ABSTRACT

Natural gas has proven to be cleaner burning and more flexible than other fuels. The unconventional gas revolution has enabled a transformation of the energy mix of the United States. The revolution has begun to spread to other parts of the world. But each new gas supply brings challenges for treating, gas quality standards, and gas distribution infrastructure. This is particularly true of shale gas as composition is likely to vary significantly from one development area to another. Operators need solutions that provide assurance they can monetize their resources. Governments, stakeholders and end-users are looking for assurance that the compositional changes will not have an adverse impact on their gas delivery infrastructure and on their customers’ end-use applications. This presentation will provide a brief primer on unconventional gas, review the innovations below ground and above ground that have enabled this revolution, highlight the challenges specific to shale gas processing, and explore how a diversified portfolio of flexible solutions can be tailored to handle the variability of shale gas composition.
AN UNCONVENTIONAL GAS PRIMER AND IMPLICATIONS FOR GAS PROCESSING

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Introduction

Natural gas has proven to be cleaner burning and more flexible than other fuels. The unconventional gas revolution has enabled a transformation of the energy mix of the United States. The revolution has begun to spread to other parts of the world; however, each new gas supply brings challenges for treating, gas quality standards, and gas distribution infrastructure. This is particularly true of shale gas as composition is likely to vary significantly from one development area to another. Operators need solutions that provide assurance they can monetize their resources. Governments, stakeholders and end-users are looking for assurance that the compositional changes will not have an adverse impact on their gas delivery infrastructure and on their customers’ end-use applications. This paper provides a brief primer on unconventional gas, reviews key innovations below ground and above ground that have enabled this revolution, highlights challenges specific to shale gas processing, and explores how a diversified portfolio of flexible solutions can be tailored to handle the variability of shale gas composition.

Unconventional Gas Primer

Unconventional gas development contributes to the supply of affordable and secure energy from the world’s cleanest burning fossil fuel. This versatile fuel provides an efficient source of power, affordable transportation in terms of natural gas vehicles, and efficient and affordable gas for end users. The environmental benefits of utilizing natural gas are clear and include generating 99% less mercury and sulfur dioxide and 82% less nitrous oxides than burning coal in a pulverized coal power plant. A natural gas power plant generates 50 to 60% less greenhouse gas than coal and natural gas produces 30% less greenhouse gas emissions than liquid fuels as a transportation fuel.1

The term unconventional gas usually refers to the combination of shale gas, tight sand gas, and coalbed methane (CBM). Some also include methane hydrates as an unconventional resource, but hydrates will not be addressed in this paper. The gas molecules are no different from conventional gas. What’s unconventional are the technologies utilized to produce the gas. Unconventional gas is easier to find than rich deposits of conventional gas as shale rock is very common and often contains hydrocarbon that started as organic material lain down with silt at the bottom of lakes and seas over a period of millions of years. In fact, the shale rock has been the source rock for conventional resources that have been produced for over a century. As the shale rock became buried deeper over millennia, the organic material began to degrade to a

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mixture of high molecular weight compounds called kerogen in an environment of increasing temperature and pressure in the presence of little to no oxygen. With additional “cooking”, the chemical bonds of the kerogen began to further break down to release oil that remained bound in the rock as shale oil. The oil further transformed to natural gas liquids and then natural gas with additional time to form shale gas. The more mature shale gas is almost pure methane and referred to as “dry” gas. Shale gas containing significant quantities of NGLs is referred to as “wet” gas. Even more mature shale gas can be found to have significant quantities of carbon dioxide. Where the organic material and sediment did not get buried deep enough to generate sufficient temperatures to drive these reactions, the result is oil shale deposits.

Some of the gas produced is held in natural fractures, some in pore spaces, and some adsorbed onto the originally buried organic material. The gas molecules are tightly bound in the sedimentary rock and do not flow readily. Over millennia, some gas has moved closer to the surface a little at a time and migrated to seal rock where it concentrated and has often been produced as conventional gas. Similar migration of oil from shale oil has led to concentrations of conventional oil resources. The shale gas itself needs help to increase permeability and generate high enough production levels to generate sufficient economic returns. Hydraulic fracturing, a technique deployed since 1949, was adapted by entrepreneurs like George Mitchell for dense shale formations. The gas in the fractures is produced immediately; the gas adsorbed onto organic material is released as the formation pressure is drawn down by the well. The gas-rich shale layer is typically several hundred meters thick. To further enhance production, horizontal drilling techniques have been applied. Whereas a vertical well might just expose a few hundred meters of shale, a horizontal well drilled carefully through the shale gas layer can expose a mile or more of resource from the same well. See Figure 1.

Tight sand gas differs from shale gas but shares some of the same challenges in yielding economic production rates. Whereas the gas molecules are trapped in the pores of the sedimentary rock in the case of shale gas, the molecules are trapped in a tight matrix of sand particles under intense pressure in the case of tight sand gas. This pressure results from the tight gas being buried at similar and often deeper distances compared to shale gas. The same hydraulic fracturing processes can be deployed to loosen this matrix and enable the gas to flow more readily to the surface.

Coalbed methane has less in common with shale gas. It is classified as an unconventional gas because it also requires the use of technologies that were not conventional when they were developed. Instead of the methane being found in void spaces as a free gas between sand grains or being bound up in rock pores, the methane is adsorbed in micropores on the solid surface of the coal. There is some free gas in the natural fractures of the coal, but most is adsorbed in the micropores. This storage mechanism is efficient and a good coalbed can hold two to three times more gas in a given volume than a similar sized sandstone reservoir. But the gas is locked in

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place by the high pressure in the matrix of the coal and conventional technologies were found lacking in producing gas at commercial rates.

Commercial production of coalbed methane at significant volumes occurred earlier than for other unconventional resources. The first tapping of coalbed methane actually was motivated to increase the safety of coal mining rather than to generate commercial returns. Mining hazards were initially reduced by venting the methane with large fans. The volume vented grew to as large as 250-300 MMSCFD by 1990. Wells drilled into coalbeds in Kansas before 1930 had produced some methane inadvertently, but it would be decades more before technologies had advanced sufficiently to enable commercial production. In 1954, Halliburton fractured the first coalbed methane well. In 1978, research began to further study the response of coalseams to fracturing. This research was successful and 1.5 BCFD of CBM was being produced from 5500 wells by 1992. CBM production currently makes up over 10% of U.S. gas production. The key to CBM development was to recognize that a huge volume of water had to be produced from a coalseam to reduce pressure sufficiently for the methane to be desorbed early in the production life of a well. The large water volumes in the first year or two of production then decrease to smaller volumes over the life of the well as gas production volume continues to rise. Once desorbed, the gas can find its way through natural fractures in the coal acting as conduits. However, coal usually has low permeability and hydraulic fracturing is often utilized to enhance production to commercial rates by adding more routes to the wellbore. Deep coals have even lower permeability due to increased pressure and these coals will often not produce at commercial rates even with the help of hydraulic fracturing. Maintaining coalseam integrity to support production over time is also challenging with deeper and more highly stressed coals. As a result, CBM development is typically focused on shallower resources than tight gas or shale gas. Since ethane and heavier hydrocarbons are more strongly adsorbed than methane, produced CBM usually has higher methane content than other natural gas. CBM is also typically low in CO2 with the exception of some CBM that is thought to have had CO2 produced from biogenic sources as a result of meteoric waters containing bacteria entering into the coalbed. Most high quality CBM can be directly input into natural gas pipelines without the need for significant processing.

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In comparison to conventional resources, unconventional natural gas requires different strategies for effective resource development. For conventional gas, the operator will drill a few wells and extract significant (20-100+ MMSCFD) volume rates of gas. Although the operator is challenged to find the traps where the resource has accumulated over time, conventional drilling and production technologies are effective in generating the required economic returns. The risks are posed upfront with the decision of where to place the few wells. For unconventional gas, the operator must drill many times with each well producing limited gas volumes. A typical shale or tight sand gas well might yield 3-5 MMSCFD with a CBM well generating 1 MMSCFD. Drilling must be typically followed by other technologies that were initially novel. The variability of the rock or coalbed also plays an important role as the unconventional technologies have to be adapted from one resource to another. The risks are distributed over time as drilling will take place over a long period with many wells and the quality of the resource can vary significantly even between wells placed just a few miles apart. Conventional and unconventional gas compositions vary widely, but unconventional shale gas adds complexity in that the composition can vary widely even within a basin and between wells located only a few miles apart as a result of the gas being locked in place and exposed to different conditions over geologic time. This adds more risk in that the surface gas processing strategy put in place initially might prove to be inadequate over time if wetter gas or gas with more impurities is added to the mix. Unconventional resource development is also perceived as introducing
additional environmental risk due to the amount of fresh water required to support hydraulic fracturing, the possibility of introducing fracturing fluid into freshwater aquifers, and the potential of increased methane emissions during well completion and production. Of course, fracturing is not a new process as it has now been used for over 2 million wells utilizing billions of gallons of fluid over a 60 year period. The vast majority of applications are performed without incident. As with the development of any energy resource, the potential for environmental impact exists and best practices must be deployed to insure that the environmental benefit of natural gas relative to other fossil fuels is not offset by the impact of production.

The Shale Revolution

The shale revolution started in the U.S. Some have estimated that shale gas could provide as much as half of the natural gas production in North America by 2020, amounting to over 14 tcf of natural gas per year and representing more than $70 billion of revenue at current market prices. It has been called a “revolution”, but the making of this revolution has a 20 year history. Few people had heard of unconventional gas just 7 years ago. But geologists and upstream experts have known about the gas contained in these resources for decades. The gas was known to be in the rock, but the knowledge and technology to recover the gas economically was not known. It took substantial investment in collaborative research and technology development for unconventional gas to become what some have called a “20 year overnight success”.

In the early 1980s, collaborative development of unconventional gas in the United States began with the help of research programs led by the Gas Technology Institute (then known as the Gas Research Institute) and supported by the U.S. Department of Energy. These collaborative research programs helped integrate the efforts of innovative entrepreneurs and made possible the scientific understanding, experimentation, and new technology development that unlocked the potential of America’s shale gas. What changed the game was a series of advances noted in Figure 2 beginning with the realization that one could economically create permeability in low permeability hydrocarbon bearing formations. Hydraulic fracturing, a 60 year old process of pumping a mixture of water, chemicals, and sand under high pressure into underground layers of rock, was the first step. George Mitchell, former head of Mitchell Energy and Development Corp, and known as the Father of the Shale Gas Revolution, is credited with the first economic extraction of gas from shale. In the early 1980s, Mitchell and his team started experimenting with hydraulic fracturing in low permeability shale. Their success in vertical wells proved that shale gas could be economically developed.

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5 Lewis, Guy, Perry, Kent and Smith, Trevor. “Unconventional Gas-A Chance for Poland and Europe?” Kosciuszko Institute July 2011: 34.
In 2000, Devon Energy Corporation acquired Mitchell Energy and combined hydraulic fracturing with horizontal drilling to make shale gas wells more productive. Horizontal drilling enables a single vertical well to turn horizontally and follow a seam of hydrocarbon bearing rock for long distances, thus increasing the contact area of the well with the formation. Devon’s success allowed the gas to flow in greater volumes and at a much lower unit cost than previously thought possible. As a result, the resource that could be ultimately recovered from gas shale wells (Estimated Ultimate Recovery, or EUR) grew from 0.7 BCF from a vertical well to 2-6 BCF for horizontal wells.\(^7\)

The high initial production from natural fractures typically declines rapidly after these fractures are depleted, yielding very steep production decline curves. Production from a typical well in the Barnett will decline from 2 MMSCFD to 1 MMSCFD in year 1 and to 0.5 MMSCFD in year 5. A Woodford well will decline from 3 MMSCFD to 1.3 MMSCFD in year 1 and to 0.7 MMSCFD in year 5.\(^8\) Fortunately, the high initial production rates are often sufficient to generate acceptable revenues in the first year to recover the upfront invested capital even with gas prices of $5 per MMBTU.

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Other technology developments including micro seismic imaging for measuring fracture performance and fracture modeling software were leveraged by the emerging independent resource developers to dramatically improve their production results. Today, these technologies are key components in the operations of all fracturing service companies. The key to enabling unconventional gas development has been and continues to be the bringing together of the right partners and technology based solutions to make unconventional resources productive.

Another development enabling the shale gas revolution has been the “fast gas” rapid NGL recovery model. As dry shale gas success grew, the rapid production increases outstripped demand for natural gas and dropped the price of natural gas. No longer was a productive dry gas well necessarily economical. Attention shifted to “wet gas” or shale gas that contained significant volumes of NGL’s (natural gas liquids) that command a market price tied to crude oil and higher than natural gas prices. However, the traditional model of stick-built NGL recovery plants taking 2 or more years to implement created a costly delay that formed a barrier to economical development of these vital resources. Just as with George Mitchell, an entrepreneur emerged with a solution. This entrepreneur was Tom Russell. He developed a model of providing pre-engineered factory built modular plants that enabled the delivery and installation of NGL recovery plants at least 6 months faster than the stick-built alternatives. In addition, the Russell approach did not require the operator to know exactly how rich their gas stream was upfront. Much of the plant fabrication could occur before the gas composition was known. For operators developing new resources, these new capabilities were critical.

Technological innovations are continuing today at a rapid rate. The development of individual wells is improving with longer laterals, more fracturing stages, and optimized pumping and fluid composition strategies. Well placement is enhanced with improved logging and core evaluation capabilities, completion design, and real-time micro-seismic fracture mapping to avoid geological hazards. These innovations continue to drive unit production costs down and reduce environmental impact and risks.

So today, the key to enabling unconventional resource development continues to be the bringing together of the right partners and technology-based solutions to make unconventional resources productive. No two unconventional gas plays have the same geological characteristics. Technology known to work effectively in one play may have to be adapted or re-invented to make another play productive and economical. The lessons learned and techniques developed must be transferred and leveraged in new plays.

**Shale Resource Processing Challenges**

New sources of gas are required to meet the increasing worldwide demand for economic and sustainable energy. These new sources include shale gas, tight gas, CBM, associated gas, biogas, SNG from coal gasification, and lower quality conventional gas. Some regions are also introducing LNG imports to supplement local production. The varying gas quality from each
source creates above-ground processing challenges. Often the gas resources are in remote regions challenged by limited water, infrastructure, and other logistical challenges requiring innovative processing solutions. New uses of gas are also being implemented in some regions. These factors increase the complexity of the gas value chain and put new demands on gas infrastructure to enable gas interchangeability as mercury, water, acid gases, inerts, and heavier hydrocarbons need to be addressed and the required product quality depends on whether the gas will be transported into a pipeline, converted to LNG, or used locally. There are now proven and emerging technologies to address all of these challenges and variables, but flexibility and agility is required to apply the right solution for each challenge.

![Increasing Gas Value Chain Complexity](image)

Figure 3

Treating technologies are selected at various points along the value chain based on feed composition and desired product specifications. Because geologic settings are uniquely different from one play to the next, it is essential that developers have a good understanding of the gas potential in terms of volume and composition as well as the desired product specifications leading to the development of an effective above-ground technology roadmap to complement the below-ground production strategy.
Shale gas is particularly notorious for variations in gas composition even within a field at distances only a few miles apart that impact interchangeability with other gas supplies and gas processing requirements. It is a daunting challenge to design a gas processing facility based on gas quality information from a couple initial wells while desiring flexibility to deal with the variation that might come as more wells are drilled in the same area. In addition, because of the lead times, operators often want to get into action on designing the gas processing plant that will be required before they have the detailed gas compositions from pilot wells. This uncertainty in future gas quality adds to the risks of any shale gas field development.
The expected gas composition is a critical factor in designing a gas processing facility, but there are many other decision criteria as well. Other upstream factors include the expected production profile of each well and the cumulative profile across multiple wells, produced gas pressure and flow rates, expected ambient conditions, fiscal requirements, environmental constraints, and factors specific to whether the development is onshore or offshore and what infrastructure might be already available. Downstream factors include what by-products are expected from processing, how each desired product will be handled, how critical uptime of the plant is, the expected level of consumption of energy, chemicals, and on-site labor, and how the disposal of wastes will affect air, water, and surface quality. Only after taking these upstream and downstream factors into account can an operator decide on midstream plant configuration and design choices. There is much to be learned from unconventional gas resource development that has already occurred. Based on this experience, decisions can be made on the proper technology within each midstream gas processing block accounting for interactions across the different processing blocks and adjusting the sequence of processing blocks for overall system optimization. Some examples of different design strategies follow for the cases of acid gas removal and hydrocarbon management.
Fortunate operators find that their gas is relatively clean. However, unconventional gas often is contaminated with “acid gas.” Carbon dioxide removal is required when the produced gas contains higher levels than the downstream pipeline will accept. In addition, when cryogenic operations are going to be used to recover NGL’s or generate LNG, CO2 concentrations above about 0.5 to 1.0% (depending on the richness of the gas) will cause CO2 freeze-out at the normal operating temperatures below -125 F. Y-Grade NGL specifications for cryogenic plant liquid product normally limits CO2 to 1000 ppmw. If H2S is present, it must also be removed to eliminate HSE risks and prevent corrosion of downstream equipment. The right technology for acid gas removal depends on the amount of acid gas in the feed and the desired contaminant level in the product. Membranes are a great choice for bulk removal. For shale gas containing CO2 and low amounts of H2S in remote locations, membranes can enable meeting pipeline specifications without dealing with solvents and complex plant operations. Chemical solvents such as amine units are often used in shale gas applications whether the product will go to a pipeline or to produce LNG. However, a physical solvent can make sense if the gas is “dry” and a mix of sulfur compounds are present and the gas is at high pressure as they then have advantages vs. chemical solvents. Adsorbents have a place when the intention is to get down to low contaminant levels in the finished product, potentially in combination with membranes for bulk removal to provide an integrated solution that does not require dealing with solvents.
In addition to removing contaminants, shale gas is often produced with natural gas liquids that bring higher value if they are recovered for petrochemical or other uses that exceed their BTU value if they are left in the natural gas stream. Depending on the inlet gas conditions (gas richness or Gallons per MSCF of gas (GPM), pressure, and temperature), the optimum liquid hydrocarbon recovery process will be selected. If the intent is only to recover heavier hydrocarbons (such as ahead of an LNG train where these components would freeze-out), a mixed adsorbent solution is best. For fairly rich gas with the intent to recover propane plus, mechanical refrigeration is a good choice. For lean or rich gas without interest in any ethane recovery and with smaller gas volumes, the JT process with mol sieve dehydration can be sufficient. A “supersonic separator” such as the Twister™ process will deliver higher recoveries albeit at a somewhat higher capital cost. For lean or rich gas and the intent to deliver high propane recovery or high ethane recovery and with medium to large gas volumes, the cryogenic process is usually the right solution. Choosing between open art and licensed technology is driven by the degree of ethane and propane recovery desired. A broad portfolio of hydrocarbon management solutions is required to fit the spectrum of hydrocarbon recovery objectives.
When it comes to developing wet shale gas resources, speed is of the essence. Without the right above-ground gas processing solution, project development is held up. Saving time in NGL recovery capability is usually very valuable. Modular solutions for NGL recovery are designed to have the operator up and running as much as 6 months faster and at lower cost than other options. An even better solution is when a modular solution can handle the widest possible range of natural gas compositions. Rapid recovery requires the entire project development process to be designed with speed in mind.
When delivered by an experienced solution provider, solutions for CO2 removal, dewpointing, and NGL recovery can be delivered as pre-fabricated, skid mounted modules that provide feed composition flexibility and rapid NGL recovery. This lowers fabrication cost, speeds installation, and provides high on-stream efficiency. Ideal candidates are packaged units sized for up to 200 MMSCFD of volume. Often these units are going to be placed in remote locations. Larger plants can be accommodated with multiple trains. In the diagram below, renderings of some typical individual skids provided by UOP are shown on the left. These skids are integrated in a factory setting before being shipped to the production site. This provides assurance that everything will flange up properly at the field site and insure a smooth start-up. When skid mounting a typical 200 MMSCFD plant, the required mol sieve vessels will be 2 meters in diameter. The demethanizer tower will be 1.8 meters diameter at the bottom and 30.5 meters tall. The cold separator will be up to 2.7 meters in diameter. The cold box exchangers will be 0.9 to 1.2 meters wide by 1.2 to 1.8 meters deep and up to 6 meters tall. Pipe sizes will typically be 10 to 18 inches in diameter. Overall, skid sizes up to approximately 14 feet wide by 14 feet high and 50 feet long can be anticipated, ensuring simple ground transportation.
This faster NGL recovery is quite valuable. A typical example of a 200 MMSCFD plant with a moderate NGL content (3 GPM) will generate $10M of additional value each month in recovering the NGLs at current prices vs. leaving them in the gas and getting heating value for them. So a six month earlier delivery is worth $60M which can be up to 50% of the total installed cost of the full plant.
In summary, a diversified portfolio of treating solutions that can be quickly delivered as modular pre-fabricated solutions enables economic development of shale gas resources that otherwise pose daunting processing challenges and risks given their inherent variability in gas composition. The above-ground gas processing challenges should be addressed early along with the below-ground production challenges if unconventional resources are to be monetized efficiently and optimally.

Figure 11

**Rapid NGL Recovery Improves Return on Investment**

- Typical example of revenue associated with NGL recovery
- 200 MMSCFD of 3 GPM gas (~1,100 BTU/SCF)
- Monthly revenue: $10.0 MM
- Potential benefit of full optimization is offset by loss in revenue due to schedule increase

![Diagram showing NGL recovery values](image)

1^Henry Hub = $3.80/MMBTU, WTI = $100/bbl; NGLs = Bentek 3Q13 Market Call