Energy Efficiency and Electrification
Best Practices for Oil and Gas Production

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Energy Efficiency and Electrification Best Practices for Oil and Gas Production

Authored by Neil Kolwey

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Acknowledgements

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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
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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 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 by installing electric rather than gas pneumatic-driven devices and electric rather than natural gas-driven compressors.

For production sites and natural gas compressor stations that are grid-connected, there are also opportunities to reduce energy consumption by 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. 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

<table>
<thead>
<tr>
<th>County</th>
<th>Total natural gas production in 2018 (mcf)</th>
<th>Total oil production in 2018 (bbl)</th>
<th>Number of permitted wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>WELD</td>
<td>799,447,344</td>
<td>154,969,228</td>
<td>3321</td>
</tr>
<tr>
<td>GARFIELD</td>
<td>495,033,611</td>
<td>1,459,041</td>
<td>686</td>
</tr>
<tr>
<td>LA PLATA</td>
<td>295,078,977</td>
<td>16,266</td>
<td>34</td>
</tr>
<tr>
<td>RIO BLANCO</td>
<td>51,267,348</td>
<td>3,770,077</td>
<td>129</td>
</tr>
<tr>
<td>ADAMS</td>
<td>7,567,328</td>
<td>3,478,827</td>
<td>310</td>
</tr>
<tr>
<td>MESA</td>
<td>61,683,821</td>
<td>164,889</td>
<td>41</td>
</tr>
<tr>
<td>LAS ANIMAS</td>
<td>57,307,735</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>ARAPAHOE</td>
<td>4,762,348</td>
<td>2,320,015</td>
<td>87</td>
</tr>
<tr>
<td>LARIMER</td>
<td>10,734,961</td>
<td>3,753,237</td>
<td>20</td>
</tr>
<tr>
<td>ARCHULETA</td>
<td>16,310,608</td>
<td>2,005</td>
<td>23</td>
</tr>
<tr>
<td>Total for top 10</td>
<td>1,799,194,081</td>
<td>169,933,585</td>
<td>4,631</td>
</tr>
</tbody>
</table>

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 percent 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 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. 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 percent of compressors are natural gas-driven.²

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

² “Electrifying Natural Gas: Opportunities for Beneficial Electrification and Load Flexibility in Natural Gas Pipeline Compressor Stations,” Xergy Consulting, May 2018, Link to cooperative.com PDF report file. Note that gas-driven compressors use either reciprocating engines or gas turbines.

³ Deborah Topacio, Manager-Utility Programs, EnerNOC, personal communication, September 2014, dotopacio@enernoc.com; “Energy Efficiency Services Program for Oil and Gas Producers,” PG&E, https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/partnersandtradePROs/ees/search/3p_fs_EESPOilGas.pdf
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 customer’s annual energy consumption by 170,000 kWh, and the net payback period per well (after including the rebate) ranged from one year to 4.5 years.⁴

Variable speed drives

This technology is used in 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, which means 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, because for most wells the pressure from the oil itself is inadequate. Pressure can be increased in various ways, some of which are 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 through better monitoring and automation. VSDs installed on blowers for steam injection can also save a lot of energy.⁶

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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
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, more can be done to optimize and sequence pump flows using enhanced controls. For compressors, there are similar opportunities to optimize the varying flow rates of gas. (See Encana compressor station case study below.)

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 percent. At another large compressor station equipped with electric compressors, Encana modified 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. The operators are then able to quickly respond to the blow-by occurrences.\(^7\)

IV. ELECTRIFICATION BEST PRACTICES

As described above, most production sites in Colorado are currently not connected to the electricity grid. 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 by selling more power to oil and gas producers. 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 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 percent of all methane emissions from the production, mid-stream processing, and gas pipeline segments of the oil and gas industry.\(^8\)

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\(^7\) Justin Lisowski, Rotating Equipment Engineer, Encana, personal communication, October 2012.

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:

- Pneumatic controllers powered by compressed air rather than natural gas;
- Electric controllers; and
- 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 and avoid potentially expensive retrofits, oil and gas operators may want to consider installing zero-emission controllers and pumps at all new production facilities (even those not grid-connected).

**Electric compressors**

By far the largest electrification opportunity, in terms of potential energy savings and greenhouse gas (GHG) emission reductions, 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 percent of compressors used to drive natural gas through pipelines are gas-fired, either reciprocating engines or gas turbines, and the other 10 percent are electric. The larger compressors used in the pipeline/transmission segment (with a typical size of 30,000 hp or 22 MW) tend to be gas turbine-driven, and the smaller compressors used in the mid-stream segment (with a typical size of 2,000 hp or 1.5 MW) are normally gas reciprocating engine-driven.⁹

Electric-driven natural gas compressors are more energy-efficient and generate less methane emissions than natural gas-fired engine or turbine compressors. The main benefit to the customer in choosing electric vs. gas engine or gas turbine-driven compressors would be the reduced compliance burden associated with air pollution regulations, including avoiding the need for an air permit. As a percentage of gas transported, methane emissions are much higher for gas engines than for gas turbines. For electric compressors compared to gas turbine-driven compressors, methane emissions are roughly equivalent. In addition, CO₂ emissions are much lower for electric vs. either gas engine- or gas turbine-driven compressors.

However, electric compressors have a much higher initial cost than gas-driven compressors. The incremental cost increase for an electric compressor vs. a gas turbine is about 30 percent, and for electric vs. gas engine compressor is about 75 percent. For both types of gas-driven compressors, the electric compressor would reduce annual inspection and maintenance costs by about 90 percent.

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⁹ Katherine Dayem, Principal, Xergy Consulting, personal communication (2/7/20), katherine@xergyconsulting.com
Because the wholesale price of natural gas is currently very low, the annual fuel costs for electric compressors are generally higher, and the higher fuel costs generally result in higher total annual operating costs for the electric compressor.10

It is possible that CDPHE will require new compressors to be electric if they can feasibly be grid-connected. In the meantime, electric utilities may want to consider providing more incentives for new electric compressors. To be effective, these incentives would have to be substantial, such as one-third or more of the incremental cost difference for the new compressor.11 (More details on the economics of electric vs. gas engine-driven compressors are provided in Appendix A.)

V. SUCCESSFUL UTILITY ENERGY EFFICIENCY PROGRAMS

Oil and gas customers can be challenging for utility programs to work with. Generally, these customers are very focused on their production operations and are very resistant to process interruptions, even to significantly reduce energy costs.

However, by offering strong energy efficiency programs and being proactive in reaching out to oil and gas producers, some utilities have been successful with these customers, achieving significant energy savings and customer satisfaction. The most effective utility programs adopt the following elements to better serve this sector:12

- Use a contractor with with oil and gas expertise;
- Offer technical assistance and incentives, and make the programs user-friendly;
- Talk to decision-makers within the company; and
- Engage with the customer’s key staff 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 interested in 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 skeptical of making changes to their processes; any suggestions that threaten production or reliability will likely not be adopted.

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10 Katherine Dayem, Principal, Xergy Consulting, personal communication (2/7/20), katherine@xergyconsulting.com
11 Katherine Dayem, Principal, Xergy Consulting, personal communication (2/7/20), katherine@xergyconsulting.com
12 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.
It is helpful to start by asking questions about the customers’ operations in order to target discussions and customize recommendations. Attending budget and facility meetings is also helpful when possible. At the same time, contractors should limit their impact on the customer’s field staff.

**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.

PG&E’s incentives are $.08/kWh of savings, and $150/kW of peak savings, up to 50 percent of measure cost for retrofits, and up to 100 percent of incremental cost for new measures.\(^{13}\)

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).\(^{14}\) 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 and 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.\(^{15}\)

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.

\(^{13}\) “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](https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/partnersandtradePros/eeis/search/3P_fs_EESPOilGas.pdf)

\(^{14}\) “Industrial Tune-up,” Rocky Mountain Power, [https://www.rockymountainpower.net/savings-energy-choices/business/energy-management.html](https://www.rockymountainpower.net/savings-energy-choices/business/energy-management.html)

\(^{15}\) Bret Carlson, Energy Resources Integration (ERI), personal communication, October 2018, [bret@eripacific.com](mailto:bret@eripacific.com)
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. Contacting decision-makers is important. Discuss the utility’s program offerings with them and how the programs can help the customer save money without interrupting operations.

Be persistent

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,\(^{16}\) found that it was necessary to have “boots on the ground,” in other words, to have direct contact with the customers’ 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 getting required data and signatures for incentive project pre-approvals.

Case study – CLEAResult/Xcel Energy in New Mexico

CLEAResult is Xcel Energy’s New Mexico contractor in charge of implementing efficiency programs serving oil and gas customers. Because of the large build-up of oil and gas production in New Mexico over the past few years, and Xcel Energy/CLEAResult were able to achieve 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 are variable speed drives on pumps at new production sites. VSDs are a prescriptive measure for pumps smaller than 200 hp, and CLEAResult prefers to start with these, in order to get the customer rebate checks as soon as possible. Then CLEAResult will 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. If the customer is willing to go further, then CLEAResult will help identify additional opportunities for process optimization, such as more advanced controls on pumps and other processes. Most of the projects and energy savings 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.\(^{17}\)

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\(^{16}\) PG&E’s contractor at the time SWEEP interviewed them about their program was EnerNOC, which was later acquired by CLEAResult.

\(^{17}\) John Steinhoff, CLEAResult Project Manager, Solutions Team, personal communication, January 7, 2020, jsteinhoff@CLEAResult.com
VI. SUMMARY AND RECOMMENDATIONS

Oil and gas customers can reduce their operating costs by taking advantage of energy efficiency practices in production and mid-stream processing operations. For production sites that are not grid-connected, the first step is to work with the local electricity provider to see if connecting is feasible. This will help reduce fuel and maintenance costs and help ease compliance with state air pollution regulations.

For sites that are already 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 by adopting the following best practices to help oil and gas customers increase their energy productivity and reduce operating costs:

- Offer technical assistance from 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, provide assistance with better controls, process optimization, improved operating and maintenance practices, and other low-cost measures; and
- Be proactive and persistent in contacting oil and gas customers.

Finally, beyond connecting to grid electricity, there are several opportunities for electrification in oil and gas production. Oil and gas producers should consider installing electric or compressed air-driven control devices and pumps, rather than gas pneumatic devices, at all new production sites, even those that are not grid-connected (and therefore not currently required to do so). Natural gas producers should consider installing electric rather than gas-driven compressors, to avoid new air permits or other air pollution compliance obligations. Utilities should consider offering substantial incentives to help persuade customers to choose electric compressors.
VII. APPENDIX A – EVALUATION OF ELECTRIC COMPRESSORS

Table A-1 summarizes our analysis of the cost-effectiveness of choosing new electric vs. natural gas engine compressors. Most of the data comes from an analysis done by the EPA Natural Gas Star program,\(^\text{18}\) which we modified slightly. The EPA analysis was for a retrofit scenario - replacing four gas engine compressors with a total capacity of 15,600 hp with four new electric compressors with a total capacity of 7000 hp. The notes explain any modifications to EPA’s data (and new data added).

Table A-1. Cost-Effectiveness of Electric vs. Gas Engine Compressors

<table>
<thead>
<tr>
<th>Incremental cost for new electric vs. gas compressors (§)(^\text{19})</th>
<th>$4,537,500</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity consumption for electric compressor (MWh/yr)</td>
<td>90,667</td>
</tr>
<tr>
<td>Electricity cost (§/yr)(^\text{20})</td>
<td>$5,712,000</td>
</tr>
<tr>
<td>Fuel consumption for gas compressor (mcf/yr)(^\text{21})</td>
<td>1,700,000</td>
</tr>
<tr>
<td>Natural gas fuel costs (§/yr) assuming $3/mcf</td>
<td>$5,100,000</td>
</tr>
<tr>
<td>CO(_2) emission reductions for electric vs. gas (lb/yr)(^\text{22})</td>
<td>79,571,333</td>
</tr>
<tr>
<td>Value of CO(_2) emission reductions for electric vs. gas (§/yr) (at $46/ton CO(_2))</td>
<td>$1,830,141</td>
</tr>
<tr>
<td>Methane emissions for gas compressor (mcf/yr)</td>
<td>32,800</td>
</tr>
<tr>
<td>Value of methane emission reductions for electric vs. gas (§/yr) (at $46/ton CO(_2)e or $1288/ton methane)</td>
<td>$1,077,283</td>
</tr>
<tr>
<td>Maintenance cost savings for electric compressor (§/yr)(^\text{23})</td>
<td>$600,000</td>
</tr>
<tr>
<td>Estimated payback period (yr) with $3/mcf gas price</td>
<td>1.6</td>
</tr>
<tr>
<td>Estimated payback period (yr) with $2/mcf gas price</td>
<td>3.8</td>
</tr>
<tr>
<td>Payback period with $3/mcf gas, without GHG emissions price</td>
<td>does not pay back</td>
</tr>
</tbody>
</table>


\(^{19}\) The incremental cost for electric vs. gas engine compressor is about 75% of the total cost of a new electric compressor, from Katherine Dayem, Xergy Consulting. In EPA’s analysis, the engines were replaced before the end of their useful life, so we assumed the incremental cost to be 75% of EPA’s estimated initial cost.

\(^{20}\) We modified the electricity cost by using a price of $63/MWh, the average industrial retail price in Colorado from EIA, rather than $75/MWh, the value EPA used.

\(^{21}\) The energy savings in this analysis is close to what we found in the Encana case study mentioned above. The two comparisons show that electric compressors reduce primary energy consumption by 44-56%.

\(^{22}\) We calculated CO\(_2\) emissions for electricity using the most current average electricity emission factor from EPA’s eGRID data (for the CO/Rocky mountain eGRID subregion), and the standard emission factor for natural gas.

\(^{23}\) Annual maintenance cost savings are about 10% of the initial capital cost for the electric compressors, according to both EPA and Katherine Dayem, Xergy Consulting.
The analysis shows that at a wholesale natural gas price of $3 per mcf, electric compressors will not be cost effective based on capital, operating and fuel costs alone. But if the greenhouse gas emissions (CO₂ and methane) are valued using a social cost of $46 per short ton of CO₂e,²⁴ then the electric compressors are cost effective with less than a two-year payback on the incremental first cost. Even at a lower wholesale natural gas cost such as around $2 per mcf (the current market price), electric compressors are still cost-effective, with a 3.8-year payback.

²⁴ $46/short ton of CO₂ is now the legislatively mandated social cost of carbon for use in electric resource planning in Colorado, and this price could also be used by CDPHE in its rulemakings.