Gas Pipeline Optimization

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Abstract

Natural gas is increasingly being used as an energy source. Natural gas transmission pipelines transport large quantities of natural gas across long distances. They operate at high pressures and utilize a series of compressor stations at frequent intervals along the pipeline to move the gas over long distances. The operating costs of transmission pipelines can be significant because of compressor station fuel costs, emission minimization, etc. The analysis of these pipelines is very complex. This paper details techniques that can be used to determine optimal operating regions, schedule changes to move the pipeline from one optimal state to another, and automatically implement these changes using model predictive controllers.

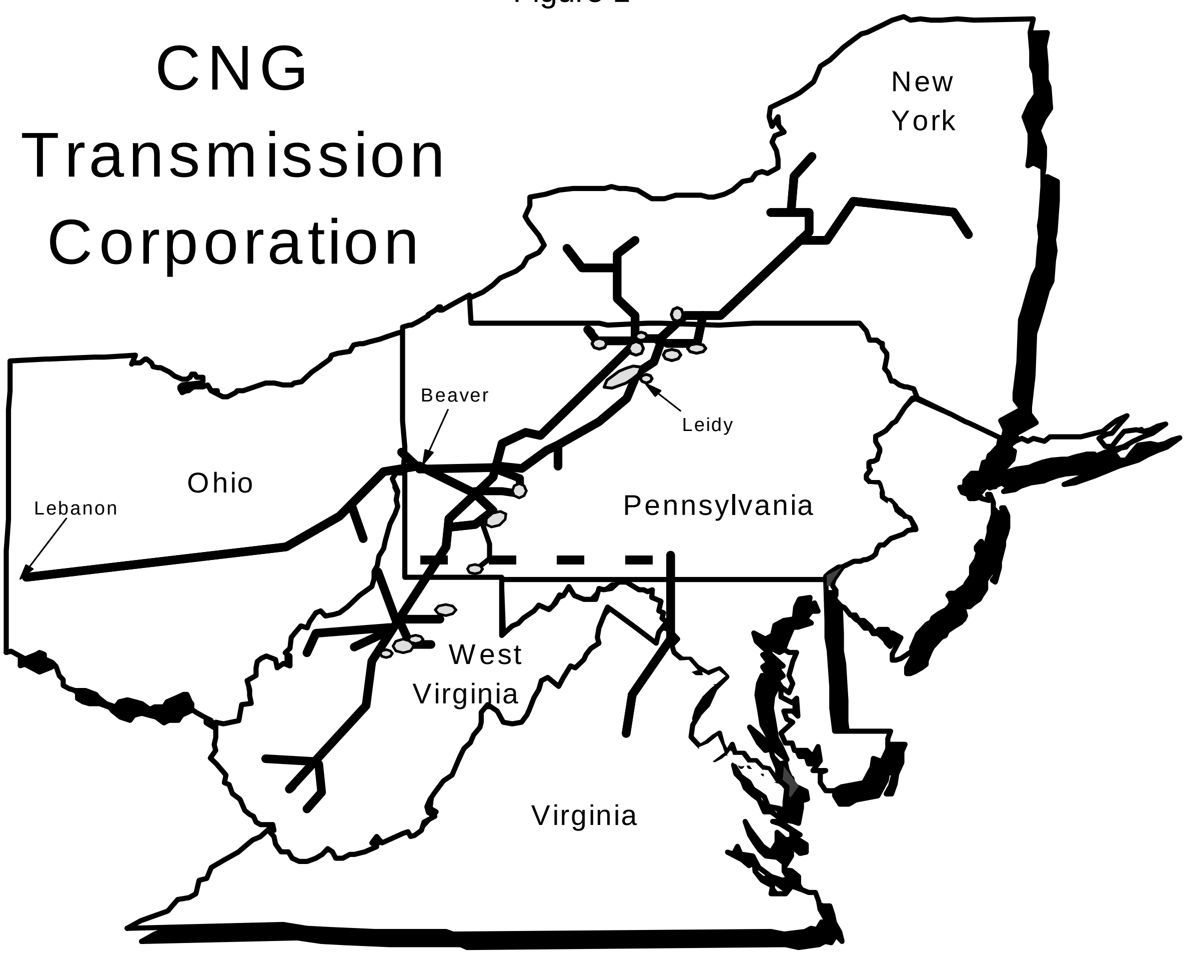
The optimal operating conditions that meet all constraints and minimize fuel consumption for the pipeline are determined by deciding (1) which compressor units need to be run at each compressor station and (2) the best suction pressure set point for each compressor station. The optimizer used is capable of running through a multitude of cases. It then selects the most optimal unit allocation and pressure profile found.

Automated controls designed to move a pipeline towards optimal conditions are a very new feature in the process control industry and non-existent in the gas pipeline industry. Each controller sets the conditions, if necessary, for a unit to come on or go off. Each controller then moves a segment of the pipeline from one set of optimal conditions at one flow to the next set of optimal conditions at the new flow. Process limitations are considered and the Scheduler provides a transition schedule to facilitate the flow change gracefully. The Gas Dispatcher either approves or rejects the schedule. Upon approval, the controllers, over a few hours, move the pipeline to the new set of optimal conditions for the new flow with the correct allocation of units. If necessary, whole stations are brought up or down.

Introduction

On September 17, 1898, for a fee of $61, West Virginia's secretary of state granted Standard Oil of New Jersey a certificate of incorporation for the Hope Natural Gas Company. Now, 101 years later, the transmission pipeline segment of Hope, after many organization changes, has evolved into CNG Transmission Corporation (CNGT) a subsidiary of Pittsburgh-based Consolidated Natural Gas Company, one of the largest producers, transporters, distributors and marketers of natural gas in the United States. CNG Transmission Corporation (Figure 1) owns and operates 10,000 miles of pipeline, 68 compressor stations, 3,362 production wells, 1,510 storage wells in 15 storage pools, 300 pipeline interconnects, and an extraction and fractionating plant. All the above is operating by two busy Gas Dispatchers around the clock.

Figure 1



By the late 1980s, natural gas had become well known as a clean burning, abundant, fossil fuel that was finding increased use as an energy source. As a result of this increased demand, the massive Lebanon-to-Leidy project was initiated around 1990. Lebanon-to-Leidy was designed to double the daily volume of transmission from line TL-400's western-most station near

Lebanon, Ohio to the Leidy hub located in north central Pennsylvania. It resulted from an agreement CNG Transmission had signed with the Transco Energy Company to provide 250 million cubic feet per day of firm capacity on the company's lines from the Texas Gas terminus at Lebanon to Transcontinental Gas Pipeline Corporation's Leidy line. As part of this project, seven new compressor stations were built, including four on the original part of TL-400, the subject of this paper. By 1995, Lebanon-to-Leidy was in service, with 61,880 horsepower in six compressor stations between Lebanon, Ohio and Beaver Pennsylvania. Those 61,880 horses eat a lot of fuel!

Fundamental changes in industry structure were imposed with the issuance of Order 636 in 1992 by the Federal Energy Regulatory Commission that allowed market forces and competition to become the primary factors influencing change in the natural gas market place. In 21 states and the District of Columbia, residential choice programs are under way or proposed on a pilot basis [1], which accounts for more than 30 percent of the gas-using households in the U.S. Ninety percent of large volume natural gas consumers, such as electric generating plants and manufacturing companies, now have the option of selecting their own gas supplier, and more than 40 percent of commercial customers can now, or will soon be able to, choose their own gas supplier. The increased deregulation of the gas industry and the resulting competition has caused many pipeline companies including CNG Transmission to streamline operations and minimize costs.

During 1995 CNGT's Gas Operations department learned about a control system that successfully minimized operating costs in the process control industry and was being proposed for natural gas pipelines. The concept looked very promising. Shortly thereafter, CNGT entered into a contract with Continental Controls Incorporated (CCI) of Houston, TX (recently acquired by General Electric, they are now GE-CCI) to develop their Multivariable Controller (MVC®) for CNGT's TL-400 pipeline. GE-CCI and CNGT then entered into individual contracts with Stoner Associates (Stoner), of Carlisle, PA to modify their Energy Minimization Module (EMM) so (1) it could determine the lowest cost steady state solution using CNGT's multi-function compressor stations, (2) would include a fuel penalty for starting or stopping compressor units and (3) could pass appropriate pressure set points and other data to the controller. GE-CCI then contracted with Linden Professional Services of Houston, TX to develop a Graphical User Interface (GUI) for the optimizer so the Gas Dispatcher would have an easy way to communicate with the optimizer.
By mid 1998, both the optimizer and the controller were installed in CNGT's Gas Operations control room. As is typical with R & D projects, there were problems. Neither the optimizer, the controller, nor the station control logic at the newly automated Lebanon and Gilmore compressor stations performed as expected. There was more work to do to more accurately optimize the

pipeline and provide the Gas Dispatchers with a more refined GUI. In normal mode, the multivariable controller was designed to control for speed driver signals 0 - 100 %. Changes had to be made to the multivariable controller after observing the low level select control logic and station start/stop logic present in the station controllers in the field to prevent compressor units being started and stopped in normal mode. The controller was taken out of service until changes to the controller and the new station logic were made. The Gas Dispatchers did an excellent job learning how to use the optimizer and GUI to manually change suction set points using their standard SCADA screens. As a result, when the Gas Dispatchers had time to watch this part of the system carefully, TL-400 ran optimally.

By the end of July 1999, the compressor station logic and the TL-400 controller were fixed, installed and working. Several ease of use enhancements were made to the optimizer and GUI that made them more accurate and easier to use.

The TL-400 Pipeline

The optimized section of the TL-400 pipeline, approximately 250 miles in length between Lebanon, Ohio and Beaver, Pennsylvania (see system map on page 3) transports gas to several states of the northeastern United States. There are six compressor stations along this particular segment. Most of the gas enters the pipeline at the first station with the balance entering at the fifth station. Gas is delivered at several points along the pipeline and the remainder flows out into the next segment of the pipeline. Either the suction pressure, the flow or the discharge pressure is controlled locally at each of these stations. Figure 2 shows a schematic of the pipeline segment with alternating reciprocating and centrifugal compressors. This installation has been described in reference [2].

TL-400 Transmission Pipeline

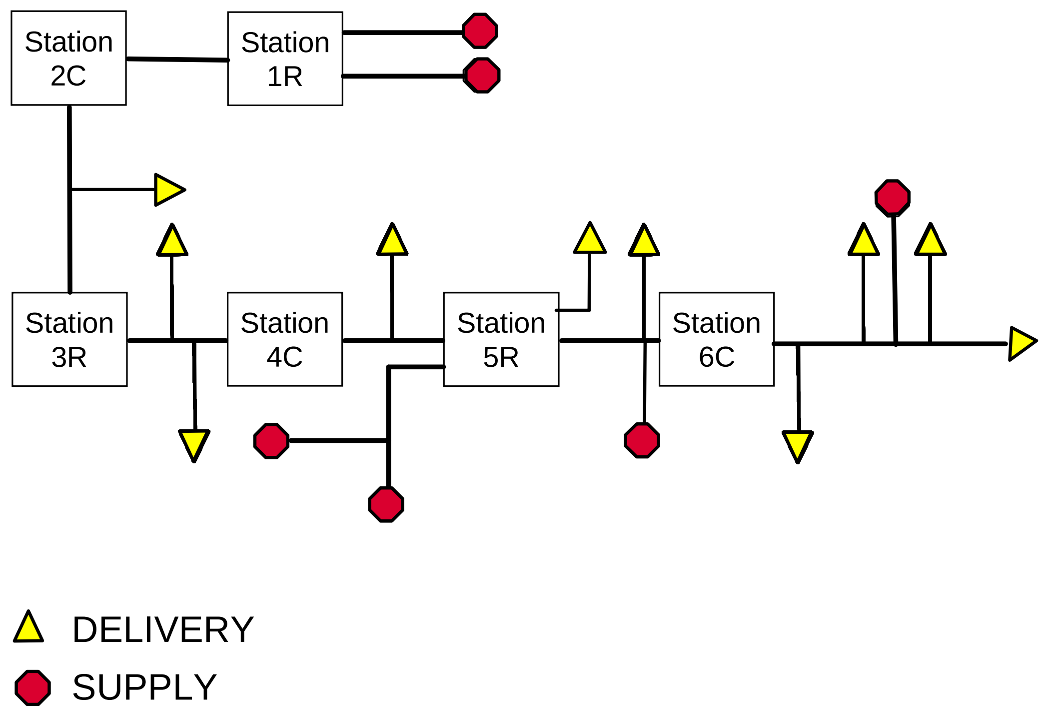


Figure 2 Schematic shows selected pipeline section with six compressor stations.

The first station consists of six integral gas engine driven reciprocating compressor units. Two of these compressors are equipped with air/fuel ratio control and digital speed control. This station is usually on flow control to meet contractual obligations. The second station consists of three gas turbine-driven centrifugal compressors and normally is on suction pressure control. Maintaining turbine speed controls suction pressure. The third station consists of three integral gas engine driven reciprocating compressor units. This station is normally on suction control and individual engine controls are very similar to the first station. The fourth station also employs three gas turbine-driven centrifugal compressors. Control is very similar to station two. The fifth station employs six integral gas engine driven reciprocating compressor units and much of the delivery along the line occurs at this station. The sixth station consists of two turbine-driven centrifugal compressors and normally is run for peak deliveries only. When operating, it normally is set on suction control.

The system is controlled centrally by the CNGT Gas Dispatchers using an on-line Supervisory Control and Data Acquisition (SCADA) system. Each day the Gas Dispatchers receive a preview of the day's nominations so they can prepare a plan of system parameters. The Gas Dispatchers are required to meet contract flow rates and pressures at all of the supply and delivery points along the pipeline.

The Gas Dispatcher operates the new control scheme from the central control room. The multivariable controller communicates with the SCADA and "sits on top" of the local station controllers (Figure 4, Page 13).

Objectives of Gas Pipeline Optimization

Two of the main objectives of gas pipeline optimization are:

1. Meet contractual obligations of flow and pressure at various points along the pipeline,

2. Minimize fuel usage and other operating and maintenance costs while meeting emissions requirements.

The pipeline industry uses sound criteria to move towards the above objectives. Gas Dispatchers attempt to run compressors close to their maximum efficiency. However, this point is often difficult to estimate and may not optimize the entire system. Besides, to the company as a whole, maintaining system integrity and meeting contracts takes a priority over fuel minimization. As flow nominations change on a more frequent basis, highly desired fuel minimization becomes a more difficult objective.

To meet the above objectives on the TL-400 transmission system, the following steps were taken:

1. We developed a steady-state optimizer which models the entire pipeline, along with all the delivery and supply points, compressor curves, pipeline constraints and system requirements and can be easily operated by a Gas Dispatcher.

2. We developed a control strategy capable of moving the pipeline to the above-calculated optima.

Optimization Strategy

The optimization package developed for TL-400 consists of three main parts:

1. A steady state model that accurately estimates fuel and compressor unit startup and shutdown costs by emulating all critical functions of the pipeline including each compressor, accounting for the variation of compressor efficiency and available horsepower with pressure, flow rate and ambient air temperature changes.
2. An optimization engine capable of sufficiently testing all reasonable combinations of equipment that operate within the bounds of contract flow and pressure constraints.
3. A Graphical user interface (GUI) that makes using the optimizer transparent and intuitive for the Gas Dispatcher.

It was critical that the steady state model be developed in sufficient detail to ensure that only feasible solutions are recognized as acceptable solutions. For example, one of the challenges we had to overcome was forcing the model to not allow compressors to operate using fewer horsepower than is possible in the field. Figure 3 shows how available horsepower for 5500 nominal horsepower centrifugal compressor units in two compressor stations on TL-400 varies as ambient air temperature and compressor speed change. Assume a cold winter night with temperature at -10 degrees F. Note that actual available horsepower is a continuum ranging between 3000 and 4300 HP at a minimum speed of 8290 RPM to between 3800 and 5750 HP at a maximum speed of 14,500 RPM. When this project began, the steady state model was able to limit maximum horsepower perfectly according to the curves. Unfortunately, none of the vendor's clients had ever requested a hard minimum horsepower limit. Consequently, there was none. The steady state model would generate a warning informing the Engineer that horsepower was below the minimum limit. However, such solutions passed to the optimizer were considered valid. There were times when the optimizer chose those as the minimum cost solution. Then the supposed optimum solution was impossible for the Gas Dispatcher to implement. A solution of setting a single minimum horsepower value was provided. Now the Engineer can set the hard low limit for the above compressors to 3800 horsepower, for example, during the winter. Then the Gas Dispatcher can be assured that the optimizer will always select a feasible solution that is close to optimum. Unfortunately, missing the true optimum is somewhat likely. We are investigating the possibility of having a minimum horsepower curve functionality that will track Figure 3. Then a truer optimum will be achievable and the Engineer will not need to frequently "tune" the minimum horsepower constant. Excepting the above, the steady state model has done an excellent job of modeling achievable conditions and predicting fuel usage.

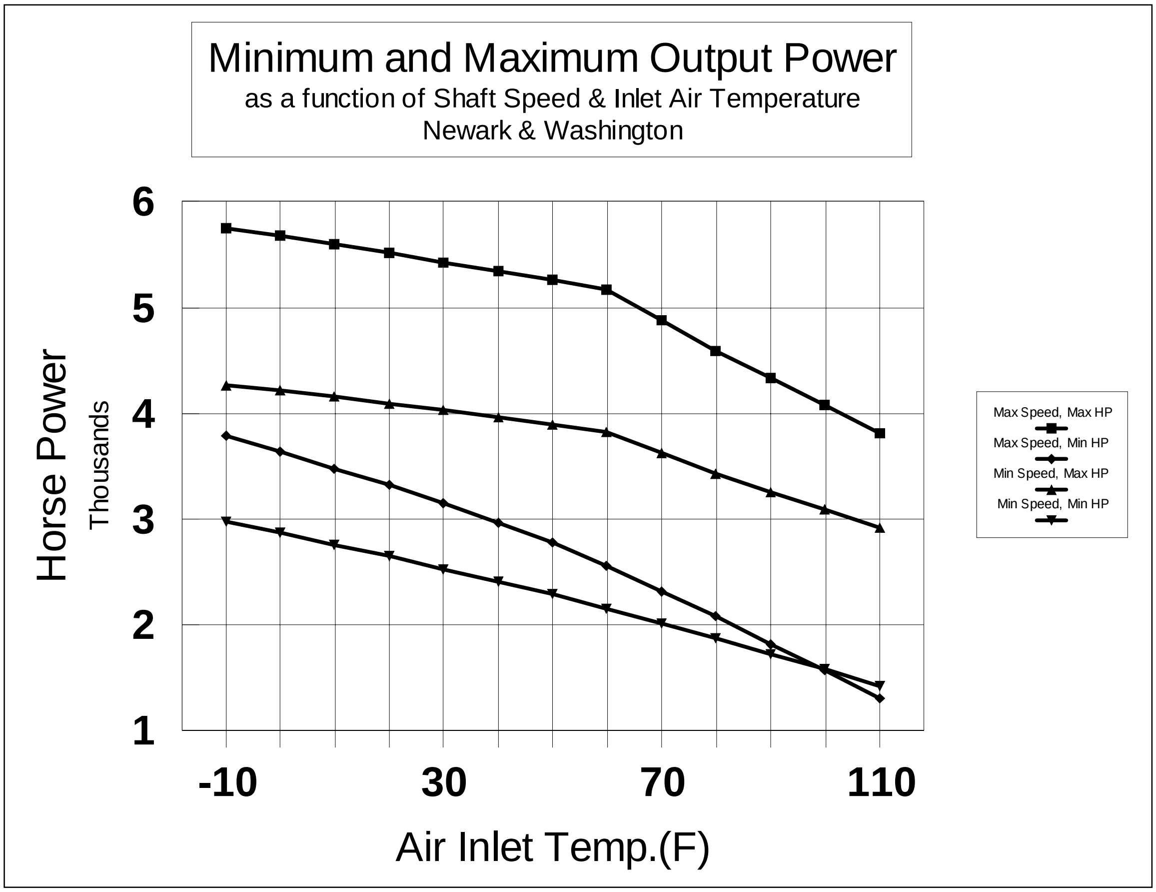


Figure 3

The optimizer is based on an engine that uses a set of linear and nonlinear techniques to find the optimum steady state operating mode that addresses the objective of the optimization, whether it is fuel, fuel cost, throughput or margin. The optimizer accomplishes this by selecting the optimum compressor station set pressures and by selecting the mix of compressors to achieve the objective [3]. Mathematically, the optimizer solves the fuel minimization problem by first determining the feasible hydraulic operating envelope of the entire network and then by selecting the best sustainable operating mode that operates the system within the operating envelope at minimum fuel consumption. The optimizer searches through many possible compressor configurations by predicting the effect of loading, unloading, starting or shutting down compressors.

An interface to the optimizer was developed which lets the Gas Dispatcher set some key parameters for the optimization run. These parameters include the nominated flows, contract pressures and the compressor units at each station that are available to be run, must run or must not run. At the click of a button, the optimizer software calculates the optimal choice of compressors at each station and the pressure profile across the pipeline. The optimizer recommendation is displayed for the Gas Dispatcher's consideration in making the final decision. In this project, Gas Dispatchers set up the optimizer models on a daily basis. Because Gas Dispatchers are unfamiliar with modeling, the interface was developed between the Gas Dispatcher and the optimizer to convert Gas Dispatcher requirements into optimizer models. This makes the optimizer quick and easy to use.

Control Strategy

Traditional control technology is ineffective and insufficient to move the pipeline towards optimality. This is because traditional control techniques such as the PID algorithm are capable of controlling only one process variable and do not handle long deadtimes effectively. Optimal control of the pipeline requires the simultaneous control of many key variables, in addition to an optimal choice of compressors. Multivariable control techniques are capable of controlling an entire system, as well as monitoring constraints.

The controller uses the optimum generated by the optimizer and approved by a Gas Dispatcher to manipulate appropriate variables. The objective of the controller is to reach the predicted optimum. The controller contains models including the effect of various manipulations on the variables to be controlled to compensate for the long deadtimes and moves the pipeline to the calculated optimum targets. Due to its ability to model the process accurately, the controller works off future predicted values of the controlled variables as well as feedback as opposed to traditional control strategies which work on feedback corrections.

Technically, the controller has three very important control objectives:

1. Maintain the pipeline at an optimal pressure profile (normal mode)

2. Gracefully handle the (daily) change in nominations (transition mode) and

3. Automatically handle operations in the event of a compressor going down (event mode).

In meeting these control objectives, the overall project objectives are met.

Normal Mode

The multivariable controller works to control the discharge pressure at an upstream station by manipulating the suction pressure at the immediate downstream station. The optimal discharge pressure values are obtained from a steady-state optimizer and these values are the targets for the controller. The Gas Dispatcher can change these targets depending on operating conditions. The controller calculates a change in the suction pressure at the downstream station to reach the desired discharge pressure target at the upstream station. These calculated suction pressure values are sent down to the local distributed controller at every station (except for the first station) as suction pressure set points. The first station is often on flow control to meet contractual obligations. The local controllers are then responsible for keeping the suction pressure at these calculated set points.

The discharge pressure at each station is affected by two suction pressures: the suction pressure of that station and the suction pressure of the next downstream station. For optimal fuel usage, the pressure profile in the pipeline should be held at the pressures determined by the steady-state optimizer. The optimal pressure profile normally tends to be high. If the suction pressure at the same station is used to control the discharge pressure at that station, then to reach a higher discharge pressure, the suction pressure must decrease (to speed up the compressors). This does not ensure a higher-pressure profile throughout the pipeline. Alternatively, if the suction pressure of the next downstream station is used to control the discharge of a particular station, then to increase the discharge pressure at a station, the suction pressure at the next station must increase (as the downstream engines slow down). This leads to a higher-pressure profile throughout the pipeline.

The controller is adaptive. If during a change in nominations, a station is scheduled to be down for the day (station not needed, down for maintenance, etc.), the upstream discharge pressure is controlled by the suction pressure two stations downstream.

Transition Mode

During the transition mode of operation, the multivariable controller prepares the pipeline for a change in nominations for the day. These changes are often around 50 million cubic feet per day (MMCFD) or less. Compressors/stations are automatically brought on and taken off as required. Due to high pressure throughout the pipeline, a “hole” must be made in the pipeline to accommodate an increased gas flow rate before it reaches the first station. This is achieved by removing gas from the pipeline by progressively speeding up the downstream stations to lower the pressure across the pipeline. A heuristic-based scheduling algorithm provides the Gas Dispatcher with the necessary information to move to the new flow. On the Gas Dispatcher’s approval, this algorithm is used to move the pipeline to its new set of optimal operating conditions.

Event Mode

An event mode is reached if a compressor goes down creating a shortage of horsepower at a particular station. The downstream stations speed up to account for this shortage in horsepower.

Control Algorithms

A nonlinear controller with dead time compensation is the primary control algorithm. The control action depends on the region of operation. The idea is to have stronger control action when the discharge pressure process variable (PV) is outside a band around the set point and weaker action when it is inside the band. This minimizes closed loop pressure fluctuations in the pipeline when the PV is within an acceptable range of its set point.

Due to the large dead time in the pressure responses between stations in natural gas pipelines, traditional control is ineffective. Control is very sluggish to account for the large dead time. To overcome this problem, a model based dead time compensator is employed in conjunction with the nonlinear robust controller.

The controller sets the suction pressure set point, discharge pressure set point and the flow set point at each station to control the discharge pressure of the previous operating station and sends these set points down to the local controllers at that station.

These set points are used to calculate three different controller outputs from the suction, discharge and flow controllers. The local controller acts upon low level logic and uses the lowest controller output of these three controllers to decide station speed.

If the local controller output (and each compressor speed) reaches its maximum value, then a compressor unit may try to start. The controller acts in a systematic manner to keep the suction set point within or above the dead band so a spare compressor will not start. The controller acts similarly when the local controller output reaches its minimum value so a compressor will not stop.

This nonlinear multivariable robust model predictive control strategy is consistent with the vendor's products for other process industries like Ammonia (Lin *et al.* (1997) [4]), Sulfur recovery plants (Berkowitz *et al.* (1997) [5]) and Gas plants (Alexander *et al.* (1998) [6]).

The controller is very easy to use and emulates an experienced Gas Dispatcher. The controller saves the Gas Dispatcher time, since the Gas Dispatcher no longer has to closely monitor the section of the pipeline under control. Finally, the controller required no change in control hardware and communicates well with the SCADA system, blending harmoniously with existing control schemes. Figure 4 shows the system architecture.

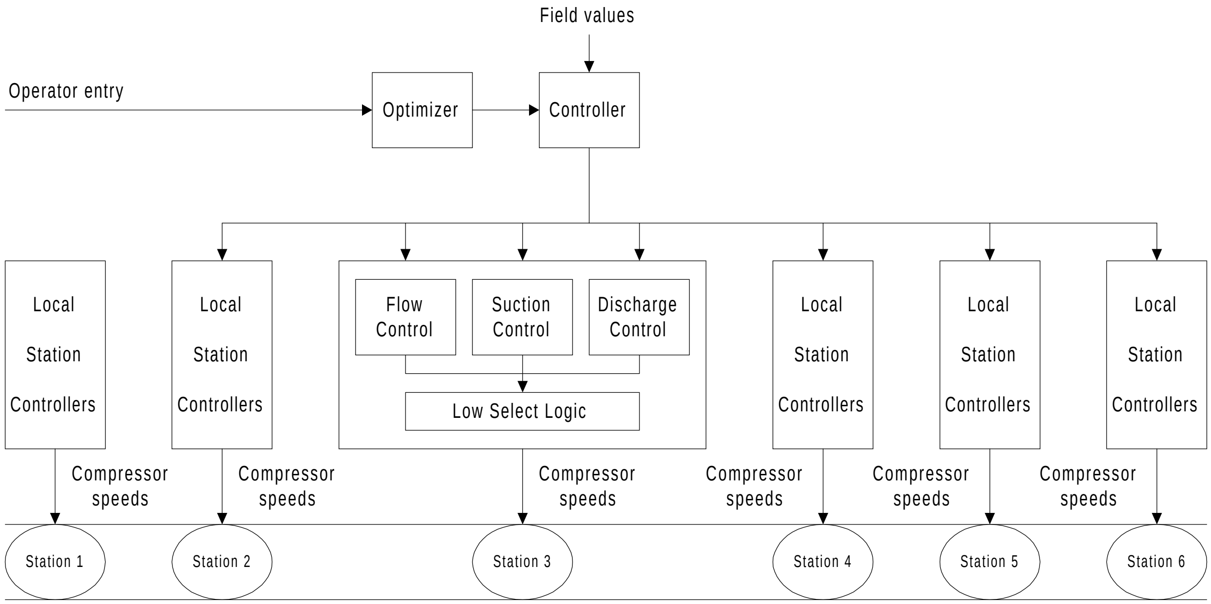


Figure 4 Schematic provides set up of the pipeline's multivariable control system.

Results

The optimizer has been installed and operating since summer 1998. Gas Dispatchers have used suction set point recommendations from the optimizer's GUI to set up the TL-400 system almost daily. Results have been very good and fuel gas has been saved. During summer 1999 the optimizer has been a particularly useful tool for the Gas Control section in determining a maximum flow rate that completely utilizes the most efficient compressor stations on TL-400.

The multivariable controller was also installed during summer 1998. During installation and testing and before the controller was taken out of service, data was collected that shows the relationship between suction pressure, discharge pressure and fuel usage as multivariable control was operated. However, flow rate into the system decreased somewhat during the sequence shown below which indicates a larger reduction in fuel usage than was the result of the controller alone.

Figures 5-7 show the results of multivariable control when data was collected during summer 1998. At around 6 o'clock, the Gas Dispatcher requested multivariable control. The multivariable controller took over control of the first

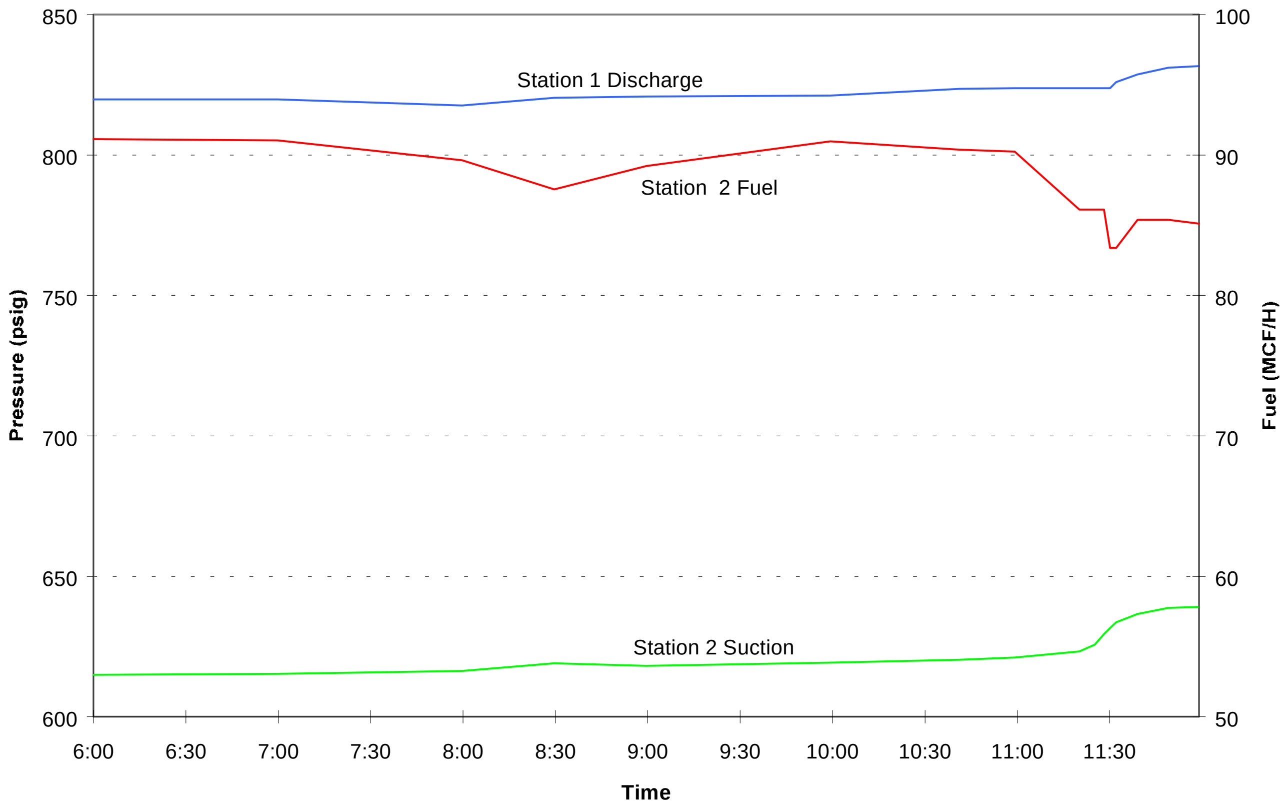


Figure 5 Station 1-2 Control

four stations only. Station 5 was undergoing automation to allow the multivariable controller to control it in the future. At the time of this request, the discharge pressures at stations one, two and three were 820, 811 and 790 psig respectively.

The local station controllers change compressor speeds about once per second to meet these set points. However, response is very dampened. Although the multivariable controller has the capability of sending set points at a higher frequency, it sends set points to the local station controllers every six minutes because new data is only available from the SCADA system every five minutes.

The band about the discharge target was set to be 2 psi for all the targets. The dead time between a change in the suction pressure at a station and a resulting change in the discharge pressure at the previous station is about 15 minutes. The model-based dead time compensator allows for aggressive tuning outside the band and weaker control action inside it.

At 8 o'clock, the Gas Dispatcher ran the optimizer to determine the optimal pressure profile for the existing flow condition. As an upper limit for the

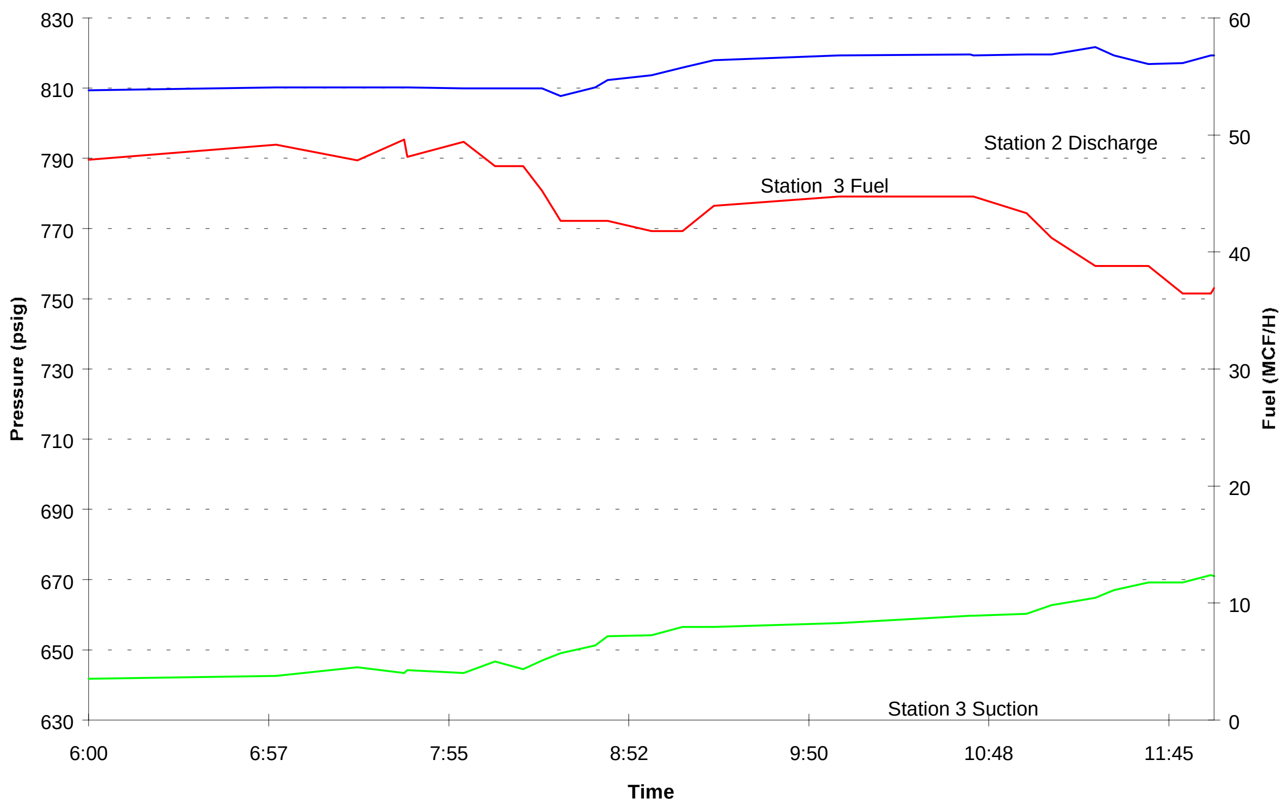


Figure 6 Station 2-3 Control

optimization, the maximum desired pressure at each station was specified to be 840 psig. After reviewing the optimizer recommendations, the Gas Dispatcher set the discharge pressure targets at stations 2 and 3 to be 821 and 800 psig respectively, an increase of 10 psi at both stations. At 10:30, a new flow was expected at station 1. Using the optimizer, the Gas Dispatcher recalculated the optimal steady state pressure profile across the pipeline for the new flow. At the new flow rate, the discharge pressure targets at stations 2 and 3 remains the same, while the discharge target at station 1 was changed to 830 psig.

At 8 o'clock, when the discharge target at station 2 was increased, the multivariable controller increased the suction pressure at station 3 to bring the station 2 discharge to its target (Figure 6). At the same time, the multivariable controller increased the suction pressure at station 4 to bring station three discharge to its target (Figure 7). As can be seen in Figures 5-7, the multivariable controller drives the pipeline towards a higher pressure

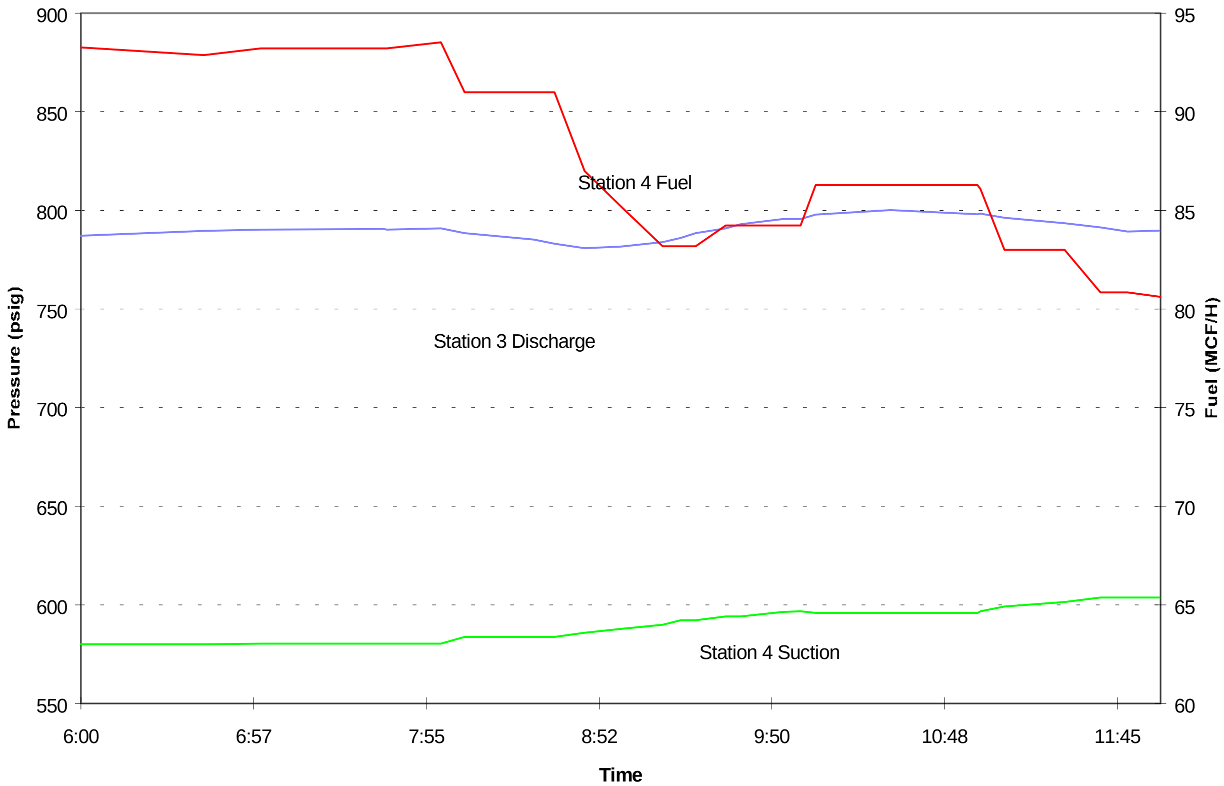


Figure 7 Station 3-4 Control

profile as flow rates decrease to fill up the pipeline. The interaction between station 3 and station 4 controllers can be seen between 8:00 and 9:00, as the station 3 discharge pressure first decreases and then increases.

At 11 o'clock, when the discharge target at station 1 was increased, the multivariable controller increased the suction pressure at station 2. The discharge at station 1 reached its target very quickly and again the resulting pressure profile was higher than the profile before the change.

The transient decrease in fuel usage can be seen in Figures 5-7. The control strategy ensures that the system moves towards a new optimal pressure profile in a way that minimizes fuel usage. Over the four-hour transient of this test, the fuel reductions at stations 2, 3 and 4 were found to be 7.68 percent, 18.78 percent and 13.33 percent respectively. When a new optimum is reached, the higher efficiency of the pipeline/compressor system will result in lower fuel usage.

Wish List

1. Improve minimum horsepower limits at centrifugal stations in the steady state model.
2. Increase flexibility of multifunction compressor stations in the steady state model.
3. Consider the value of extending the optimizer and multivariable control to other parts of CNGT's system.
4. Develop a GUI that is easier to maintain and more transparent and intuitive for the Gas Dispatcher.

Acknowledgements

The authors would like to thank their respective companies for their support with the project. The contributions of Steve Wainscott of GE CCI and Jason Johnson of CNG Transmission Corp. to the success of the project are also acknowledged. Thanks are also due to Bill Poe, Engineering Manager at GE CCI and Larry Turner, Manager, Gas Control and Barry Ranson, Director, Gas Operations, CNG Transmission Corp., for their guidance during this work.

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