GAS QUALITY IMPROVEMENTS TARGETED VIA 88% REDUCTION IN COMPRESSOR CYLINDER LUBRICATION RATES

PART 1

BY C.J. SLOAN AND KEITH SCHAFER

EDITOR'S NOTE: *This article is based on a paper presented at the 2021 GMRC Gas Machinery Conference held October 3–6, 2021, in Louisville, Kentucky.*

INTRODUCTION

The TC Energy Columbia Gas Pipeline system encompasses 11,500 miles (18,507 km) of pipeline across 10 states with a transmission capacity of 3.8 Bscf/d (1.1×10^8 m^3/d) and more than 200 Bscf (5.7×10^9 m^3) of gas storage. This system is positioned in the Appalachian region and is well situated to service gas supply and demand for continued growth in the Marcellus and Utica Shale plays. Portions of this system date back to the 1940s and it is one of the largest gas transmission systems in the United States today.

In late 2019, TC Energy management identified gas quality as a primary area of focus for improvement as part of an ongoing modernization project for the system. Liquids are a primary contaminant in the system. The sources of liquids include condensate dropout from source gas, bypass from dehydration facilities, and carryover from compression. Condensate has become a more relevant issue as heavier gas production has come online from the shale plays in the region, and is typically handled via knockout vessels, filter/separators, and as part of processing gas to remove the heavier constituents of the raw gas. Oil contamination of storage wells is also a concern as the fluid reduces capacity of storage formations and tends to contaminate facilities during withdrawal. Carryover from compression can be reduced in several different ways, such as adding filtration/separation, changing to entirely nonlube compressor units, or using lubricants that permit compressors to operate with smaller quantities of oil.

Adding filtration to every unit or station can be prohibitively expensive, and non-lubricated compressors can have limited maintenance intervals — particularly in areas where gas can be heavy or have other fluids introduced upstream of compression.

The impact of liquids to operation of the pipeline is significant.[1] Liquids can build up in low-lying portions of pipelines

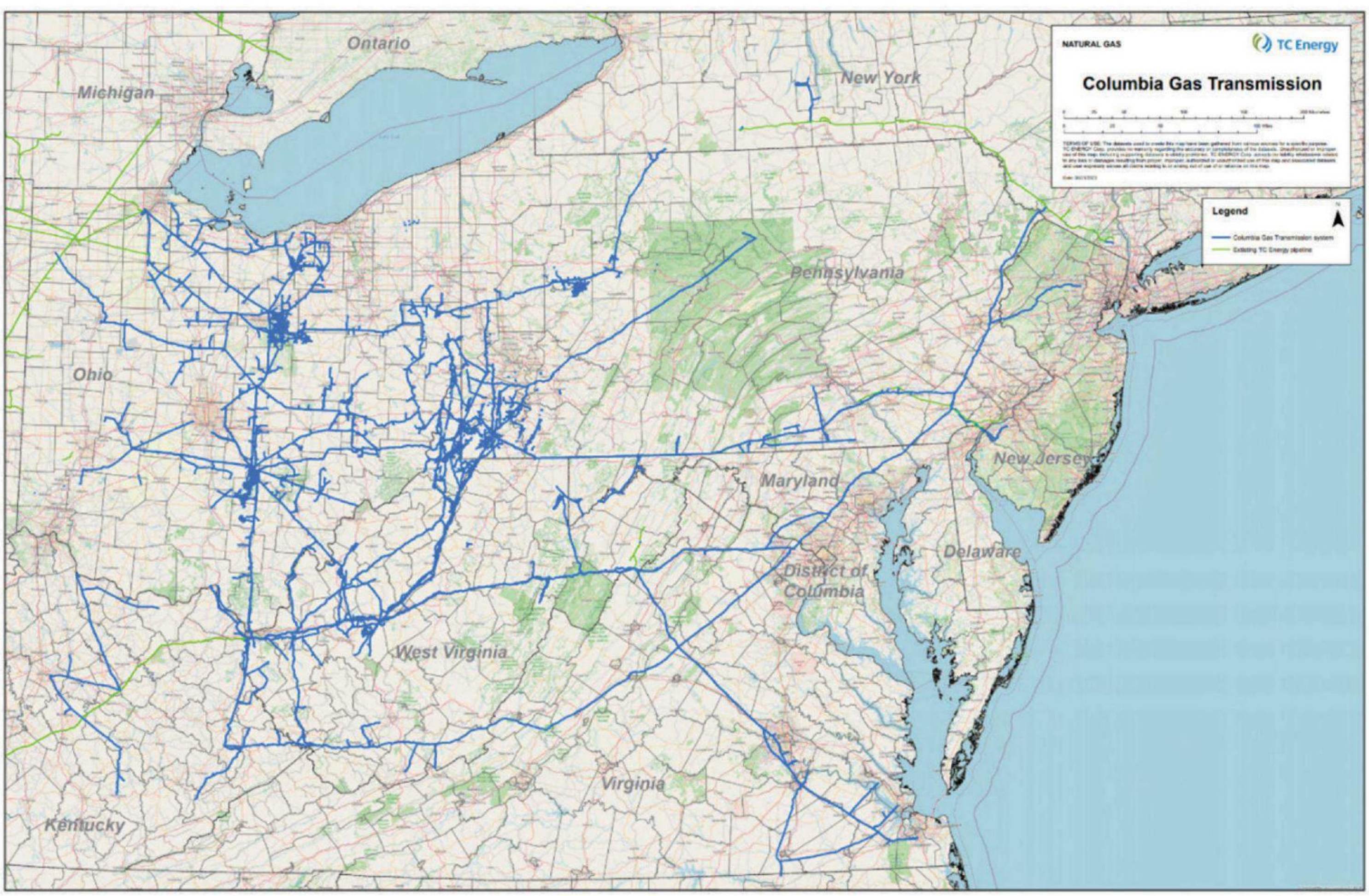

Figure 1. Columbia Gas Transmission System Map

causing restrictions, flow control issues, and slugging, which can damage equipment that is designed to handle only gas, such as reciprocating compressor cylinders. Flow metering equipment is also contaminated, which results in reduced accuracy with more frequent maintenance required to repair. Liquids introduced into underground gas storage formations can also cause problems as they reduce the capacity of the formation and contaminate glycol in dehydration units during withdrawal from the formation.

Delivering liquids to customers can severely impact their operations as their facilities are engineered to receive clean, dry gas from the transmission system and lack the protection necessary to prevent liquids from damaging expensive equipment like power generation gas turbines.[1,2] Removal of liquids entrained in the pipes is a costly and time-consuming process and must be completed prior to the use of smart pigs that analyze the integrity of the pipe.[3]

As part of this project, all the above solutions were put into play. For example, where the system receives raw, largely unprocessed gas from producers, 14 filter/separators were added to reduce the prevalence of inbound liquids. Compressor lubrication systems were upgraded with systems that use a specialty fluid to enable reliable compressor operation with significantly less volume of fluid. Mainline gas analyzers were also installed at key points in the system to better track gas quality in the future.

This article focuses primarily on the reduction of oil consumption by compression units through the combination of a new lubricant and delivery system that permits large reductions in oil. The principle of this portion of the project is that the liquid being introduced is self-imposed as a function of operating the pipeline system. If the oil is not brought into the pipeline in the first place, costs associated with removing and disposing of it from other areas will also be reduced. The lubricant reduction portion of the project made up approximately a quarter of the total project budget.

THE PROJECT

The focus of this upgrade was 35 compressor stations in Ohio, West Virginia, Pennsylvania, Virginia, Kentucky, and New York, as 134 reciprocating compressors in these stations were identified as the targets for system upgrade and encompassed a wide variety of unit types. The compressors are primarily in transmission service, with several locations serving "double duty" in storage injection and both transmission/storage withdrawal depending on the season and system demands.

TC Energy kicked off the project in early 2020 with initial planning. Before any work could start, the COVID-19 pandemic began and prevented personnel movement. Since the existing state of the units needed to be well established to estimate the project resources required to upgrade each, a virtual site survey process was developed to utilize location operations at each site to do that work. That process was challenging even after initial training as the local operations personnel at times had limited knowledge of what would be required and, in some cases, took several rounds of discussion, photos, and drawings to establish a solid scope of work for each unit. Several portable cardboard mockup units were distributed and used at many sites to facilitate locating the lubrication system cabinet within the station.

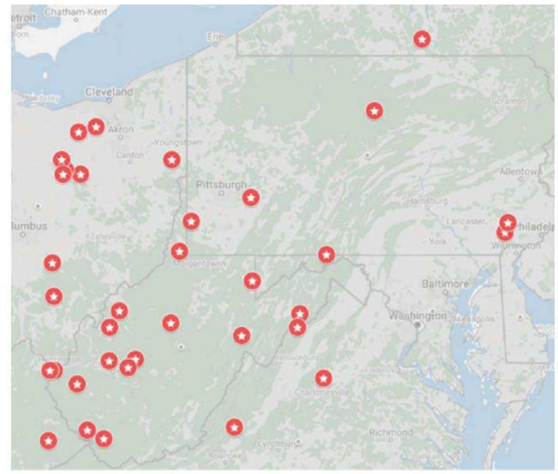

Figure 2. Project Target Compressor Stations

UNIT VARIETY

As expected from the project start, the surveyed units represented a wide variety of types, sizes, and conditions. The oldest units are 1952 GMW6-2 machines running at 250 rpm, while the newest was a 2018 JGK/4 at a speed of 1200 rpm. Drivers consisted of 2-stroke, lean-burn integrals; 4-stroke, rich-burn integrals; electric motor separables; and separable gas engines. Some units already had modern or well-maintained lubrication systems in place, sometimes factory new, while some had old systems (40+ years old) in poor condition.

A general trend within the industry is that the installation date of a unit correlates strongly with the crankshaft rpm, as shown in Figure 3. Integral engine compressors have given way to high-speed separable units. Higher-speed units are smaller and easier to maintain for a given horsepower and gas throughput than slow-speed units, so they became the primary choice when installing new compression starting in the 1970s. Higher-speed units typically have shorter strokes to keep average piston speed constant and reduce the over-

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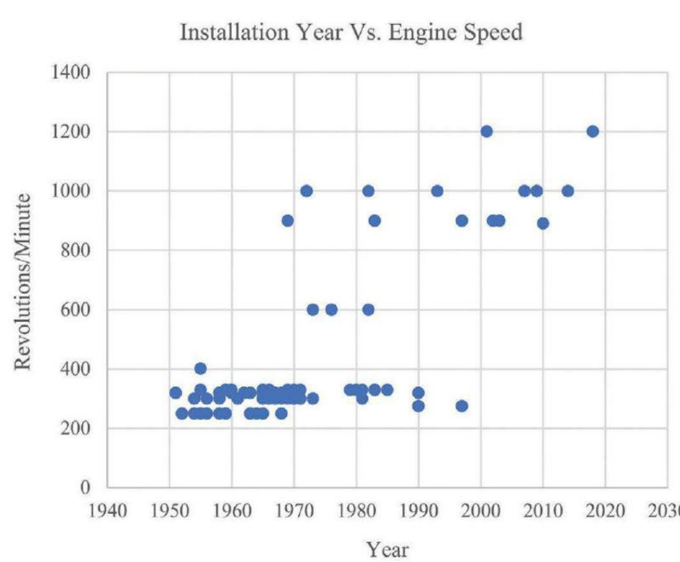

Figure 3. Installation Year Vs. Engine Speed Trend

all load when accelerating and decelerating their reciprocating mass. This has resulted in more concentrated wear areas within the machines and increased surface temperatures due to friction, which has increased demand for lubrication.

Several units also received upgraded control systems as part of the modernization project or were undergoing other major work at the same time to simplify outage scheduling. All units had already been in operation with or were built with modern polytetrafluoroethylene (PTFE)-based wear materials (piston rings/rider bands/packing) that decreased the extra work needed, particularly on slow-speed units. As part of TC Energy standards, all copper lubrication system tubing was slated for replacement with stainless steel tubing and nonmetallic tube mounts to mitigate metal-on-metal contact. As reciprocating compressor components are inherently subjected to vibration, reducing metal-to-metal contact of items, such as tubing, is crucial for reliability. With sufficient vibration, tubing has been observed to wear through in only a few years if not properly supported, resulting in casting damage at points as well as pinhole leaks in tubing.

SYSTEM DESIGN

The lubrication system installed on each unit was standardized as much as possible. The design methodology and component selection in this section follows the descriptions laid out in a previous 2018 GMC paper,[4] so only the changes from that design are detailed here. The oil supply for these systems changed from plastic cartridges to a bag-in-box system. This has the same advantages of reduced supply contamination, portability, shipping, and storage, but results in less waste than solid cartridges. Eliminating supply contamination becomes increasingly important as oil consumption decreases. Excessive lubrication rates have the capability of masking issues within the lubrication system such as contamination and broken tubing that is internal to the compressor and therefore not visible during operation when broken. Because of the downstream costs introduced by higher lubricant usage, it is not a reasonable strategy for addressing these issues. The cardboard and bags can also be recycled locally, take up significantly less space than empty cartridges, and represent a more cost-effective method of delivery versus using large bulk oil tanks with underground piping to be filled by tanker trucks.

The new lubrication systems all share the same design: sensors to monitor oil supply level, dual supply cartridges, direct current (DC) variable speed motor drives, and small displacement divider blocks capable of delivering the low-target flow rates. By designing all systems around the same platform, spares between unit types and stations in different locations are uniform, meaning that maintenance and troubleshooting are standardized because all units now have the same common lubrication system. Each system is capable of lubricating two zones, so for slow-speed units, additional pumps and other items can easily be added in later projects to lubricate power cylinders or serve other lubrication needs on the unit.

Each unit has a variable speed electric motor controlling two parallel pumps for each zone, which enables more advanced flow control than crankcase-driven pumps. Because of this and the tight integration with the unit's programmable logic controller (PLC), flow adjustments like high pre-lube rates on startup, break-in rates, flow limitation adjustments, or mechanical wear to pumps can be handled through software instead of requiring regular manual alterations. In addition to this, each zone has a pressure sensor both upstream and downstream of the pumps, enabling more rapid diagnostics in the case of an issue.

Because this was a project driven by pipeline gas quality, the systems were designed to lubricate cylinders and packing cases only. If a unit had additional lubrication needs, such as lubricated 2-stroke power cylinders or 4-stroke valve guides, that work was not a part of the scope of this project. However, as mentioned previously, that provision remains and can be added later to units that require it.

FLOW RATE METHODOLOGY

The units were split into two major groups: slow speeds (less than or equal to 600 rpm) and high speeds (greater than 600 rpm). For slow-speed units, the compressor cylinders and packing were combined into a single delivery zone, with the design rate for cylinders being 20 million sq.ft. (1.8 million m^2) per pint of fluid, with the packing receiving half of the cylinder's rate. For high-speed units, heat buildup in non-cooled packing cases, in some applications, has been a concern, so the cylinders and rod packing cases were split into separate delivery zones. This provides the ability to adjust each independently of the other and/or to deliver separate fluids to each. At the time of writing, all high-speed units are receiving 7.5 million sq.ft. (696,773 m^2) per pint to the cylinders and original equipment manufacturer (OEM)-recommended delivery rates to the packing cases. A plan is in place to further reduce these packing rates over time; however, the risk to gas quality was considered minimal as most of this injected fluid is captured in the packing and goes out the packing drain line, rather than ending up directly in the gas stream.

The lubrication system controls for this project were integrated directly into the customer PLC. Systems of this type typically have independent control systems; the preference for this project was for tighter integration between the engine and compressor control system. This permitted much closer integration into the pipeline-wide supervisory control and data acquisition (SCADA) and data historian systems. The system software was integrated into the unit's skid control PLC as a module. The PLC communicates with a remote ethernet I/O rack built directly into the system itself, permitting rapid deployment and factory testing before field installation. DC power is delivered directly to each system from the facility's uninterruptible power supply (UPS) so that fluid will be delivered, even during an outage. Power demand for these systems is low, so the impact to battery capacity is minimal.

IMPLEMENTATION

Due to rapidly changing restrictions on travel, our implementation had to be flexible, so during project planning it was difficult to have an exact start date. The plan was to schedule outages station by station, achieving five unit installations per week, which would allow completion of the project in the second half of the year. During planning, the management team was hopeful that once pandemic safety protocols were established, installations could begin in early June.

The initial conceptual plan was a simple, two-phase approach for each unit. Phase 1: Removal of existing system components, fabrication/electrical prep work, installation of the cabinet and tubing. Phase 2: Modification or removal of frame-driven lubrication system, PLC integration, software installation, testing without the compressor running, inspection, startup, and test run. The estimated time to complete these phases, from start to finish, was three days, with the unit being down the second and third day. Working simultaneously, three crews were planned to complete five units each week, with built-in contingency time on Saturdays.

Some stations have special environmental considerations due to existing polychlorinated biphenyls (PCB) concerns in paint and piping. A third party was required when any paint or concrete disturbance was necessary, such as to drill mounting holes for a tubing track. Some tubing was also painted in place, so the lubrication system installation crew had to rely on the contractor to remove and dispose of that tubing safely. For units with this designation, an extra two days were allocated. Fortunately, these tended to be locations with multiple units, so some efficiency was realized at those locations.

IMPLEMENTATION CHALLENGES

The reality of the project was different from the initial plan. Coordinating installation crews from multiple companies across 35 locations turned out to be a challenge. Travel and facility restrictions due to the pandemic were a scheduling hurdle, as were coordinating outages at various locations to ensure that segments of the pipeline could meet flow and availability goals.

Key project management personnel were located in four states and never met in person as a team during the project, so all coordination was virtual. This ended up being a net benefit as online communication allowed the management team to meet regularly. The virtual management of the project proved difficult at the same time, however, because many pipeline locations are remote, so it was often difficult to find a reliable high-speed connection with which to share meeting materials and project documents.

One major roadblock encountered early in the project implementation was that several units were found to have mechanical issues that needed to be repaired prior to reduction of lubricant delivery rates. These preexisting issues were not as much a problem with high initial lubrication rates but had to be resolved prior to dropping below the OEM-recommended rates. This resulted in some units taking as much as a five-day outage to complete and additional replacement parts to inspect, disassemble, and replace components, and then continue with the installation. This resulted in two additional installation crews being brought onto the project to keep the timeline of completing five units per week on track. In some cases, this work required removal of suction and discharge bottles from compressor skids to access tubing that had to be upgraded, so it added an extra layer of complexity to the project. This additional work was required on 15 units. Relying on excess lubricant in the compressor cylinders to mitigate these mechanical issues permitted these compressors to operate before this project, but at the cost of negative effects downstream of the compressors themselves and at the expense of additional fluid consumption.

An additional consideration was that a small number of the units did not have existing controls suitable for interfacing with the upgraded lubrication system. Four units fell into this category and required complete control system overhauls. While not directly impactful to the installation process of the lubrication systems, these units did have to push to near the end of the schedule before the unit modernization work was complete and the units could be started up with the upgraded systems. This pushed other units forward so that room would be available in the schedule.

Various supply chain problems also impacted delivery of the systems themselves at times, so work had to begin in some locations before the new systems could be delivered. Supply chain constraints encountered in the project were largely due to COVID-19 and included electric motors, control I/O modules, pressure sensors, solenoid valves, electrical connectors, and tube fittings. All supply chain concerns were resolved in time for the project to finish on schedule and have been attributed largely to plant closures, raw material availability, or other pandemic-related difficulties.

As a result, the planned schedule to start a unit, finish it, and then move on to the next had to change early in the process. The plan was then modified, beginning Phase 1 work without compressor outages at as many locations as possible, until all required materials could be available on-site to complete the Phase 2 work. While beneficial, this did result in significant extra travel time as crews would complete the work they could at one site, travel to another, and then return when additional materials became available, or when outages were scheduled.

Training was another concern, because the new systems were quite different from the previous lubrication systems that station operators were used to. While they contain similar components, there is additional complexity due to the added sensors, motor controls, and other features. A comprehensive operations and maintenance training program was conducted during installations, ensuring that operators were familiar and comfortable with all major features of the systems. One benefit of a common system design is that now all units, regardless of type, have the same interface and operate in the same manner. This will reduce the need for separate lubrication system training programs at various locations.

By the end of the project in December 2020, the project was completed on time with the startup of the 133rd unit. Note: The final and 134th unit was undergoing a major overhaul during this project and due to component constraints work had not yet been completed to start up that unit.

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GAS QUALITY IMPROVEMENTS TARGETED VIA 88% REDUCTION IN COMPRESSOR CYLINDER LUBRICATION RATES

PART 2

BY C.J. SLOAN AND KEITH SCHAFER

EDITOR'S NOTE: *This article is based on a paper presented at the 2021 GMRC Gas Machinery Conference held October 3–6, 2021, in Louisville, Kentucky. Figures follow consecutively from Part 1, which ran in the January 2022 issue of* Gas Compression Magazine, *p. 28.*

CURRENT RESULTS

In the year since the project began, lubricant consumption has been reduced significantly. These 134 units have accumulated 324,668 hours of runtime with upgraded lubrication systems. Overall, lubricant consumption is down a total of 88%, or 18,680 gallons. The highest reduction achieved was 97% on two Ariel JGZ/6 units, installed in 2009 and found to be running higher than original equipment manufacturer (OEM)-recommended rates.

The lowest reduction achieved was on several Clark TRA 6-3 units, which had already been highly optimized via improved wear materials and lubrication systems since their initial installations in 1960. Fluid consumption on those units was reduced by 55%.

As seen in Figure 4, several compressor stations realized much larger reductions in overall consumption due to many factors. Some stations have far more units than others, or more high-speed units that run more consistently, requiring far more fluid to operate. Since the conclusion of this project, several locations have had lower runtimes due to construction or other necessary maintenance taking place on the line or around those stations.

The outlier units from the group were the units found to be running at higher than the OEM-recommended rates. This is likely due to failure to adjust rates after a break-in period or some other external factor. There is a tendency for high-speed units to have higher flow rates. Due to this, high-speed compressors typically have a greater potential for savings. That is not the rule though, as significant reductions were also achieved in older slow-speed units, just not as universally.

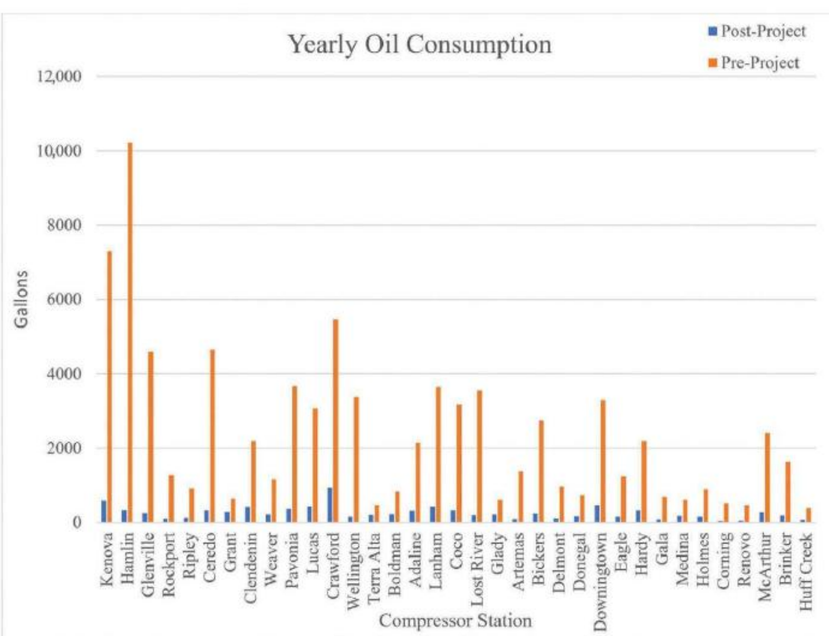

Figure 4. Yearly Oil Consumption Per Station

The chart in Figure 5 is shown in log scale to more clearly represent the large change in flow rates resulting from this project.

Not every pipeline segment is pigged every year and there is still a significant amount of residue in the lines. Analysis of the long-term benefits will be ongoing, and projected benefits will become clear with more run time. TC Energy is estimating that it will take two to three years from project start to get all the historically entrained liquids out of the system via pigging, drip point drains, and capture at filter/knockout vessels. At that point, the real long-term effects of the reduced lubricant consumption will become quantifiable.

At the time of writing, there have been no major issues related to the project in terms of mechanical or control reliability, despite the total of 88% reduction in lubricant consumption by the 133 compressors in service. All units are running smoothly, and a plan for further reduction on high-speed units is being put into place to optimize those units over time. All high-speed units also were dimensionally inspected to verify that they were within OEM limits and had new wear materials installed at the time of system installation so that wear rates can be tracked over time. Regular inspections will be performed during maintenance outages and will inform additional flow rate reductions on these units in the future.

As pigging operations continue, a close eye will be kept on trends that arise as a result of the significantly lower quantity of fluid being injected into the pipeline. In comparison to the alternative of installing filter separators in the discharge line of each station, the lubrication system modifications were quite cost-effective. Fitting each of the 35 stations in this project with filters sufficient to achieve the same result would have cost 7.2 times more than the lubrication system upgrades. In comparison to the alternative of switching to nonlube compressor cylinders, lube rate reduction yields similar gas quality improvements while increasing reliability as opposed to introducing the reliability and performance issues associated with nonlube compressors.

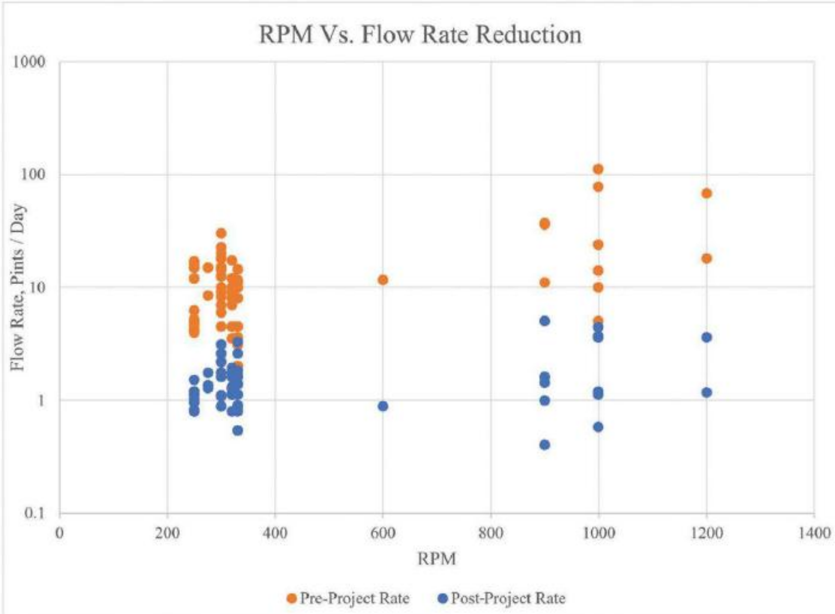

Figure 5. Logarithmic Scale Of rpm Vs. Flow Rate Reduction

LOOKING FORWARD

TC Energy has projected long-term savings from this project. While direct savings data were not available at the time of this report, trends were expected to be discernable by the end of 2021. The effects of excess liquid in gas pipelines are well understood. In terms of cost savings, the breakdown of expectations is as follows:

- Failed and unplanned in-line-inspection (ILI) pig runs. This is a frequent occurrence and can result from lack of pre-inspection cleaning or liquid entrainment between cleaning and inspection runs.[3] Improvements in cleaning processes and a decrease in failed and repeated inspections is expected to produce around US$500,000 in annual savings.
- Flow meter tube cleaning savings. Flow meters depend on straight, consistently sized sections of tubing to normalize flow for accurate measurement. Liquids build up on flow meter tubes, requiring removal and cleaning. This is an estimated US$250,000 in annual savings.
- Break/fix savings due to liquids in the line or equipment. This includes damages to or malfunction of meters, valves, chromatographs, pressure sensors, and so forth throughout the pipeline system, estimated at US$250,000 annually.
- Break/fix savings due to direct liquid damage to equipment is estimated at US$150,000 annually. This includes slugging into compressor stations, compressor valve breakage due to valve plate or poppet stiction, or other in-station equipment damage.
- Fluid disposal savings of an estimated 36,000 gallons of excess lube oil annually based on 2019 actual run hours are estimated at US$150,000. Note that while lube oil disposal savings is estimated at 36,000 gallons, there will be additional fluid disposal at inbound collection points due to the 14 added filter/coalescer units installed as part of this project. That value is not quantified currently. There is also an expectation that as system throughput increases due to additional gas supply coming online in the region, compressor runtime will also increase. Maximum calculated fluid volume savings for the system is just under 60,000 gallons/year if compressor utilization is 85%.
- Lastly, reduced volume of fluid required to operate the 134 compressors has resulted in a fluid purchase cost savings of US$100,000.

Beyond the direct cost savings, there are additional ancillary benefits that are expected as a result of this project. Smaller portable cartridges reduce the opportunity for spillage in comparison with large bulk tanks during fluid supply operations. Due to the lower volume and decreased frequency of fluid handling during disposal, the chance of incident also goes down. The lower volume of fluids required to operate a compressor over time reduces the environmental footprint of those operations. Reduced contamination of glycol in dehydration units extends the life of that fluid as well, so less-frequent fluid changes are required to operate the system.

CONCLUSION

Fluid introduction into a natural gas transmission system can be effectively reduced through lubrication system upgrades and fluid selection, resulting in an initial consumption reduction of 18,679 gallons of oil. The majority of compressor units on a gas transmission system can achieve significant gas quality improvements via upgraded lubrication systems and greatly reduced lubrication rates that will have beneficial financial impacts in a relatively short time. Despite the challenges introduced due to a global pandemic, wide variety of unit types, and number of locations to service, the project was completed on time and within budget. Analysis of flow and runtime data show large reductions in compressor lubricant usage, which is expected to provide long-term savings and operational efficiency to the Columbia Gas Pipeline gas transmission system. Increased unit reliability through system design, standardization, and increased maintenance efficiency, while delivering cleaner gas, is what will stand this solution apart from others, benefiting not only the user but the environment as a whole.

ABOUT THE AUTHORS

Keith Schafer started his career with Columbia Gas Transmission and has 44 years of service at CPG and later TCE. An expert in his field, Keith continues his involvement in natural gas compression as a consultant, where he helps companies optimize operations.

C.J. Sloan is a member of the fourth generation of family leadership at Sloan Lubrication Systems. As CTO he is responsible for engineering and R&D. He holds several patents for new technology developed by Sloan Lubrication Systems and was team lead for development of the TriCip System.