Technology Options and Economics for Unconventional Shale Gas and Gas Liquids Monetization

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Background

Unconventional shale gas is playing an increasingly prominent role in United States (U.S.) natural gas supply. The U. S. Energy Information Administration (EIA) estimates, 13.6 Tcf from shale gas in 2035, comprising 49% of total dry gas production, up from 5 Tcf in 2010, when shale gas comprised 23% of total US dry gas production. U.S. ethane production is expected to increase 50% or 475 Mb/d by 2016. Enormous infrastructure costs for gas and liquid pipelines and compressor stations, gas processing and NGL extraction facilities, expansion of fractionation facilities and similar infrastructure is required in addition to the drilling, hydraulic fracturing and other direct production expenditures. Further, the importance of economic returns from the associated liquids, when present, in making the whole enterprise viable, is only recently being appreciated.

The growth of shale gas production has been made possible by advancements in directional drilling in combination with hydraulic fracturing (fracking) technology. The progress has enabled multiple-well pads with multiple completions per well. Using horizontal drilling, wells can be extended on the order of a mile from the pad. The fracturing process, which injects high-pressure fluid (mostly water with some chemicals) enables the tightly-bound natural gas to flow out of the otherwise tight formations. This technology was developed to its full potential by companies such as Chesapeake in the Barnett formation in Texas and more recently by Range Resources in the Marcellus in Pennsylvania, but by now the technology is widely available and reasonably well understood. Similar technology being employed in the Bakken formation is resulting in high production of oil along with some gas, but this paper will focus on the primarily gas-oriented developments. Key plays in the U.S. are Eagle Ford, Haynesville, Barnett, Marcellus, Bakken, and Granite Wash. The Utica is expected to be a future play but has not been thoroughly evaluated yet. The whole story of the Marcellus infrastructure needs and monetizing opportunities may need to be repeated in the Utica. In Canada, Horn River and Montney are developing plays, but mainly dry gas.

Under normal circumstances the natural gas produced would satisfy existing demand, perhaps displacing higher cost resources such as imported liquefied natural gas (LNG), but the sheer volume of gas being produced, and considering the magnitude of the expected longevity and additional formations being discovered, e.g. the Utica, are leading to structural changes in the entire natural gas industry in the U.S. The flow of gas from west to east through major pipelines is being disrupted as the eastern production is quite naturally satisfying eastern demand, reducing the now unnecessary long haul transportation. The high ethane content of the western part of the Marcellus production is causing shifts in pipeline quality, disrupting the balance of feedstock demand in petrochemical plants which are now preferentially cracking ethane instead of naphtha or other natural gas liquids (NGL) components (e.g., propane), creating a demand for gas storage, gas processing and fractionation facilities and liquids pipelines, export terminals and so on. The dry gas volumes are such that prices are relatively depressed, dipping well below $3 per MMBTU in 1Q 2012, which has historically been the winter peak season for gas, fetching prices above

$10 per MMBTU. A lot of this production would be shut in at these prices, except the leases generally require that production occur to hold the lease. This situation has led major energy producers to begin considering converting the few U.S. LNG import terminals into export terminals.

Where natural gas liquids are produced in particularly large proportion to gas, such as in the Haynesville, Eagle Ford and a portion of the Marcellus formation, since the liquids can be four times more valuable on a BTU basis, the dry gas is produced almost as a byproduct. Several producers have stated that they can be profitable even when giving the gas away for free. Some producers have stated that their cost of production for dry gas is around $3 - 4 per MMBTU, and long term forecasts are looking for prices in the $6 per MMBTU range.

Aims

It is the aim of this paper to provide an overview and explain the various options that exist for monetizing the gas and liquids produced in the prolific unconventional shale formations in the US and elsewhere. Knowledge of the alternatives is essential for the full utilization of the massive resources existing in these types of geological formations. Although the discussion in this paper is North American-centric, as exploration geology advances in other parts of the world there will likely be many parallels to this scenario as well as additional unique situations.

Where shale gas plays are close to existing pipeline, gathering, gas processing and fractionation infrastructure, the conventional approaches to monetization will be followed. Connecting dry gas production through nearby, existing processing, compression and then on to the associated sales gas line for transportation to the customers is the obvious solution and may often be the best solution. Where such infrastructure does not exist, where there are no connected end users for the liquids or gas, and where there are gas and liquid quality issues is when producers need to get creative, as they certainly have been.

Methods

By examining the various announcements and plans made by producers in the shale gas plays in the trade press and at conferences, which are being made at a dizzying pace, we can get a very good idea of the range of feasible options that can be considered to expand the infrastructure in order to monetize the gas and liquids. It is recognized that such announcements are often intended to dissuade competitors or to take the pulse of the market. On the other hand many of the projects are already a “fait accompli”, in that capital has been raised, pipeline rights of way have been obtained, pipe is being laid in trenches, flow in existing gas or liquid pipes is being reversed, gas processing plants have been built and additional capacity ordered, and fractionators are being expanded. More grandiose projects such as building crackers, gas to liquids (GTL) complexes, repurposing LNG import terminals are obviously more long-range and speculative. Before something like a GTL complex could be built, a front end engineering design would be needed, a substantial financial commitment itself, detailing the site-specific cost of the facility. Ultimately, an investor would have to raise and obligate several billion dollars to actually construct the plant and auxiliary facilities. Only a few of these have been built to date. The issues surrounding this type of monetization approach will be discussed in more detail later on. It is not the intent of this paper to provide a complete and comprehensive listing of every relevant expansion project in the North American shale plays but rather some representative projects to give a sense of the scale of activity.

Results

The natural gas production which emanates from the shale gas plays is of generally good quality. Often the hydrocarbon content is a sufficient fraction of the gas to both warrant and necessitate its separation from the dry gas. The usual dehydration and CO_2 removal steps that are used in most natural gas production are also needed for shale gas. The presence in shale gas of sulfurous compounds, such as H_2S, does not seem to be endemic and when it is, it is usually at a modest level where removal is easily and inexpensively accomplished, say by H_2S scavenging or amine removal. This is not technologically challenging. In the early development in some areas, removal of the NGL was either not needed, because the availability of existing dry gas production or transportation lines afforded blending possibilities, or was accomplished with small mechanical refrigeration plants, so-called propane refrigeration plants, or was sent to an existing, under-utilized gas processing/extraction facility. Once the blending opportunities were saturated or strained by the relative volumes of wet gas, bona fide NGL extraction plants were needed. In the Marcellus, where there was virtually no existing infrastructure, these had to be built as quickly as possible to avoid constraining overall production. MarkWest, Caiman Energy and others quickly began to meet the challenge by installing several large-scale cryogenic expander plants and several more are ordered and under construction (Caiman 2X200 MMscfd in 2012, 200 MMscfd in 2013; MarkWest adding 320 MMscfd in 2012 on top of 625 MMscfd of existing capacity). Delivery times of such facilities are now becoming prolonged due to the increased demand.

Liquids can be tolerated by the pipelines only up to a point. The issues are hydrocarbon dew point, i.e., free liquids dropping out in the pipeline, and gas compatibility with end user equipment, e.g., burners, gas engines, turbines etc. The Wobbe number and other indices sensitive to the hydrocarbon content are used to set limits on the gas that a pipeline will take under its tariff. Up to 17% ethane has generally been accepted by major pipelines in the Marcellus, but the limit may revert to 12% at some point. Nonetheless this requires a significant amount of additional ethane removal to be in place to enable the production of the expected gas from this region. Fortunately the demand for ethane has skyrocketed because it is being used in crackers instead of more expensive feed stocks such as naphtha. New crackers have been announced and when these are built there should be a closer approach to supply-demand balance in ethane. Williams Co. predicts an excess of 200 Mbpd of ethane over demand in the Marcellus unless major projects, pipelines, crackers, fractionators etc., such as are discussed below, are carried out.

Once all required NGL removal has occurred and all residue gas has met pipeline specifications, the NGL has to be somehow transported to market. In some areas such as the Eagle Ford there already existed some of the necessary pipeline infrastructure to carry this out, but much more is needed. In the Marcellus, early production was dealt with by brute force approaches such as trucking the liquids out. Some was delivered to terminals on the Ohio River and barged down to Louisiana where major chemical infrastructure exists. Ideally, the liquids should be sent to a proper hub that has the fractionation, storage, product pipelines and other necessities such as exist at facilities in Mt. Belvieu, Texas, and Sarnia, Ontario, Canada. Propane is somewhat less of a problem as there are often local markets for it (for heating fuel, drying of agricultural products, and as the rural substitute for natural gas where pipeline connections are not feasible), and because it is not as volatile as ethane. On the Gulf Coast there is ample shipping capacity and robust export markets for the propane.

If residue and dry gas production is borderline economic due to suppressed prices, monetization options other than selling into the takeaway pipeline infrastructure at breakeven prices should be looked at. For those with the financial resources and without compelling obligations to produce (for example, because of lease provisions), waiting for prices to go up is an option but carries opportunity risk. Ultimately, if there is too much residue gas to be absorbed by the market, wet gas and “hold by production” producers will have to develop alternative uses. Development of new markets for the gas is obviously a broader problem than individual producers can undertake.

The power industry is an obvious choice to consume more of the produced gas. New EPA rules for coal-fired power plants will most likely result in the closing of many older coal-fired power plants and favor the construction and operation of natural gas-fired combustion turbines. Natural gas is already the premier fuel for new generation, but even absent the misfortunes of its competitor fuels it has several key advantages. These are short construction times, generation efficiency (heat rates of ~6500 vs. ~9,000 Btu/kWh), ~half the capital cost, low (~half of coal) CO_2 emissions on a feed Btu basis and 40% on net power basis, incremental, modular construction at ~100 MW scale, low environmental consequences of its production, widespread applicability, availability other than at mine-mouth or rail/barge locations, no sulfur emissions or need for scrubbers with their associated solid wastes, and is easier to site close to metropolitan areas. What has been keeping natural gas from gaining market share have mainly been perceptions of high price volatility and even availability. There is substantial natural gas electricity generation capacity in place, in fact more than coal, but because of gas prices the utilization factor has been very low, around 20%. The current shale revolution is well on the way to dispelling those qualms.

Industry consortiums are renewing their commitments to develop and promote natural gas vehicle use as a way to create additional natural gas demand. The U.S. Energy Information Agency reports that natural gas, on average, costs 42 percent less than diesel fuel on an energy equivalent basis and is expected to cost 50 percent less by 2035. Although NGV use has been growing steadily, it still represents only a miniscule fraction of the total liquid fuels market (Diesel, Gasoline). As the infrastructure of fueling stations across more widespread geographical locations grows, adoption of NGVs becomes feasible to a broader spectrum. The rate of growth of such infrastructure is itself limited by the current demand and the size of the NGV fleet. Government and industry subsidization in this area is crucial to expansion. Over time this sector will make a contribution to gas demand and supply and demand balance. Industry targets include the displacement of 12 billion gallons per year of traditional liquid fuels with over 1 Tcf of natural gas, mostly in heavy duty fleet trucks and buses. At this level, NGV fuel use will still remain less than 5% of total natural gas use. Low natural gas prices may also ultimately engender the resurgence of the domestic natural gas-based chemical industry (ammonia, methanol). Most of the domestic gas-based chemical and fertilizer production was closed down as gas prices became untenable and uneconomic in the face of cheap imports from low natural gas price countries, e.g., methanol and ammonia from Trinidad and Tobago. Vertical integration into chemical and fertilizer production could provide a profitable outlet for natural gas producers, especially if there are mothballed plants that can be reopened. Methanol and fertilizer (ammonia) production, produced domestically, may be economic if prices remain in the low after consideration of import transportation costs. New-build plants, given that the low gas prices are not necessarily expected to persist indefinitely would be more risky. Inherent in this monetization option is the price risk of the end product whether fertilizer, methanol or other chemical. Hydrogen can also be made from natural gas, and in fact most of it is. Increasing sulfur contents of crude have created an increasing demand for hydrogen in refineries. Some of that is captively satisfied by petcoke gasification. But there are some other companies, for example Air Products & Chemicals, that have a merchant hydrogen business and they and others may be evaluating the feasibility of additional hydrogen manufacture from the new gas supplies given the low price forecasts. In areas like the Marcellus the issue is mainly whether there are any markets for the hydrogen close enough to warrant investment. On the Gulf Coast, where there is already a merchant hydrogen infrastructure, this may be a more obvious opportunity.

The production of LNG, mostly for export, has to be considered a viable, albeit long-range option for monetizing shale gas. Worldwide LNG production stands at ~260 million tonnes annually produced by 20 or more total plants throughout the Caribbean (Trinidad and Tobago), Middle East, Africa (Algeria, Nigeria, Equatorial Guinea) and Malaysia/Indonesia. New entrants are cropping up as well, such as Peru, Norway and Australia. The predominant reason these plants were able to be built, at a cost of several billion dollars each, along with the other necessary expensive infrastructure of receiving terminals, regasification facilities, and specialized LNG ships was that the local demand and gas distribution infrastructure and pricing was too little and low to absorb the gas supply domestically and long range pipelining was infeasible or too costly. For example in Russia, although LNG was an option on the eastern side of Siberia it was deemed more economical to build a pipeline through continental Russia to Europe. LNG plants, in order to capture economies of scale, are huge; typically gobbling up 250 MMscfd of gas and producing 3 to 8 million tons per year (MTA) of LNG. About 50 Bcf of natural gas per year is needed per ton of LNG, so it is clear the reserves in the Marcellus alone could support a number of world-scale LNG plants. Put another way, for each 4 MTA LNG plant we would need 4 Tcf of reserves over a 20 year plant life. Estimates of reserves vary but a reasonable number is >200 Tcf. Very small scale LNG plants, or mini plants, on the order of 5,000 bpd, are technically feasible, using different thermodynamic cycles and equipment than is used in the large plants, but are aimed at different markets with different cost structures than commercial commoditized LNG, such as producing LNG for peak shaving uses, or for vehicle fleet fueling using pipeline gas at locations far from existing LNG terminals. U.S. LNG could go to Europe displacing some current Middle Eastern sourced LNG, which would free up more cargoes from the Middle East to go to Asia. Certainly the reserves and resources of gas in today's shale plays are sufficient to feed at least a few world-scale LNG plants. Some of the existing LNG receiving terminals are being converted for export for this purpose and associated LNG liquefaction is being planned. Dominion Resources has announced their intentions to do this at Cove Point, Maryland and Cheniere Energy likewise at Sabine Pass. Cheniere Energy stated that they expected U.S. Henry Hub prices could reach $2.50/MMBTU. Cheniere liquefaction costs add $2.75 and transport to Asia another $2.50. European delivery would be in the area of $2, meaning that Henry Hub gas would be competitive even up to $6/MMBTU with Asian and European prices of $10 to $12 today. In Canada, plans have been discussed to export gas to Asia from Horn River and Montney shale plays through Kitimat, BC.

It is not a simple matter to estimate the cost of an LNG plant. Most of the companies engaged in this area keep their cost estimation close to the vest. Although the cost of the actual liquefaction plant should be deterministic for a given capacity and process design (there are 3 different major thermodynamic cycles being used), the plant itself is less than half of the overall facility cost as there would be the need for docks and marine loading facilities, variable gas treating and processing upstream of the plant, and other site specific issues. Given that the Marcellus is landlocked, these plants would have to be located on the coast of the U.S. in such places as Freeport, Houston (for gas from Eagle Ford, Haynesville etc.), Louisiana, or Philadelphia and so on and would need to pay additional transportation costs and possibly pipeline interconnect costs above the hub and field prices.

Among the more far reaching monetization options is GTL. New GTL plants have been built in Ras Laffan, Qatar by Qatar Petroleum (Oryx and Pearl). Pearl, the latest GTL plant built, uses Shell's Middle Distillates process. The capacity of the plant is 140,000 bpd of a range of clean liquid products and fuels, comprising naphtha, GTL fuel, normal paraffins, kerosene and lubricant-based oils. The earlier plant, Oryx, was the first commercial GTL plant, and was a joint venture of Qatar Petroleum and Sasol of South Africa, and used the Fischer Tropsch process. It is rated at 34,000 bpd GTL products. Qatar was faced with a similar situation that will exist in the U.S. if the envisioned production is realized. They previously used much of their natural gas in LNG. They perceived the growth of the LNG market and profitability to be adequate but decided they needed to diversify and thus made this ~$20 billion investment. It is not known what the effective price of natural gas was for deciding whether this project would have adequate returns, but reasonable assumptions of breakeven pricing with crude oil at $40 or $50 per bbl are likely. Considering the prices of liquids being at such a high multiple to gas it is a reasonable conclusion that this project is immensely profitable and that Qatar's risk taking is being amply rewarded. Clearly, GTL is a bona fide option for monetizing the gas portion of the shale plays. One of the issues in this area is that the large complexes involved will take a considerable time to erect and get into operation, probably no less than four years from concept to first production, and possibly longer. This makes these projects a long term bet on gas and liquid price differentials over not only the period of construction but also over the ten to twenty years that such investments require to pay out, under normal circumstances. It remains to be seen how investors will price this risk.

Another approach is smaller GTL facilities and new conversion technologies. Ultimately, if a direct conversion technology is developed that can bypass the expensive and thermodynamically inefficient steam reforming step, the cost of gas conversion can be greatly reduced. This has been a holy grail of the GTL industry for some time, but to date is not close to realization. Also, there are other conversion processes besides SMDS and Fischer-Tropsch, and new process technology such as the Velocys micro-channel architecture may lower the conversion costs incrementally and enable smaller facilities to be economic. Haldor Topsoe is also developing the TIGAS process that converts syngas after steam reforming of natural gas into gasoline requiring negligible hydroprocessing or refinery upgrading. This may be especially beneficial in N. America where gasoline demand is relatively high compared to distillate.

U.S. natural gas liquids prices are forecast to remain high, at multiples to the natural gas prices, so maximum recovery of these commodities is necessary to maximize profitability to producers and other value chain participants. This in turn is predicated on the forecast growth of the petrochemical industry, their major user. North American NGL supply is around 3.3 MMbpd of which 2.6 MMbpd comes from gas processing. More than half of the demand is as chemical feedstock. The likely areas to produce this supply are the Eagle Ford, Permian, Rockies, Woodford and Marcellus / Utica plays. The monetization of the NGL opportunity depends on continued investment in gas treating and NGL extraction facilities, liquid pipelines and distribution infrastructure, liquid storage, and fractionation capacity. These are more or less straightforward and familiar investment decisions for the companies in this field. Enterprise Product Partners estimates a $200 billion dollar investment (over 25 years) is needed. As examples of the pipeline infrastructure build out, Enterprise, in partnership with Chesapeake also announced a plan to build a 1,230 mile pipeline from the Marcellus to the Texas Gulf Coast. El Paso, jointly with Spectra Energy is offering the Marcellus Ethane Pipeline System (MEPS) option, a proposed 1,100 mile ethane pipeline to transport up to 90,000 barrels per day of ethane from origin/receipt points located in the Marcellus Shale area to a destination/delivery point located in Eunice, Louisiana; Plaquemine, Louisiana; or Mt. Belvieu, Texas. At the current level of production and in consideration of competing projects, this one is probably on the back burner for now. In the Eagle Ford, DCP Midstream is building the 750 mi. Sand Hills pipeline to enhance the transportation of NGLs from the Permian Basin and Eagle Ford to the Gulf Coast with 350 Mbpd capacity. Several gas processing plants are needed along the route and are also included in DCP's capital expansion. Williams summarized 5 other major liquids pipeline expansions totaling another 700 Mbpd connecting up to Mt. Belvieu and Conway, Kansas (where there is a lot of fractionation capacity.) In the Marcellus, Sunoco Logistics in partnership with MarkWest announced a plan to move ethane to the Eastern seaboard at Marcus Hook, where they have existing infrastructure, and load several ships with ethane for transport to the Gulf Coast or elsewhere. MarkWest has announced the 50,000 bpd Mariner West project to get Marcellus ethane to Sarnia (also in partnership with Sunoco Logistics) and an ethane pipeline from the Marcellus (Majorsville, on the Pennsylvania - Ohio border) to Mt. Belvieu. The Mariner West project already has firm commitments from one of the large Marcellus producers, Range Resources. There are numerous other projects of this sort in the major plays, the bigger projects necessarily being in the Marcellus where the lack of infrastructure and distance from end users of the liquids warrants it. In addition to the liquids lines, dry gas transmission lines are also expanding to meet the needs in the various areas.

In the past, extraction margins for natural gas, that is the price differential between the value of liquids removed and the natural gas itself, accounting for costs of operations and shrinkage, have been mostly positive. At times, low liquids prices lead to a scenario where it is more economical to leave the liquids in the gas in which case processing plants shut down and bypass the gas to the sales lines. For some of the shale production, the high percentage of liquids would also require the gas to shut in since the pipelines would have to refuse it as it would cause problems and hazards for customers as well as the pipelines themselves. Although these days is seems almost heresy to talk about such an eventuality, it behooves producers and operators to plan ahead. One option is to ensure sufficient liquids storage is available to weather these hopefully short periods of "reversed" margins. Using extraction technology that has an operating cost that is less sensitive when ethane rejection is preferred is also sensible. Such technology is being developed by GTI and others.

Conclusions

The growth of unconventional shale plays in North America that are such prolific producers of natural gas and natural gas liquids is changing the dynamics of the gas and chemical industry and is appropriately being referred to as a revolution. Hopefully this will be repeated in other parts of the world. There are numerous logistic challenges to making this revolution happen and to its realizing its full potential. The foremost challenge after the actual land/lease acquisition, drilling and fracking costs, which are themselves a huge investment, is the build out of the required infrastructure of pipelines, gathering systems and compression, gas treating and processing including natural gas liquids removal, and product storage, transportation and distribution. Hundreds of billions of dollars will be spent on these facilities. Viability of this enterprise is contingent on sustained levels of natural gas prices and liquids prices (for wet gas producers. Creative monetization of the dry gas is key to the sustainability of the enterprise and realizing the ultimate value of the resources.

Re-opening closed natural gas to chemical plants (ammonia, methanol, urea etc.), GTL, LNG export, and use in natural gas vehicles, have been identified by current players as options being pursued for monetizing dry gas. LNG export is in some cases actually being implemented, but in the near term is limited by a dearth of available terminals. Longer-term expansion of gas demand by power producers as well as general growth of the economy may improve the supply and demand balance.

Developing new crackers to absorb the ethane supply and routing ethane by pipeline to Mt. Belvieu and Sarnia to integrate it with existing NGL and petrochemical infrastructure will help with the ethane supply-demand imbalance. Ethane export by ship is also being developed.

Overall, it is clear the industry has stepped up to the challenges and is engaged in robust infrastructure additions to deal with the new natural gas and NGL abundance in North America. It seems we are making good progress as an industry towards rationalizing the investments and capturing the economic rent the new shale gas plays have made available.