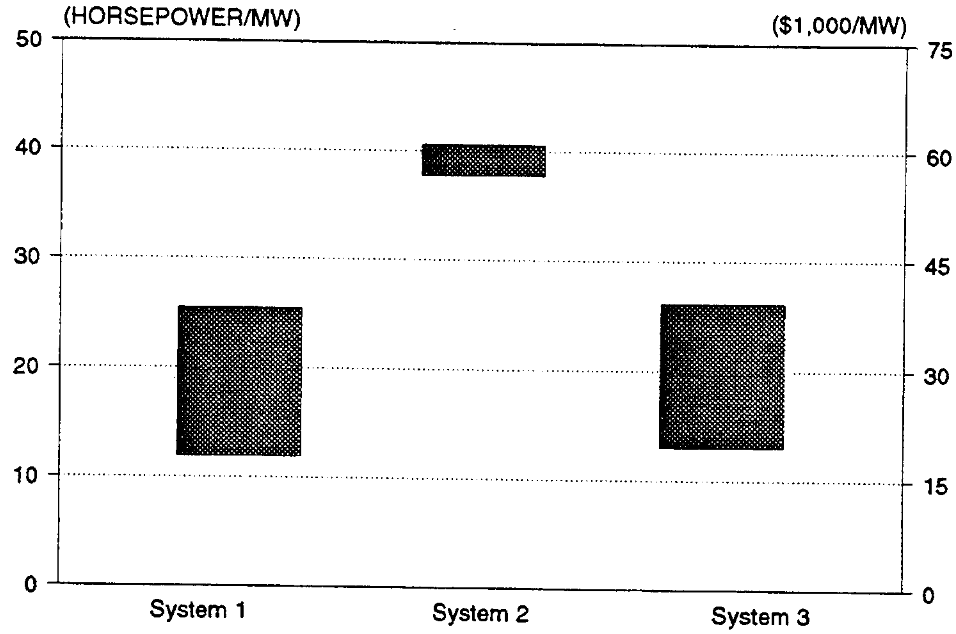
The most important general conclusion from the research done for this report is that pipelines, LDC's and end users need to use transient flow analysis when evaluating new load opportunities that are both large and subject to considerable variation, as is the case with many electric utility applications. Some of the major conclusions associated with the specific modeling done for this report are summarized below.

- *Varying Timing of Load:* Varying the number of power generation load burn periods per day did not effect facility requirements, provided that the total burn time remained constant. For example, increasing combustion turbine loads from one - four hour burn period per day to four - one hour burn periods per day had no significant impact on the amount of facilities required.

- *Varying Amount of Load:* Varying the total amount of combustion turbine burn time per day had a significant effect on facilities required. For example, in one case tested, the additional facilities associated with increasing the daily combustion turbine burn time from four hours to 12 hours totaled 20 HP per MW.

Exhibit 2-27

COST OF POWER GENERATION LOAD ADDITIONS



Source: GRI/EPRI Project Team

- *Additional Facilities:* The facility additions necessary to support incremental power generation loads varied between 12 and 41 HP per MW, but a significant amount of this variation was dependent on the pipeline system that was analyzed. Assuming an average capital cost of $1,500 per HP, that equals a range of $18,000 to $62,000 per MW. Exhibit 2-27, as does the table in Exhibit A-23 in the Appendix, compares and contrasts that amount of facility additions required to support incremental power generation for the three pipeline systems analyzed in this report. The costs for Systems 1 and 3 are very similar and in both cases the upper end of the range is due to the additional load requirements for alternative of using the combustion turbine units for three - 4 hour periods per day. The overall higher costs for System 2 are similarly the result of higher load requirements of this system, which only added combined cycle units and had no combustion turbine units with their relatively low capacity factor per MW.

- *Steady State vs. Transient Flow:* Use of steady state flow equations to design pipeline systems to serve low load factor combustion turbine and combined cycle power generation loads may result in (1) significant over design if that design is based upon maximum hourly flow conditions or, conversely, (2) significant under design if that design is based upon the average 24 hour flow rate.

- *CT Ramping:* While power generation ramping rates may affect operations, particularly if communication between pipeline and power generation operating personnel is inadequate, ramping time had little impact on the basic facility design (e.g., increasing combustion turbine ramping rates from five minutes to 30 minutes did not affect facilities).

- *Load Compression:* Generally, it was less costly to use "local" booster compression to satisfy power generation minimum pressure requirements than to increase pressure on the entire pipeline system, provided that the power generation load was localized and not distributed along the entire pipeline.

- *Pipeline Design Alternatives:* Larger diameter pipe operating at lower pressure (e.g., 30" @ 720 psig) was slightly less costly to expand for power generation loads than smaller diameter line operating at higher pressure (e.g., 24" @ 1,200 psig), provided that minimum line pressure was 200 psig and that "local" compression was used to satisfy the power generation pressure requirements.

- *Storage:* Local gas storage reduced or eliminated significant pipeline facilities that would have otherwise been required to support incremental power generation load operations.

- *Alternative Fuels:* The use of distillate or other alternate fuels to fuel power generation loads (when pipeline delivery pressure drops below power turbine minimums) may be more cost effective than paying for and utilizing fuel gas booster compression, since the need for this horsepower was very limited, in terms of "on line" time, in all cases tested.

3

INDUSTRY EXAMPLES

Overview

In the previous chapters of this report the basic tools that are available to the pipeline designer to meet the requirements of large load customers, such as electric utilities, were discussed along with some of the approaches that might be taken for several hypothetical examples. In this section several examples of how specific pipelines have responded to changing loads using transient flow analysis are examined. These industry examples include the following:

- *Tennessee Gas Pipeline:* This example illustrates how a pipeline uses transient flow analysis to demonstrate that it has the capability to meet large load changes near the end of its system without any major changes to its compressor stations.

- *Public Service Electric and Gas (PSE&G):* This example illustrates how required pressure conditions can be met at the delivery point through the use of a small electric powered gas compressor.

- *SONAT:* In an effort to further illustrate the concepts discussed in this report SONAT developed an example of how their pipeline, which has been constructed to meet winter design conditions, would be able to meet electric utility load requirements during the summer period.

- *El Paso Natural Gas:* This analysis provides an illustration of when transient flow analysis is not required in order for a pipeline to meet changing load conditions.

- *Sunshine Pipeline:* This is a new pipeline which is being designed using transient flow analysis and in particular, using hourly flow data rather than the historical 24 hour average flow data.

- *Mayflower Pipeline:* This pipeline is still in the planning stages. Transient flow analysis has been used to illustrate how this pipeline will be able to respond to a change in load requirements from a power generation plant.

Tennessee Gas Pipeline

In 1990 Tennessee Gas Pipeline adapted its facilities in the New England region, specifically Massachusetts and Rhode Island, to provide service to the initial Ocean State

Power project (OSPI),[1] which was a base loaded 250 MW gas-fired combined cycle plant. Tennessee used transient flow analysis to determine the required incremental facilities to support the OSPI project. For the most part, the pipeline configuration and incremental power generation load requirements for OSPI were very similar to the expansion of System 2 presented in Section 2 of this report. The chief exceptions were that, since Tennessee was a fully powered pipeline, pipeline looping, as well as additional compression was required to meet the new load requirements.

Subsequently, as part of a regional analysis of the capability of the pipelines serving the New England region to meet changing load requirements under worst case conditions,[2] a transient flow study was undertaken concerning Tennessee's capabilities under such a scenario. The critical points in this study, as illustrated in Exhibit 3-1, were the discharge pressure at Station 264, the Burrillville delivery point, which is the sole delivery point to the Ocean State Power project, and the suction pressure at Station 267 (i.e., see Exhibit 3-1). The changes in pipeline pressure at the OSP under these conditions as determined by the transient flow study are summarized in Exhibit 3-2, which illustrates that the pipeline could maintain service under the postulated worst case conditions.

Public Service Electric & Gas

The addition of new power generation loads to both Systems 2 and 3 (i.e., see Section 2) resulted in the use and analysis of booster compression inside the plant gate of the power generator. Recently, Public Service Electric & Gas (PSE&G) incorporated the use of booster compression for its new 250 MW combined cycle units at its Burlington, New Jersey facility.

PSE&G installed four Pratt-Whitney PW-4-FT-8 Turbo Power and Marine Twin Pac combustion turbines, each driving a single electric generator. The waste heat from these units is used to produce steam for an existing steam turbine generator. These units have been designed to burn natural gas and/or kerosene.

The guarantee of low NOx emissions was an important factor in selecting these aircraft derivative turbine units, however, they require a minimum natural gas pressure of 445 psig at full load. These units can run at reduced load with a pressure as low as 375 psig before tripping out.

After negotiations with Transcontinental Gas Pipe Line (Transco) and a transient flow study of the pipeline, PSE&G agreed to tie into an existing 16-inch pipeline that was 2 miles long and had a MAOP of 800 psig. The Burlington plant is 20 miles from the Transco main line, which consists of 30-inch, 36-inch and 42-inch pipelines. Final requirements were to provide gas at 250 psig to the Burlington site. In order to ensure a

[1] Subsequent to the development of OSPI, OSPII was constructed (i.e., an additional 250 MW combined cycle unit). OSPII was a part of a separate pipeline expansion project (i.e., the TGP Niagara Settlement Expansion).

[2] For a complete discussion of this regional analysis see EPRI *Natural Gas and Electric Industry Coordination in New England* (TR-102948), November 1993.

Exhibit 3-1
TENNESSEE GAS PIPELINE BASE CASE TRANSIENT ANALYSIS

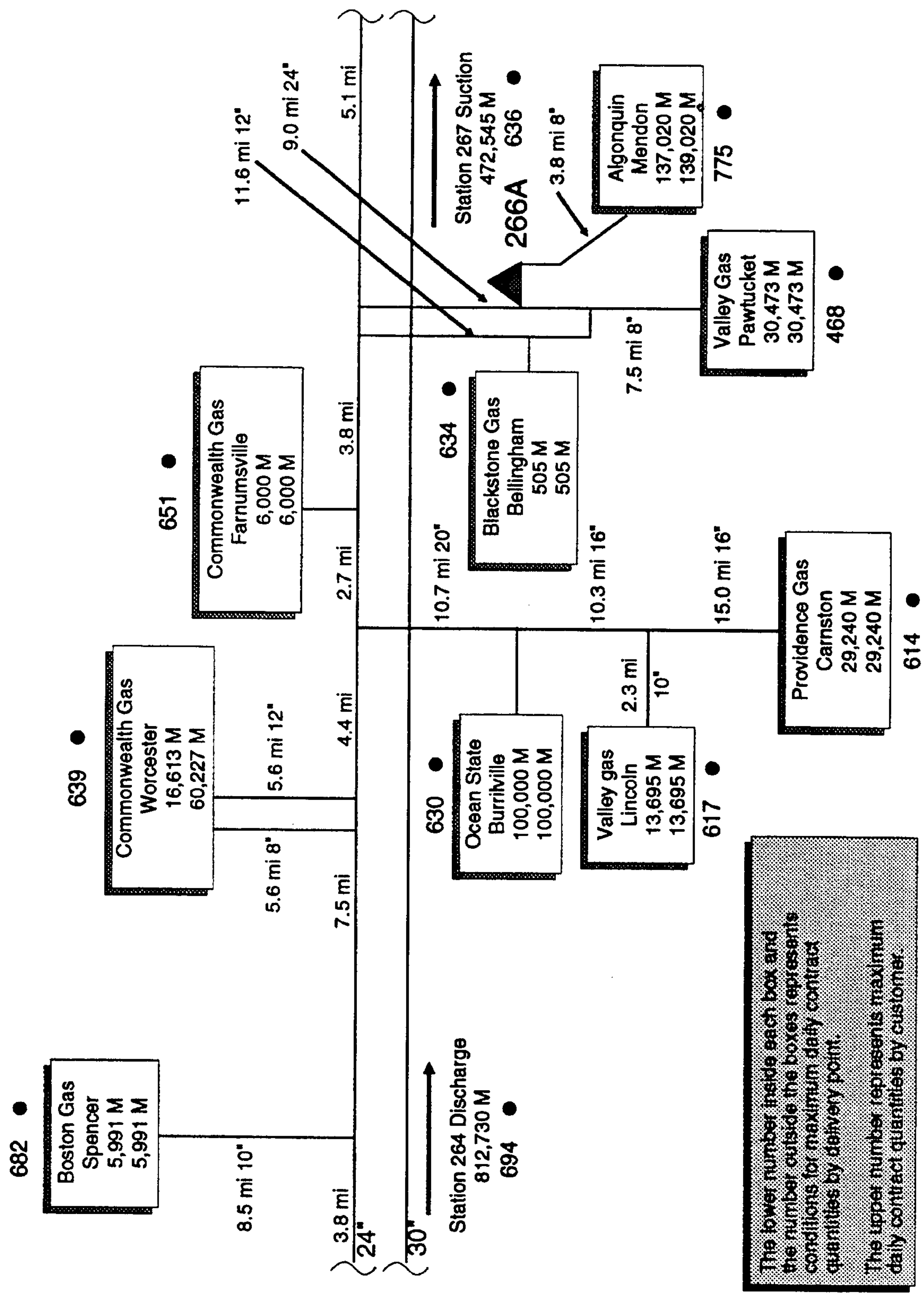
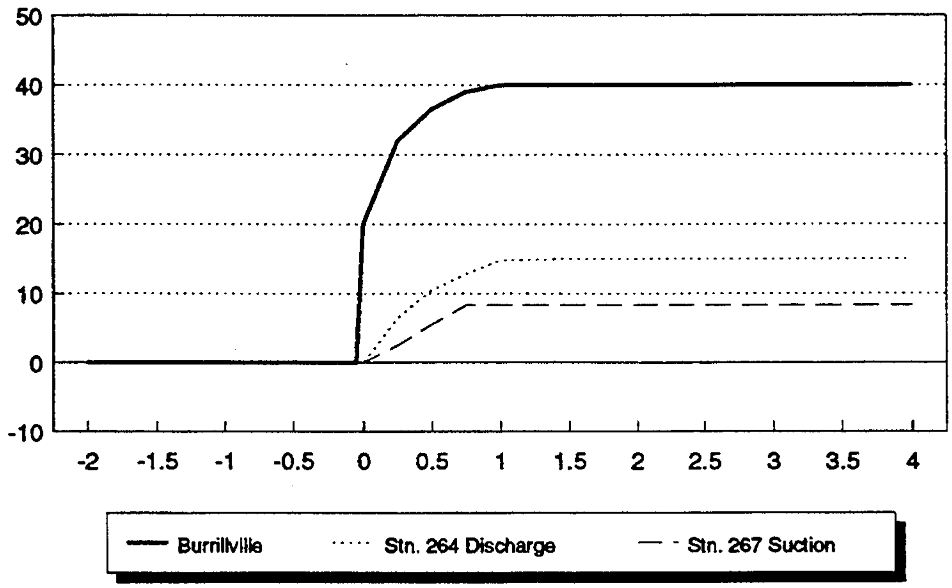
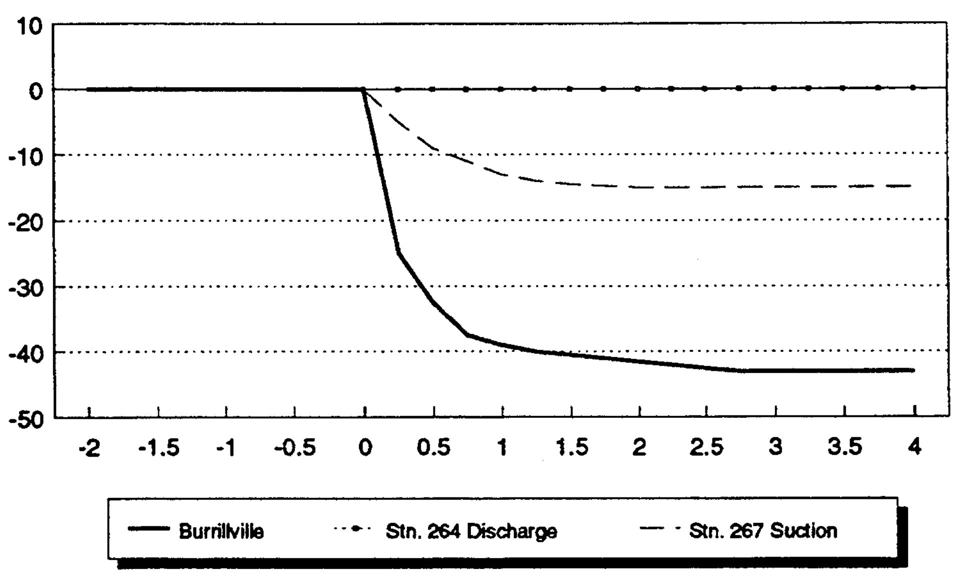


Exhibit 3-2
TENNESSEE GAS PIPELINE
PRESSURE EFFECTS OF LOSING OSP PLANT



Base conditions taken from Exhibit 3-1

TENNESSEE GAS PIPELINE PRESSURE EFFECTS
OF BRINGING OSP PLANT ON LINE



Assumes constant discharge pressure at
station 264.

high enough pressure to meet the requirements of its Pratt-Whitney turbines, PSE&G installed booster compression at its plant site.

The selected booster unit consists of two electric motor driven reciprocating compressors, each rated at 1250 HP and designed to pump a maximum of 56 MMCFD of natural gas with a suction pressure of 240 psig and a discharge pressure of 475 psig. Each motor drives two reciprocating compressors that can be loaded and unloaded automatically over the range of operating flows and pressure. Gas cooling and a gas bypass system are provided to give the broad operating flexibility needed. Furthermore, this installation utilized existing technology and hardware, which presented no special problems during the installation, initial testing and operation. These units were installed for approximately $2 million, or about $800 per HP- of which $925,000, or about $370 per HP, was for equipment and installation.

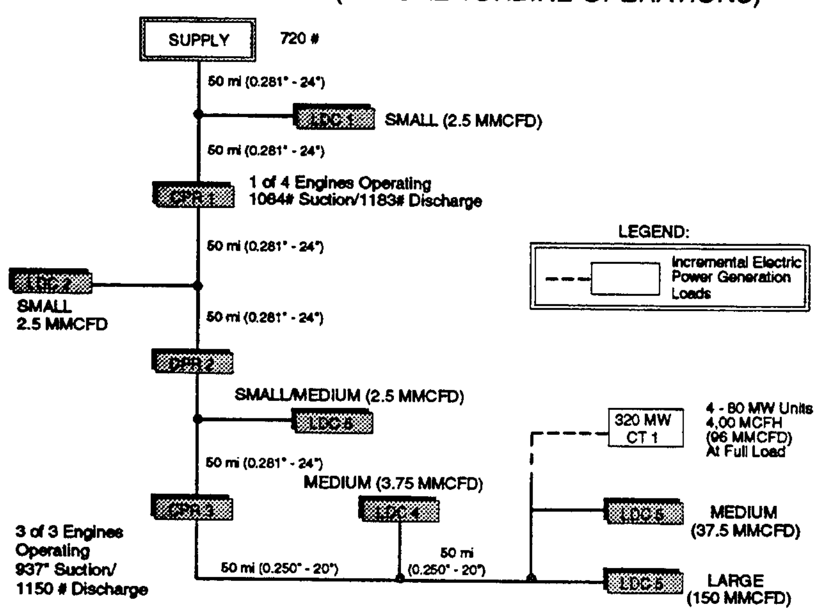
Southern Natural Gas Company (SONAT)

As an adjunct to the pipeline models examined in Section 2, SONAT used transient flow analysis to assess the impact of adding new power generation loads to its system. While the proposed new load requirement was hypothetical, the pipeline conditions were as they exist on the SONAT system, which represents a more tangible example than that discussed in Section 2.

The pipeline configuration and initial load requirements used by SONAT (i.e., see Exhibit 3-3) were very similar to that contained in System 2, except that the SONAT pipeline is telescoped at the end of the system (i.e., the pipeline is reduced from 24 to 20 inches). In addition, SONAT examined adding new power generation loads during the summer when the pipeline is under utilized (i.e., about 72 percent overall). A

Exhibit 3-3

SUMMER DAY SCENARIO (BEFORE TURBINE OPERATIONS)



comparison between summer and winter design conditions is noted in Exhibit 3-4. In addition, all of the LDC loads are double their summer levels in the winter, except for the one large LDC, which is near full load requirements throughout the year.

Exhibit 3-4
SONAT: COMPARISON OF SUMMER AND WINTER DESIGN CONDITIONS

Season	Compressor Station	Operating Units	Horse Power	Pressure (Psig)		
				Suction	Discharge	Maximum
Summer	1	1	1000	1084	1183	---
Winter	1	4	4000	943	1190	1200
Summer	2	0	0	---	---	---
Winter	2	4	4000	937	1150	1150
Summer	3	3	3000	937	1150	---
Winter	3	3	3000	912	1108	1150

The specific new power generation load analyzed was four 80 MW combustion turbines, which require 4000 MCF per hour when at full load. These units were assumed to come online over a one hour period and then remain at full load for eight hours, and then taken off line. This basic cycle was repeated over a 24 hour period. Assuming no change in pipeline facilities, these load requirements resulted in pipeline pressures declining below minimum contract limits, as illustrated in the top of Exhibit 3-5. To avoid this condition, the idle compression at Station No. 2 was put on line. The specific amount of horsepower required to serve this new electric load, which ranged from approximately 1,000 to 3,400 HP, is illustrated in Exhibit 3-6. With the use of this additional compression the pipeline pressure was able to stay above the contract minimum, as illustrated in the bottom of Exhibit 3-5.

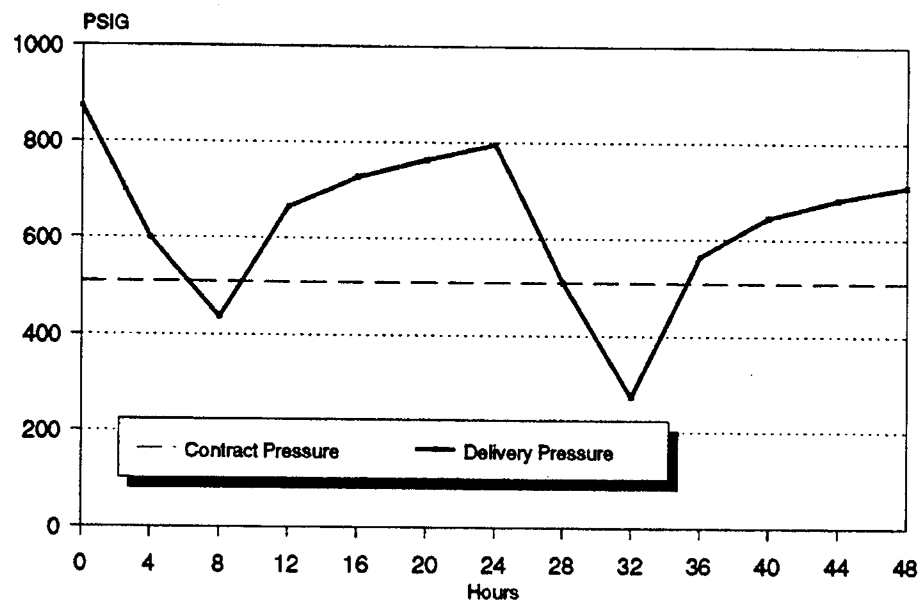
El Paso Natural Gas Co. (EPNG)

While the use of transient flow analysis is usually required for large load requirements, this is not always the case. Under certain conditions pipelines may be able to accommodate large power generation loads without the need to perform a transient flow analysis. Location of the load on the pipeline is usually a critical factor in such instances

One example of where transient flow analysis was not required in order to ensure the pipeline's capability of meeting large power generation loads exists in the Phoenix area of EPNG (i.e., see Exhibit 3-7). The EPNG mainline at the Casa Grande Station consists of a 26-inch and a 30-inch pipeline and has a design throughput capacity of approximately 900 MMCFD. Coincident load changes at the South Mountain location (i.e., Index 302) and the Ocotilla power plant (i.e., Index 232) of 190 and 70 MMCFD, respectively, have resulted in pressure drops of 90 and 200 psig, respectively. While these are significant pressure declines, the EPNG system in the Phoenix area is large enough to accommodate such changes in load requirements, which have historically been served on an interruptible basis, and are not always available during the peak winter heating season.

Exhibit 3-5
EFFECT OF COMBUSTION TURBINES ON PIPELINE DELIVERY PRESSURE

NO CHANGE IN STANDARD SUMMER COMPRESSOR UTILIZATION



ADDITIONAL ENGINES BROUGHT ON-LINE

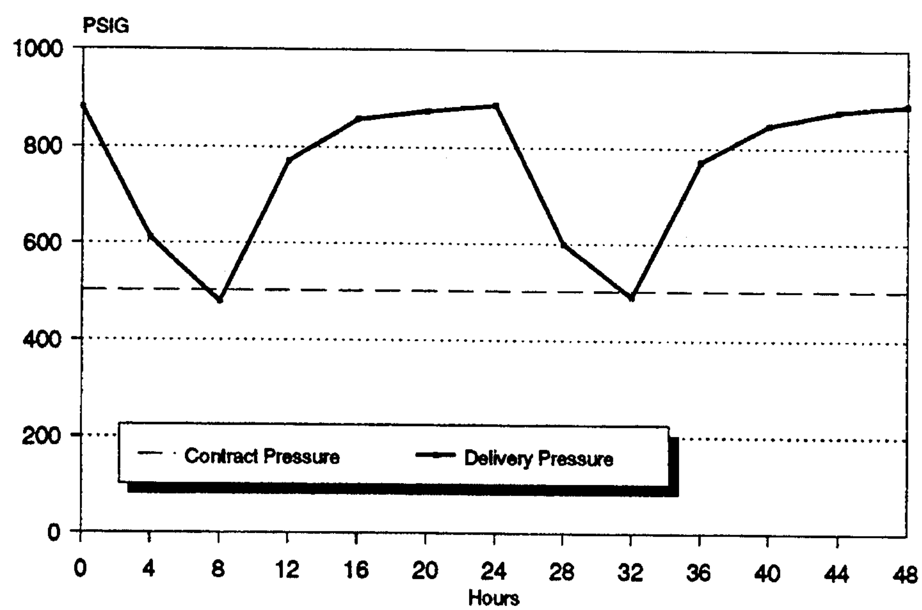


Exhibit 3-6
EFFECT OF COMBUSTION TURBINES ON SYSTEM OPERATIONS COMPRESSOR STATION #2

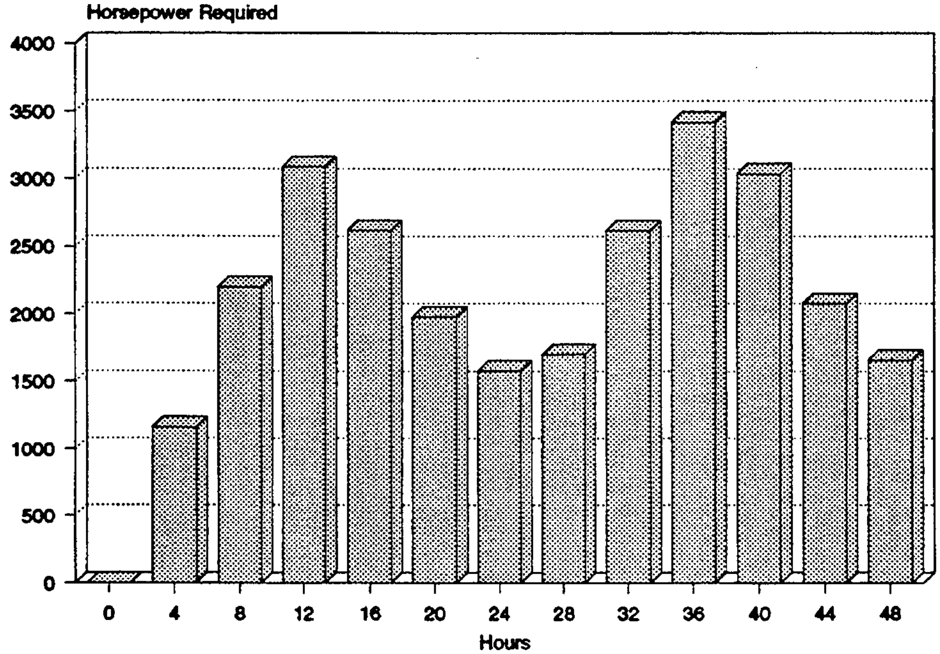
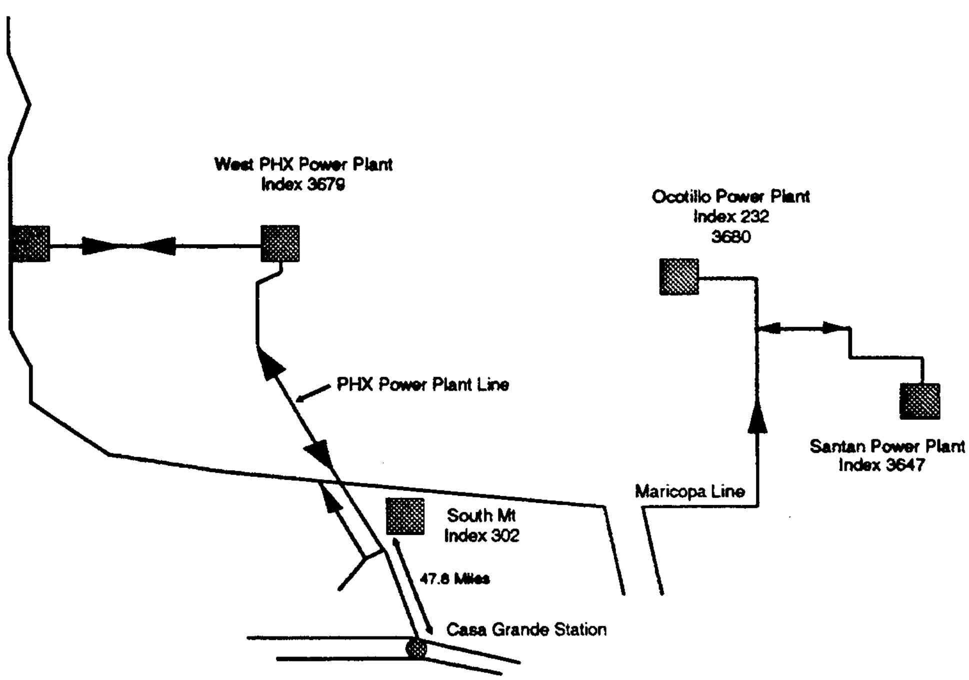


Exhibit 3-7
PHOENIX PIPELINE AREA



Sunshine Pipeline

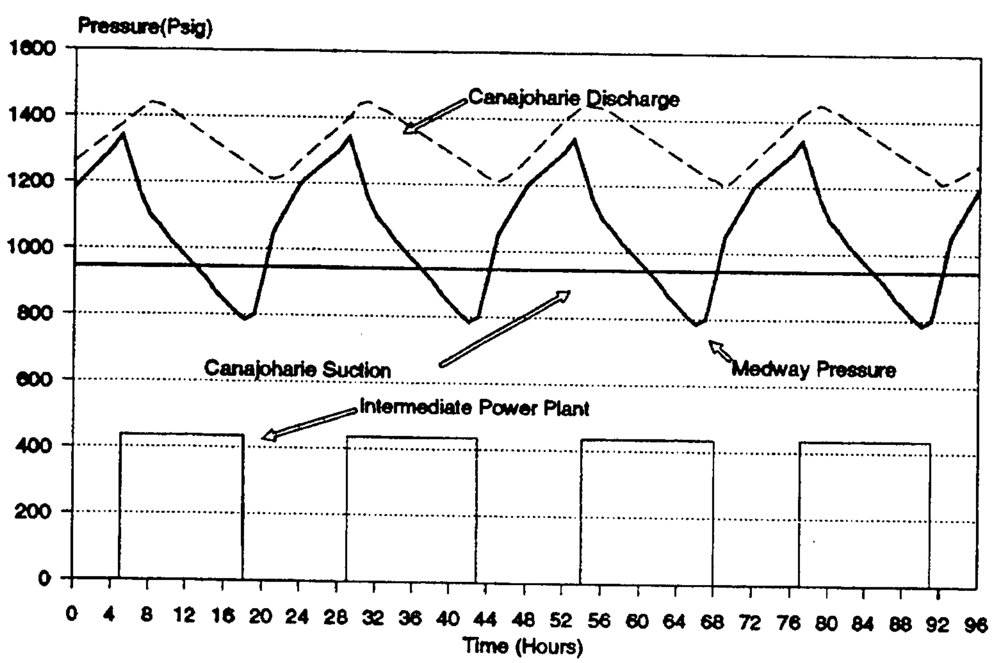
The SunShine pipeline system (i.e., SunShine Pipeline Co. and SunShine Interstate Transmission Co.), which will provide service to Florida, is currently in the planning stage, but has received the required certificates from the Florida Public Service Commission. Construction for this system, which consist of approximately 540 miles of 30" and 24" mainline, most of which is planned to be in place by 1996 with full power requirements (i.e., 23,000 HP) being achieved by 1999.

In many respects the SunShine system resembles System 1 in Section 2 of this report, in that it will serve predominantly low load factor power generation loads located near the downstream terminus of the system. As a result, it is anticipated that the pipeline load requirements will vary from 8 to 33 MMCF per hour over a 24-hour period. This is a 25 MMCF per hour variation in load requirements, while the average load is 20 MMCF per hour. As a result of the large variation in hourly load requirements, it was necessary to use transient flow analysis in the design of this system.

Mayflower Pipeline

The Mayflower Pipeline, which is located in the New England region, represents another example of a pipeline in its planning stages that anticipates serving large power generation loads and has relied upon transient flow analysis for the design of the system. Exhibit 3-8 illustrates one of the transient flow analyses that have been prepared for

Exhibit 3-8
MAYFLOWER PIPELINE
UNDER 14 - HOUR OPERATION



Mayflower system. This particular analysis examines the pipeline's response to the load requirements of a power generator.

Summary

The above series of examples illustrates a variety of situations where pipelines have employed the use of transient flow analysis in the design or expansion of their systems. While there are cases where the use of transient flow analysis may not be required, it is highly recommended when the new requirements are the large, relatively high pressure loads for low load factor power generators. In these applications the pressure requirements at the delivery point, which is heavily influenced by the type of turbines selected by the power generator, and hourly gas requirements are of great importance to the pipeline designer trying to provide service. This information is also important to the economics of proposed projects and can affect the contractual arrangements.

4

PRIMER ON NATURAL GAS PIPELINE DESIGN, CONSTRUCTION AND OPERATION

Overview

The primary purpose of this report is to present an analysis of the capability of natural gas pipelines to meet the load requirements of electric utilities. Section 2 of this report presents the quantitative results of such an analysis for three hypothetical, but realistic situations, while Section 3 reviews several recent industry examples. The information presented in both Sections 2 and 3 assumes a certain level of knowledge concerning gas pipeline design and operation. This may not be the case for some readers, particularly those primarily associated with the electric utility industry. To overcome this limitation and increase the breadth of the audience for which this report can be of significant use, a primer on natural gas pipeline design, construction and operation has been added to the report and is contained in this section. This primer provides the reader with a basic background on pipeline design and operation, as well as some history on the pipeline industry and is intended to both broaden and enrich the overall content of the report. However, the reader that is well versed in pipeline operations may desire to skip to the final section of the report.

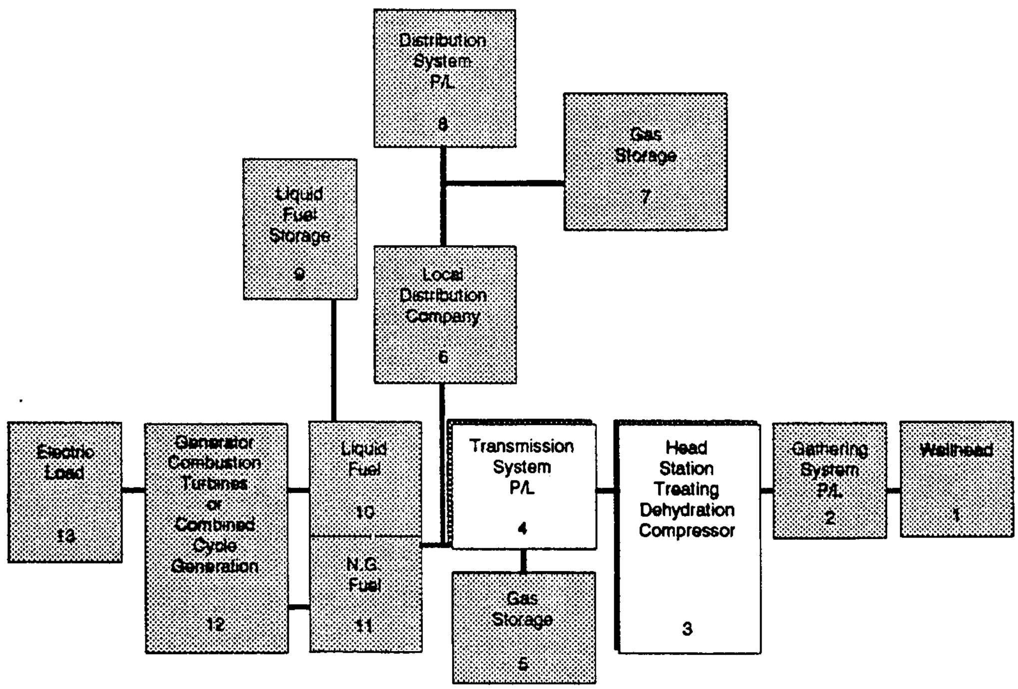
The material presented below provides a conceptual overview of the delivery process for natural gas and then discusses in more depth basic principles of pipeline design construction and operation. The industry's progress from using steady state flow design to analysis of transient flow is provided. A series of exhibits have been incorporated in the text for those desiring more detailed information. These exhibits provide additional information concerning pipeline design, pipeline and compression costs and specific equations used by pipeline designers.

Wellhead to Burner Tip: Major Steps in the Delivery of Natural Gas

The natural gas industry, unlike the electric utility industry, is a highly segmented industry, involving several entities in the overall process of production and delivery of natural gas. These segments, despite separate competitive interests, must coordinate closely with each other in order to provide an efficient means of delivering natural gas from the wellhead to the eventual consumer (i.e., the burner tip). This is one of the reasons why communication is so important within the natural gas industry.

A conceptual picture of each of the segments of the industry and how they interact is useful background information and is presented in Exhibit 4-1. While it is beyond the scope of this report to examine in detail each of the steps in the overall delivery process, a simplified description of each is given below, in order to provide a perspective on the entire industry. The discussion begins at the wellhead - the many prior steps involved in exploration and development of gas supplies are not addressed in this study. The material in the following portions of this section discuss treating (i.e., Step 3) and, the primary focus of this report, transmission of natural gas (i.e., Step 4).

Exhibit 4-1
MAJOR STEPS IN THE DELIVERY OF NATURAL GAS FROM WELLHEAD TO BURNER TIP



- *Wellhead (Step 1):* The discovery and production of natural gas is the function of several hundred exploration and production (E&P) firms within the industry. In general, E&P firms drill and maintain gas wells. Most gas is metered at the wellhead and then delivered into a field gathering system. In total, there are approximately 285,000 domestic gas wells. Gas delivery by an E&P firm usually ends at the wellhead. The E&P firm designated as operator of the well is responsible for the division of revenues between all joint interests and payment of royalties to land owners.

- *Gathering Systems (Step 2):* The pipelines used in a gathering system can vary in size from 2" to 30" in diameter, the pressures can vary from less than 20 psia to over 1,000 psia, and the length can extend several miles. Liquid build up and freezing of these lines during cold weather can occasionally cause severe operating problems. The liquid build up can be removed with the use of cleaning plugs called "pigs". These pipelines may be owned and operated by either the producer or the transmission company depending upon the contractual arrangements in effect.

- *Treating, Dehydration, Compression (Step 3):* The Head Station is the first station in a transmission system. Here the gas from the gathering system is purified, liquids removed and the pressure increased to the Maximum Allowable Operating Pressure (MAOP) of the transmission system. Some or all of these functions may be performed by one company or by several different companies depending upon the contractual arrangements. Usually the processor will remove the water, hydrocarbons, carbon dioxide and hydrogen sulfide from the gas and the transmission company will compress the gas.

- *Transmission System (Step 4):* The pipelines used in gas transmission systems typically vary in size from 16" to 42" in diameter and can extend several hundred miles from the field to the load center. The MAOP for these systems varies from 500 psia to 1,440 psia. Compressor stations are located about 30 to 100 miles apart. Many of these transmission systems are interstate pipelines, while others are intrastate systems. There are 78 interstate pipelines on file with the Federal Energy Regulatory Commission (FERC). Approximately 27 of these are considered major pipelines with transportation greater than 50 BCF per year.

- *Gas Storage (Steps 5 and 7):* Several kinds of gas storage systems are provided and include storage in abandoned gas reservoirs, in salt dome caverns, and in aquifers. Gas can also be stored at low pressure in large above ground vessels or it can be liquified and stored in large insulated vessels, which are also above ground.

  Gas storage is expensive but it does offer the operators additional flexibility and reliability. Some forms of storage can be provided in the field, along the transmission system and/or at the load center. Currently there are about 395 storage pools in the U.S.[1]

- *Local Distribution Companies (LDC) (Step 6):* Historically the largest customers of the interstate pipelines have been the LDC's. Currently, there are about 1,600 LDC's in the U.S. A few of these companies are also integrated with their own transmission system, provide their own storage and even have field facilities that they operate. However, under the current regulatory environment many of the functions are being "unbundled" and services are being provided separately.

- *Distribution System (Step 8):* The gas distribution systems at the load center have been in operation for many years. In fact, some were in operation before the advent of natural gas. These systems are low pressure systems (less than 200 psi) and in many cases can not be easily adapted to serve the large high pressure loads of heavy industrial and/or electric utility firms. New pipelines must be laid to serve these newer loads.

- *Liquid Fuel Storage (Step 9):* The variable nature of the peaking requirements for some gas turbines may require the load center to provide some sort of liquid storage that can be used by the electric generator. The ability of the combustion gas turbine to switch fuels at full load in less than a minute makes this kind of storage especially useful to increase reliability and provide flexibility.

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[1] For a further discussion on natural gas storage consult a report by the Gas Research Institute, *Evaluation of United States Natural Gas Storage Operations* (GRI-92/0467), December 1992.

- *Liquid Fuel and Natural Gas Fuel (Steps 10 & 11):* The fuel system of a modern electric generating facility usually has dual fuel capability. Many of the newer gas-fired units require high gas pressure (350 to 600 psia), as well as the ability to switch from one fuel to another fuel at full load in less than one minute.

- *Combustion Turbine (CT) and/or Combined Cycle (CC) Generation (Step 12):* While electric utilities use a variety of gas-fired power generation units, including the traditional steam generator, the focus of this report is on the newer gas-fired CT and CC units that require high pressure gas (i.e., 350 to 600 psia) and, in general, place greater requirements on the transmission system and thus, heighten the need for coordination between the gas and electric industries. While CTs are usually used as peaking units, CC units are often used as either cycling or base load units.

- *Electric Load (Step 13):* The final result of the delivery of natural gas to a electric utility is the generation of electricity. Interestingly, one of the greatest areas of uncertainty within the electric utility industry is the prediction of amount of gas-fired generation required within a specified time period (e.g., a day or a month) for an individual electric utility. This is because not only is there uncertainty concerning the total amount of electricity required on a given day (i.e., weather changes), but also because natural gas tends to be the swing fuel for the entire electric utility system. Thus, natural gas requirements for any given electric utility can be very volatile.

While each of the steps in the delivery of natural gas is important, the focus of this report is on the long-distance transmission system (i.e., Step 4).

Gas Treatment Facilities

Natural gas[2] has, as its primary constituent, a gas called methane whose heating value at 60 degrees Fahrenheit and 14.7 psia is 909 BTU/CUFT (Net) or 1,009 BTU/CUFT (Gross).[3] Depending on the amount of extraction at the processing plant in the field it may also contain some ethane, propane, and butane. These heating values range from 1,767 BTU/CUFT (Gross) to 3,262 BTU/CUFT (Gross). Generally, pipeline quality natural gas is considered to have a heating value of about 1,030 BTU/CUFT.

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[2] The major constituents of a natural gas stream consist of a variety of straight chain hydrocarbons of which methane is the dominant component. Normally these hydrocarbons are methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and some heavier molecules having five or more carbon atoms, which as a group are referred to as natural gasoline.

[3] The gross heating value of any fuel is defined as the amount of heat it will produce in BTUs. For gas the pressure of the gas is given and is equal to atmospheric pressure at sea level at the temperature of 60°F. The net heating value is the amount of heat that will be available to the process. It is always smaller than the gross heating value, which accounts for the heat used in raising the temperature of the water formed in the combustion process. The gross heating value is more commonly used in the U.S. and will be used throughout this report.

When natural gas is produced from a well it sometimes is contaminated with carbon dioxide, and/or hydrogen sulfide which are corrosive and/or poisonous. Some natural gas contains inert gases, such as nitrogen. Naturally occurring radioactive materials (NORM) have also been detected in very small amounts. Pipeline quality gas is often treated to limit carbon dioxide to less than two percent, hydrogen sulfide to less than 1/4 grain/100 cubic feet, and water to less than 7 lbs. per million cu. ft.

Natural gas that has negligible amounts of impurities and meets the above specifications is considered to be "pipeline quality." However, large amounts of gas have to be treated at a gas processing plant in order to obtain "pipeline quality" natural gas. This gas treatment process is described briefly in the following material.

Certain hydrocarbons that are produced with methane must be separated and removed. The main reasons for their removal are primarily economic, and secondarily operational. In the early days when the utilization of natural gas was developing, the value of the heavier hydrocarbons, including ethane, propane, butane and natural gasoline was minimal. Over time however, these products became valuable feedstocks to petrochemical and refining operations. Today it is common practice to remove most of these heavier hydrocarbons such that only small quantities of the heavier hydrocarbons are found in the pipeline gas stream. An additional reason for their removal is to avoid pipeline operational problems, since these heavier hydrocarbons, depending on temperature and pressure, could liquify and build up into large slugs of liquid.

The technology for removing the heavier hydrocarbons has changed over time. Initially, they were removed by compression and cooling, which provided for removal of the heaviest hydrocarbons (i.e., pentanes and higher). This method has been almost completely replaced by the absorption process, which was the primary process for the last 25 to 30 years. Today the newer treatment systems primarily rely upon cryogenic extraction systems. Exhibit 4-2 provides a brief discussion of these hydrocarbon removal systems along with a discussion of other treatment systems.

Both carbon dioxide and hydrogen sulfide must also be removed from the gas stream, since both form acids when combined with water. Such acids are corrosive to steel pipe and could eventually cause the pipe wall to fail and leak gas. Therefore, such potentially acidic gases must be removed in a processing plant. "Sour gas" refers to the presence of potentially acidic gases and other corrosive constituents in a gas stream. The process of removing these undesirable elements is referred to as "sweetening" the gas stream. Many processes may be employed to remove these components. The processes can involve chemical reaction, absorption and/or adsorption (i.e., see Exhibit 4-2).

Lastly, water is removed from the gas steam. Nitrogen has no major detrimental effect on the pipeline system other than to occupy space in the pipeline, increase horsepower requirements for compression and increase nitrogen oxide emissions when burned with the natural gas as a fuel.

When the above mentioned products are removed, "pipeline quality" gas is odorless. For safety reasons namely to enable leaks to be easily detected, a harmless odorant, such as a

Exhibit 4-2
GAS TREATMENT SYSTEMS

Hydrocarbon Removal System

- Absorption Process: The absorption process was the primary process used for 25-30 years. In this process rich gas (gas containing a high percentage of heavier hydrocarbons) entered the bottom of a large vessel and flowed upwards. Lean oil (which had been stripped of the hydrocarbons) entered the top of the vessel. As gas and oil came in contact the heavier hydrocarbons were absorbed by the lean oil. The rich oil was then stripped of the hydrocarbons and recycled back to the vessel as lean oil. The amount of hydrocarbons that could be removed by this process was limited both economically and operationally, and therefore the remaining gas had a higher heating value.

- Cryogenic Extraction Process: The cryogenic extraction process has largely replaced the lean oil absorption process discussed above. Removal of hydrocarbons by the cryogenic process came about because of greater demand for feedstock hydrocarbons by the petrochemical industry. In a cryogenic process, natural gas is cooled through expanders. As gas is cooled, the heavier hydrocarbons liquify and drop out of the process. This process, because of low temperature, removes the bulk of the ethane and other heavier hydrocarbons and can produce almost pure methane.

Acid Gas Removal Systems

- Chemical Reaction Process: Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are removed from the gas stream by chemical reaction with a material in a solution solvent. The reaction may be reversible or irreversible. In the reversible reactions, reactive material removes H_2S and/or CO_2 in the reactor. The reaction is then reversed by high temperature and/or low pressure in the stripper.

- Absorption Process: This process depends on physical absorption of H_2S and/or CO_2 in a solvent. The sour gas is absorbed in a vessel when the solvent is mixed with the gas and then the H_2S and CO_2 is stripped from the solvent. Since H_2S is poisonous, H_2S is normally further converted to elemental sulfur or burned in the atmosphere to form sulfur dioxide (SO_2). Environmental restrictions limit the amount of H_2S flaring that can be done.

- Adsorption Process: This process depends on physical attachments of the H_2S and/or CO_2 molecules to a material. Once the material is saturated, the acid gases are stripped from the material with steam and/or gas.

Water Removal Systems

- Liquid Desiccant: An absorbing liquid (glycol) is circulated through the natural gas in a large vessel and the water is absorbed by the liquid desiccant. This desiccant is then sent to a reboiler where it is heated and the water boiled off. The glycol is then returned to the vessel after cooling to absorb more water from the gas.

- Dry Desiccant: Gas is passed through a vessel containing a solid desiccant. This desiccant absorbs the water. When the desiccant becomes nearly saturated with water, it is desorbed by driving off the water with heat. Then the cycle is repeated.

- Refrigeration: Gas is cooled until all of the water vapor condenses. The water is removed with float controls and the cold dry gas is returned to the system through a heat exchanger to improve the cycle efficiency.

mercaptan, is added in small quantities. Treatment of the gas to become pipeline quality is the first major step in the gas transmission process. Gas processing or treatment facilities tend to serve as major collection points or hubs for onshore gas supplies. Specific examples include plants located at Henry Hub (LA), Katy (TX), Waha (TX), Blanco (NM) and Opal (WY). Also, the Head Station of a pipeline usually contains the necessary processing equipment to assure pipeline quality gas, in addition to serving as the initial compression station for the gas transmission system.

Pipeline Design

Overview

Prior to examining the design of the pipeline system a general overview in the evolution of the basic design methodology for gas transmission systems, particularly the transition from steady-state to transient flow analysis is provided. This is followed by a description of the basic design equations used for gas pipeline design and the associated use of compression. Subsequent material will review the construction of a pipeline and pipeline operations.

Transition From Steady State to Transient Flow Analysis

Pipeline flow analysis or modeling on a steady state basis typically involves mathematical solutions to historically developed steady state pipeline flow/pressure loss equations in which the pressure, flow and temperature are assumed to be independent of time. That is, steady state always implies that mass flow into the upstream end of a pipe section is the same as the mass flow out the downstream end, with no increase or decrease of pipe section mass inventory as a function of time.

While such a steady state analysis is useful for true steady state situations wherein pipeline system loads and supplies are relatively constant over long periods of time, this type of analysis is not valid, and sometimes can be very misleading for pipeline systems that experience highly variable loads and supplies. For example, in the case of a pipeline system that has significant, weather dependent LDC loads, it is not clear if the steady state analysis be based upon loads representing the average winter day, the peak day, or the peak hour of the peak day. If the peak hour is chosen as the representative flow condition and facilities, in turn, are designed to accommodate this maximum flow condition without system inventory, or line pack, draw down, then those facilities are likely to be significantly over designed. Conversely, the use of average winter day or even peak day flow conditions may result in an under designed system, in that available system inventory draw down may not be sufficient to cover the difference between the peak day average hour load and the peak hour load.

Before the advent of computers, it was common practice in the gas industry to use some modified forms of steady state analysis for verifying the adequacy of system facilities for future load and supply conditions as well as for designing new facilities. A common method of modifying the steady state analysis was to use some representative period flow condition and then impose an additional pressure requirement on top of the known or desired allowable minimum pressure. That is, facilities were designed to meet some estimated representative system flow condition, which was statistically typical of the system's design operating period (e.g., average hour of the peak day), while meeting a minimum pressure condition some arbitrary amount in excess of the contract minimum. This method, when successful, allowed the pipeline to meet its volume and pressure obligations under moderately variable load and supply conditions.

Given the advent of transient hydraulic analysis capabilities, pipelines, engineering companies and others are now routinely simulating, modeling, planning, and designing pipeline facilities using computers when dealing with highly variable load situations. Such computer simulation for transient analysis basically consists of numerical solutions in space and time of the simultaneous partial differential equations that govern the physics of pipe flow and pressure loss. The four basic equations solved in the computer by numerical solution techniques are:

- Equation of State;
- Continuity Equation;
- Momentum Equation, and
- Flow Area Equation.

The time dependent partial differential equations derived from these four equations can also be solved for the special case of time independent variables to yield many of the well known steady state gas flow equations.

Current practice among most major pipelines is to use transient flow analysis for highly variable, low load factor situations, but these pipelines will use steady state analysis for most high load factor situations, because the benefit of the additional sophistication of transient flow analysis is not commensurate with the additional expense.

Basic Pipeline Design Equations

The following is a brief summary of the basic equations used in pipeline design and how they have changed over time. Exhibit 4-3 presents, in detail, many of the equations used in pipeline design, along with a definition of the various parameters within the pipeline design equations discussed below. The general equation for steady-state flow of gas (i.e., isothermal behavior) is relatively complex and is pre-sented below for illustrative purposes (i.e., also see Exhibit 4-3).

$$Q = 38.77 \frac{T_b}{P_b} E \left(\frac{1}{f_f}\right)^{0.5} \left(\frac{P_1^2 - P_2^2}{SLTZ}\right)^{0.5} d^{2.5}$$

Initially, the American Gas Association (AGA) developed a set of equations to define the internal roughness factor of the pipeline (f_f). The AGA Equations,[4] which are provided in Exhibit 4-3, resulted in separate and very complex formulas for partial and fully turbulent flow.

In 1912, a direct relationship between pipeline diameter and the internal roughness factor, or the coefficient of friction (f_f), was developed. Incorporation of this relationship into the steady-state equation became known as the Weymouth Equation. This equation was found to agree with metered rates in short pipelines and low pressure gathering systems. However, as pressure increased the error in the equation increased, which required the equation to be modified by the compressibility factor.

Exhibit 4-3
PIPELINE DESIGN EQUATION

Basic Steady-State Flow Equation for Isothermal Flow of Gas

$$Q = 38.77 \frac{T_b}{P_b} E \left(\frac{1}{f_f}\right)^{0.5} \left(\frac{P_1^2 - P_2^2}{SLTZ}\right)^{0.5} d^{2.5}$$

1. Capacity (Q) in cubic feet per day.
2. Distance from Head Station to Market (L) (miles).
3. Delivery pressure (P_2) and Head Station Pressure (P_1) (psia).
4. Specific Gravity (S).
5. Flow Temperature (T) Absolute Temp (460 + °F).
6. Inside Diameter of Pipeline (d) (inches) or (D) (feet).
7. Internal Roughness Factor (f_f).
8. Temperature base (Tb) and Pressure base (Pb).
9. Pipeline efficiency (E).
10. Compressibility Factor Z. (Ave.)
11. Reynolds Number (Re).

AGA Equations for Transmission Factor $(1/f_f)^{0.5}$

(A) For fully turbulent flow:

$$\left(\frac{1}{f_f}\right)^{0.5} = 4 \log_{10} 3.7\frac{D}{\epsilon}$$

the flow equation becomes

$$Q = 38.77 \frac{T_b}{P_b} E \; 4\log_{10} \frac{3.7D}{\epsilon} \left[\frac{P_1^2 - P_2^2}{SLTZ}\right]^{0.5} d^{2.5}$$

[4] See AGA, "Steady Flow In Gas Pipelines" Institute of Gas Technology Report #10, American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209.

Exhibit 4-3
PIPELINE DESIGN EQUATION (Continued)

(B) For partially turbulent flow:

$$\left(\frac{1}{f_f}\right)^{0.5} = 4 \log_{10}\left(\frac{Re}{\left(\frac{1}{f_f}\right)^{0.5}} - 0.6\right)$$

Weymouth Equation (Published in 1912)

(A) Definition of Internal Roughness Factor or Coefficient of Friction (f_f)

$$f_f = \frac{0.008}{d^{1/3}}; \quad or \quad \left(\frac{1}{f_f}\right)^{0.5} = 11.18\ d^{1/6}$$

(B) The Weymouth Equation becomes:

$$Q = 433.5\frac{T_b}{P_b}\ E\left(\frac{P_1^2 - P_2^2}{SLTZ}\right)^{0.5} d^{2.667}$$

(C) For high pressure must be modified to include the compressibility factor, which is (1/Z)

Panhandle Equations

(A) Panhandle A (developed in 1940's) used

$$\left(\frac{1}{f_f}\right)^{0.5} = 7.211\left(\frac{QS}{d}\right)^{0.07305}$$

(B) Panhandle B (revised in 1956)

$$\left(\frac{1}{f_f}\right)^{0.5} = 16.70\left(\frac{QS}{d}\right)^{0.1961}$$

$$Q = 737\left(\frac{T_b}{P_b}\right)^{1.02} E\left[\frac{P_1^2 - P_2^2}{S^{0.961}LTZ}\right]^{0.51} d^{2.53}$$

Exhibit 4-3
PIPELINE DESIGN EQUATION (Continued)

Transient Flow Solutions
Transient flow solutions evolve from the simultaneous solution of the equations of state, continuity and motion, each which are separately noted below.

(A) Equation of State
$p = z \rho R T$

Where	p	=	Absolute Pressure (100-900 psi)
	z	=	Compressibility (1.0 to .87)
	R	=	Universal Gas Constant
	T	=	Absolute Temperature (60 degrees - 100 degrees F + 460 degrees)
	ρ	=	Mass Density

For Isothermal Flow conditions and with temperature constant, the acoustic wave speed is:

$$B = \left(\frac{P}{\rho}\right)^{0.5} = (ZRT)^{0.5}$$

(B) Equation of Continuity
Net Mass Inflow in a pipe segment ($\delta\chi$) equals time Rate of increase of mass

$$-Mx\delta x = (\rho A \delta x)t$$

where	M	=	mass rate of flow
	δ	=	partial derivative
	A	=	Cross sectional area of pipe segment
	δx	=	Length of Pipe Segment
	t	=	Time
	B	=	Acoustic wave speed

Divide and substitute

$$\frac{B^2}{A}Mx + Pt = 0$$

Exhibit 4-3
PIPELINE DESIGN EQUATION (Continued)

(C) Equation of Motion

$$-Px\delta xA \;-\; \tau\pi D\delta x \;-\; \rho gA\delta x\sin\theta \;=\; \rho A\delta x\Upsilon$$

τ	=	frictional wall stress
θ	=	angle pipe makes with horizontal
g	=	acceleration of gravity
D	=	diameter of pipe
Υ	=	Velocity

by substitution and certain assumptions

$$\frac{\delta\rho}{\delta x} + \frac{1}{A}\frac{\delta M}{\delta\tau} + \frac{\rho g}{B^2}\sin\theta + \frac{fB^2M^2}{2DA^2\rho} = 0$$

(change in length) + (change mass) + (change elevation) + (friction factor) = 0

In the early 1940's, expressions for the Reynolds Number under turbulent conditions[5] were developed and incorporated into the basic gas transmission design equation. This version of the equation was known as the Panhandle A Equation, which was subsequently modified in 1956 and became known as the Panhandle B Equation.

Since that time, and with the advent of computers, more complex equations that take into account elevation changes, as well as heat exchange between the flowing gas and the surrounding soil have been developed. However, the greatest computation advances that have occurred recently have been in the area of solving transient flow problems in a pipeline system. The solution of transient flow involves the simultaneous solution of the equations of state, continuity and motion as functions of time and space. (i.e., see Exhibit 4-3). These solutions are very complex and beyond the scope of this report. However, the solutions are available in the commercial market place and were used in the examination of the impact of large variable loads on pipeline systems that was presented in Section 2 of this report. In addition, by the elimination of time as an independent variable these equations can be used to derive the steady-state flow equations that are used by the natural gas pipeline industry.

[5] There are two distinct flow conditions of gas in a pipe. At low flow rates, the velocity flowing stream-lines are parallel to the direction of flow. Increasing the flow rate causes random velocity components to occur at the center of the flow stream, gradually spreading, with increasing velocity. This kind of flow is referred to as turbulent flow and requires some modification of the Friction Factor.

Compression

If a designated section of pipeline is longer than the design calculation for the maximum allowed pressure drop, the pressure in the pipeline can be restored with the use of a natural gas compressor. There are many kinds of gas compressors that may be used, but the most widely used compressors are referred to as reciprocating and/or centrifugal compressors.

Reciprocating compressors on a pipeline system are usually driven by a reciprocating engine using pipeline gas as fuel. They are sometimes driven by electric motors, however, historically, the lack of variable speed in synchronous motors has limited their flexibility. In more recent times the availability of variable speed motors has improved. The reciprocating compressor is a simple positive displacement pump that, with the proper design of the suction and discharge valves, can raise the gas pressure to a desired level.

The centrifugal compressor is usually driven by a gas turbine or an electric motor and is used mostly for low compression (1.1 to 1.3) ratios and high flows that are ordinarily found on a gas transmission pipeline. Low pressure ratio pipeline centrifugal compressors usually have an efficiency ranging between 76% to 82% depending on the number of stages needed to meet the pressure ratios and the aerodynamic design of the compressor. The equations normally used to calculate the amount of horsepower required to drive a compressor are presented in Exhibit 4-4. The use of centrifugal compressors on pipelines is subject to three main restraints, (1) discharge temperature, (2) surge and (3) stone wall. Furthermore, the discharge temperature is a function of compression ratios, unit suction temperature and compressor efficiency. Most centrifugal compressors for gas transmission have a discharge temperature of about 150 degrees Fahrenheit. The term surge is a condition in the centrifugal compressor when the impeller can no longer produce sufficient head and back-flow occurs. Such a condition is detrimental to the machine and can cause permanent damage to the bearings, seals, shaft and/or impeller. Surge occurs at about 65% of design flow condition, so it is usually not a problem, except under upset conditions such as the loss of a compressor station or a pipeline failure. At about 120% of design flow, the centrifugal compressor enters into a condition referred to as "stone wall". At this condition the flow has become so high that the impeller can no longer produce any head.

System Design

The basic tools for designing a pipeline system are the design equations for gas transmission and system compression. These basic tools are used to make an assessment of the proper combination of variables (e.g., pipeline diameter, pressure, compressor station spacing, etc.) that could be used to provide a certain economic capacity. Exhibit 4-6 illustrates some of the basic tradeoffs between these variables. Once thoroughly evaluated, the proper combination of these variables will lead to the selection of specific hardware for constructing a pipeline.

Exhibit 4-4
COMPRESSOR DESIGN EQUATION

Reciprocating Compressors

$$Horsepower = (Bhp/MMscfd)\left(\frac{P_1}{1.44}\right)\left(\frac{T_s}{T_l}\right) Z_{avg}\, Q$$

Where	P_1	=	Pressure base	Z	=	Compressibility factor
	T_s	=	Suction temperature	Q	=	Flow (MMSCFD)
	T_1	=	Temperature base	Bhp	=	Brake horsepower

Using curves shown in Exhibit 4-5.

Example: Determine the amount of horsepower required to drive a reciprocating compressor under the following conditions:

Suction Pressure	=	600 psia
Discharge Pressure	=	800 psia
Flow	=	500 MMSCFD at 14.73 psia + 60
Gas Property S.G.	=	.628 Mol. wgt. = 18.19
Suction Temperature	=	80 degrees Fahrenheit

BHP/MMSCFD from curve in Exhibit 4-5= 21

Z	=	from curve in Exhibit 4-5	= .886
HP	=	21 x 14.73 x 540 x .886 x 500	= 9771 H.P.

Centrifugal Compressors

$$Ghp = \frac{w\ Hp}{33{,}000\ \eta}$$

$$\frac{(MW)\ (P_1)\ (144)}{Q_1\ (1545)\ (T_1)\ (Z_1)} = wgt\ flow\ lbs/\text{min}$$

$$Hp = \frac{ZRT_1}{\left(\frac{K-1}{K}\right)MW}\left[\left(\frac{P_2}{P_1}\right)^{\frac{K-1}{K}} - 1\right]$$

Exhibit 4-4
COMPRESSOR DESIGN EQUATION (Continued)

Where

Ghp	=	Gas horsepower
Q	=	Flow in cuft/min
Hp	=	Head developed by the compressor ft-lbs/lb
W	=	Weight flow in lbs/sec
η	=	Compressor efficiency
K	=	Ratio of specific heats of gas
MW	=	Molecular weight of gas
P_1	=	Suction Pressure
T_1	=	Suction Temperature

One variable that is always considered is the diameter of the pipeline. The capacity of a pipeline increases exponentially as the diameter increases (see Exhibit 4-6). Another variable that is carefully evaluated is the pressure at which the pipeline will operate. This pressure is normally referred to as the maximum allowable operating pressure (MAOP). The pipeline capacity increases linearly as the pressure increases (see Exhibit 4-6); however, so does the wall thickness of the pipe and the cost of the pipe.

The solution of the steady-state pipeline flow equation will yield the downstream pressure at a given distance. As the distance increases the pressure declines exponentially, as shown in Exhibit 4-6. Also, as the pressure declines the need for heavy pipe wall thickness also decreases, however, this results in a situation where the capability of the pipe is not fully utilized. Furthermore, there is an eventual limitation to the distance gas will flow in a given size of pipe. Thus, the use of pipeline compression is incorporated into the system design in order to restore pipeline pressure (i.e., see Exhibit 4-6).

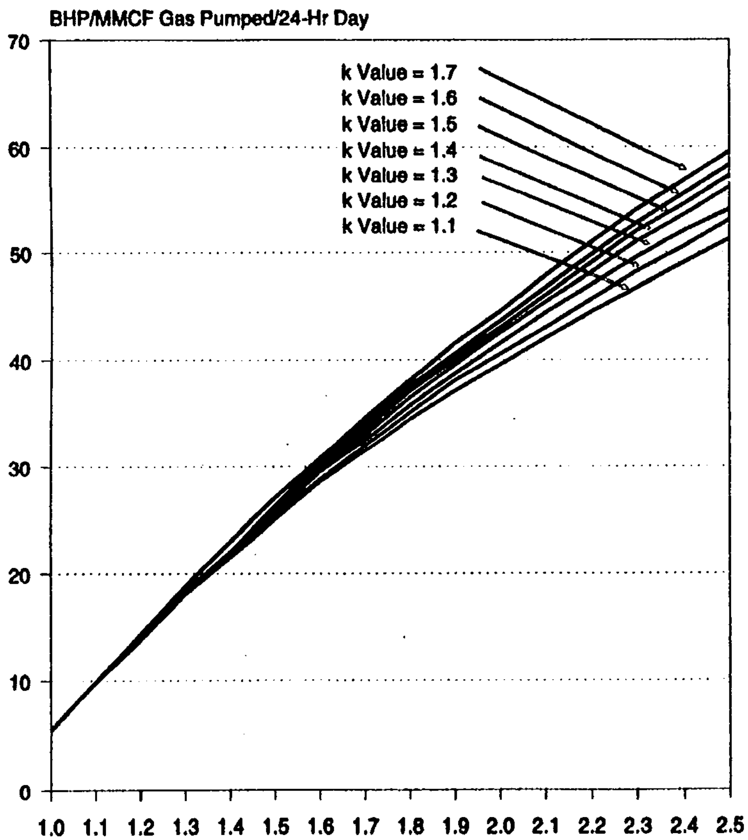
The selection of the most economical solution that utilizes the following variables:

1. Pipeline diameter,
2. Pipeline wall thickness (impacts MAOP),
3. Load Factor,
4. Distance from supply to market, and
5. Number and size of compressor stations.

Experience has shown that the higher the MAOP the more cost-effective the pipeline will become. The only limitations here are environmental factors, such as the population density, and weldability of the steel pipe during construction. Furthermore, the distance from supply to market is usually set at the beginning of the project, thus the remaining variables are diameter, load factor and number and size of the compressor stations.

Exhibit: 4-5
FACTORS FOR RECIPROCATING COMPRESSOR DESIGN EQUATIONS

BHP PER MILLION CURVE



Footnote:
Mechanical Efficiency 95%, Gas Velocity Through Valves ≈3000 Ft/Min (API Equation)
Source: ENE'RE DATA BOOK

GAS ANALYSIS

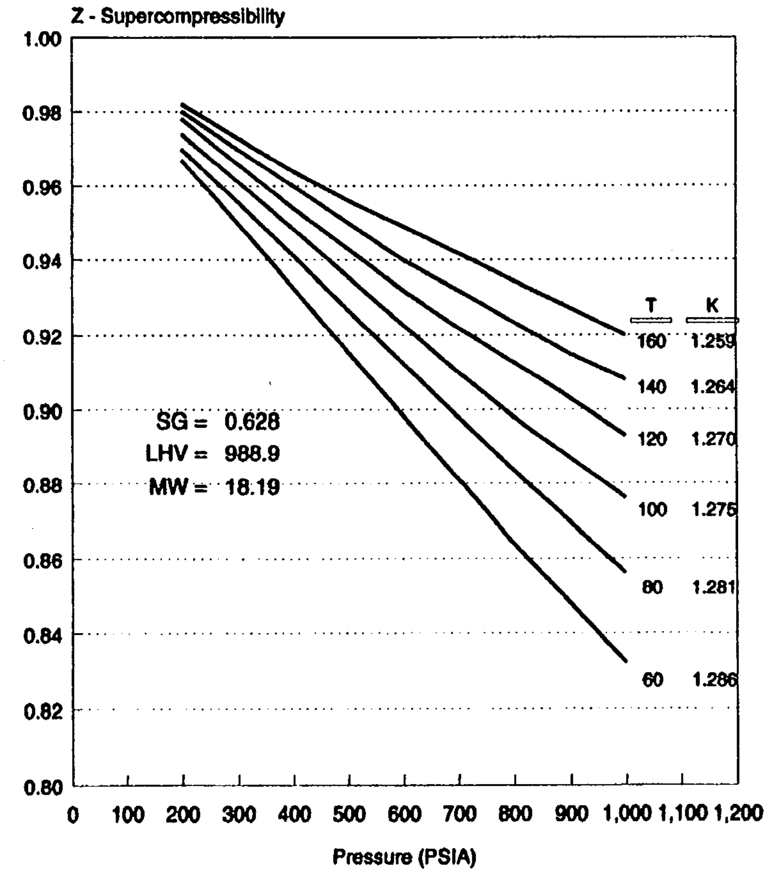
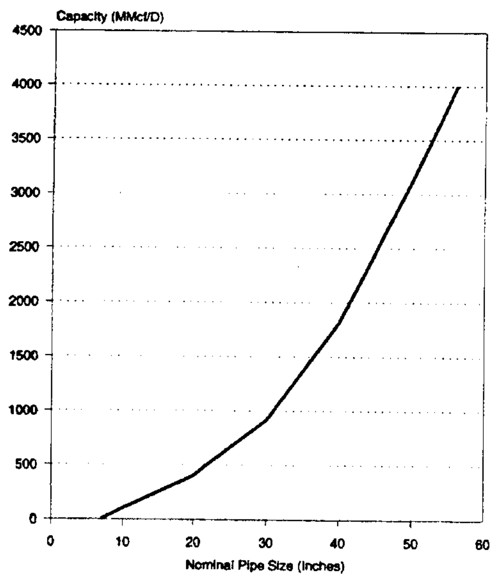


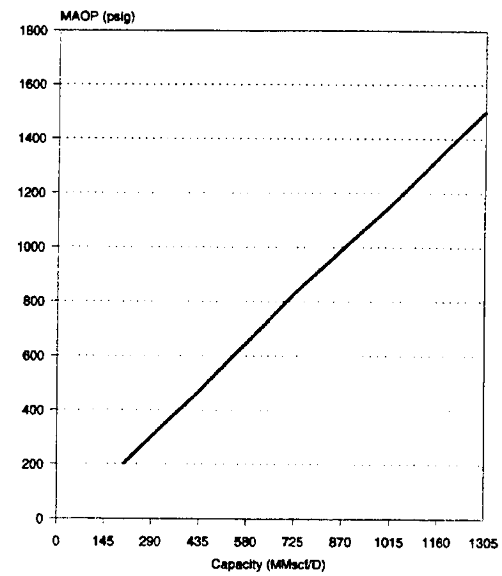
Exhibit: 4-6
TYPICAL RELATIONSHIPS FOR KEY PIPELINE PARAMETERS

CAPACITY Vs. DIAMETER



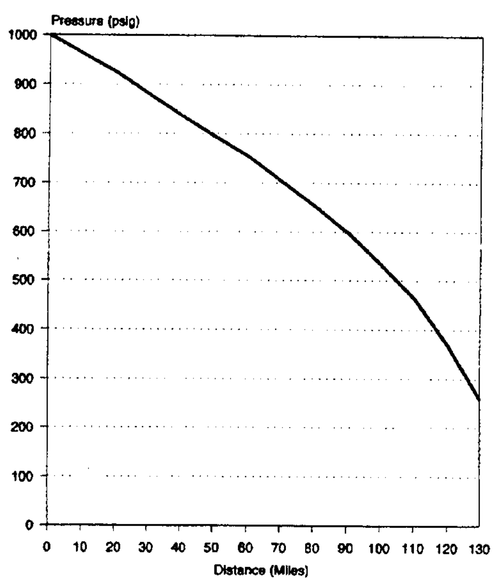
Footnote: 62 Miles; P1=MAOP=1000#g; P2=766#g

CAPACITY Vs. OPERATING PRESSURE



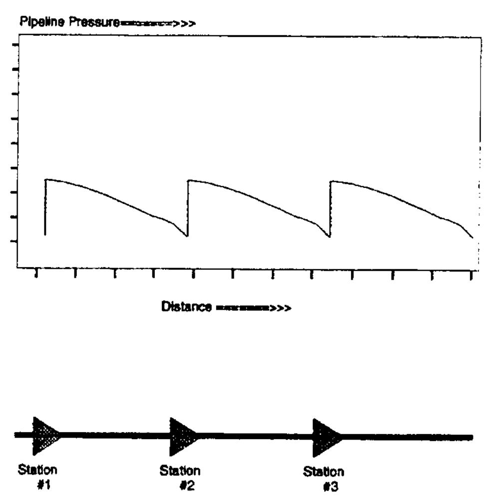
Footnote: 36"; 60 degrees F; P1=MAOP; P2=MAOP/1.3

PRESSURE DROP IN A TYPICAL PIPELINE



Footnote: 30"; 706 MMscf/d; 60 degrees F

DISTANCE Vs. PIPELINE PRESSURE



With the help of the computer, a series of designs are developed where the number and size of stations can be changed while holding the load factor constant.[6] The "J" Curve on the left of Exhibit 4-7 illustrates the impact on the cost of service of a 24" pipeline by changing capacity and the number of stations. The other curve in the same figure shows how cost of service changes for a 36" pipeline. For each pipeline design there is a minimum cost of service for a given load factor, which is the bottom portion of the "J" curve. However, in the illustrative case, the number of compressor stations ranges from one to four for a 24" line and one to three for a 36" line. These sets of curves are for only one load factor. Results may vary considerably for other potential load factors. For example, the load factor for a given pipeline system sometimes varies from 50 percent to 98 percent during the course of a year and, in general, the lower the load factor the higher the cost of service.

A critical factor in the initial design of the pipeline is the tradeoff between the initial cost of the pipeline and the ability to expand pipeline capacity in subsequent years as the market increases. Usually the smaller the pipeline, the lower the initial cost. However, over time this may not be the optimum choice as demonstrated in the right figure of Exhibit 4-7. This curve shows how the cost of service is impacted by the size of the pipe selected for a given load. For this example there is very little difference in the cost of service for a 36", 40" and 42" diameter pipeline. However the 36" pipeline will have the lowest initial cost.

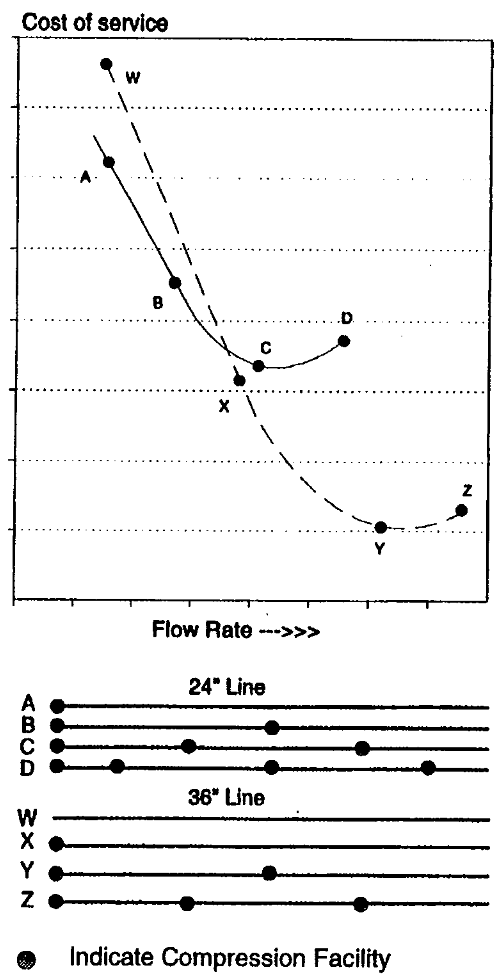
After the selection of the initial pipeline design, it possible to expand the pipeline through the use of added compression or looping the original pipeline. Typically, additional compressor stations and/or horsepower at existing stations is added to expand system capability. However, as shown in the "J" curves in Exhibit 4-7, this method soon becomes uneconomical. The next choice is to add pipeline to the existing system. Such action is normally referred to as "looping" the pipeline and its impact on capacity is shown in the figure on the right of Exhibit 4-8, which illustrates that when loop pipe is added to an existing system, it is more effective at expanding capacity as the loop length increases. For example, the first 25 miles of loop added increased capacity 75 MMCFD, while the last 25 miles of loop added increases the capacity 195 MMCFD.

While each of the variables involved in the design of a pipeline requires careful evaluation, probably the most difficult to predict throughout the entire process of initial pipeline design and subsequent expansion is estimating the load factor of the pipeline. This is true in nearly all pipeline designs.

[6] The pipeline system annual load factor is the amount of gas that must be delivered in a year divided by the maximum capacity of the system during the year.

Exhibit 4-7
COST OF SERVICE vs. FLOW RATE "J" CURVES

CONCEPTUAL EXAMPLE



COST OF SERVICE Vs. FLOW RATE

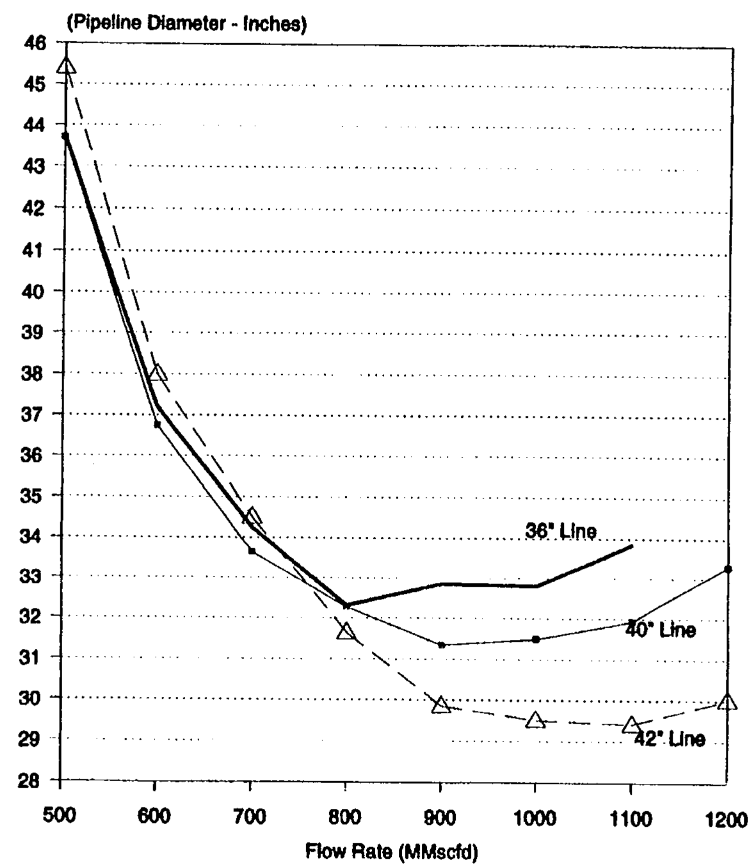
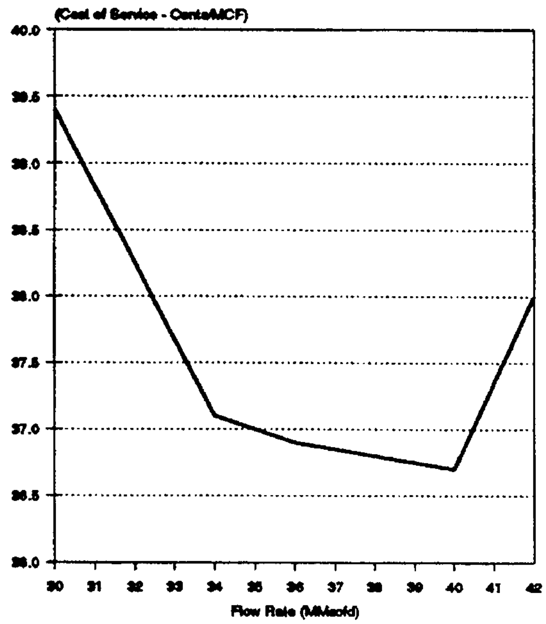
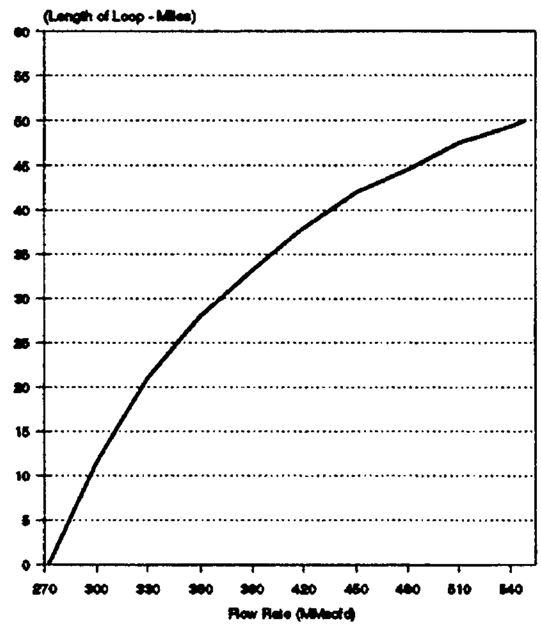


Exhibit: 4-8
ILLUSTRATIVE ANALYSIS OF A PIPELINE EXPANSION

THROUGHPUT CAPACITY VS. COST OF SERVICE



THROUGHPUT CAPACITY VS LOOP



Foot: 20" w/800 to 400# Pressure Gradient

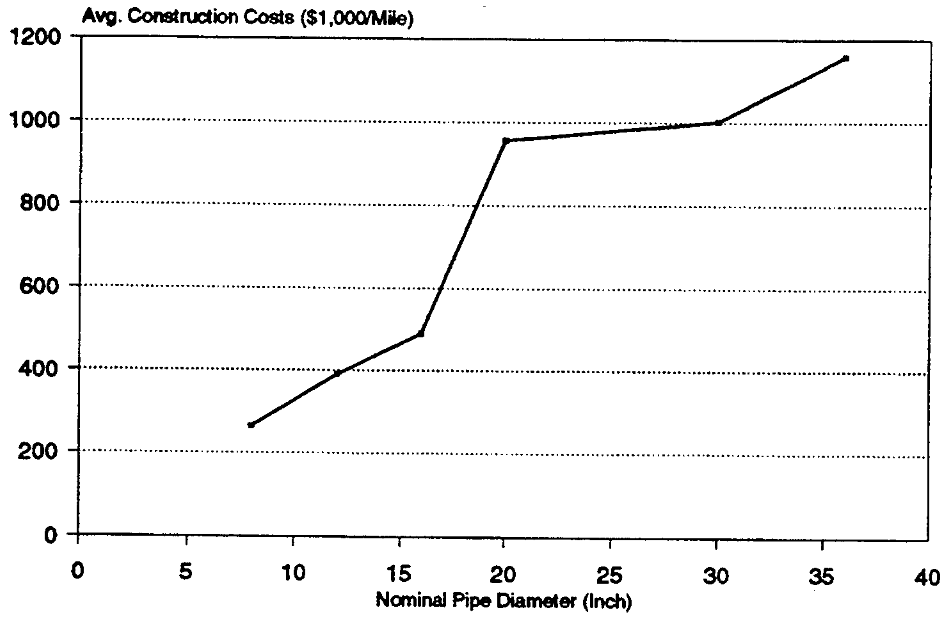
Typical Pipeline Costs

There is a wide variation in the costs for individual pipelines primarily due to the different lengths of specific pipeline projects. However, even when these costs are limited (e.g., dollars/mile) there is still significant variation due to differences in terrain, particularly when water crossings are required. Realizing that there may be considerable variation in costs for individual projects, Exhibit 4-9 presents the average pipeline construction costs during 1993 for various pipeline diameters. These average costs range from $264,000 per mile for 8" diameter pipe to 1,158,000 mile for 36" diameter pipe. Similarly there is considerable variation in the cost of compressor stations even when presenting costs on a dollar per horsepower (hp) basis (see Exhibit 4-10).

Pipeline Construction

Once the pipeline design is completed the construction phase of the pipeline begins. This construction phase can be segmented into the following series of steps, which occur approximately in the order discussed below, although some actions for each step often occur in parallel.

Exhibit 4-9
PIPELINE ECONOMICS
AVERAGE CONSTRUCTION COSTS



Source: Oil & Gas Journal Nov. 22, 1993

Exhibit 4-10
AVERAGE PIPELINE COMPRESSOR CONSTRUCTION COSTS

Size of Facility (hp)	Range of Costs ($/hp)	Average Costs ($/hp)
<5,000	1,100-4,400	2,480
5,000 to 10,000	1,600-1,800	1,708
>10,000	800-2,500	1,314

Source: Oil & Gas Journal, November 22, 1993.

Permits

Before construction on an interstate pipeline in the USA begins, many permits must be acquired. Probably the most important permit, or authorization, is that received from the Federal Energy Regulatory Commission (FERC). Obtaining this authorization is a rather long and tedious effort which culminates in awarding the applicant a certificate of public convenience and necessity. If the application is not contested, it usually takes about 12 months to get approval.

As part of this certification process, there are several other approvals that must be received, most of which relate to the environmental impact of building the pipeline in a specific location. Some of these required approvals include the following, which are described more fully in Exhibit 4-11:

- Culture Resource Regulatory Requirements
- Federal Endangered Species Act Requirements
- National Environmental Policy Act (NEPA) Requirements
- Clean Water Requirements
- Air Quality Requirements

Obtaining these additional approvals for the construction of the pipeline can be a lengthy and time consuming step and is potentially the longest phase in the construction of the pipeline.

Procurement

The next step in building a gas transmission system is the procurement of the steel pipe, compressors and associated equipment. Pipe specifications are prepared and issued to steel pipe suppliers. The quality of the pipe used and the welding of the pipe is monitored very carefully from the time it is produced at the steel mill until it is laid in the ditch. Once a successful construction bidder is selected, schedules are prepared. All such actions are often done in advance of regulatory approval and are timed so that the pipe can be received in the field simultaneously with final approvals. Such timing involves considerable risk in that steel mills usually require "take-or-pay" contracts in return for reserving space at the mill to produce steel plate on a timely basis. This step in the construction of a pipeline usually takes from four to six months depending on the availability of the steel mills.

Simultaneously with specifying and ordering of pipe, the design of the compressor station(s) is often initiated. Usually, an engineering contractor will prepare a bid package which specifies all of the major equipment. Such a package allows the pipeline company to solicit bids for detailed engineering and construction. As soon as major equipment is identified, orders are placed with appropriate cancellation clauses included in the bid, again, at considerable financial risk to the pipeline company. Preparation of the bid package usually takes two to three months and the detailed design will take four to six months. Sometimes detailed engineering and drafting are not completed until after field construction has begun. In addition, procurement plans are structured such that material begins to arrive in the field as needed to maintain continuous construction.

Construction

Construction of a pipeline is a unique operation because when the work is completed there is nothing visually apparent to illustrate the effort expended. The following outline of pipeline construction makes reference to a series of photographs of actual

Exhibit 4-11
REQUIRED PIPELINE PERMITS AND APPROVALS

Cultural Resources Regulatory Requirements
Consultations and approvals involve both state and federal agencies and are concerned with preservation of historic and prehistoric sites, as required by the National Historic Preservation Act. The primary agency that administers the program is the State Historic Preservation Office. A survey is conducted of the route and if any historic sites are located on the proposed route, steps must be taken to protect or collect information from the sites. In large pipeline projects, this process can take as much as 12 to 18 months. Construction can't begin until agreed settlements or litigation are completed.

Federal Endangered Species Act Requirements
Approvals are granted after thorough review of the route survey report by the U.S. Fish and Wildlife Services, and other jurisdictional federal agencies. These surveys are normally conducted in the spring and fall of the year and are designed to identify the presence of, or habitat for, endangered species that could be impacted by the new construction. Issuance of these approvals can take nine to 12 months.

National Environmental Policy Act (NEPA) Requirements
NEPA requires preparation of an Environmental Assessment (EA) or Environmental Impact Statement (EIS) document that addresses all possible impacts of the project. The document is normally prepared by the FERC using reports provided by the applicant company. Completion and approval of the EA and EIS is one requirement for the FERC in granting a Certification of Public Convenience and Necessity. Other federal agencies, such as BLM, Forest Service, and Bureau of Reclamation, may serve as cooperating agencies in preparation of the EA or EIS. Preparation and final public issuance of EA/EIS normally requires four to 12 months.

Clean Water Act Requirements
If the pipeline project crosses what is defined as "Waters of the U.S.", the Corps of Engineers becomes involved. The Corps jurisdiction includes wetlands, lakes, navigable rivers, etc. Receiving Corps approval can take 60 days to six months depending upon the amount of possible environmental impact of the project. The Corp approval is termed a Section 404 or Section 10 permit.

Air Quality Requirements
Any new installation or modification to an existing source which causes a net gain or net loss of a regulated air pollutant will trigger a permit action. In the gas industry the regulated pollutant of concern is normally NOx which is emitted from the gas engine or gas turbine at a compressor station. If an existing source emits 250 tons or more per year of NOx, then it is a major source. If the source emits less than 250 tons per year of NOx, it is considered a minor source. If the source is major, then any net increase of NOx greater than 40 tons per year, triggers a permit action which generally takes one to two years, depending on the amount of air monitoring required. Such a permit is issued by the state agency or the EPA depending upon jurisdiction. If the source is minor (less than 250 tons per year), the permit can be issued by the state agency only, and usually takes four to six months.

pipeline construction, which are intended to provide the reader unfamiliar with pipeline construction a better appreciation of the overall construction phase.

The first step in construction of a pipeline is the purchasing and clearing of the right-of-way. Exhibit 4-12 shows a right-of-way that has been cleared for construction. Trees may be boxed and set to one side so they may be replanted when construction is complete. This is one of many requirements commonly imposed by governmental environmental agencies. Once the right-of-way has been cleared, digging the ditch with the use of a large ditch digging machine and/or a backhoe begins (see Exhibits 4-13 and 4-14). Simultaneously with this work, pipe is being received and stored in a central location as shown in Exhibit 4-15. Prior to moving the pipe to the right-of-way, two joints are machine welded together as shown in Exhibit 4-16. This action is referred to as "double jointing." The pipe is then moved to the right-of-way and unloaded near the ditch. This action is referred to as "stringing the pipe" (see Exhibit 4-17). The pipe is then welded into one continuous line as shown in Exhibit 4-18, welds are covered with plastic material, and then the pipe is lowered into the ditch.

The pipeline is then hydrostatically tested (see Exhibit 4-19) to make sure there are no leaks and that it will withstand the MAOP. The procedure of hydrostatically testing a pipeline can be quite complicated. Usually a section of newly constructed pipe is sealed at both ends and filled with water. The pressure is then raised to a minimum of 90 percent of minimum specified yield and held for eight hours. If there are no leaks, the water is removed and the pipeline is ready for service. Removal and disposal of the water presents its own set of environmental problems that must be addressed. Finally, the right-of-way is restored to its original condition as required by the various permits (see Exhibit 4-20).

Construction of compressor stations is very similar to the construction of small electric power stations. A series of illustrations concerning the construction and basic equipment included in a compressor station is discussed in Exhibit 4-21. The entire layout of a compressor station is commonly designed to allow for future expansion with minimal interruption of service. In general, it takes six to nine months to construct a station once all the required permits have been received.

As previously noted, the actual construction phase of a pipeline can often be completed in a matter of months. A typical construction schedule for pipeline expansion project is illustrated in Exhibit 4-22 and was taken from an actual construction schedule of a recently completed large expansion of a major pipeline. The term "spread" used on this schedule is defined as a length of pipeline that will be awarded to a pipeline contractor. The time of construction required for each spread ranges from two to four months depending on the right-of-way problems encountered, the size of pipe being laid, the length of the spread and the distance of the line from where material can be received from the steel mills.

Exhibit 4-12
CLEARING RIGHT
OF WAY

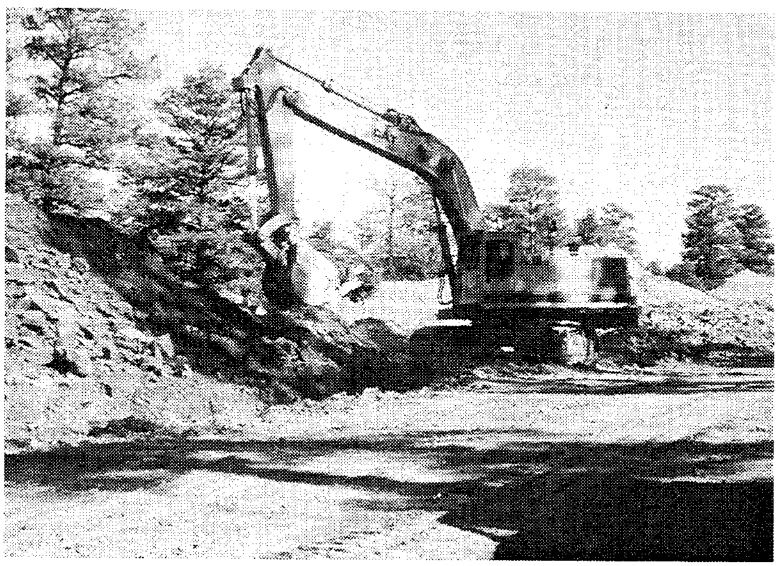


Exhibit 4-13
DIGGING DITCH
WITH BACKHOE

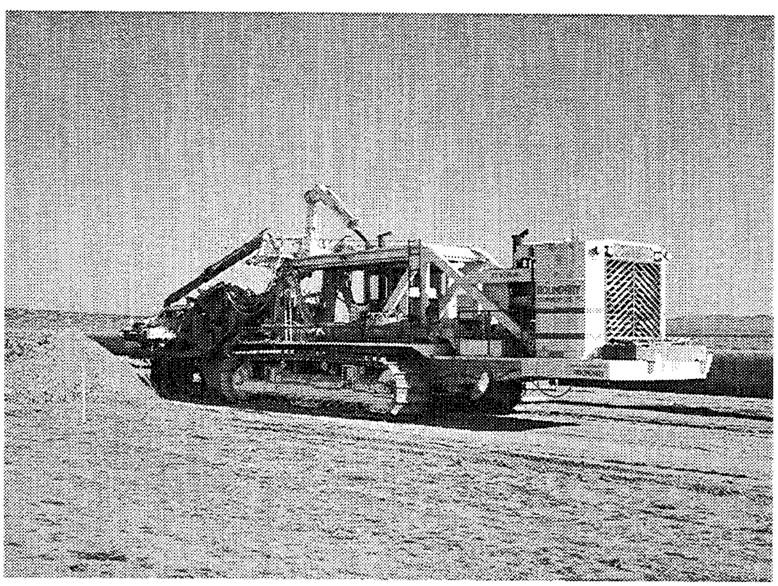


Exhibit 4-14
DIGGING DITCH
WITH DITCHING
MACHINE

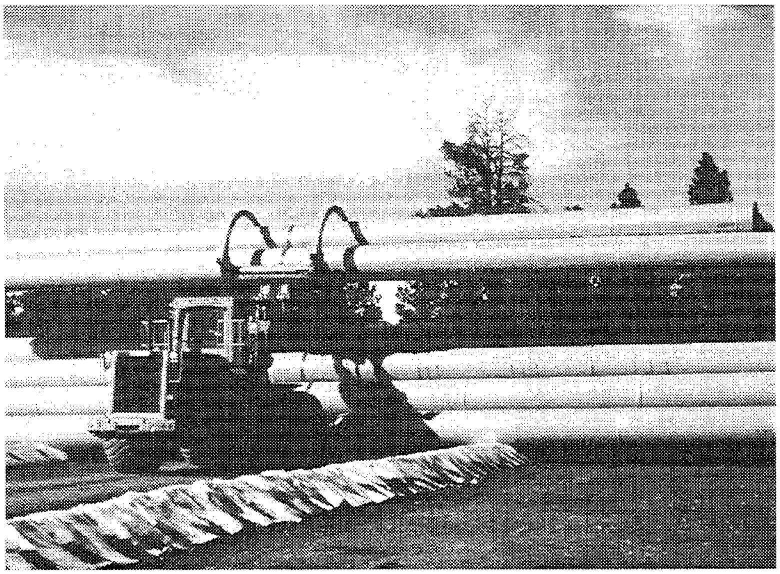


Exhibit 4-15
RECEIPT AND
STORAGE OF PIPE

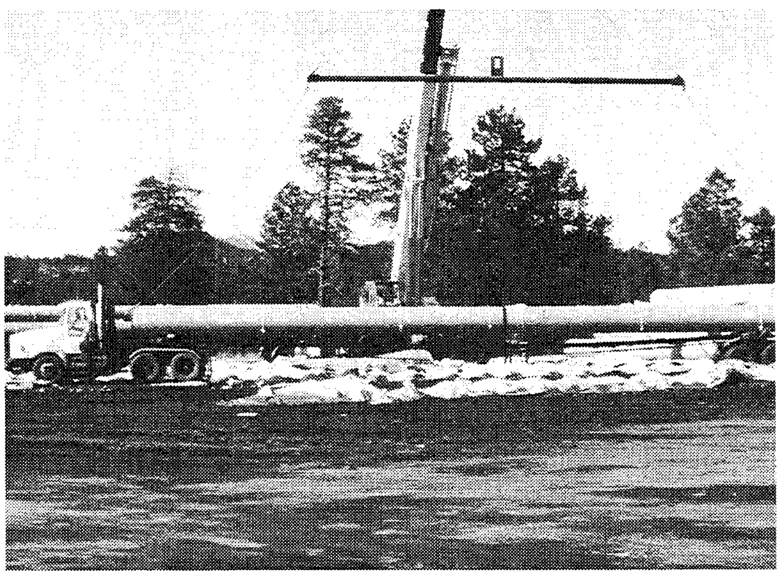


Exhibit 4-16
DOUBLE-JOINTED
SECTION OF PIPE

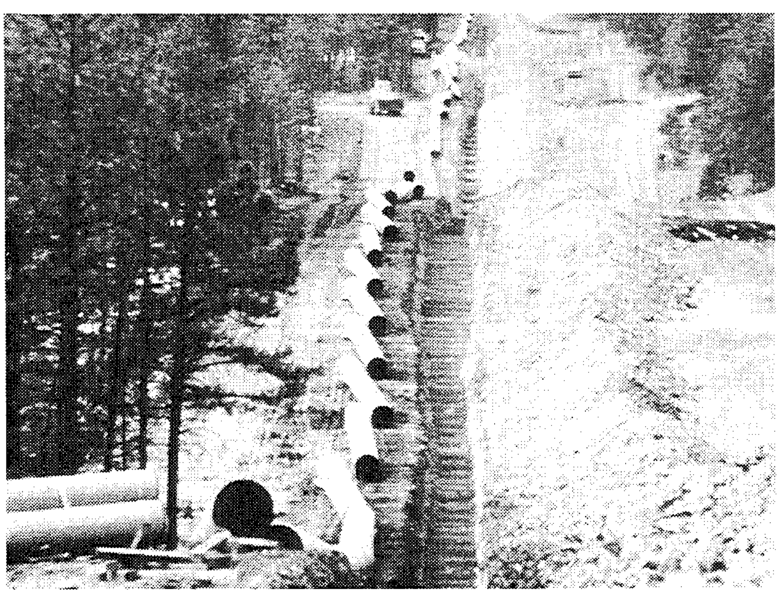


Exhibit 4-17
PIPE MOVED TO
RIGHT OF WAY
("Stringing the Pipe")

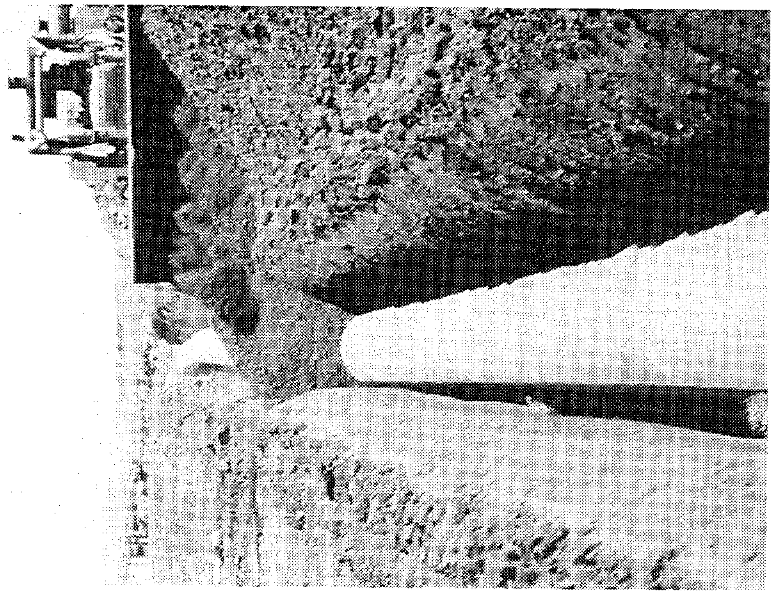


Exhibit 4-18
WELDED PIPE
LOWERED INTO
DITCH

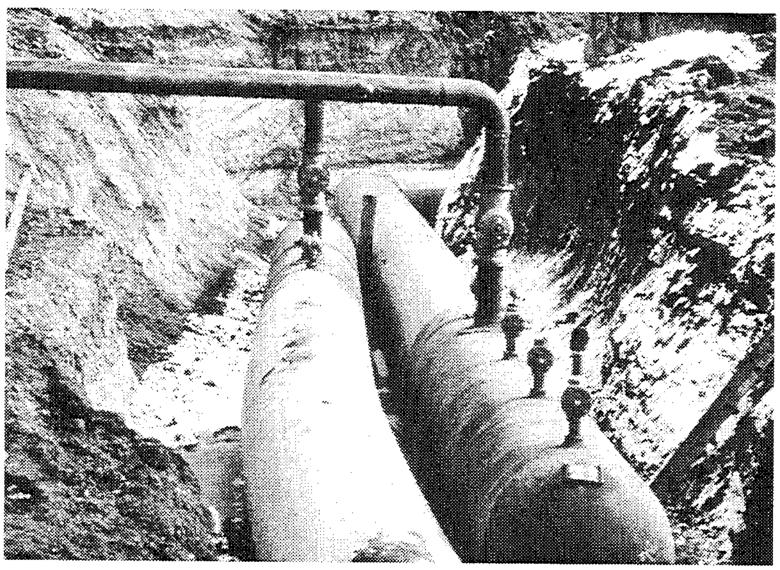


Exhibit 4-19
PIPELINE BEING
HYDRO-
STATISTICALLY
TESTED

Exhibit 4-20
COMPLETED
PIPELINE
RIGHT OF WAY
RESTORED TO
ORIGINAL
CONDITION

Exhibit 4-21
KEY ASPECTS OF COMPRESSOR STATIONS

The major components of a pipeline compressor station are illustrated in Exhibits 4-21A through 4-21I. A brief description of the salient features of each of these exhibits are as follows:

- Exhibit 4-21A shows an aerial review of a typical reciprocating compressor station. Such a station normally contains an office-warehouse building, an auxiliary building, a compressor building, and the associated gas piping, cooling, and scrubbers. These stations are self-sufficient, providing their own water and electric power.
- Exhibit 4-21B shows a close up of the outside of the compressor building and illustrates the inlet filter, the exhaust muffler and tall exhaust stacks required by air permits to reduce NOx. The small building on the left attached to the compressor building houses the automatic controls for operating the engines remotely.
- Exhibit 4-21C shows the outside of the auxiliary building which contains the auxiliary engine driven generator, and other plant supporting equipment such as air compressors, switch gear, etc.
- Exhibit 4-21D shows the reciprocating engine mounted compressors. The suction and discharge piping at the bottom of each compressor are highlighted.
- Exhibit 4-21E shows a close up of the auxiliary engines and the connected electric generators that are housed in the auxiliary building.
- Exhibit 4-21F shows a close up of yard piping, air-gas cooler and inlet scrubber.
- Exhibit 4-21G illustrates a typical gas turbine drive centrifugal compressor station. Such a station usually contains an office-warehouse building, a compressor building, an auxiliary building and the associated gas piping. These stations are self-sufficient, providing their own water and electric power.
- Exhibit 4-21H shows the inside of the compressor building containing the gas turbine and centrifugal compressor. The large insulated pipe on the discharge side of the compressor reduces centrifugal compressor created noise and protects personnel from high temperatures.
- Exhibit 4-21I shows a close up of the inlet gas scrubber on the right and the discharge air to gas cooler on the left side. The construction is very compact and does not allow room for future expansion.

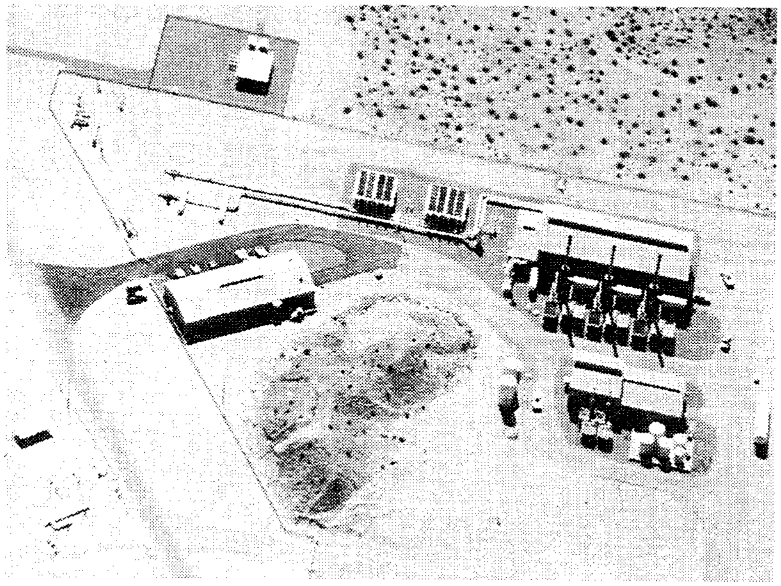


Exhibit 4-21A
AERIAL VIEW OF RECIPROCATING COMPRESSOR STATION

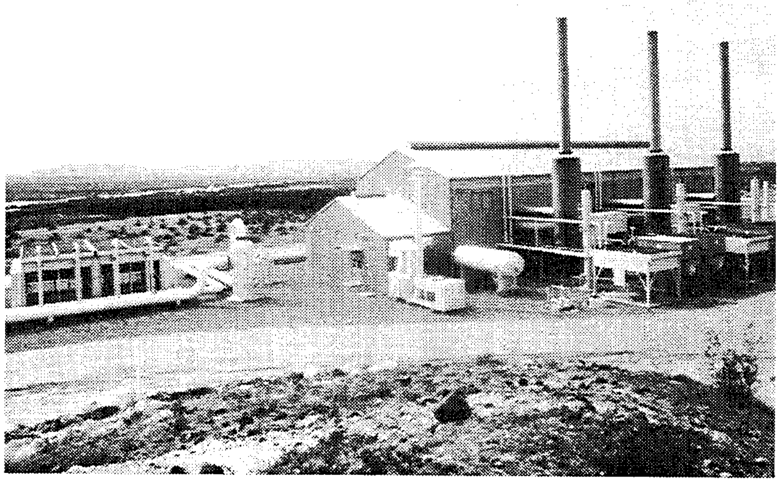


Exhibit 4-21B
COMPRESSOR BUILDING

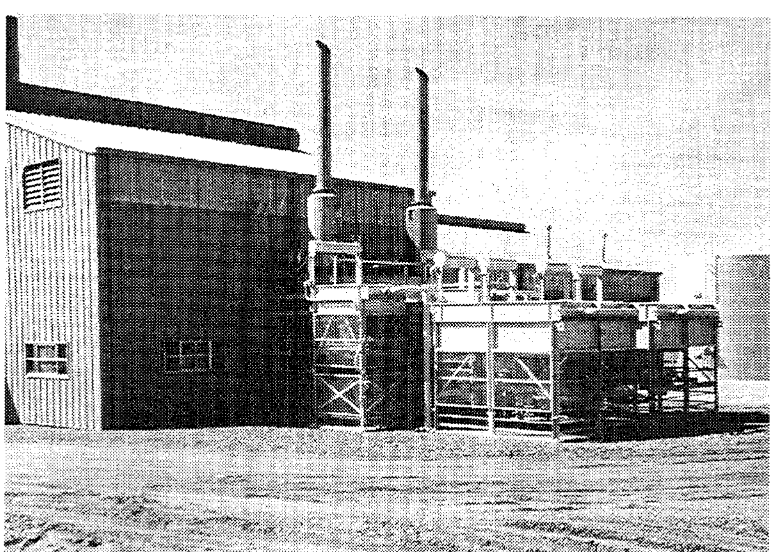


Exhibit 4-21C
AUXILIARY BUILDING

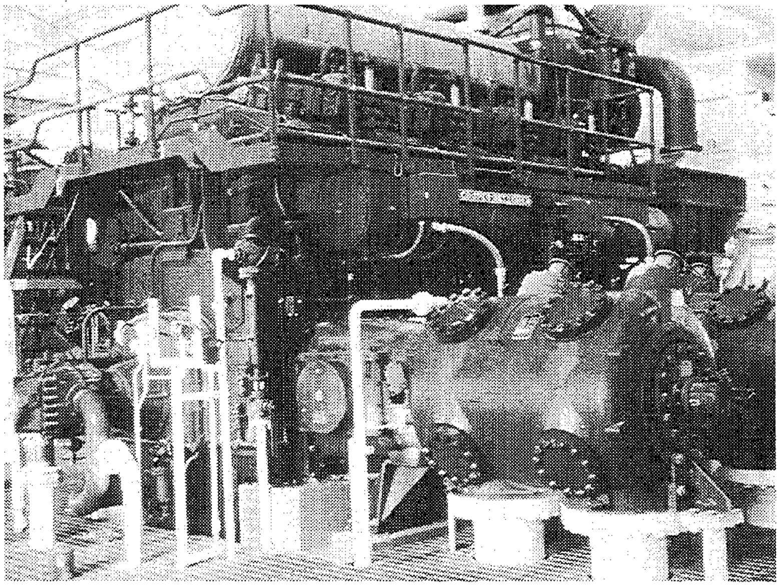


Exhibit 4-21D
RECIPROCATING ENGINE WITH COMPRESSOR

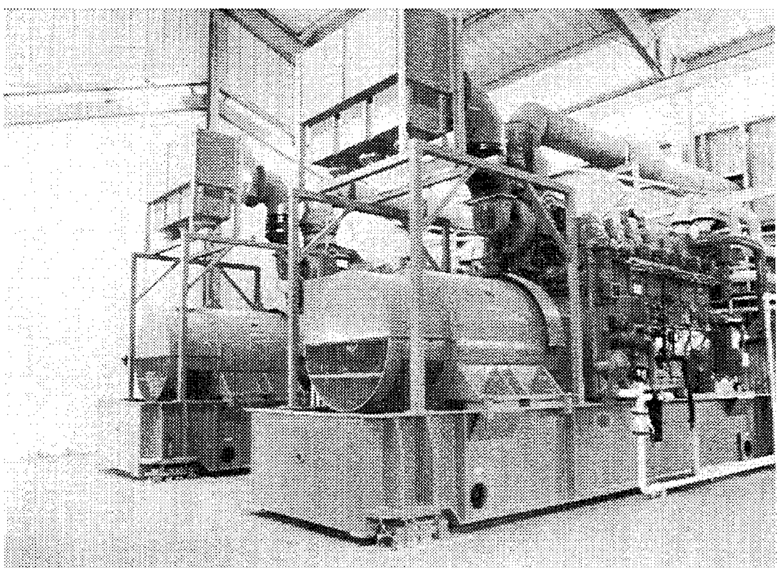


Exhibit 4-21E
AUXILIARY ENGINE DRIVEN GENERATORS

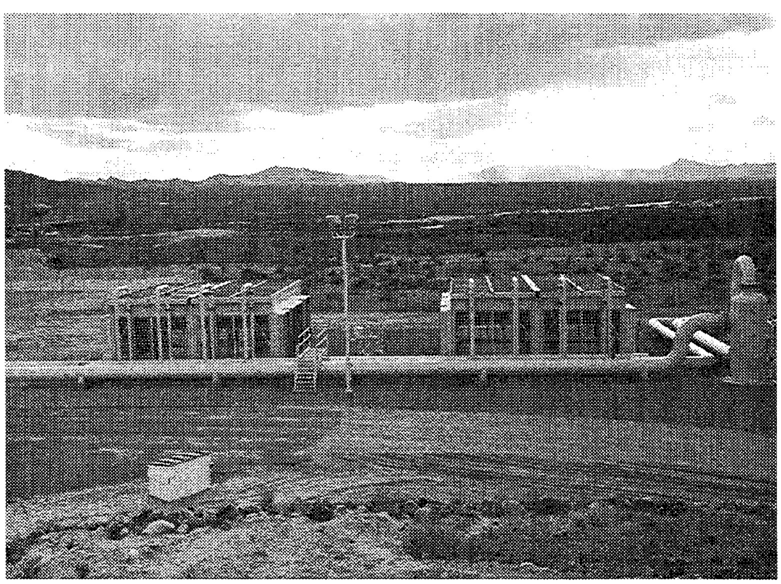


Exhibit 4-21F
PIPING YARD, AIR-GAS COOLER AND INLET SCRUBBER

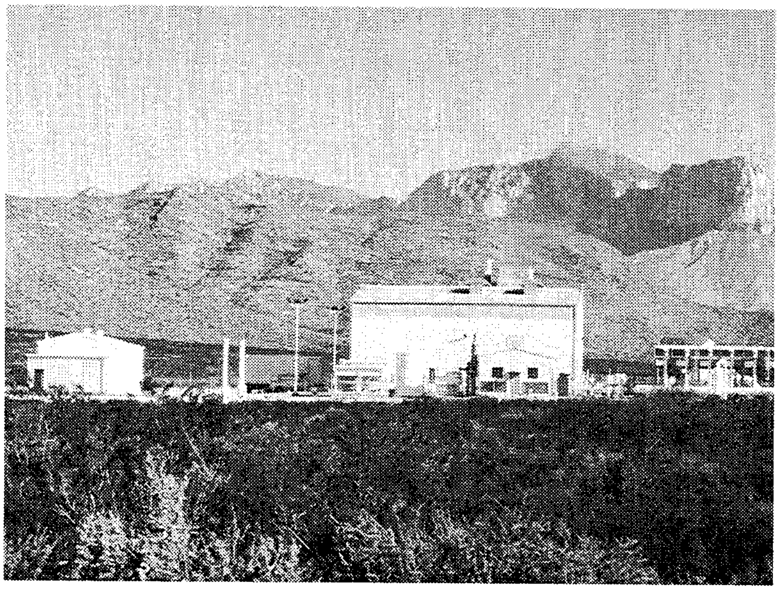


Exhibit 4-21G
GAS TURBINE
DRIVEN
CENTRIFUGAL
COMPRESSOR
STATION

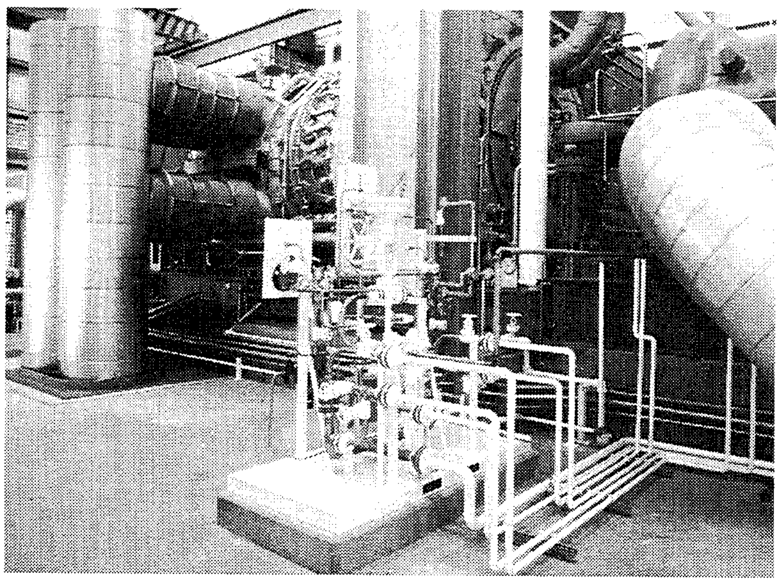


Exhibit 4-21H
GAS TURBINE
DRIVEN
CENTRIFUGAL
COMPRESSOR

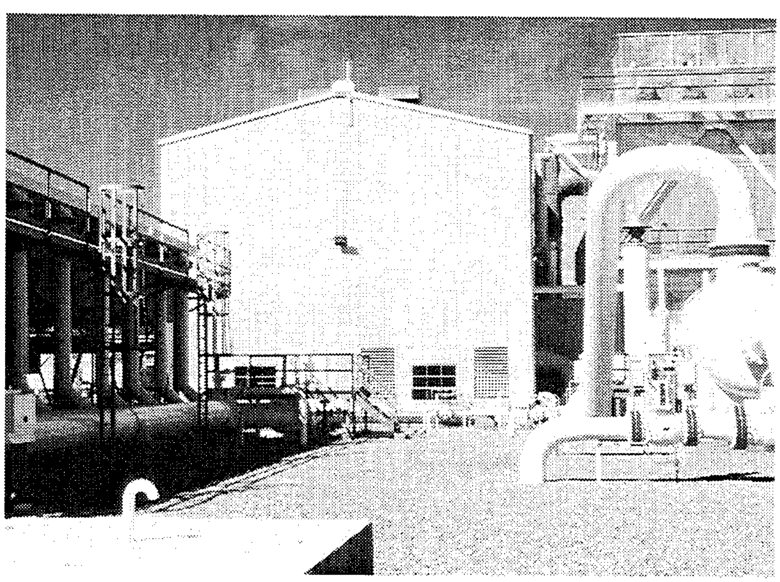
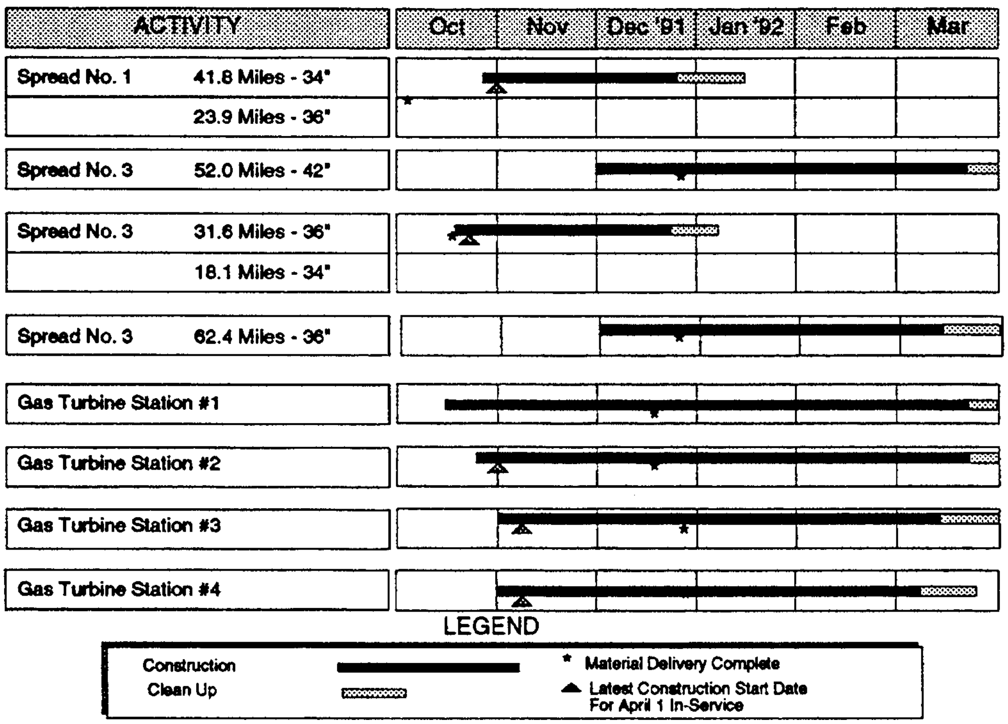


Exhibit 4-21I
INLET GAS
SCRUBBER
AND DISCHARGE
AIR-GAS COOLER

The construction schedule of a typical gas turbine compressor station is also depicted in Exhibit 4-22. The time for construction is subject to the same variables as pipeline construction, including distance of the construction site from a railroad delivery point and the quality and amount of skilled labor available in the area.

Exhibit: 4-22
TYPICAL RECENT PIPELINE EXPANSION PROJECT SCHEDULE



Pipeline Operations

Operations Control

Actual gas operations are very pipeline specific. The following is a brief description of the operating procedures for one interstate pipeline.

The focal point of day-to-day operations of a typical natural gas pipeline company is the Operation Control Department which is directly responsible for the proper, safe and efficient movement of gas to each customer.

Within the Operations Control Department there are usually three main groups as noted below:

- The Scheduling Group has direct contact with the customer and the producer. This group schedules gas needs on a daily basis. The scheduling day begins at 7:00 a.m. and usually ends by 4:00 p.m. seven days a week. Schedulers are usually available until 6:00 p.m. to ensure nightly processing is proceeding properly.

- The Gas Control Group fits the gas requested into the system, as it will exist on the day gas will be delivered. Their day begins at 7:00 a.m. and usually ends at 8:00 p.m., seven days a week.

- The Pipeline Control Group actually controls the pipeline through the Supervisory Control and Data Acquisition (SCADA) System, or issues verbal orders, via telephone, to the person in charge at a location to make whatever changes are necessary on the pipeline system.

A fourth group within the Operations Control Department is responsible for the design and maintenance of the computers and software of the SCADA system. While the specific organization of an Operations Control Department will vary among pipeline companies, the basic functions described above should exist within each department of a given pipeline company.

Scheduling and control of gas supplies is done by the Operating Control Center. While the scheduling and control is a seven day a week process, in general the process for an individual package extends over a three day period, as noted below:

- Day One - 7:00 a.m: The customer contacts the pipeline transmission company via computer, telephone and/or fax and informs the scheduler in the pipeline company the amount of gas required, under what agreements it will be provided, and where it is to be delivered. Also, at this time, the producer confirms that the gas for the particular customer is available. This information is passed on to the Gas Control Group, where, with the use of computers, available capacity will be determined and scheduling will be confirmed.

- Day Two: Customer has the option of increasing the amount of gas needed.

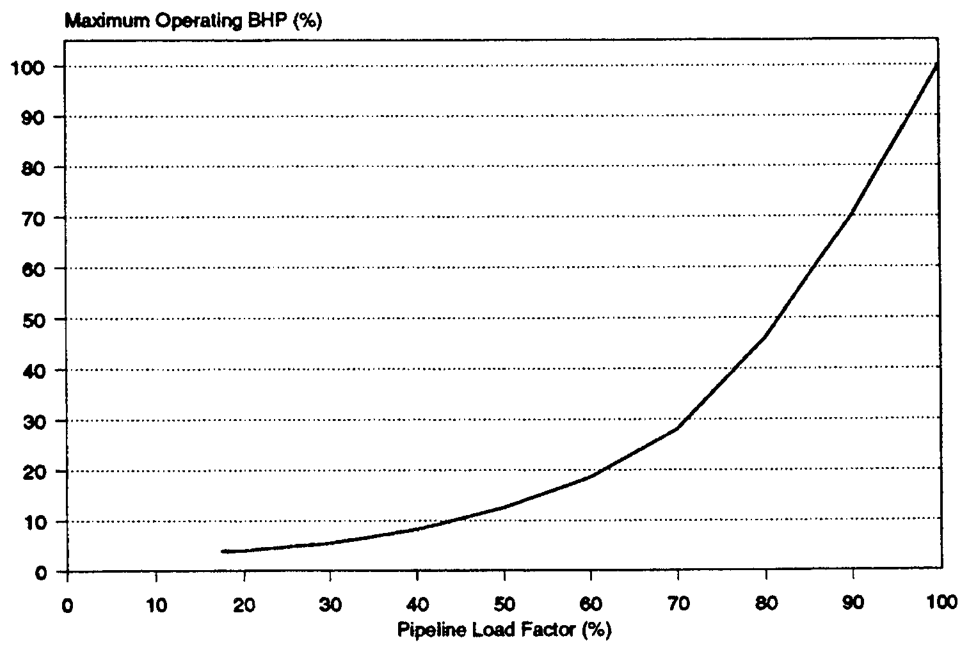
- Day Three - 7:00 a.m.: The gas ordered for delivery is available at the point requested by the customer.

The pipeline controller has the ability to regulate flow within the gas transmission system. This can be accomplished by turning on or off compressor stations along the pipeline, which raises and lowers the operating pressure, and/or by refusing gas from the producer in the field. Control of compression is managed through the SCADA System or by direct telephone conversation with the station operators. In addition, the most efficient way to run a pipeline is at MAOP, however such operation provides the gas controller with very little flexibility. By raising and lowering the pipeline pressure the pipeline inventory can be controlled and system flexibility can be increased. In actuality the adjustment of system pressure results in changing the "line pack"[1] in the system.

[1] A pipeline system under a certain set of flow and pressure conditions has stored in it a certain amount of gas. As the pressure and flows change the amount of gas stored also changes. When the storage increases the "line pack" increases, and when the storage decreases the "line pack" decreases. It is this difference in "line pack" that is useful to the gas controller as gas is scheduled on a daily basis.

The gas controller also has the responsibility of operating the system as efficiently as possible in order to minimize costs. When a pipeline is operating at full load, it is using 100 percent of its horsepower. When it is operating at 50 percent load, it is using less than 10 percent of its horsepower (see Exhibit 4-23). This feature is characteristic of all pipelines and again gives the gas controller flexibility and the system greater reliability.

Exhibit: 4-23
OPERATING HP Vs. PIPELINE LOAD FACTOR



Operations Issues Common to Electric Utilities

The use of gas turbines by the electric utility industry is not new and is projected to increase in the future. Therefore, it is important that there is a common understanding between the pipeline company and the electric utility of what is required by each party to make use of natural gas efficiently and reliably. Some of the principal considerations are outlined here. The material in this section has been updated with information supplied by EPRI (J. Platt, G. Booras, A. Cohn, and G. Touchton).

- *Pressure Requirements* : The gas pressure required by a combustion gas turbine is a function of the Axial Flow Compressor Discharge Pressure (AFCDP). This is the pressure in the combustion chamber that the gas will have to overcome so that it can be injected into the chamber for combustion. This pressure is usually described as a ratio -- 10:1, for example, means 10 atmospheres or about 150 psi. The minimum gas fuel pressure must take into account several additional considerations which are machine-specific. Engineers describe these considerations differently, but they generally include: (a) pressure drops across the fuel nozzles, (b) pressure for fuel control, typically about 60-75 psi, (c) additional pressure required for cold day operations, and (d) additional pressure to permit acceleration of the machine. The minimum resulting gas fuel pressure required by industrial (or "heavy-frame") gas turbines, which operate at pressure ratios of about 12:1 to 15:1, is about 250-350 psia. Aero-derivative units use aircraft turbine engines in their design, are much lighter than heavy-frame units and operate at higher pressure ratios. The pressure ratios of aero-derivative units range from about 20:1 to 30:1, corresponding to minimum gas fuel pressures of 400-700 psia. At these higher pressure ratios, generators will routinely install gas compressors to achieve minimum pressures and assure control of the gas flow.

- ***Ramp Time*** : Ramp time is defined as the time required for the gas turbine electric generator to go from zero load, cold start, to full load. In large industrial gas turbines it can take 10 minutes to reach synchronizing speed and 20-30 minutes to reach full load. In aero-derivative units, it can take 5 minutes to reach synchronizing speed and 15 minutes to reach full load.

- ***Fuel Consumption*** : Fuel consumption must be accurately defined so that starting fuel and on line fuel requirements can be accurately determined. Fuel consumption will increase disproportionately at part load due to poor partial load heat rates.

- ***Switching Capability*** : The ability of the gas turbine generator to switch quickly from natural gas to an alternate fuel and back is an important feature for most power generators. Both industrial and aero-derivative gas turbines can switch fuel within about 30 seconds, although a slightly longer period of about two minutes is desirable for a smooth transition.

- ***Performance*** : The prime mover in an electric generator station should have good efficiency and a reasonable time between overhauls based on the anticipated mode of operation. The light weight construction of the aircraft derivative gas turbine seems to favor frequent starting and stopping. Their high gas pressures and lower exhaust gas temperatures (due to greater amount of expansion of the gas through the turbine) lead to higher simple cycle efficiency. For cogeneration or combined cycle applications, however, where a higher temperature exhaust gas is an advantage and the machine will be run in a more stable mode, the heavy-frame models will often be more efficient.

- ***Maintenance.*** An integral consideration for the power generator is maintenance. Heavy-frame turbine maintenance costs may run one-half as much as aero-derivatives (on a cents per kilowatt hour basis), but they must be repaired in situ -- leading to longer downtime and purchase power costs. The engine core of aero-derivatives, on the other hand, can be replaced with a leased unit in only two or three shifts, with repairs then made at a specialized facility.

5

FUTURE RESEARCH

Overview

The information presented in this report provides considerable insight into the flexibility of pipelines to handle large electric utility loads however, it represents only a portion of the research that needs to be done on this subject. Of the major areas of additional research the most critical would be the development of complementary research on the impact on natural gas pipelines of daily variations in load requirements of power generators. Beyond this, area expansion of the scope of the design-oriented research presented in this report would be beneficial in order to provide greater breadth and depth in the coverage of this subject. Lastly, the implications of all of this research could be examined in a series of regional workshops.

Day-to-Day Operations

The information contained in this report represents a significant step in examining on a quantitative basis the flexibility, and associated costs, of pipelines to handle the large, highly variable loads of power generation. However, the scope of the research summarized in this report was limited primarily to the design phase of pipeline operations. In order to provide a more complete picture, additional research should be conducted on the flexibility, and associated costs, of pipelines to handle, under a variety of scenarios, the daily variations on load requirements which are reflective of many current operations and distinctly different from the design-oriented project contained in this report, which assumes full knowledge of all load requirements by both the power generator and the pipeline.

This research would examine a series of scenarios that would analyze the impact on natural gas pipelines of unscheduled variations in daily load requirements of power generation. The focus of these unscheduled variations would be for already constructed facilities where projections of daily load requirements (i.e., nominations) are often imperfect. Furthermore, in those scenarios where additions to pipeline facilities are required to handle these variations in daily load requirements, their costs would be compared to alternative approaches, such as the use of alternative fuels or onsite storage, in order to assess that most cost-effective means of serving these loads.

The scenarios for this research would be modeled using the same three pipeline configurations developed for this report. An initial list of scenarios that could be modeled include the following:

- *Variation from Nominated Load*: Both increases and decreases in load requirements from those submitted the prior day for pipeline nominations would be modeled for each pipeline system. A range of variations would be examined to provide insight on the degree of variation that can be accommodated before additional facilities are required. The addition of such facilities, in essence, represents the cost of providing the equivalent of no-notice service for power generators.

- *Multiple Day Variation*: The above scenario would be extended to cover three or more days during which the power generator experiences substantial variations from nominated load requirements. This situation maybe more difficult for the pipeline to accommodate because of the decay in line pack over the period.

- *Impact of Location*: The impact of location on the ability of pipelines to serve such load variations, as well as the requirements for new facilities, would be modeled. In particular, differences between power generators located at the end of the pipeline system and loads located upstream would be compared and contrasted.

- *Impact of Weather*: The ability of pipelines to accommodate load variations by power generators will be modeled during peak periods of demand for both LDC's and power generators (i.e., usually during adverse weather conditions) and during periods of off-peak demand for LDC's. While something approaching no-notice service for power generators may be feasible during off-peak periods, it is anticipated that a significant amount of additional pipeline facilities would be required during peak demand periods.

- *Impact of Pressure Requirements*: The impact of a wide range of pressure requirements for combustion turbines (i.e., 250 to 600 psig) would be modeled in order to assess the impact of this single variable on changes to pipeline facilities to accommodate variations in daily load requirements.

Expand Scope of Design - Oriented Analysis

There are several areas of research that would both expand the breadth of information contained in this report and provide greater depth in this material. Some of these areas of additional research were developed as a result of the project team for this report uncovering areas that merited investigation that were beyond the initial scope of the report. Other items were the suggestions of individuals in the gas and electric industries who have reviewed drafts of this report. A brief summary of these areas is as follows:

- *Analysis of Single Variables*: The current research examines the impact of changes to three pipeline systems. In general, the changes, or alternatives, examined for each system involved changing several variables in order to illustrate in broad terms a likely, or practical, change to the entire system. It would be beneficial to also provide a detailed analysis of each variable to more clearly establish the impact of that variable. For example, what is the impact if only CT units are added to the pipeline system? Similarly, what if only CC units are added? An initial list of variables that should be examined contain the following:

- *CT Load*: Analyze the impact on various types of pipeline systems of adding 100% CT loads.

- *CC Load*: Analyze the impact on various types of pipeline systems of adding 100% CC loads.

- *Pressure:* Examine the impact on pipeline facilities and operations of a broad range of pressure requirements for new electric utility units (i.e., 250 to 600 psig).

- *Compressor Spacing*: Examine the impact of variations of compressor spacing on the addition of electric utility loads to a variety of pipeline systems.

- *Load Siting*: Further examine the impact of alternative locations for new electric utility loads on a variety of pipeline systems (i.e., load at the end, middle or beginning of the pipeline).

- *Detailed Analysis of Costs*: More information on pipeline costs would be beneficial. While the current project explains the concept of the J-curve analysis for pipelines, detailed illustrations of the costs tradeoffs for a particular change to a pipeline system using the three systems modeled for the project would provide greater insight into the design of pipeline systems. In each case the illustration would note where the proposed change was on the J-curve. Additionally, cost tradeoffs between the use of compression, looping pipelines, building storage, etc. could also be provided.

- *Analysis of Other Systems*: The report was limited to the examination of three pipeline systems. It would be beneficial to examine the flexibility of other types of pipeline systems, such as a telescoped system and a system with spare capacity (e.g., similar to many pipelines in the West). Neither of these types of gas transmission systems were analyzed in this report. Additionally, it would be beneficial to expand the examination of seasonal impacts on the various pipeline systems.

Analysis of Implications of Current Research

A series of regional workshops could be held as a means for management and planners, in both the gas transportation and electric utility industries, to assess the scope and implications of the combination of the design-oriented research in this report and the research on day-to-day operations discussed above. This assessment could be augmented with an analysis of existing and projected gas demands within a region, along with an overview of the gas transportation infrastructure within the region. The applicable industry examples in Section 3 to a specific region, along with others, could be used to promote discussion. These workshops could have as a central objective increasing the understanding of project tradeoffs and uncertainties for both industries.

Appendix A

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A-3	System 1: Changing Turbine Ramping Time	A-5
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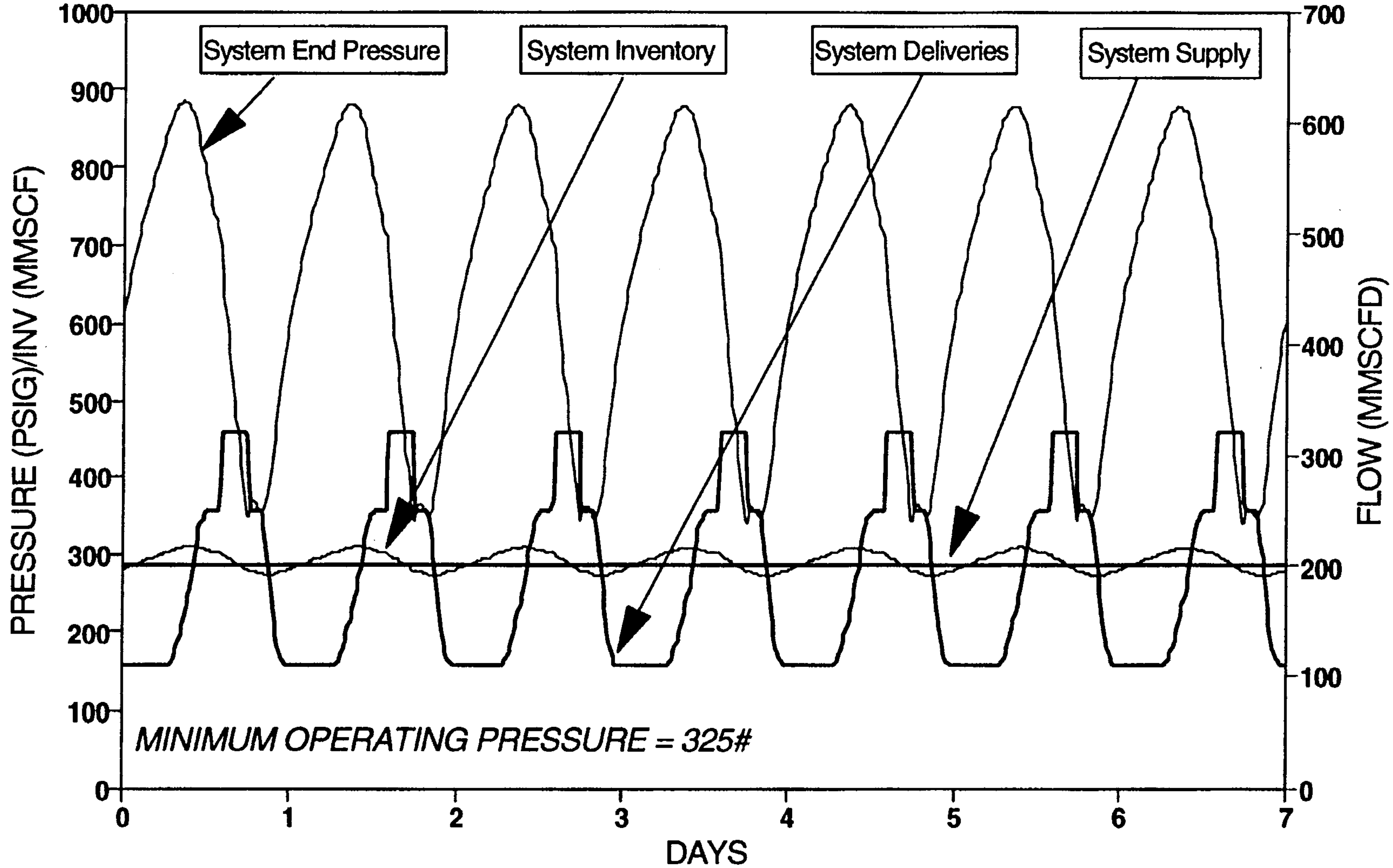
A-22	System 3: Downstream Storage Use of Booster For 3-4 Hour CT Load Requirements	A-24
A-23	Cost of Power Generation Load Additions for Cases Tested	A-25

Exhibit: A-1

SYS. 1: PRESSURE REQUIREMENTS WITH FOUR 1-HR BURN FOR CTs

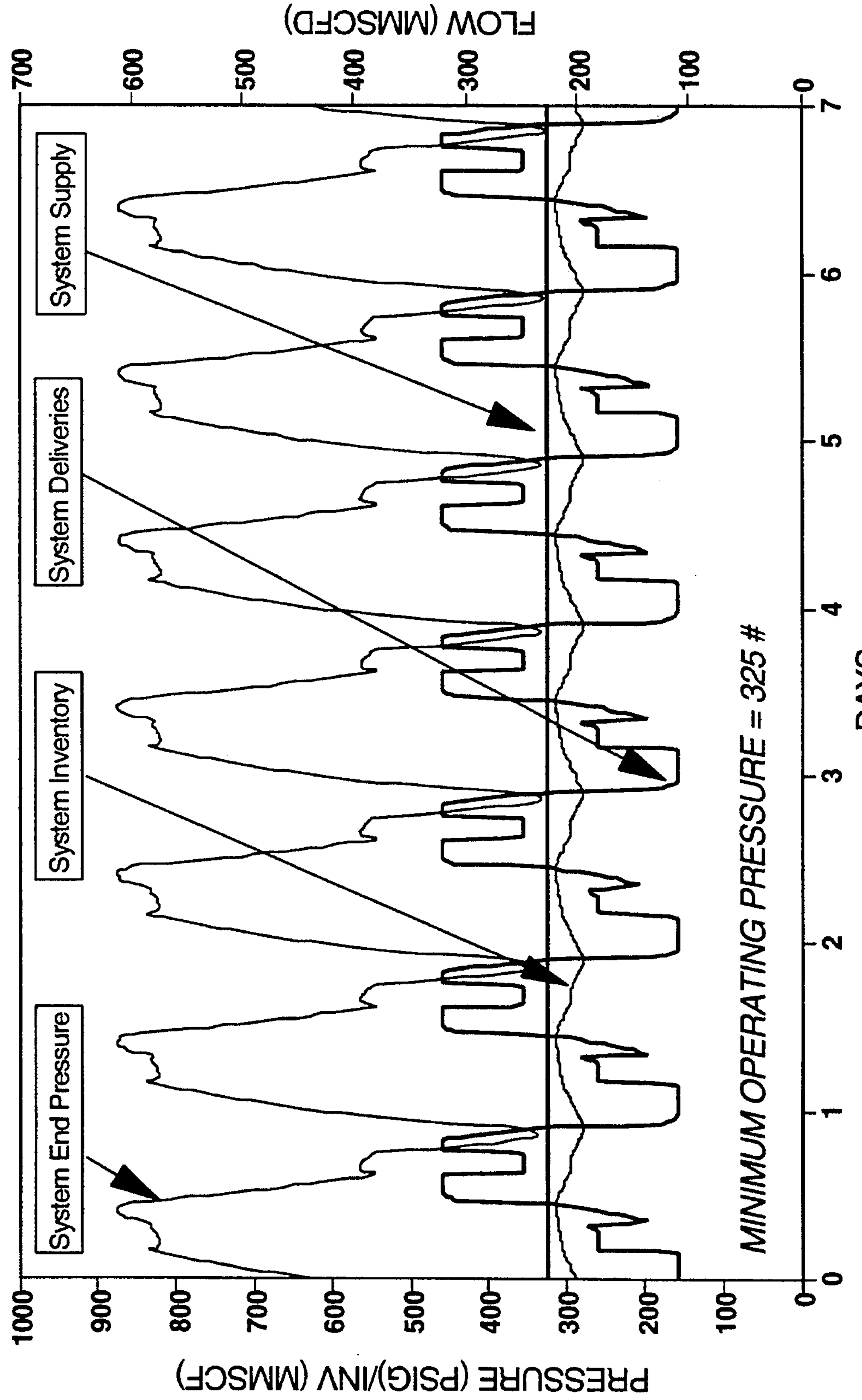


Footnote: System 1 (1B.1A)

Source: GRI/EPRI Project Team

Exhibit: A-2

SYS. 1: CHANGING PRESSURE REQUIREMENTS THREE 4-HR BURNS FOR CTs

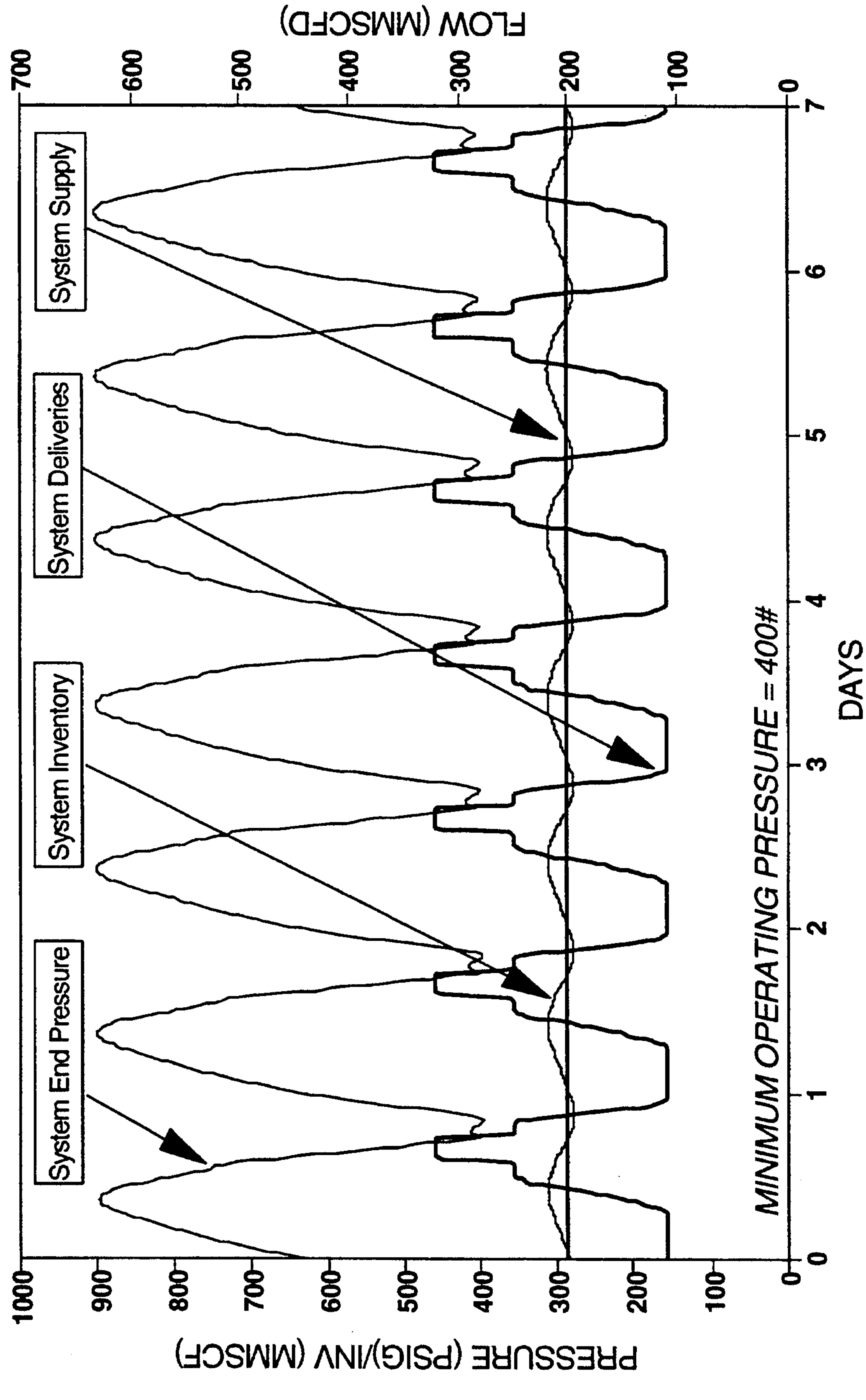


Footnote: System 1 (1B.3A)

Source: GRI/EPRI Project Team

Exhibit: A-3

SYS. 1: CHANGING TURBINE RAMPING TIME

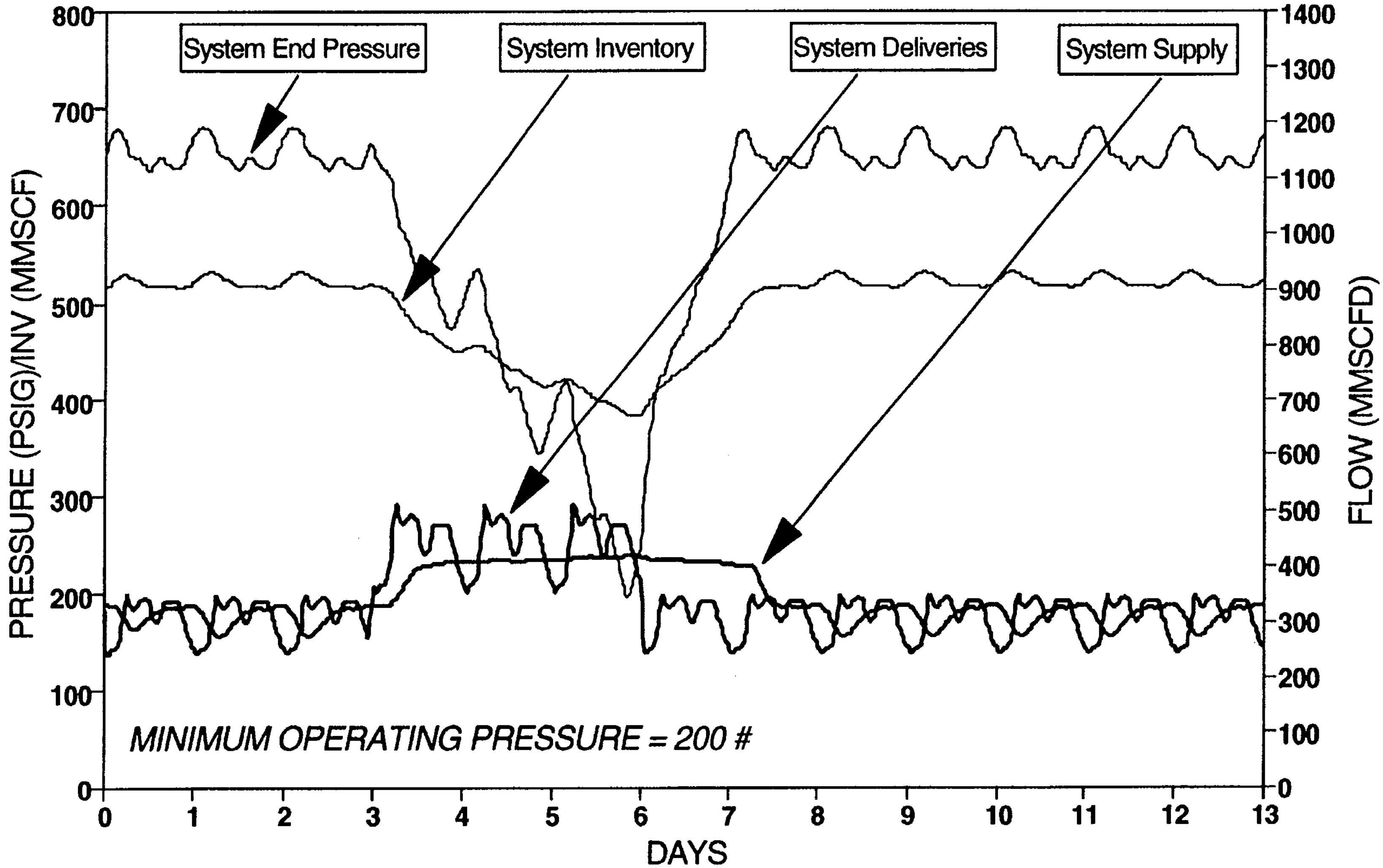


Footnote: System 1 (1B.1B)

Source: GRI/EPRI Project Team

Exhibit: A-4

SYS. 2: ADDITIONAL NEW ELECTRIC LOADS

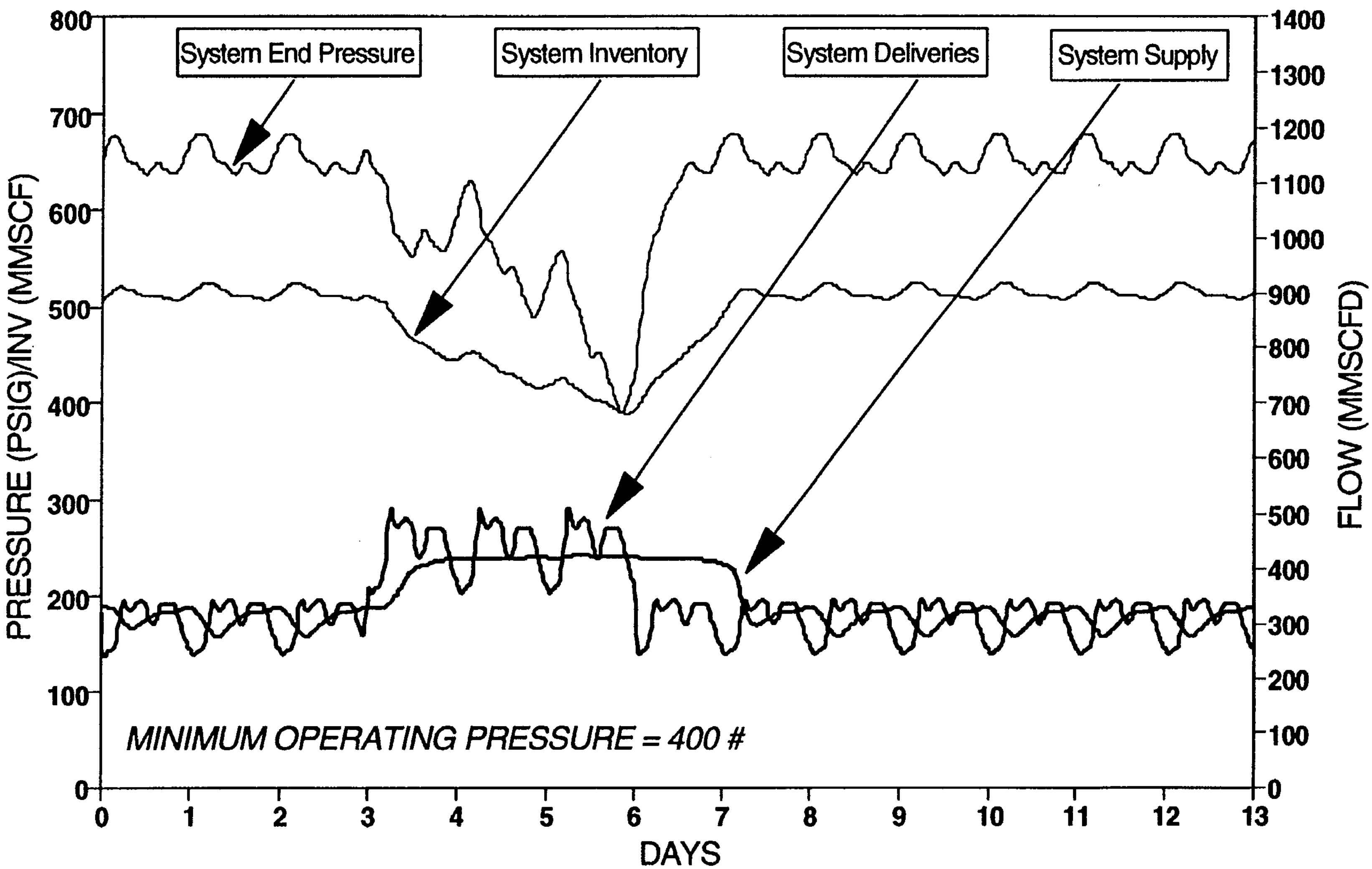


Footnote: System 2 (2A.2)

Source: GRI/EPRI Project Team

Exhibit: A-5

SYS. 2: ADDITION OF NEW ELECTRIC LOAD (BASE CASE 30" SYSTEM)

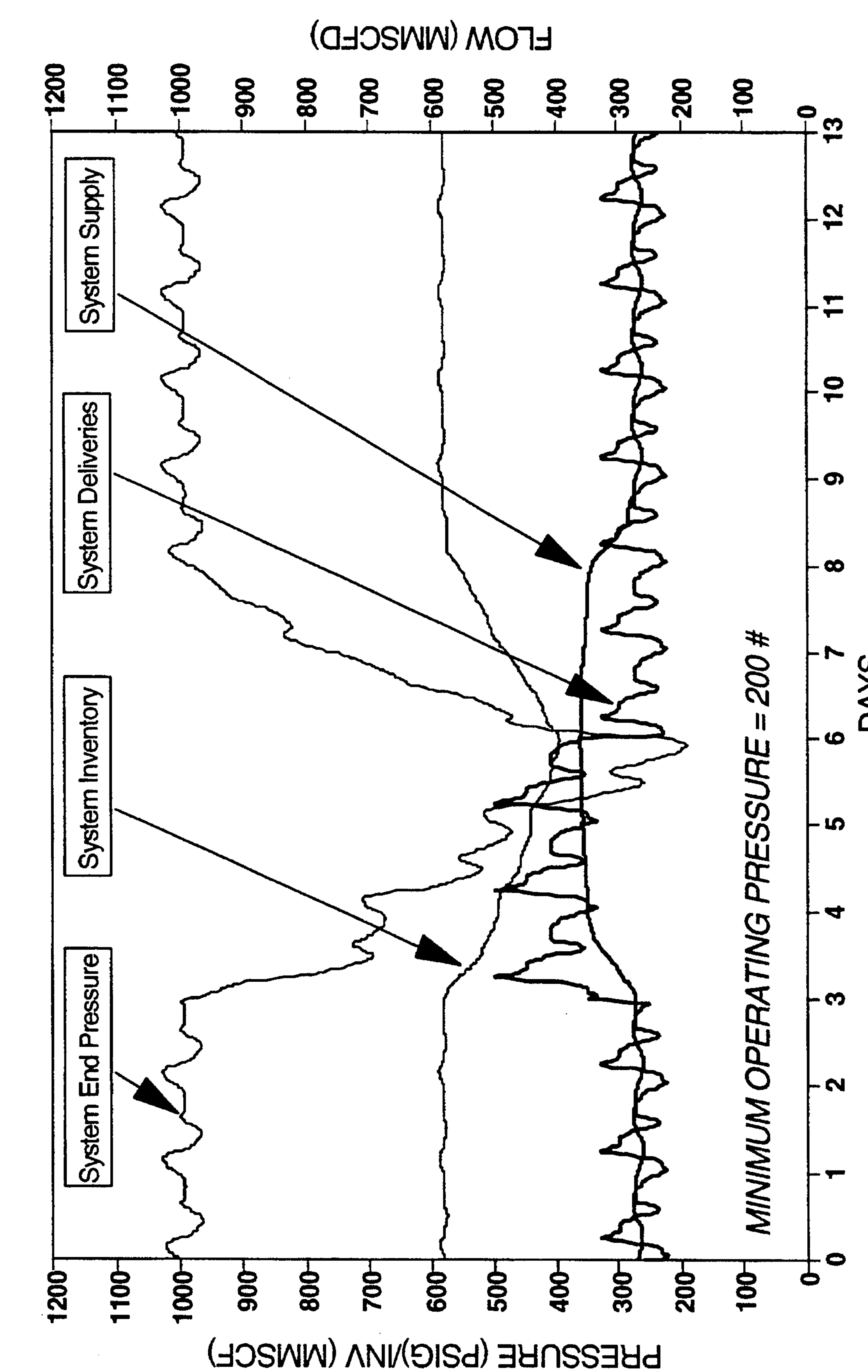


Footnote: System 2 (2A.3)

Source: GRI/EPRI Project Team

Exhibit: A-6

SYS. 2: ALTERNATE PIPELINE DESIGN 24" SYSTEM

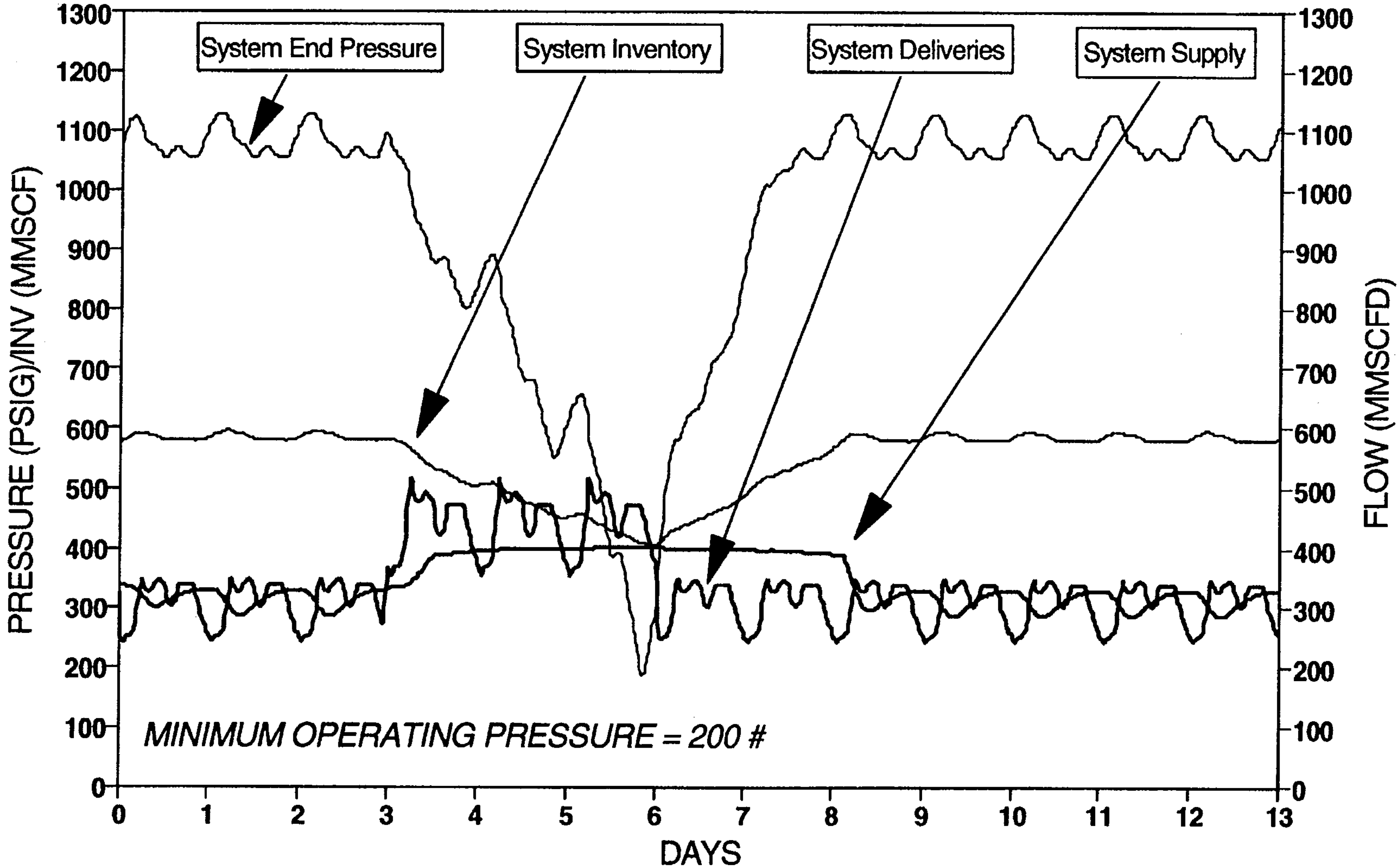


Footnote: System 2 (2B.1)

Source: GRI/EPRI Project Team

Exhibit: A-7

SYS. 2: ADDITION OF ELECTRIC LOAD ON ALTERNATE PIPELINE DESIGN (24" SYSTEM)

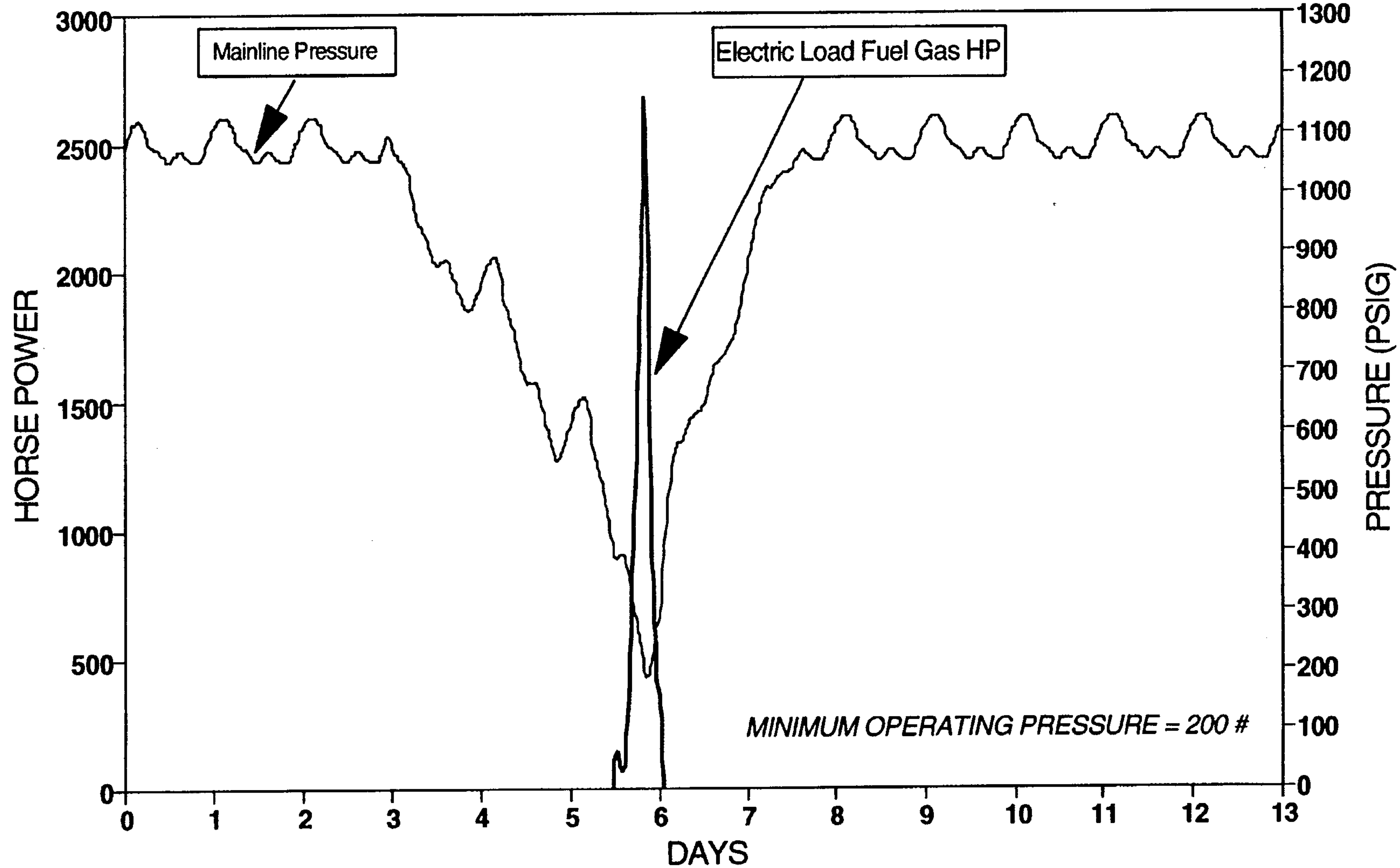


Footnote: System 2 (2B.2)

Source: GRI/EPRI Project Team

Exhibit: A-8

SYS. 2: USE OF BOOSTER COMPRESSOR FOR ALTERNATE PIPELINE DESIGN SYSTEMS (24")

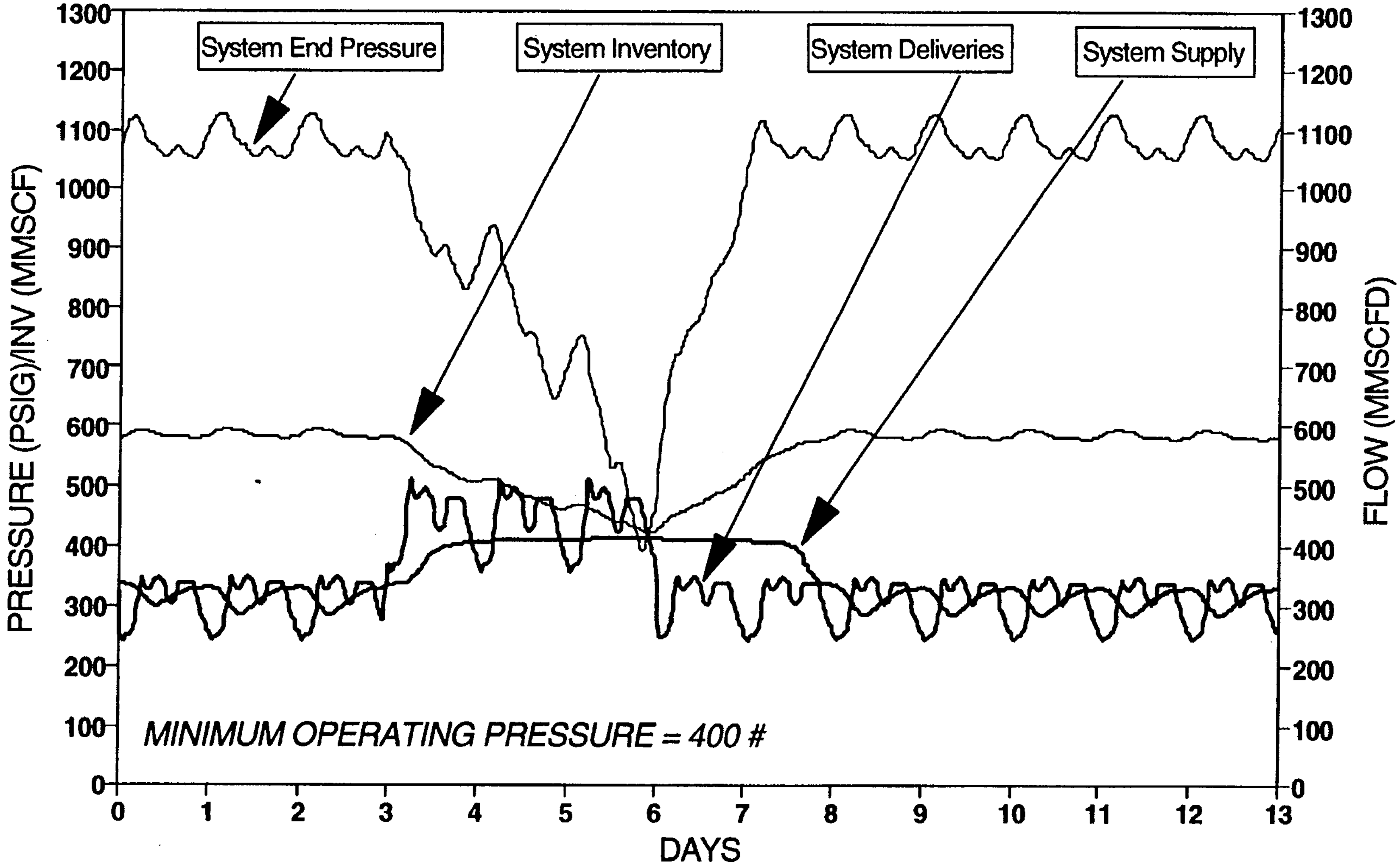


Footnote: System 2 (2B.4)

Source: GRI/EPRI Project Team

Exhibit: A-9

SYS. 2: INCREASE PIPELINE MIN. OPER. PRESSURE FOR ALT. DESIGN (24" SYSTEM)

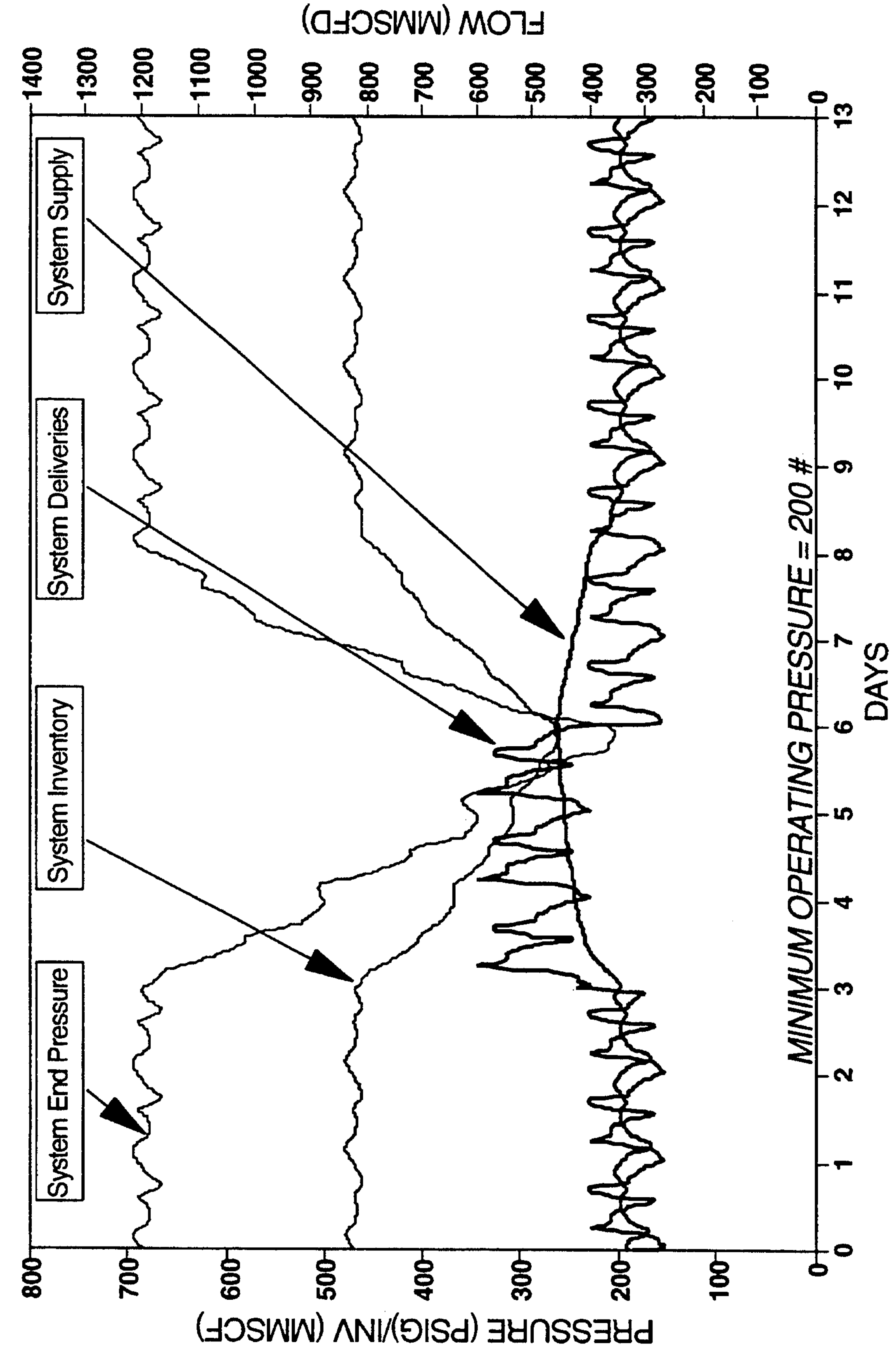


Footnote: System 2 (2B.3)

Source: GRI/EPRI Project Team

Exhibit: A-10

SYSTEM 3 UPSTREAM STORAGE ADDITION OF INCREMENTAL CT LOADS

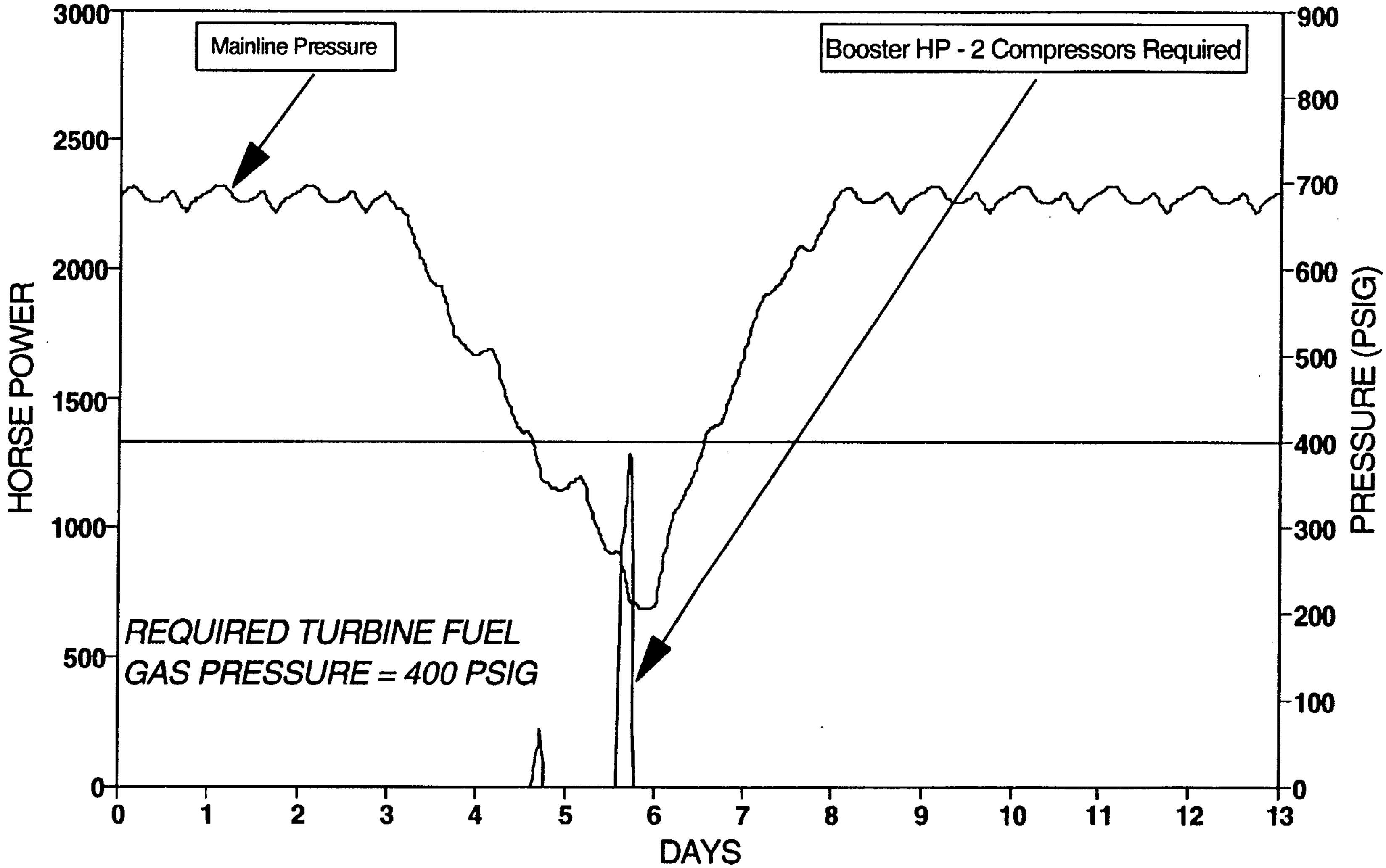


Footnote: System 3 (3A.2A)

Source: GRI/EPRI Project Team

Exhibit: A-11

SYS. 3: UPSTREAM STORAGE USE OF BOOSTER COMPRESSION FOR INCREMENTAL LOADS

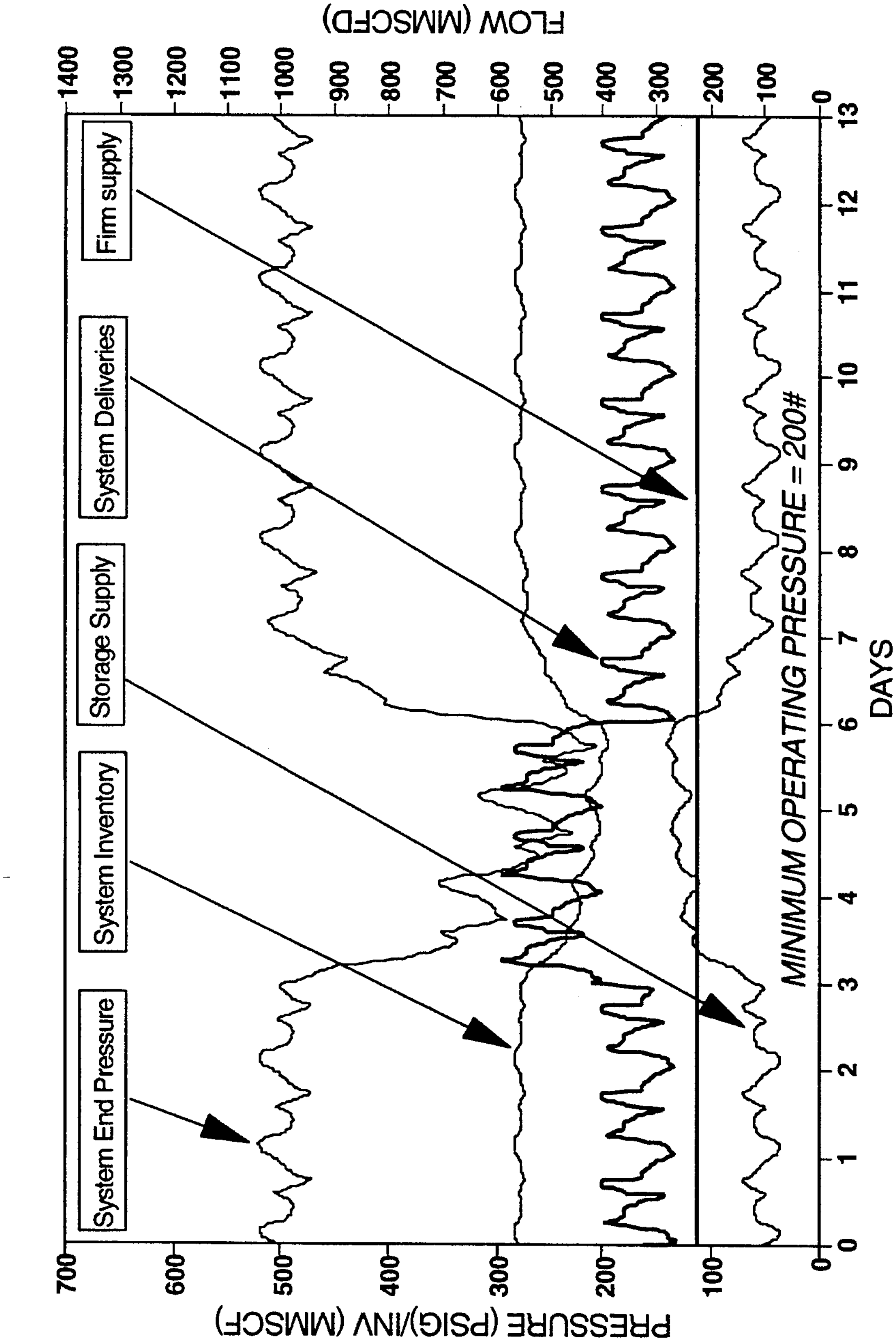


Footnote: System 3 (3A.2A1)

Source: GRI/EPRI Project Team

Exhibit: A-12

SYS. 3: DOWNSTREAM STORAGE ADDITION OF INCREMENTAL CT LOADS

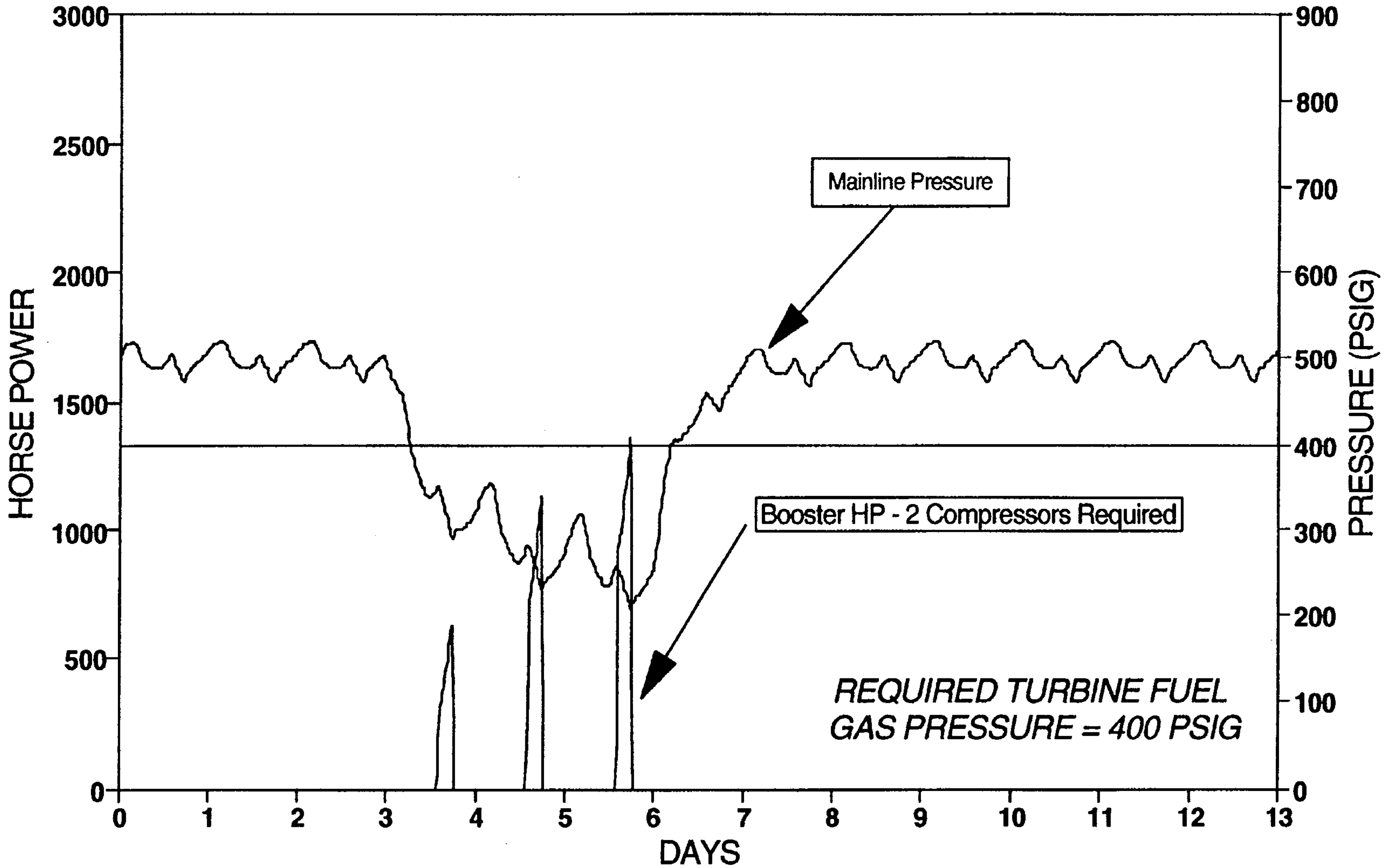


Footnote: System 3 (3B.2A)

Source: GRI/EPRI Project Team

Exhibit: A-13

SYS. 3: DOWNSTREAM STORAGE USE OF BOOSTER COMPRESSION

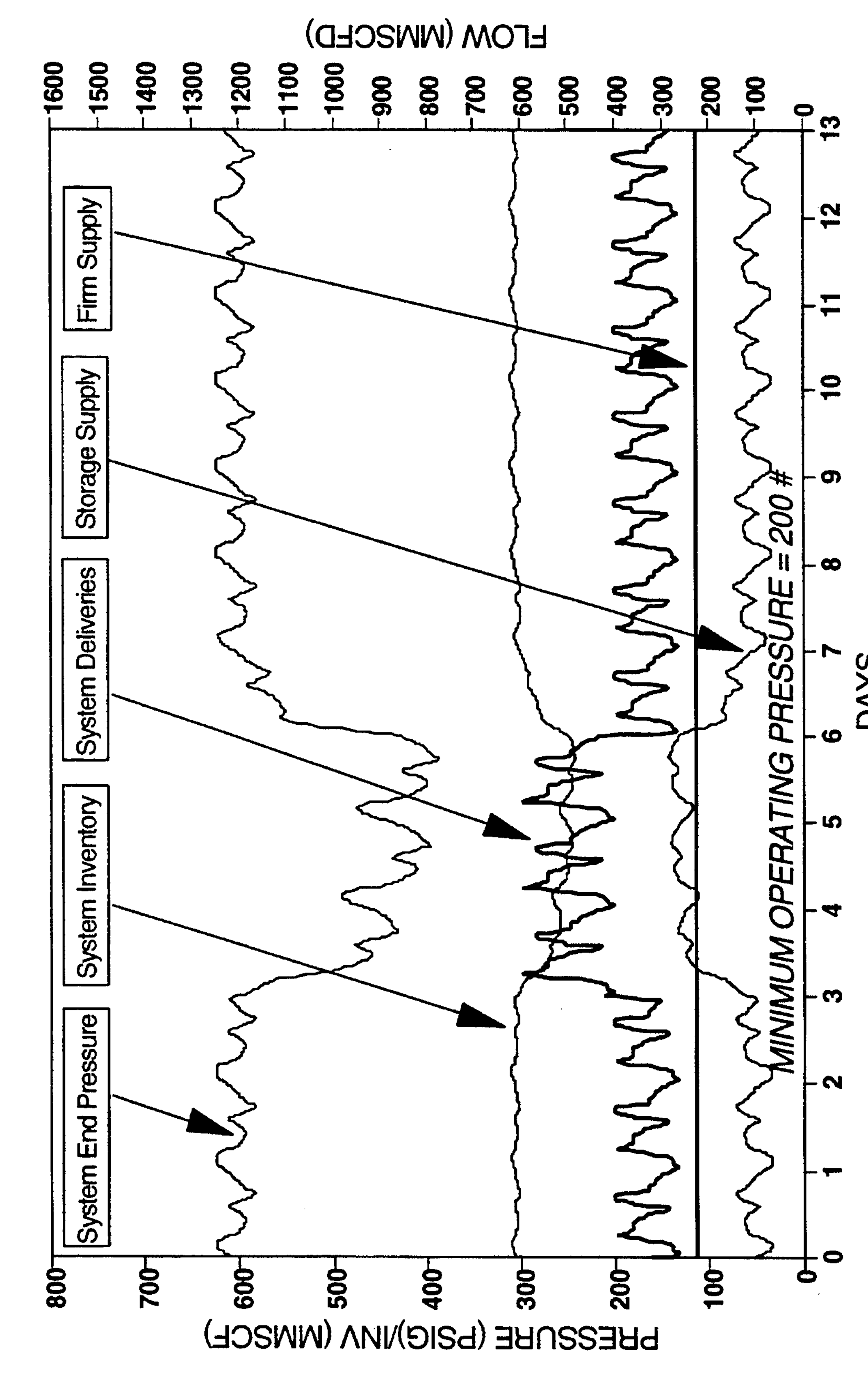


Footnote: System 3 (3B.2A1)

Source: GRI/EPRI Project Team

Exhibit: A-14

SYS. 3: DOWNSTREAM STORAGE INCREASE MINIMUM PRESSURE REQUIREMENTS

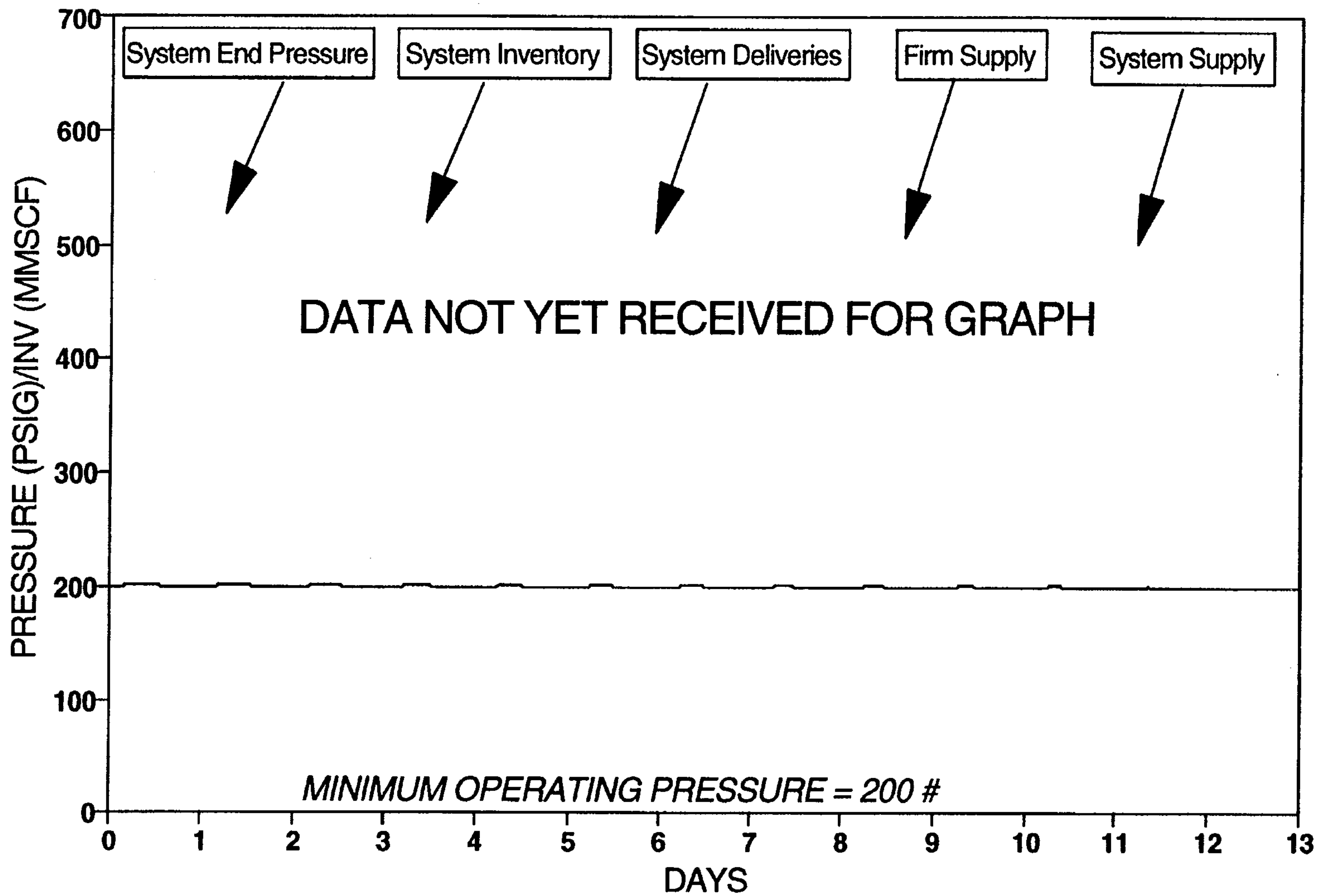


Footnote: System 3 (3B.3)

Source: GRI/EPRI Project Team

Exhibit: A-15

SYS. 3: UPSTREAM STORAGE ALTERNATIVE CT LOAD REQUIREMENTS OF 4 1-HR PERIODS

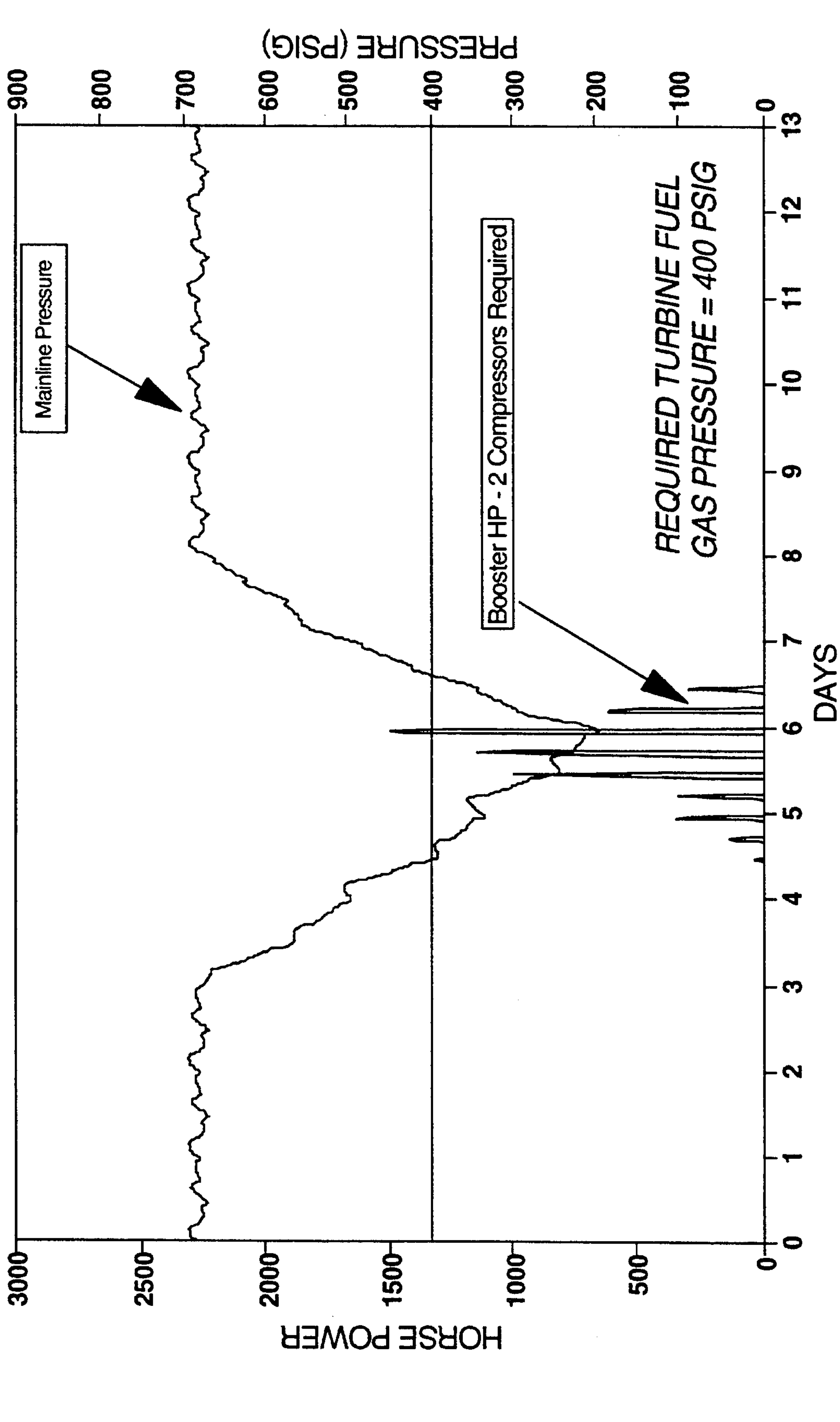


Footnote: System 3 (3A.2B)

Source: GRI/EPRI Project Team

Exhibit: A-16

SYS. 3: UPSTREAM STORAGE USE OF BOOSTER FOR 4-1 HR CT LOAD REQUIREMENTS

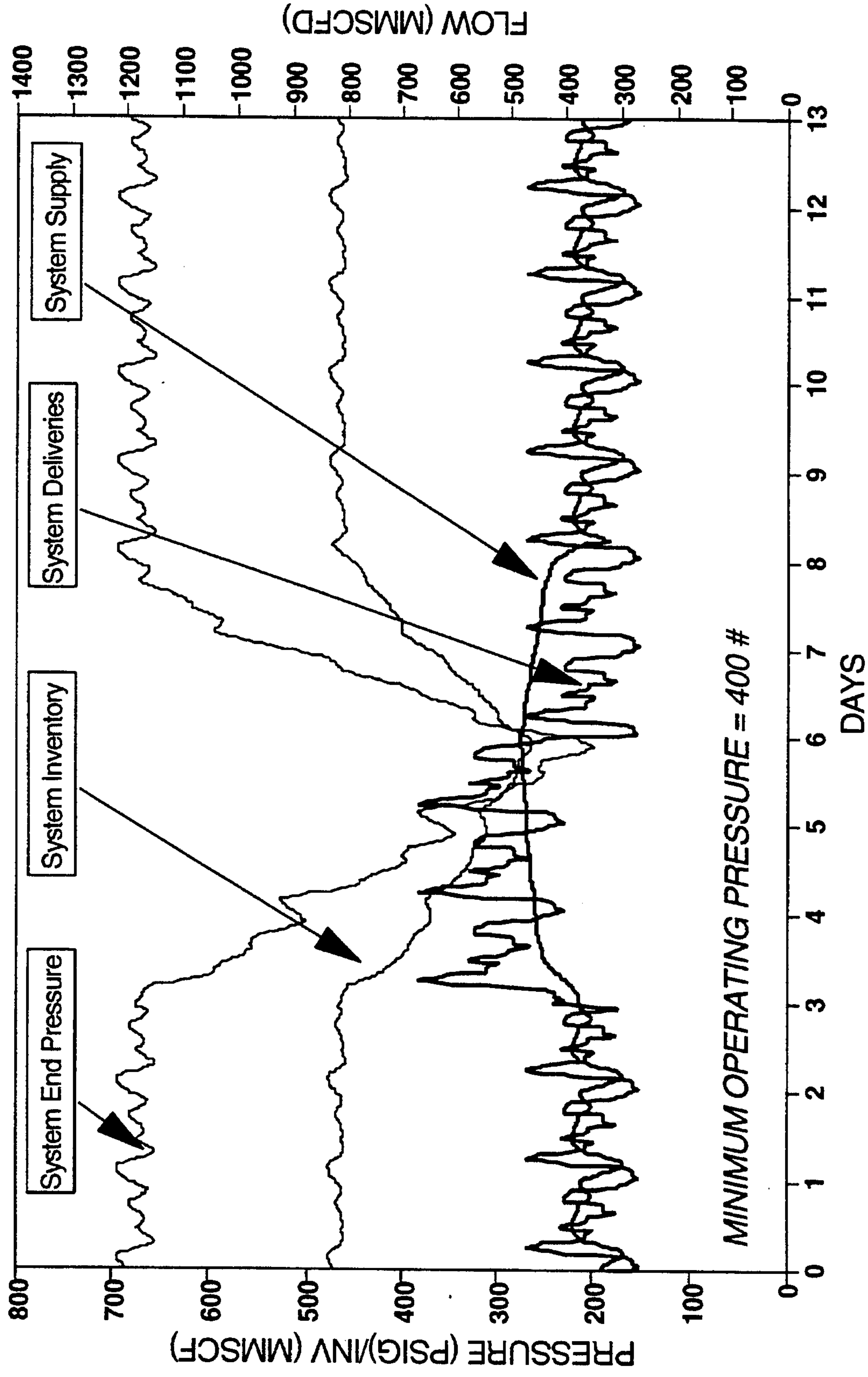


Footnote: System 3 (3A.2B1)

Source: GRI/EPRI Project Team

Exhibit: A-17

SYS. 3: UPSTREAM STORAGE ALTERNATIVE CT LOAD REQUIREMENTS OF 3 4-HR PERIODS

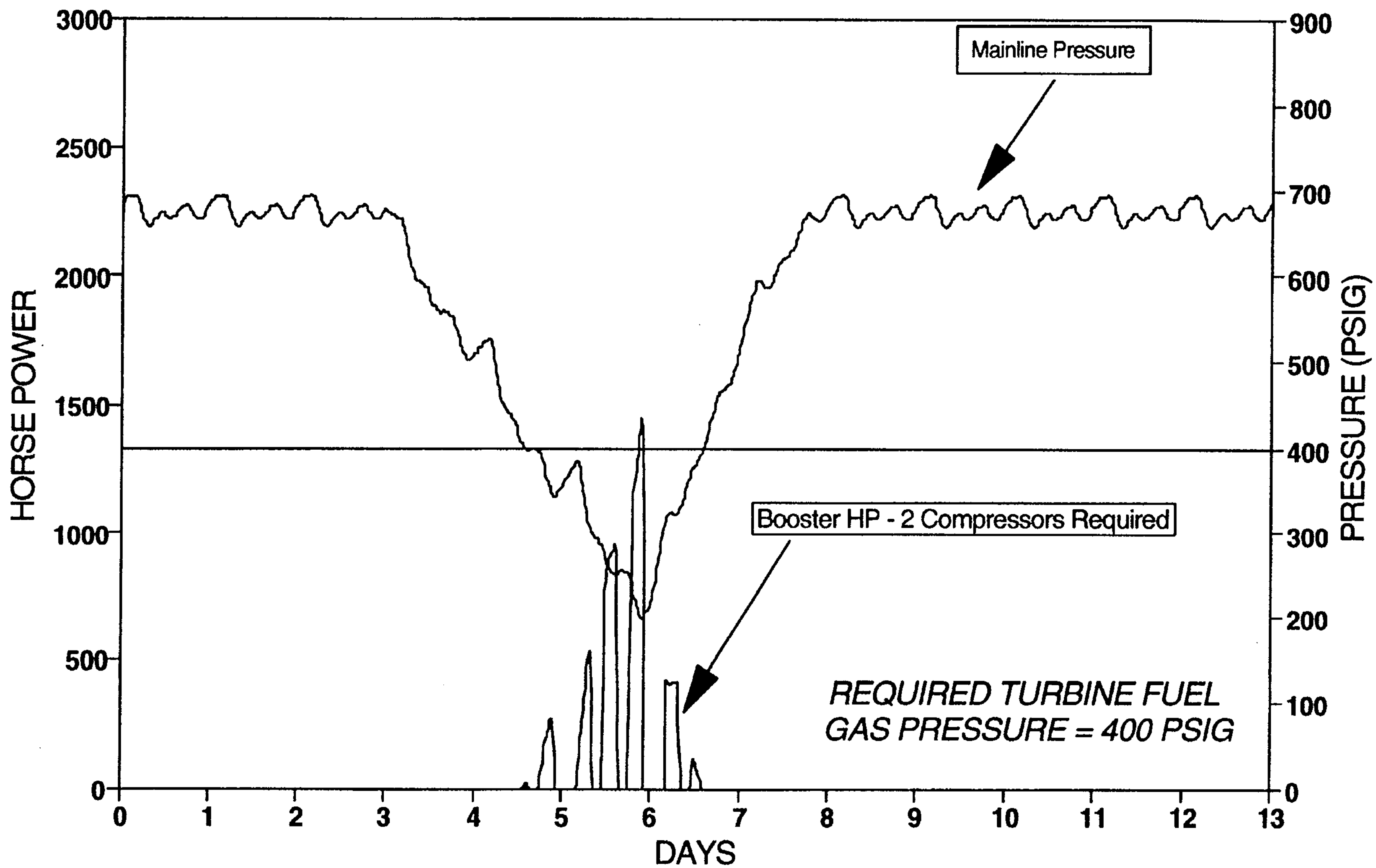


Footnote: System 3 (3A.2C)

Source: GRI/EPRI Project Team

Exhibit: A-18

SYS. 3: UPSTREAM STORAGE USE OF BOOSTER FOR 3-4 HR CT LOAD REQUIREMENTS

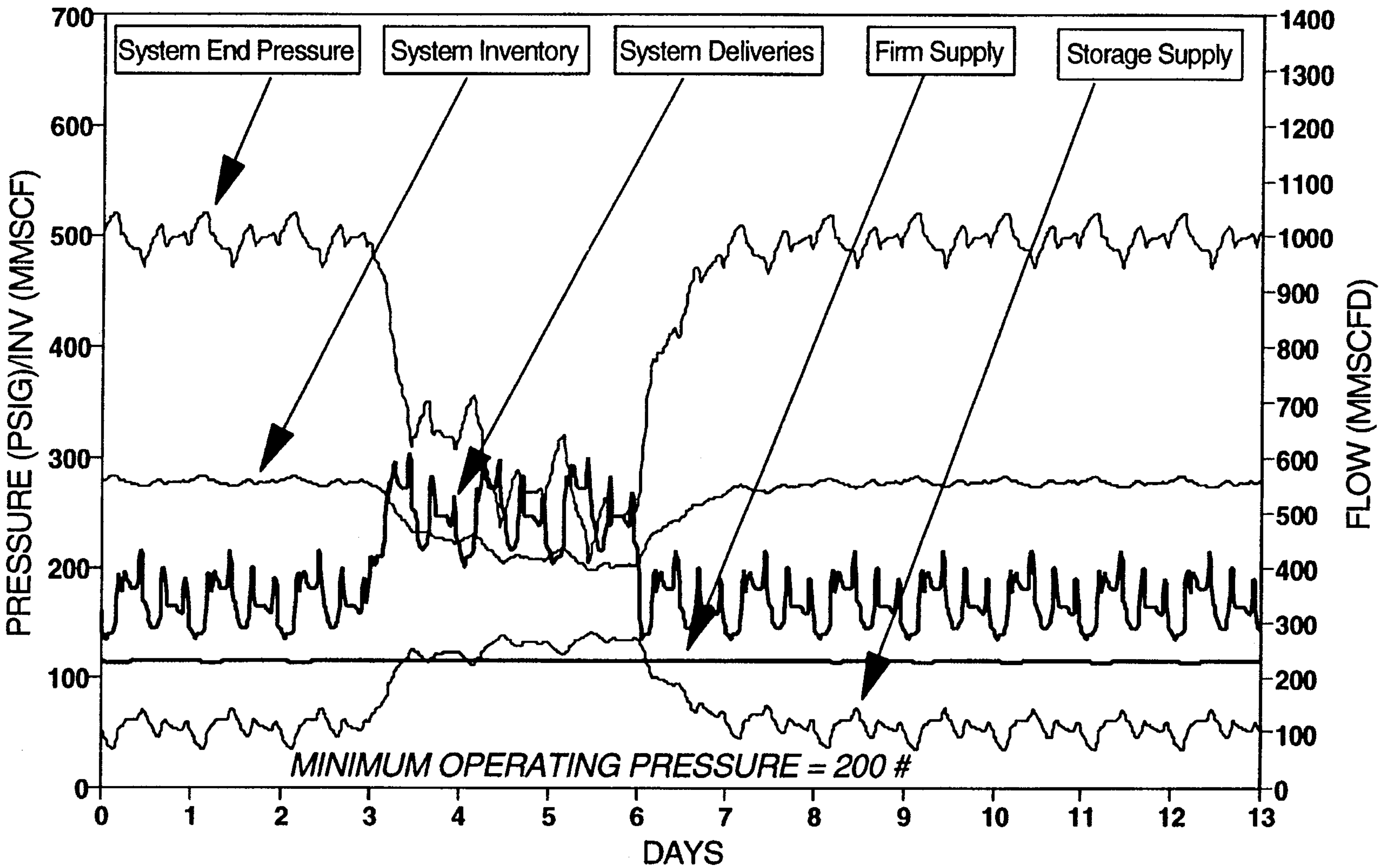


Footnote: System 3 (3A.2C1)

Source: GRI/EPRI Project Team

Exhibit: A-19

SYS. 3: DOWNSTREAM STORAGE ALTERNATIVE CT LOAD REQUIREMENTS OF 4 1-HR PERIODS

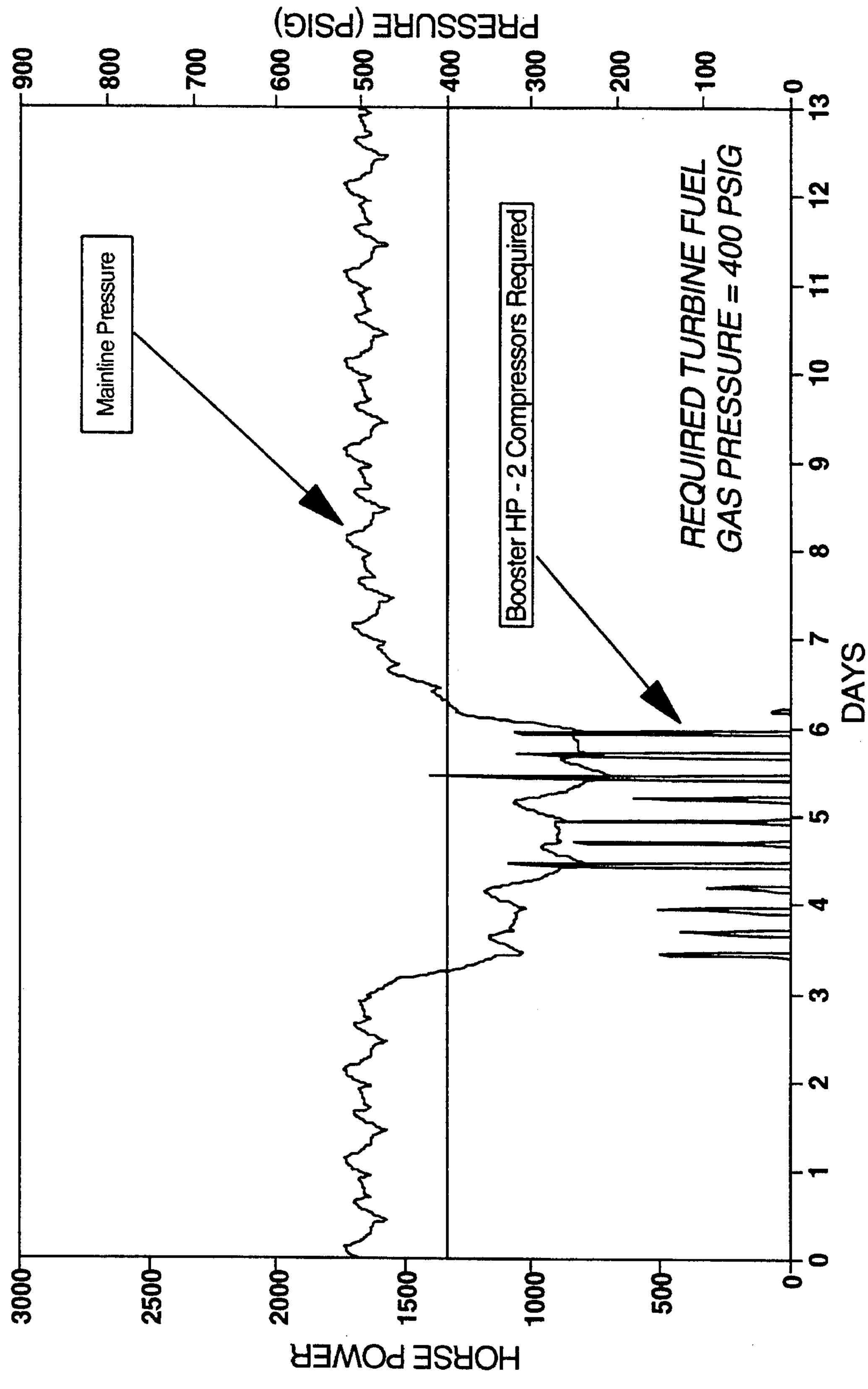


Footnote: System 3 (3B.2B)

Source: GRI/EPRI Project Team

Exhibit: A-20

SYS. 3: UPSTREAM STORAGE USE OF BOOSTER FOR 3-4 HR CT LOAD REQUIREMENTS

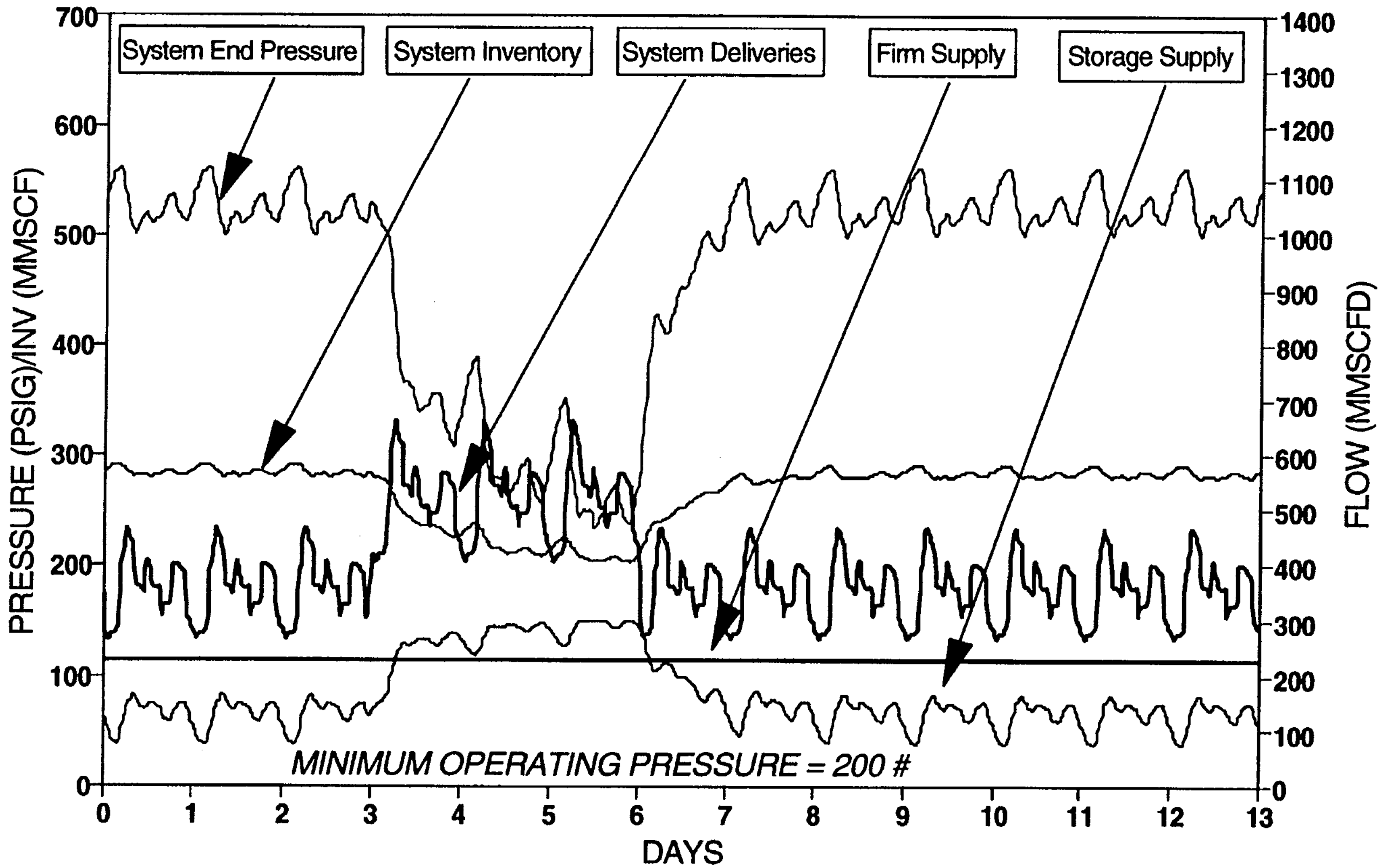


Footnote: System 3 (3B.2B1)

Source: GRI/EPRI Project Team

Exhibit: A-21

SYS. 3: DOWNSTREAM STORAGE ALTERNATIVE CT LOAD REQUIREMENTS OF 3 4-HR PERIODS

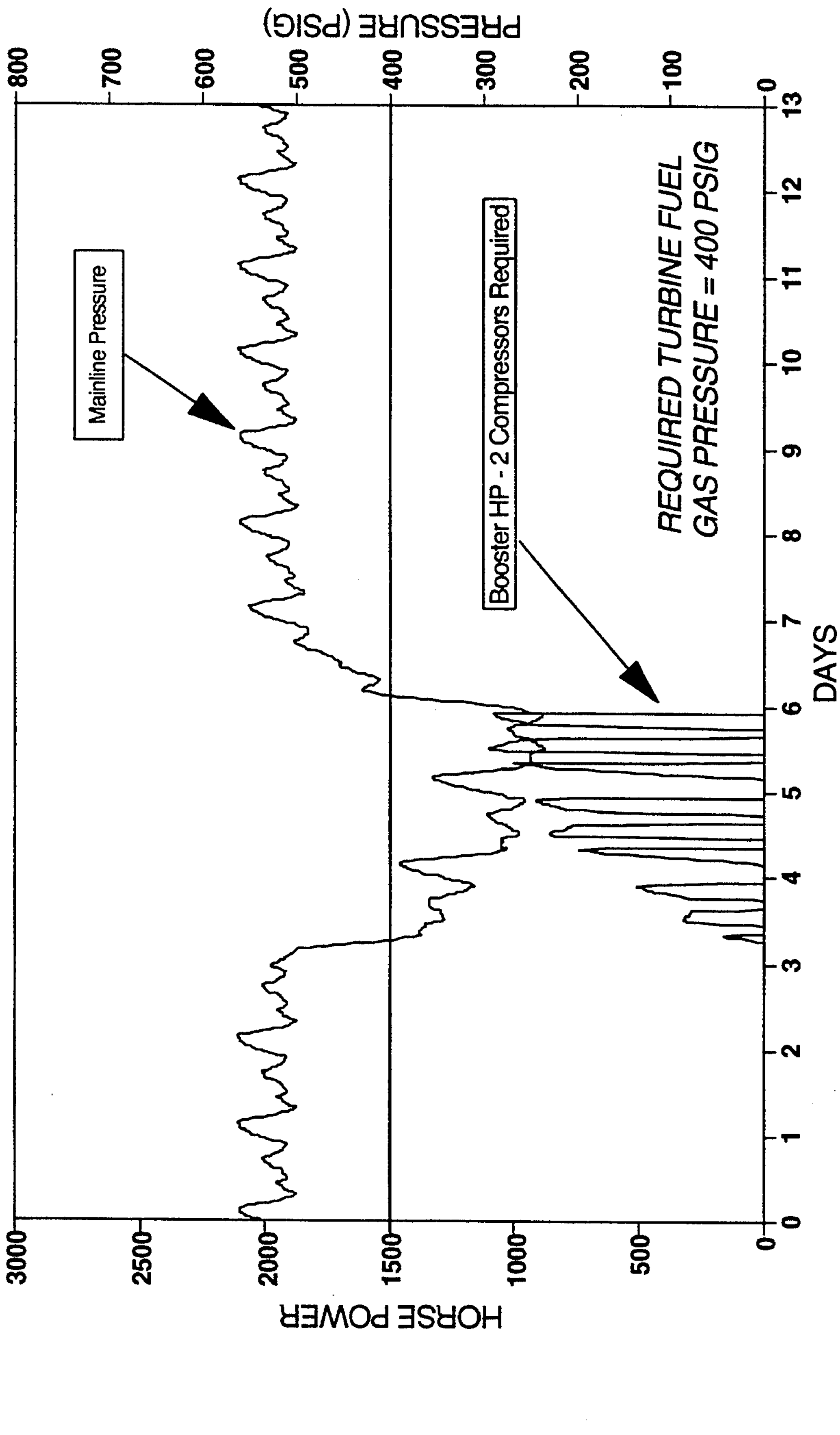


Footnote: System 3 (3B.2C)

Source: GRI/EPRI Project Team

Exhibit: A-22

SYS. 3: DOWNSTREAM STORAGE USE OF BOOSTER FOR 3-4 HR CT LOAD REQUIREMENTS



Footnote: System 3 (3B.2C1)

Source: GRI/EPRI Project Team

Exhibit A-23
COST OF POWER GENERATION LOAD ADDITIONS FOR CASES TESTED

System 1					
Size and MAOP	CT Burn Time	HP	MW[2]	HP/MW	Cost/MW[1]
20" & 1,200 psig	1-4 hours	7,000	500	14.0	$21,000
20" & 1,200 psig	4-1 hours	6,000	500	12.0	$18,000
20" & 1,200 psig	3-4 hours	13,000	500	26.0	$39,000
System 2					
Size and MAOP	CT Burn Time	HP	MW[3]	HP/MW	Cost/MW[1]
30" & 720 psig	N/A	13,500	350	38.6	$58,000
24" & 1,200 psig	N/A	14,500	350	41.4	$62,000
System 3 (with Upstream Storage)					
Size and MAOP	CT Burn Time	HP	MW[4]	HP/MW	Cost/MW[1]
24"/20" & 720 psig	1-4 hours	4,000	300	13.3	$20,000
24"/20" & 720 psig	4-1 hours	4,000	300	13.3	$20,000
24"/20" & 720 psig	3-4 hours	8,000	300	26.7	$40,000
System 3 (with Downstream Storage)					
Size and MAOP	CT Burn Time	HP	MW[4]	HP/MW	Cost/MW[1]
20" & 720 psig	1-4 hours	4,000	300	13.3	$20,000
20" & 720 psig	4-1 hours	4,000	300	13.3	$20,000
20" & 720 psig	3-4 hours	5,000	300	16.7	$25,000

1 At $1,500 per horsepower.
2 2 - 100 MW CT; 1 - 250 MW CC & 1 - 50 MW NUG.
3 1 - 250 MW CC & 1 - 100 MW NUG.
4 2-150 MW CT

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