Energy Efficiency and Electrification Best Practices for Oil and Gas Production

Authored by Neil Kolwey

August 2020

Updated July 2022

SWEEP
SOUTHWEST ENERGY EFFICIENCY PROJECT

COLORADO
Energy Office

Acknowledgements

This report was sponsored by the Colorado Energy Office, and we thank them for their support. We thank CLEAResult for their assistance in identifying and describing the best practices for oil and gas producers as well as for utility programs serving these customers.

About SWEEP

The Southwest Energy Efficiency Project is a public interest organization dedicated to advancing energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming. For more information, visit: www.swenergy.org

About the Colorado Energy Office

The mission of the Colorado Energy Office is to reduce greenhouse gas emissions and consumer energy costs by advancing clean energy, energy efficiency and zero emission vehicles to benefit all Coloradans with a vision for a prosperous, clean energy future for Colorado. The Colorado Energy Office is a non-regulatory department within the Governor's Office.

About the Author

Neil Kolwey is Industrial Program Director at SWEEP where he promotes best practices in utility energy efficiency programs for industrial customers and policies to support combined heat and power.

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

Production of oil and gas consumes a significant amount of energy, both electricity and fuels, and generates significant emissions of methane and other air pollutants. Most oil and gas production sites in Colorado are not yet connected to the electricity grid. In order to power their pump jacks, and water and oil pumps, these sites use diesel engines and natural gas or diesel generators. Connecting these sites to the grid reduces energy consumption and emissions from the engines and generators and reduces operating costs for the oil and gas producers. This aspect of "electrification" of oil and gas production has advantages for both the oil and gas producers and the electric utilities. There are also opportunities to reduce energy consumption and greenhouse gas emissions through installing electric rather than gas pneumatic-driven devices and electric rather than natural gas-driven compressors.

For production sites, mid-stream gas processing sites, and natural gas compressor stations that are grid-connected, there are also opportunities to reduce energy consumption through implementing cost-effective technologies and improved operating practices. Utilities serving these customers can offer technical assistance and incentive programs to help oil and gas customers improve their energy productivity and reduce operating costs.

II. OVERVIEW OF OIL AND GAS PRODUCTION

Colorado produces a significant amount of both natural gas and oil. Weld County has by far the most production of both fuels, as shown in **Table 1** (below)**.** The top ten counties shown below account for 97% of Colorado's total natural gas production, and 98% of total oil production.

Table 1. Top 10 Colorado Counties in Oil and Gas Production

County	Total natural gas production in 2018 (mcf)	Total oil production in 2018 (bbl)
WELD	799,447,344	154,969,228
GARFIELD	495,033,611	1,459,041
LA PLATA	295,078,977	16,266
RIO BLANCO	51,267,348	3,770,077
ADAMS	7,567,328	3,478,827
MESA	61,683,821	164,889
LAS ANIMAS	57,307,735	0
ARAPAHOE	4,762,348	2,320,015
LARIMER	10,734,961	3,753,237
ARCHULETA	16,310,608	2,005
Total for top 10	**1,799,194,081**	**169,933,585**

Most drilling rigs in Colorado are not grid-connected and instead are powered by diesel engines. Many oil and gas production sites are connected to grid electricity, but according to a recent survey for the Colorado Department of Public Health and Environment (CDPHE), about 80% of production sites in Colorado are not.[1] For these sites, the pump jacks, electric pumps (for water or oil) and other electrical needs require diesel or natural gas engines or generators. These sites will also rely on gas pneumatic-driven controllers. Connecting to the grid reduces fuel and maintenance costs and emissions from the diesel and natural gas engines.

The main steps in the production of oil and gas, from production sites to mid-stream processing are shown in **Figure 1** below. These steps are common for all onshore oil and gas production in the U.S., including Colorado. The largest energy-consuming steps include artificial lift methods (such as steam and CO2 injection), pumps for oil and water, and natural gas compressors. Overall, the largest consumers of electricity are the large pumps for oil and water, and the large blowers for steam injection. Natural gas compressors consume a lot of energy and can be driven with either electricity or natural gas, but 90% of compressors are natural gas -driven.[2]

[1] "No-Bleed/Self-Contained Pneumatic Controller Survey Results: Well production Facilities and compressor stations," January 2020, https://drive.google.com/drive/folders/1TSLirTlVeHcEZggthxx6wbh375VMzxIe.

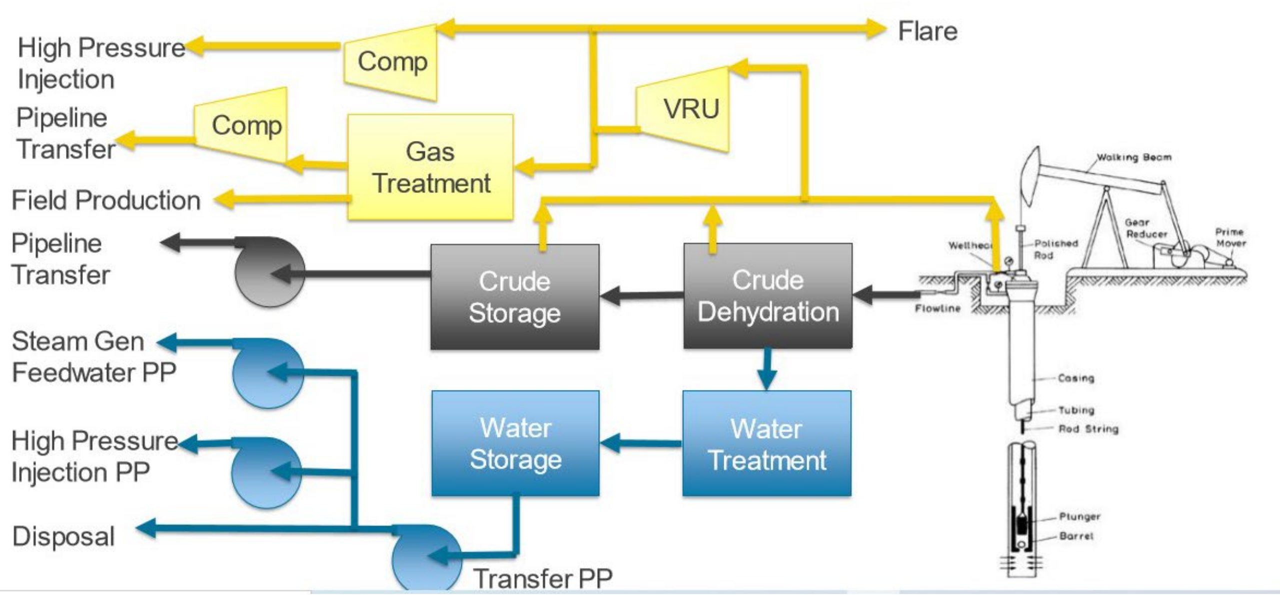
[2] "Electrifying Natural Gas: Opportunities for Beneficial Electrification and Load Flexibility in Natural Gas Pipeline Compressor Stations," Xergy Consulting, May 2018, https://www.cooperative.com/programs-services/bts/Documents/TechSurveillance/TS-Beneficial-Electrification-Natural-Gas-Pipeline-Compressors-May-2018.pdf. Note that gas-driven compressors means using either reciprocating engines or gas turbines.

III. ENERGY EFFICIENCY BEST PRACTICES

For production sites that are grid-connected, some of the main opportunities for improved energy efficiency include the following:[3]

- pump-off controllers;
- variable speed drives on pumps;
- high-efficiency submersible pumps;
- high-efficiency artificial lift well conversions;
- optimized sizing of motors, pumps, and compressors; and
- process optimization, better sequencing, turning off under-utilized pumps or compressors.

Figure 1. Oil and Gas Field Production Process



Note: "VRU" means vapor recovery unit. Source: CLEAResult

Pump-off controllers (POCs)

POCs allow conventional rod pumps to operate more efficiently and effectively. POCs are a common practice for new wells, but many old oil wells rely on older, less efficient clock/timer technology. Retrofitting these older wells can be cost-effective for the operator, especially with utility incentives. For example, one oil and gas operator in New Mexico retrofitted seven wells with pump-off controllers and received a rebate from Xcel Energy for $21,000. The project reduced the

[3] Deborah Topacio, Manager-Utility Programs, EnerNOC, personal communication, September 2014, dtopacio@enernoc.com; "Energy Efficiency Services Program for Oil and Gas Producers," PG&E, https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/partnersandtradepros/eeis/search/3P_fs_EESPOilGas.pdf

customer's annual energy consumption by 170,000 kWh, and the net payback period per well (after including the rebate) ranged from 1 year to 4.5 years.[4]

Variable speed drives

This technology is used by many industrial sectors. In oil and gas production, the production of liquids vs. gases is unpredictable, and pumping loads vary considerably, making VSDs an important technology for reducing pumping energy. In addition, there are large pumps (over 200 hp) for oil and water throughout the upstream production processes, so there is significant energy savings potential through employing this technology. Specifically, there are opportunities for VSDs in the following areas:

- electric submersible pumps;
- gas compressors used for artificial lift (on high gas content wells);
- treated water transfer pumps;
- produced water injection pumps;
- vapor recovery unit compressors;
- natural gas injection compressors (electric); and
- boiler feedwater pumps and combustion air fans.

The best time for installing VSDs on large pumps, blowers, or compressors is during construction of new production and processing sites. However, it is also possible to do the installation cost-effectively as a retrofit of an existing site.[5]

High efficiency artificial lift well conversions

Artificial lift means using additional energy to drive more oil to the surface, since for most wells the pressure of the oil itself is not sufficient. There are various ways to increase the pressure, some more efficient than others. There can be significant efficiency gains through optimal motor and pump designs, such as efficient electric submersible and progressive cavity pumps, and also through better monitoring and automation. VSDs installed on blowers for steam injection can also save a lot of energy.[6]

Process optimization and sequencing

Pumps and compressors are often under-utilized due to variable production rates. Proper sizing, sequencing, use of variable speed drives, and preventive maintenance can result in significant energy savings from pumps and compressors. Even with VSDs, there is more that can be done to optimize pump flows and sequencing through enhanced controls. For compressors, there are similar opportunities to optimize the varying flowrates of gas. (See Encana compressor station case study below.)

[4] "Pump Off Controllers and the Opportunity for Customers," Xcel Energy, https://www.xcelenergy.com/staticfiles/xe/Marketing/Files/Case-Study-Pump-off-Controllers.pdf.
[5] John Steinhoff, CLEAResult Project Manager, Solutions Team, personal communication, January 7, 2020, jsteinhoff@CLEAResult.com.
[6] Ben Crandall, CLEAResult, personal communication, January 15, 2020, bcrandall@clearesult.com.

Compressor tune-ups and optimization – Encana case study

In 2010 and 2011, Encana made a series of improvements to two of its compressor stations/processing facilities in Colorado. At one plant, Encana retired seven old gas-fired engines and replaced them with two new efficient engines, which reduced the plant's overall energy consumption per unit of gas processed by 38%. At another large compressor station equipped with large electric compressors, Encana made some modifications to the flow control valves. Encana also hired a contractor, Detechtion Services (DS), which provides 24/7 online compressor monitoring, and provides recommendations on variable volume pocket adjustments to maximize compressor efficiency. DS also installed a system to automatically notify the site operators when compressor "blow-by" occurs, which decreases compressor efficiency. Through these efforts, the electric compressor station was able to improve its efficiency by 16%, reducing energy costs by about $3.5 million per year.[7]

IV. ELECTRIFICATION BEST PRACTICES

As described above, most production sites in Colorado are currently not grid-connected. If it is possible to get more sites connected to the grid, oil and gas producers can reduce their operating costs (fuel and equipment maintenance costs) and reduce their on-site air emissions. Utilities benefit from being able to sell more power to the oil and gas producers. And these businesses are typically 24/7 operations, which means a very attractive load for the utilities. Several Colorado utilities with oil and gas customers not yet grid-connected, such as Xcel Energy, United Power, and San Isabel Electric are taking steps to add new distribution feeder lines to reach these customers.

Two of the largest sources of methane emissions in production operations are gas pneumatic controllers and natural gas engines. Natural gas-driven compressors are also one of the largest consumers of energy for natural gas producers. There are electric technologies for both of these applications that reduce methane emissions and overall energy consumption, which we highlight in this section.

Zero-emission controllers and pumps

Generally, production sites that are not grid-connected use gas pneumatic controllers. Many sites also use gas pneumatic pumps for injecting chemicals and other purposes. Nationally, the U.S. EPA estimates that gas pneumatic control devices account for about 25% of all methane emissions from the production, mid-stream processing, and gas pipeline segments of the oil and gas industry.[8]

Currently, the Colorado Department of Public Health and Environment (CDPHE) requires operators to install zero-emission control devices for all production sites in non-attainment areas and for all new production sites that are grid-connected. There are three technologies that qualify as a zero-emission controller:

a) pneumatic controllers powered by compressed air rather than natural gas;
b) electric controllers; and

[7] Justin Lisowski, Rotating Equipment Engineer, Encana, personal communication, October 2012.
[8] U.S. EPA Natural Gas Star Program, "Estimates of Methane Emissions by Sector in the U.S.," https://www.epa.gov/natural-gas-star-program/estimates-methane-emissions-sector-united-states.

c) gas pneumatic controllers which pipe the methane to a control device.

The first two of these options involve electricity use, so for sites that are not grid-connected, the production facility would need to generate its own power on-site, which it could do using a natural gas generator, or a small solar PV and battery system. Similarly, chemical injection pumps can be powered by compressed air or electricity rather than being gas pneumatic-driven.

CDPHE is currently working on new oil and gas methane regulations, and in December of 2020, it may require zero-emission controllers and pumps for all new and existing sites with more than 4 wells (including sites not grid-connected and sites outside non-attainment areas). To be proactive, oil and gas operators may want to consider installing zero-emission controllers and pumps at all new production facilities (even those not grid-connected), rather than waiting for CDPHE to require this later, as a possibly expensive retrofit.

Electric compressors

By far the largest electrification opportunity, in terms of potential energy savings and new electricity load, is to convert natural gas-fired compressors to electricity. Compressors use considerable amounts of energy to move natural gas from production sites to mid-stream gas processing sites, and from there to transport the gas through interstate transmission pipelines.

About 90% of compressors used to drive natural gas through pipelines are gas-fired – either reciprocating engines or gas turbines, and the other 10% are electric. Compressors larger than about 5,000 hp used at mid-stream processing sites and at larger compressor stations tend to be gas turbine-driven, and the smaller compressors below this size used at gathering and boosting stations or in the mid-stream segment are normally gas engine-driven or electric motor-driven.[9]

If electricity is available at the site, there are several advantages of choosing electric drives over gas engine compressor drives. As described below in more detail, electric drives cost less to install, and they reduce annual operating costs significantly. Electric-driven natural gas compressors are also more energy-efficient, and they significantly reduce methane emissions and net CO_2 emissions compared to natural gas engine-driven compressors.

In September of 2020, the Colorado Department of Public Health and Environment (CDPHE) will propose a new regulation on natural gas engines larger than 1,000 hp. There are 860 engines in this size category in Colorado, with 858 of them (all but 2) used by natural gas producers to drive natural gas compressors. These compressor engines range in size from 1,000 hp up to 5,000 hp, with 70% of them in the 1,000-1,800 hp range. The new rule will establish limits on these engines for emissions of nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs), but the rule is mainly focused on NOx emissions. The standards will apply to all new engines installed after the adopted rule date (currently proposed to be November 2020), and the requirements will be phased in for existing engines over a four-year period from 2022-2026.

The regulation will specify emissions standards for new and existing engines of three types. (See **Table 2** below) To achieve compliance, gas producers could meet the standards for each individual engine, or they could achieve the required overall level of emissions (per horse-power-hour) for their fleet of engines through submitting an "alternative company-wide plan." Companies that

[9] David Garcia, Business Development, Solar Turbines, personal communication (6/9/20), Garcia_David_E@solarturbines.com.

chose this option must submit a plan to CDPHE by May of 2021 to show compliance. The alternative plan may involve combining these elements: a) converting some existing engines to electric motor-drives, b) installing control technology, such as three-way catalytic reduction, on some existing engines, c) allowing some engines to continue to operate un-modified until they need to be replaced, and d) purchasing low-emitting new engines or electric drives for new compressors.

Table 2. Proposed Natural Gas Engine Emission Limits

Engine Type	NOx Emission Limit (g NOx/hp-hr)	CO Emission Limit (g CO/hp-hr)	VOC Emission Limit (g VOC/hp-hr)
2-Stroke Lean-burn	3.0	2.0	0.7
4-Stroke Lean-burn (new)	0.7	2.0	0.7
4-Stroke Lean-burn (existing)	1.2	2.0	0.7
4-Stroke Rich-burn (new)	0.5	2.0	0.7
4-Stroke Rich-burn (existing)	0.8	2.0	0.7

The flexibility to submit an alternative plan will encourage gas producers to explore opportunities for electrifying many of their existing and new compressors in lieu of relying on natural gas engines. Colorado electric utilities should take advantage of this opportunity to work with their oil and gas customers to get more sites with large compressor engines connected to their electricity service.

If a site with compressors can be connected to electric power at a reasonable cost, there are several advantages of choosing electric drives compared to gas engine-drives.

- The installed cost of a new electric drive for a reciprocating natural gas compressor is about 50-60% less than the cost of an equivalent natural gas engine-drive. For example, a 1,500 hp electric drive will cost about $200,000 to install, compared to ~$500,000 for a similar size natural gas engine drive.[10]
- For an existing compressor, replacing a lean-burn natural gas engine (2- or 4-stroke) with an electric motor drive will often be cheaper than installing the necessary emission controls.[11] According to CDPHE data, there are 149 lean-burn natural gas engines that will require emission controls or need to be replaced in order to comply with the new proposed standard. (For rich-burn gas engines, this is not the case; the needed emission controls will generally be much cheaper than the cost of a new electric drive. For example, adding catalytic reduction to a rich-burn engine costs about $20,000-40,000.[12])
- Gas engines require maintenance about every 5,000 hours of operation, which is costly and results in added down-time. Electric motor drives require very little maintenance. The

[10] Bob Keller, Sales Representative, Caterpillar, personal communication (6/24/20), Cat4power@msn.com; and Andy Kaiser, Sales Representative, ABB, personal communication (6/24/20).

[11] CDPHE estimates annualized costs of about $400,000 per engine to retrofit the large lean-burn engines that exceed the NOx limits. See "Initial Economic Impact Analysis – Regulation 7," CDPHE, June 2020, https://drive.google.com/drive/folders/12Q6l41WlMfWreRqWwBaDwL77WZ89mDT8.

[12] Based on estimates from Caterpillar (see footnote 11); and "Initial Economic Impact Analysis – Regulation 7," CDPHE, June 2020.

reduced annual maintenance costs and higher annual availability for the electric drive will more than offset the slight increase in annual fuel/electricity costs.[13]

In addition to the economic benefits, electric drives also significantly reduce greenhouse gas emissions. **Table 3** below shows the greenhouse gas (GHG) emission benefits of converting natural gas engines to electric drives. If we assume that 200 large engines with an average size of 1500 hp will be replaced with electric drives between now and 2030,[14] this would achieve a reduction in emissions in 2030 of 220,000 metric tons CO_2e/yr**.** This would also result in an increase in electricity consumption of 1,300,000 MWh/yr.

Table 3: Emission Reductions from Converting Gas Engines to Electric Drives

Technology	Size (hp)	Avg load factor	Annual hours of operation	Annual energy consumption (MMBtu for gas, MWh for electric)[15]	Annual GHG emissions (metric tons CO2e/yr)[16]	Percentage reduction in GHG emissions
Gas engine	1500	70%	8,000	61,100	4,210	---
Electric motor drive	---	---	---	6,520	2,307	---
GHG emission reductions for electric drive	---	---	---	---	**1,903**	**45.2%**

V. SUCCESSFUL UTILITY ENERGY EFFICIENCY PROGRAMS

Generally, oil and gas customers are focused on their production operations and not very concerned about anything that may interrupt those operations, even to save money/reduce energy costs. However, by offering strong energy efficiency programs and being proactive in reaching out

[13] Bob Keller, Sales Representative, Caterpillar, personal communication (6/24/20), Cat4power@msn.com; and David Garcia, Business Development, Solar Turbines, personal communication (6/9/20), Garcia_David_E@solarturbines.com.

[14] We assume that 100 of the 149 lean-burn engines requiring upgrades may be replaced with electric drives. In addition to these, we assume 100 other large engines will be replaced with electric drives at the end of the engine's useful life, between now and 2030.

[15] Energy consumption for the gas engine was calculated assuming an average engine efficiency of 35%; and for the electric motor drive, assuming an efficiency of 96%. These efficiency estimates are from Caterpillar specification sheets.

[16] For the gas engine, we used an emission factor of 117 lb CO2/MMBtu for natural gas combustion, and a methane emission factor of 1.25 lb methane/MMBtu, from EPA, AP-42. For electricity, we used the average annual projected emission factors for Colorado from NREL, for 2022-2032. The average emission factor for this period is 780.2 lb CO2e/MWh. For the source of the NREL emission factors, see https://scenarioviewer.nrel.gov/, and for derivation of these emission factors, see https://www.nrel.gov/docs/fy21osti/78239.pdf.

to oil and gas producers, it is possible to achieve significant energy savings and improved customer satisfaction.

Some electric utilities offer effective programs that achieve significant energy savings, while helping oil and gas customers reduce their operating costs and environmental footprint. The most effective utility programs adopt the following elements to better serve this sector:[17]

- use a contractor with engineers on staff with oil and gas expertise;
- offer technical assistance and incentives, and make the programs user-friendly;
- get to the right people within the company; and
- engage with the customer's key people consistently.

Another factor for success that is beyond the utility's control, but helpful to be aware of, is the price of oil and gas. If the commodity price is in the right range - not too high (in which case customers are more focused about increasing output), and not too low (in which case they want to minimize any additional investments, even to save money); then these customers will be much more likely to engage with utility energy efficiency programs. (Note that currently oil and gas prices are very low due to the corona virus and economic recession.)

Choose a contractor with oil and gas expertise

To earn the respect of oil and gas customers, contractors need to have expertise with this industry and be able to speak its language. Oil and gas customers are very skeptical of making changes to their processes; any suggestions that threaten production or reliability will likely not be adopted.

It is helpful to start by asking a lot of questions about the customers' operations in order to target discussions and help shape recommendations. It is also helpful to attend budget meetings as well as facility meetings if possible. At the same time, contractors should try to limit their impact on the customer's staff in the field.

Offer a variety of user-friendly incentive programs

Having good incentive offerings that are easy to understand and user-friendly is also very important. For example, PG&E provides incentives for the following types of measures:

- pump-off controllers;
- VSDs;
- high efficiency pumping system conversions;
- process optimization;
- pipeline upsizing and optimization;
- water or gas shutoff measures; and
- optimized sizing of motors, pumps, and compressors.

[17] Most of the ideas and best practices in this section are from a presentation by EnerNOC (now part of CLEAResult) at a webinar led by SWEEP in October 2014.

PG&E's incentives are $.08/kWh of savings, and $150/kW of peak savings, up to 50% of measure cost for retrofits, and up to 100% of incremental cost for new measures.[18] In addition to prescriptive and custom incentives, Rocky Mountain Power (RMP) offers an "industrial tune-up program" to oil and gas customers in Utah and Wyoming. The program helps identify low-cost measures such as better sequencing and controls for pumps or compressors, and offers an incentive of $0.02/kWh of energy saved (for the first year in which the measure is implemented).[19] For example, one customer was producing natural gas from a coalbed methane field, which was in decline. The customer had six large electric compressors running, but two of them were running at low capacity. RMP's contractor assisted the customer in shutting one compressor down completely, re-directing the flow to the remaining compressors. The customer achieved large electricity and cost savings, and in addition received RMP's industrial tune-up incentive. RMP would not have been able to support this type of measure under its custom or prescriptive incentive programs.[20]

Xcel Energy in Colorado offers prescriptive and custom incentives for efficient pumps, VSDs, and better controls. Xcel also offers a strategic energy management (SEM) program, which includes help identifying pumping or compressor system optimization measures as described above. Some Tri-State member co-ops offer incentives for VSDs on pumps or compressors.

It is also helpful to be precise when requesting data; in other words, try to understand how that data is collected, such as through SCADA, other data logs, or through operators. An understanding of which types of data are available will help shape measurement and verification efforts.

Get to the right people

Typically, the operators and engineers in the field are not the ones within the customer's company that make decisions about potential upgrades/retrofits to production operations. The decision-makers are more likely to be at the company's main office, which is often out of state, e.g., in Houston. So, it is important to identify and contact these key people, and to then discuss the utility's program offerings with them and how the programs can help the customer save money without interrupting operations.

Persistence

With some level of support from the managers at the customer's main office, then the utility/contractor can contact the customer's key people in the field. To be successful in this regard may require methods such as organizing "lunch and learn" sessions, as well as frequent phone calls and emails.

PG&E's contractor for its oil and gas energy efficiency program, CLEAResult,[21] found that it was necessary to have "boots on the ground," in other words, to have direct contact with the customers'

---

[18] "Energy Efficiency Services Program for Oil and Gas Producers," PG&E, https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/partnersandtradepros/eeis/search/3P_fs_EESPOilGas.pdf

[19] "Industrial Tune-up," Rocky Mountain Power, https://www.rockymountainpower.net/savings-energy-choices/business/energy-management.html

[20] Bret Carlson, Energy Resources Integration (ERI), personal communication, October 2018, bret@eripacific.com.

[21] PG&E's contractor at the time SWEEP interviewed them about their program was EnerNOC, which was later acquired by CLEAResult.

staff in the field, in order to develop relationships. In addition, CLEAResult found it helpful to build trust with newer program participants by starting with smaller, easy to adopt energy efficiency recommendations. CLEAResult also works to find and develop a company champion, who becomes the focal point for required data and signatures for incentive project pre-approvals.

Case study – CLEAResult/Xcel Energy in New Mexico

CLEAResult is Xcel Energy's contractor in New Mexico, in charge of implementing its efficiency programs serving oil and gas customers. There has been a large build-up of oil and gas production in New Mexico in the past three years or so, and Xcel Energy/CLEAResult achieved a combined total of 13.7 GWh of savings for 2018 and 2019 from oil and gas customers.

By far the most common measures implemented through Xcel Energy's programs were variable speed drives on pumps for new production sites. VSDs are a prescriptive measure on pumps smaller than 200 hp, and CLEAResult likes to start with these, getting the customer its rebate checks as soon as possible. Then CLEAResult will begin to investigate opportunities with VSDs on pumps larger than 200 hp (up to 450 hp), which generally require custom incentive evaluations. CLEAResult works with Xcel Energy staff to reduce the time required for these custom evaluations. Next, if the customer is willing to go further, then CLEAResult will help identify further opportunities for process optimization, such as through more advanced controls on pumps and other processes. Most of the projects and energy saving have come from new facilities, where it is much easier and more cost-effective to install new equipment such as VSDs on pumps without any disruptions to production. However, CLEAResult has also had successes with retrofit projects, especially with some of the larger oil and gas producers or those with energy managers.[22]

VI. SUMMARY AND RECOMMENDATIONS

Oil and gas customers can reduce their operating costs through taking advantage of energy efficiency practices in their production and mid-stream processing operations. For production sites that are not grid-connected, especially those with natural gas engines larger than 1,000 hp, electric utilities should work with their customers to see if it is feasible to provide electricity service to these sites. Providing service to these customers will provide them the option to convert their large gas engines used for compressor drives to electric drives. Access to electricity will also make it easier for oil and gas customers to install electric or compressed air-driven control devices and pumps to replace their gas pneumatic devices.

For sites that are grid-connected, there are many potential opportunities to reduce energy consumption and save money. The best time to implement these practices is at the time of constructing a new production operation; however, there are opportunities for retrofits as well. Cost-effective energy efficiency practices include efficient pumps, variable speed drives, controls, and process optimization of pumping and compressor systems. There are also opportunities for more efficient types of artificial lift.

Electric utilities can achieve significant electricity savings and improve customer satisfaction through adopting the following best practices, to help oil and gas customers increase their energy productivity and reduce operating costs:

[22] John Steinhoff, CLEAResult Project Manager, Solutions Team, personal communication, January 7, 2020, jsteinhoff@CLEAResult.com.

- offer technical assistance through a contractor with strong oil and gas expertise;
- offer prescriptive and custom incentives, and make the process of obtaining the incentives as user-friendly as possible;
- in addition to equipment upgrades, offer assistance with better controls, process optimization, improved operating and maintenance practices, and other low-cost measures; and
- be proactive and persistent in contacting the oil and gas customers.