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CONDITIONING TRANSPETRO'S GAS PIPELINE NETWORK TO THE BAÍA DE GUANABARA LNG TERMINAL NEW REGASIFICATION PROFILE

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ABSTRACT

Petrobras Transporte S.A. – TRANSPETRO's Gas Pipeline System, composed by 7.3 thousand kilometers, 135 delivery stations and 21 compressor stations, has a very seasonally dependent operation. Highly linked with the Brazilian energy grid, during the dry season of the year a large part of the 77.3 million cubic meters of natural gas daily transportation are used to generate around 6.4 gigawatts to power the country. Additionally, the ever increasing number of power plants and distribution companies around the country demand more and more gas to be offered to supply the system. Among the different sources of natural gas available, the LNG is the most flexible for such seasonal operation.

In order to support this current demand and to attend future demands, the regasification ability of Baía de Guanabara LNG Terminal was increased in December 2012, by changing the regasification vessel that supplies the southeast portion of the gas pipeline network, from 14 to 20 million cubic meters per day. To prepare to receive the new ship, some tests were performed to determine the operational limits on system survival time without LNG supply during vessel exchange. This assessment involved two different issues. The ship change operation occurred during a period of high consumption, when the LNG terminal was needed to sustain the network inventory. A long period without this supply, caused by the exchange of LNG vessel, would affect the deliveries. On the other hand, the new ship's commissioning curve would introduce a large amount of natural gas into the system during a short period of time, demanding that the deliveries absorbed such volume. Four planning scenarios were assessed based on some expected pipeline supply and delivery conditions. The work was

important as a reference for future changes on operating supply units of TRANSPETRO gas pipeline system, showing the importance of pipeline simulation both as a planning tool for pipeline logistic problems and as operational support.

NOMENCLATURE

TRBG	Baía de Guanabara Regasification Terminal
LNG	Liquefied Natural Gas
GASENE	Southeast-Northeast Gas Pipeline
ECOMP	Compressor Station
UTE	Thermal Power Plant
TECAB	Cabiunas Terminal
ONS	National System Operator
MAOP	Maximum Allowable Operational Pressure

INTRODUCTION

Operating a complex gas pipeline network, with its many intersections and mesh like configuration can be tricky, demanding a high level of attention to detail on the several segments concurrently, and being able to interpret and predict the network response to different scenarios. Every intervention must be evaluated to determine the impact on the system, requiring continuous study in regards to the day to day operation.

Transpetro operates Petrobras gas network, which includes 7.3 thousand kilometers of pipeline, 21 Compressor Stations, both owned and outsourced, 17 supplies and over 135 deliveries across the country. The Figure 1 shows the network and its geographic location within the country.



Figure 1. TRANSPETRO OPERATED GAS NETWORK

The Transpetro Gas Network can be divided in 3 separated systems. Each system has its own characteristics and peculiarities, from their physical configuration to the way they operate. The three regions are the North, the Northeast and the southeast network. While the North network is completely separated from the rest, both the Northeast and Southeast network are linked by a single pipeline system, called GASENE (Southeast-Northeast Gas Pipeline).

The entry of a new supply or a significant change in an existing one can drastically change the logistics of a pipeline network. They can affect contracts, change the gas quality of a delivery, change the flow direction or even decommission a compressor station. Because of this, the possible effects of these changes in the system must be evaluated in great detail to determine the full benefit.

The more immediate side of this change, however, is when to introduce it to the network. From a new delivery, a new compressor station, or even a new supply, the effects on the network can be easily controlled with adequate planning. When changing an existing supply, however, it can be more complex.

On an existing system with complex delivery schedules, many factors must be aligned effectively.

Specifically talking about a Regasification Terminal, the range of variables is enormous. From overhauling terminals and plants to ship scheduling and tide planning, the number of professional and discussion needed is overwhelming. This paper will focus solely on the view from the gas pipeline operation view needs require to change the supply, and the experience learned from it.

PIPELINE NETWORK

To understand the Brazilian network as whole, one must first understand the country's energy matrix. While most of the energy comes from hydroelectric power plants, this energy source is seasonal and highly influenced by changing climate. During the dry period, a number of gas thermal power plants are used to save water at the reservoirs. Historically the dry period occurs between June and November. The Thermal plants are a very important part the grid, especially during this period, so

the safe and continuous operation of the gas network is paramount to the country's energy grid.

For the purpose of this study, the focus will be on the GASENE and Southeast network. The thermal plant locations operating at the time will pointed out on the network.

The GASENE pipeline system is of the utmost importance to the operational safety of the network. Linking the Northeast and the Southeast network, it is composed by three supplies, two of which are in the top five supplies in the system, five compressor stations, a single power plant delivery and several small deliveries along the pipelines. A simplification of the network is presented in Figure 2.

The northern limit is defined by the Catu compressor station, with a minimal operating pressure of 55 kgf/cm²g (53.94 barg), and responsible to supply a large part of the Northeast network. At the southern end, there is the Cabiunas Terminal (TECAB). While not in the figure, there is a compressor station inside the Terminal, as well as a natural gas processing unit. The TECAB is the link between the Southeast network and the GASENE system. All compressor station in this system can and do work bi-directionally during day to day operation. This ability, added to the size of the pipelines, make the GASENE system the main storage element of the network. Located at the middle of both networks, with high volume supplies and small deliveries, it's responsible for most of the networks operational flexibility.

The compressor stations are Catu, Prado, Aracruz, Piúma and Cabiunas, located inside the TECAB terminal. The three supplies are Cacimbas, UTGSUL and TECAB. The connections

to the other network represented here as deliveries, can also function as supplies, depending on the network requirements.

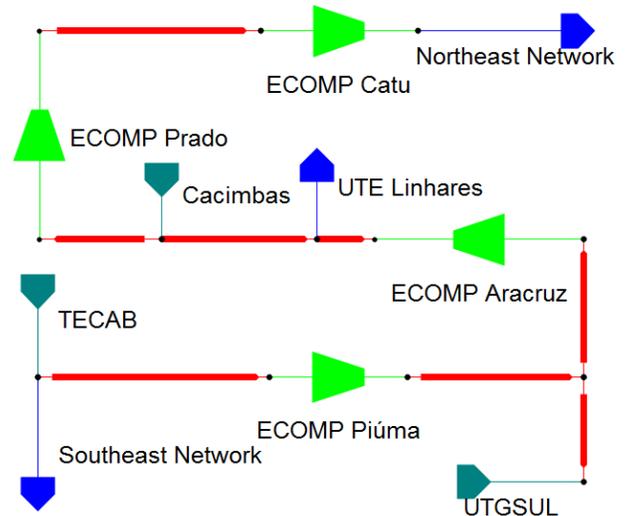


Figure 2. GASENE NETWORK

The Southeast network is the most complex network in the whole country. With three different pipeline pressure limits, several supplies, compressor stations, refineries, thermal power plants, large consumers and a connection with a different pipeline network makes this pipeline grid difficult to operate and study. Figure 3 shows a simplification of the Southeast network.

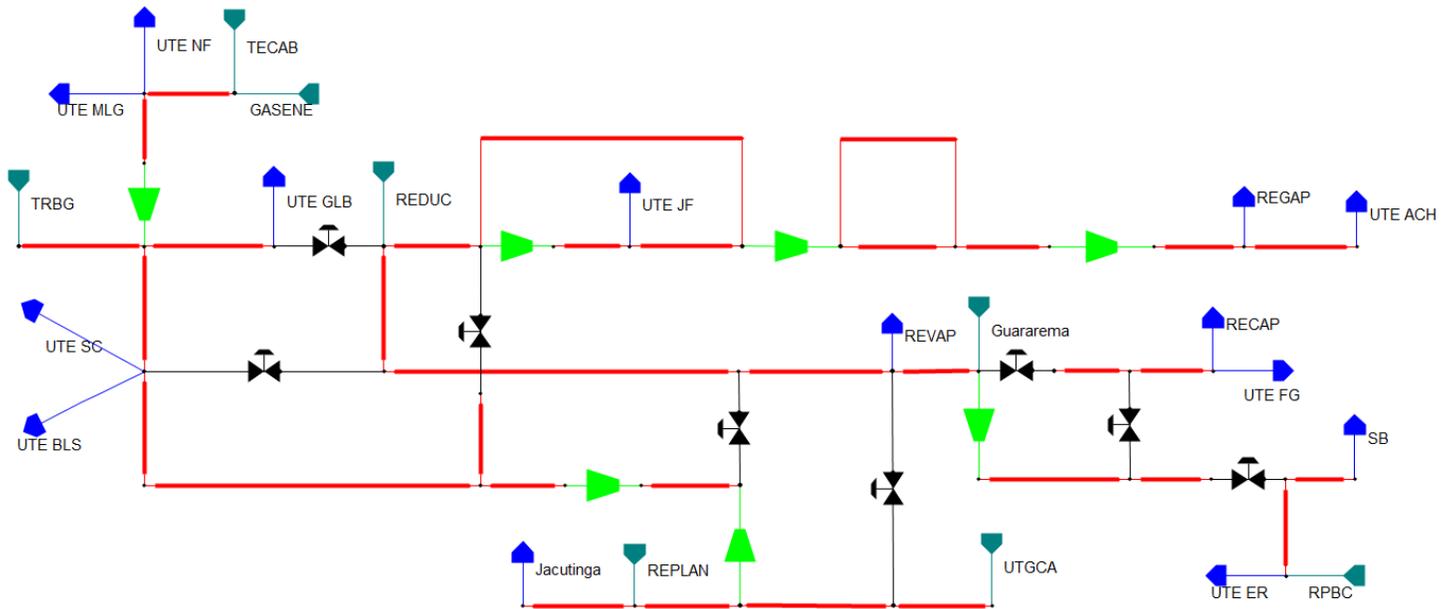


Figure 3. SOUTHEAST NETWORK

As said before, the link with the GASENE system is made through the TECAB terminal. While represented here as a demand, the GASENE network can also work as a delivery,

depending on the network condition. There are several thermal power plants, due specially to the fact the southeast is a high energy consumption area, where most of the country's

population and industry is located. Many refineries are also located in the region, contributing to the high delivery requirements. This high concentration of elements makes its operation very fast paced and dynamic, and in need of constant attention.

REGASIFICATION TERMINAL AND SHIP

The Baía de Guanabara Regasification Terminal (TRBG) was the second Brazilian regasification terminal built, alongside the Pecém Regasification Terminal, located in the state of Ceará, in the Northeast network. Located in the state of Rio de Janeiro, its right in the middle of the network high consumption area. The original ship, operating since 2009, had the capacity to vaporize 14 million cubic meter of natural gas per day. A 28 inch pipeline lateral between the main network and the terminal, with 15.5 kilometers in length and with a MAOP of 100 kgf/cm²g (98.07 barg), completes the terminal transportation structure.

The Baía de Guanabara is a very challenging area to maneuver ships and is highly dependent on tidal conditions.

This was a significant condition during the operations planning, since there was a possibility of not having both ships (the old one and the new one) present at the terminal. Exchanging ships could require a minimum of 12 hours to complete. Any problems during the maneuver, however, could extend that time to the next tide change. Considering that both ship were able to be simultaneously at the terminal, the time between the first ship leaving to the second actually mooring at the terminal was at least 9 hours, due to technical testing, pressurizing units, health and customs agents checking the new ship and other requirements.

The new ship had a flow testing curve required to insure its operation. This curve, agreed previously with the ship company had a top flow value of 24 million cubic meters per day and 72 hours length. Figure 4 shows the commissioning curve studied originally.

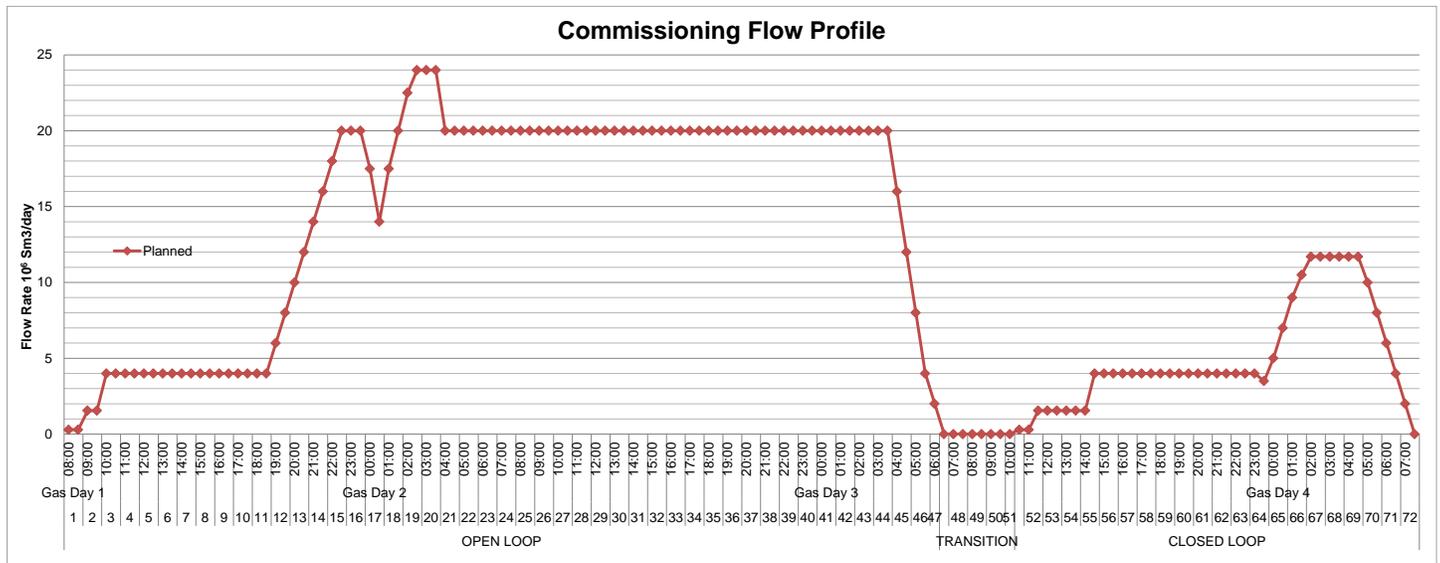


Figure 4. SHIP COMMISSIONING FLOW PROFILE

GAS NETWORK CONDITION AND SCENARIOS

The expected dry season in Brazil, as stated before, is from June to mid-November. In 2012, however, the season extended to January of the following year. This resulted directly in the continuous operation of the gas power plants, since the hydro power plant reservoirs were at an all-time low level, well beyond their safety point. As a consequence, all of the country’s non hydro power plants were operating at full or almost full capacity. The National System Operator (ONS) controls the country’s energy distribution system, determining which power

plant will operated, and at which capacity. Any changes on the gas power plant deliveries must first be approved by them.

The pipeline network was working on a weekly based profile. During the week days, the gas stored as usable line pack was being consumed by the deliveries, especially the gas power plants, faster than the supplies could replenish it. The sustainability of the operation was insured by restoring the line pack on weekends, a period of lower energy and gas consumption. During the time period, The TRBG was working at almost full capacity during the week. It is an important asset to the operation, since it is one the few supplies with the ability to control the flow rate. Most of the others supplies come from

associate gas wells, making it difficult to control flow without affecting the oil production. The LNG terminal allows for a fine tuning of the supply/delivery ratio. 10^6

To study the problem, different scenarios were defined to determine the maximum allowed time the Network could survive without the LNG terminal, considering also the commissioning profile. To study these scenarios, three main control points were used to determine the constraints or boundary conditions for safe operation of the system during the simulation. These constraints were set considering the network limitation and experience with the network operation: Catu compressor Station suction low pressure limit of 55 kgf/cm²g (53.94 barg); the power plant UTE MLG delivery low pressure limit of 60 kgf/cm²g (58.84 barg); and the Terminal high pressure limit of 100 kgf/cm²g (98.07 barg).

Scenarios

The scenarios were determined after several compromises from all parties involved, including the ONS, to insure the smoothest transition possible, without affecting the delivery schedule of the network, whenever possible. The scenarios were based upon assuming the southeast network and the GASENE operated at a single average pressure on the high pressure pipelines (with a MAOP of 100 kgf/cm²g or 98.07 barg) and all the power plants operating at maximum capacity. After this initial state, the TRBG supply initialize its ramp-down procedures to stop the terminal. The delivery schedule used was based on a typical schedule for a week in December, but with all the power plant operating.

The first two scenarios are based on the normal delivery schedule, with two different base pressure on the system. The purpose was to determine a range a time considering a lower system pressure and a higher system pressure. The selected pressure were chosen based on a review of historical data for the period.

The latter two scenarios, while based on the same pressures as the first ones, considered a different premise. The network operator can, due to maintenance or changes in the network request a change in the delivery schedule of the network. For the purpose of this intervention and through negotiations with ONS, the delivery for two gas power plants would be turned off only during the ship exchange, to insure the other deliveries and permit a longer ship exchange period, in case of any contingency.

Scenario A. The average network pressure is 80 kgf/cm²g (78.45 barg) at the high pressure pipelines and all deliveries maintain their original schedule.

Scenario B. The average network pressure is 90 kgf/cm²g (88.26 barg) at the high pressure pipelines and all deliveries maintain their original schedule.

Scenario C. The average network pressure is 80 kgf/cm²g (78.45 barg) at the high pressure pipelines and the power plants

UTE MLG and UTE BLS are turned off during the operation. All other deliveries maintain their original schedule.

Scenario D. The average network pressure is 90 kgf/cm²g (88,26 barg) at the high pressure pipelines and the power plants UTE MLG and UTE BLS are turned off during the operation. All other deliveries maintain their original schedule.

MODELING

The software use for these simulations was PipelineStudio®, from ESI®. The base model used was conceived by the operation programing and intervention area, and is widely used in day to day operation. It has being previously validated and tuned to insure optimum results with the network.

The main assumptions used in the modeling were:

- Equation of State: BWRS
- Gas Equation: Colebrook
- Thermal calculation: Non Isothermal
- Minimum time step: 10 minutes
- Maximum time step: 30 minutes
- Knot spacing: Variable accordingly to pipe length

Due the size of the model used, some simplification are made in regards to elevation profile and deliveries location, without affecting significantly the results.

RESULTS

Several simulations were attempted, using the software, to determine the maximum time the network could survive without the gas from the TRBG, keeping the original delivery schedule. The decision to turn on or off any compressor station was made to optimize this time, considering their availability during December 2012 (maintenance schedule, machine problems, etc.).

An interesting issue emerged from the initial results. While the goal was to maximize the ship exchange time, it was noticed that if the exchange time was too short, it wasn't possible to immediately begin the commissioning profile without violating the MAOP of the pipeline lateral between the terminal and the main network. Too long time could affect deliveries and minimal pressure boundaries. These results showed that the actual process had a fairly narrow window of opportunity, which helped reduce the number of simulations.

Scenario A

Considering the high pressure pipelines at 80 kgf/cm²g (78.45 barg) average pressure and keeping the original delivery schedule, it was found that the greatest allowable time for the ship change was 17 hours. Figure 5 shows the Terminal flow and pressure profile during the operation, to show the relation between the commissioning profile and the terminal pressure, while Figure 6 shows the pressure profiles of the control points,

to insure that neither the maximum pressure limit at the terminal nor the minimum pressure at the deliveries was reached.

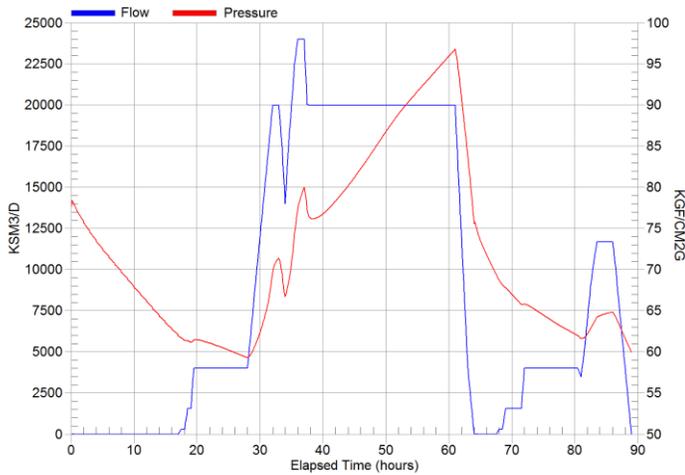


Figure 5. TERMINAL FLOW AND PRESSURE (A)

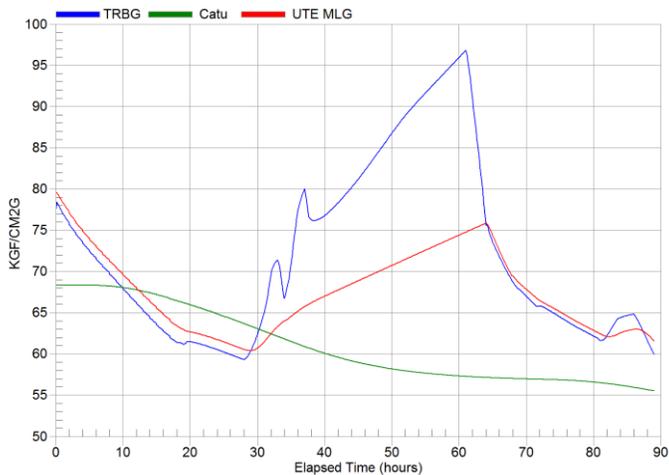


Figure 6. CONTROL POINTS PRESSURE (A)

Scenario B

Considering the high pressure pipelines at 90 kgf/cm²g (88.26 barg) average pressure and keeping the original delivery schedule, optimum time for the ship change was 34 hours. Figure 7 shows the Terminal flow and pressure profile during the operation, to show the relation between the commissioning profile and the terminal pressure, while Figure 8 shows the pressure profiles of the control points, to insure that neither the maximum pressure at the terminal nor the minimum pressure at the deliveries was reached.

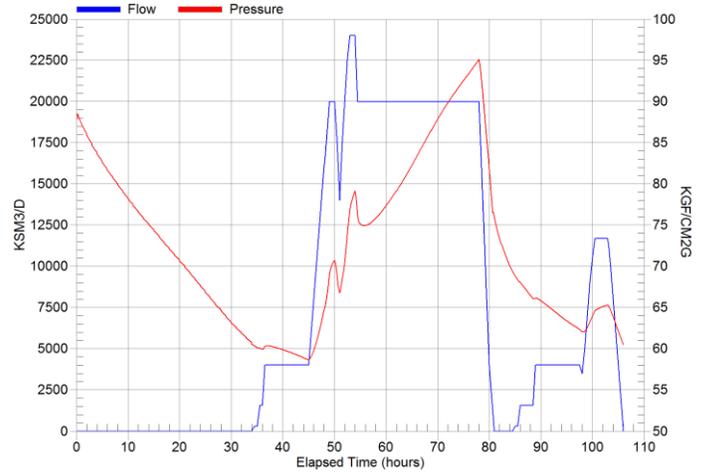


Figure 7. TERMINAL FLOW AND PRESSURE (B)

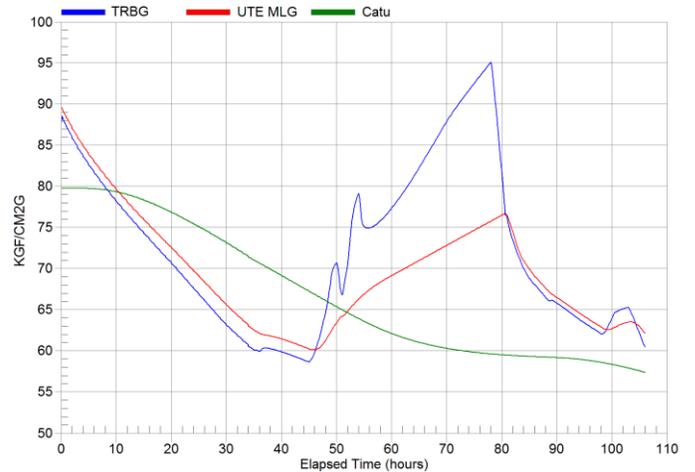


Figure 8. CONTROL POINTS PRESSURE (B)

Scenario C

Considering the high pressure pipelines at 80 kgf/cm²g (78.45 barg) average pressure and only interrupting the deliveries of UTE MLG and UTE BLS during the ship change, the optimum allowed time for the ship change found was 35 hours. Figure 9 shows the Terminal flow and pressure profile during the operation, to show the relation between the commissioning profile and the terminal pressure, while Figure 10 shows the pressure profiles of the control points, to insure that neither the maximum pressure at the terminal nor the minimum pressure at the deliveries was reached.

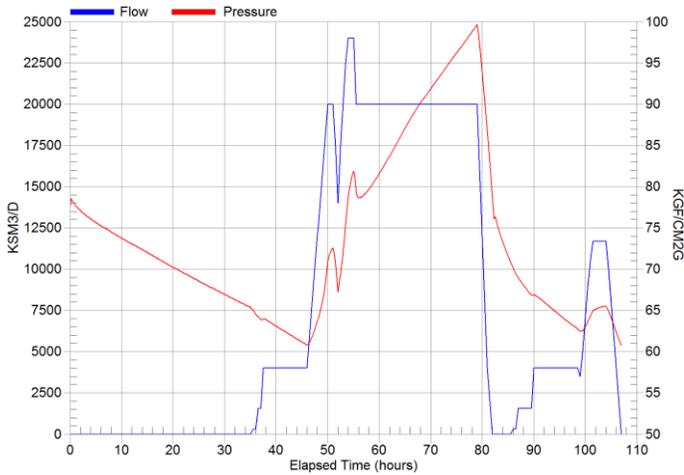


Figure 9. TERMINAL FLOW AND PRESSURE (C)

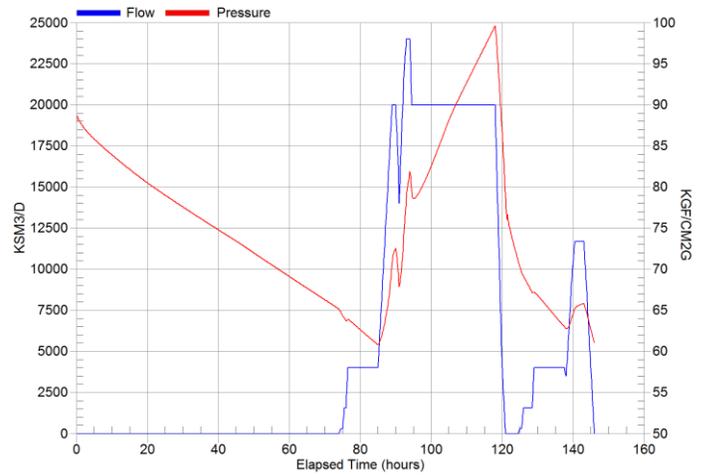


Figure 11. TERMINAL FLOW AND PRESSURE (D)

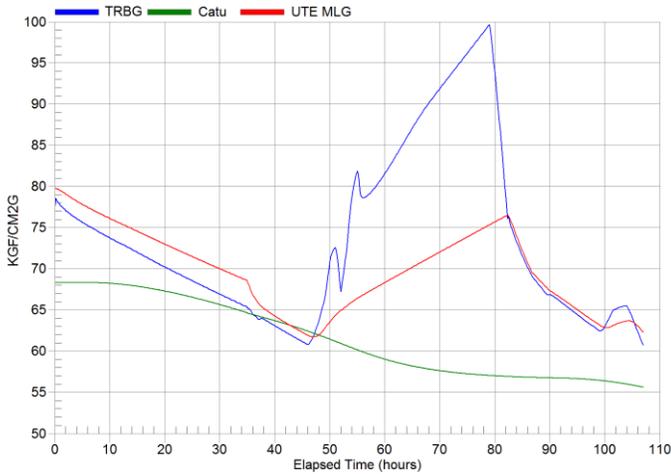


Figure 10. CONTROL POINTS PRESSURE (C)

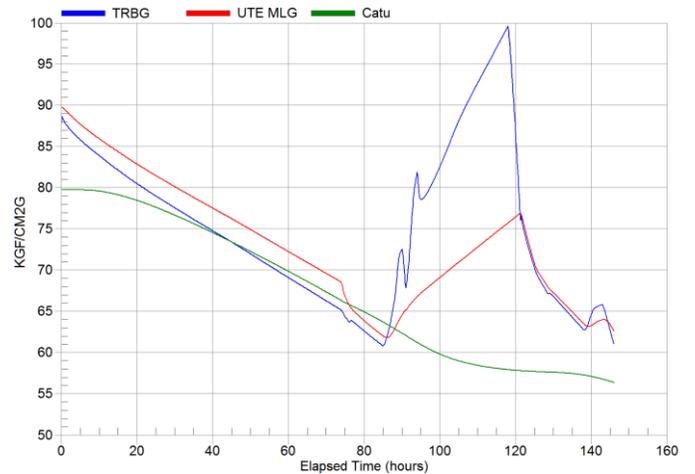


Figure 12. CONTROL POINTS PRESSURE (D)

Scenario D

Considering the high pressure pipelines at 90 kgf/cm²g (88,26 barg) average pressure and only interrupting the deliveries of UTE MLG and UTE BLS during the ship change, the optimum allowed time for the ship change found was 74 hours. Figure 9 shows the Terminal flow and pressure profile during the operation, to show the relation between the commissioning profile and the terminal pressure, while Figure 10 shows the pressure profiles of the control points, to insure that neither the maximum pressure at the terminal nor the minimum pressure at the deliveries was reached.

A summary of the results can be found at Table 1. The table shows that while for scenarios A and B there is a small operational margin between the TRBG max pressure and the UTE MLG and Catu minimum pressure, for scenarios C and D that margin is smaller, since both limits have almost been reached.

Table 1. RESULT SUMMARY

Scenario	Ship Change	TRBG Max Pressure (kgf/cm ² g)	UTE MLG Min Pressure (kgf/cm ² g)	Catu Min Pressure (kgf/cm ² g)
A	17 h	96.83	60.41	55.52
B	34 h	95.11	60.10	57.38
C	35 h	99.65	61.73	55.62
D	74 h	99.59	61.82	56.37

CONCLUSION

The objective of this paper is to show the importance of simulation and operational planning on pipelines. While this work was a small part of a larger project, it clearly showed that without a preliminary study of the gas network conditions, including knowledge of operational bottlenecks and the ability to simulate the network response, the ship change would have been much more difficult, and with a great deal of uncertainty on the ability to maintain delivery schedules. The expected use of compressor stations, the pressure fluctuation on the main supplies and deliveries were passed to the operators to assist in planning and executing the actual operation.

The simulation showed that while the operational window was somewhat narrow, if the gas network operator could prepare the network prior to the ship change, while maintaining its delivery schedule, it would significantly improve the ability of the delivery schedules to be maintained in the event of unexpected delays in the LNG ship exchange and commissioning.

During the actual operation, the network was at an even higher pressure than the ones simulated, at an overall 95 kgf/cm²g (93.16 barg), which require a verification using the same models used in the planning stage. This allowed a faster response from the contingency team in regards to delivery programming and operation follow up.