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Mapping the Opportunities for Shale Development in Ohio

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Prepared for:
**THE ECONOMIC GROWTH FOUNDATION
RECS SHALE COMMITTEE
JOBSONHIO**

**MAPPING THE
OPPORTUNITIES
FOR SHALE
DEVELOPMENT
IN OHIO**

September 2015

2121 Euclid Avenue Cleveland, Ohio
44115

Prepared for:

The Economic Growth Foundation

RECS Shale Committee

JobsOhio

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Acknowledgments

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EXECUTIVE SUMMARY

1. Anticipated Production of Natural Gas in the Utica/Marcellus Basin Will Create a Surplus of Ethane in the Region by 2020 in Excess of the Take Away Capacity.

By the spring of 2015, over 1,000 wells had been drilled into the Utica Shale. Much has been learned about the Utica in more than three years of drilling and producing. Operating companies can now predict with considerable accuracy the nature and amount of production likely to be recovered from the region, and from each well. This is so despite the fact that only about 3% of the anticipated commercial area for the Utica has been tested.

Among the most important insights gleaned from production to date is that certain areas of the Utica are rich in not only natural gas, but also natural gas liquids. The result is that a handful of midstream companies have made major investments in the Appalachian Basin, building a natural gas processing infrastructure capable of processing some 7.9 billion cubic feet per day (bcf/d). Further, notwithstanding low hydrocarbon prices, regional processing capacity is anticipated to grow to nearly 12 bcf/d by 2020. This regional capacity will be used to process both Utica and Marcellus natural gas.

The hydrocarbon price depression has been the major story of 2015. Low prices may be a boon to local industry and transportation, but have been hard on the upstream oil and gas industry. Drilling rig count in the Utica, which had been steadily rising through 2014, reaching a high of around 50, dropped dramatically by June 2015 to 19. However the reduced rig count has been offset somewhat by increasingly long laterals from each well being completed, meaning more production per well.

The Study Team identified “low,” “most likely” and “high” scenarios for production in the next five years. Ohio Department of Natural Resources April estimates for the number of wells drilled in 2015 (600) come closer to those projected by the Study Team for the “low scenario” (584), than the “most likely” scenario (701). Nevertheless, because of the increased efficiency in drilling, together with longer laterals and more completion zones per well, the “most likely” production scenario continues to provide the best estimate for Utica throughput volumes over the next five years.

Using the data from the most likely production scenario, the Study Team projects that there will be around 4.75 bcf/d of Utica natural gas throughput in the Ohio gathering pipeline system by 2019. It is anticipated that about half of this will be wet gas (2.36 bcf/d). From this number, and using assumptions obtained from industry experts, the Study Team estimated that by 2019, the anticipated ethane throughput will be around 162 thousand barrels per day (mmbbl/d). This assumes that ethane will make up around 60% of the liquids, and that there will be a 20% rejection of ethane (meaning that the ethane is left in the natural gas stream).

Publicly available industry projections in the fall of 2014 indicated that total throughput in the Utica would likely be around 8.1 bcf/d by 2020, of which around 3.6 bcf/d would be wet. As of the summer of 2015, despite large cuts in upstream operation budgets, these projections had not been materially revised. Assuming 60% ethane and 20% rejection, this suggests that we can expect a throughput volume of around 247 mmbbl/d in 2020. This is higher than the Study Team

projected for its “most likely scenario,” and may reflect a more aggressive view of production due to longer laterals and drilling efficiencies.

Natural gas liquid processing capacity has ramped up quickly in the Utica region. However comparing processing and fractionation capacity to projected Utica production throughput only tells part of the story. Consumers of ethane and other natural gas liquids don’t distinguish between Marcellus and Utica production, and there is also a significant wet gas window for the Marcellus. Accordingly, total production from the two wet gas provinces must be compared to total processing and fractionation capacity for the region. Industry estimates for total wet gas production in 2020 from the Utica and Marcellus together has been placed at around 9.3 BCF/Day. That equates to 638 thousand barrels per day (mmbbl/d) for ethane, assuming 60% ethane and 20% rejection. Total de-ethanization and C2 fractionation capacity for the region is projected to be around 371 mmbbl/d. Accordingly, if production reaches the anticipated levels, and if 20% of ethane is rejected, we can expect a shortfall of ethane fractionation capacity in 2020, unless additional capacity is built.

Any shortfall of de-ethanization and C2 (ethane) fractionation capacity will be handled either by additional ethane rejection or, if there is a market for the ethane, the building of more capacity. The midstream industry has shown already that it can respond quickly to the need for more processing capacity. If there is a viable local market for ethane, there is little reason to expect that regional processing and fractionation infrastructure will be a long-term bottleneck for ethane supply.

Regional Projected Production Compared to Fractionation and Take Away Capacity, 2020

	Total NGL Volume	Ethane (mmbbl/d)
Industry Projected Wet Gas Production	9.3 bcf/d (3.6 Utica + 5.7 Marcellus) (1)	638.4 (2)
Industry Projected Fractionation Capacity	12 bcf/d	371 (3)
Industry Projected NGL Take Away Capacity, plus local use	1,525 mmbbl/d	460 (4)

- (1) Blue Racer Investor Presentation – Fall 2014; Williams projects 1,400 mmbbl/d
- (2) Assumes 60% ethane, 6 gal/mcf, 42 gal/bbl, and 20% ethane rejection; (Williams: 672 mmbbl/d - 60% ethane, 20% rejection)
- (3) One third of C2+ fractionation (87 mmbbl/d) plus de-ethanization (C2) (284 mmbbl/d)
- (4) The Mariner East 1 and Utopia pipelines are dedicated to ethane and propane, with capacities of 70 and 75 mmbbl/d, respectively. The Mariner East 2 pipeline expansion is projected to be 275 mmbbl/d, however most of this pipeline is anticipated to be used for propane. Accordingly, all 145 mmbbl/d of the propane/ethane capacity is used to make this number, but none of the 275 mmbbl/d.

Regional take away pipelines for liquids also do not distinguish between Marcellus and Utica liquids. The total take away capacity for ethane is projected to be between 315 and 735 mmbbl/d, depending upon how pipelines are used. Several pipelines are capable of taking ethane

or propane, and at least one can also take heavier liquids. However Sunoco, the owner of the new 275 mbb/d Mariner East line, has indicated the line would be used primarily for propane. Accordingly, a reasonable estimate for take away capacity is around 460 mbb/d by 2020. This estimate assumes that the lines dedicated to ethane and propane jointly are used for ethane, and the lines dedicated for C2 and up are not used for ethane.

For purposes of evaluating the likelihood of a developing local market for ethane, this number is important. Current industry projections for ethane production, assuming 20% rejection, are such that we can expect a shortfall in the ability of the industry to ship ethane out of the region. Such a take-away shortfall invites the development of a local ethane market.

Based upon projections for production and take away capacity, it appears that ethane production (with 20% rejection) could outpace take away capacity in 2020 by 200 mbb/d or more, depending upon how much take away capacity is used for propane and heavier liquids. This excess production should be attractive for petrochemical companies locating or considering a location in the Ohio/West Virginia/Pennsylvania region of the Appalachian basin. However the local market will have to be at least as valuable as that for methane, because producers should be able to reduce this excess considerably, and possibly entirely, by rejecting more ethane. A local market needs to be developed to prevent ethane rejection or a building of additional take away capacity.

2. Ethane Surplus in the Utica/Marcellus Basin Should Drive the Development of Downstream Markets for Ethane in Ohio, Creating Opportunity for New Growth in the Downstream Petrochemical Business.

A regional surplus of ethane creates an opportunity for the development of Ohio businesses downstream of the processing and fractionation facilities. Ohio is already a significant national player nationally in the chemical industry, exporting chemical commodities worth \$6.5 billion/year. Chemical industries in Ohio have an employment location quotient of 2.0, and a Gross Regional Product location quotient of 1.81 – among the highest in the nation. This means that the concentration of employment in the chemical industry in Ohio is twice that of the national average.

The Ohio chemical and petrochemical industries in particular could gain from a regional surplus of natural gas liquids. These industries use ethylene and polyethylene, among other refined hydrocarbon products, as raw material for their products. In the United States, ethylene and polyethylene are primarily made from cracking ethane. Currently most of the cracking facilities are located in the Louisiana and Texas Gulf Coast, where natural gas liquids have been historically produced in abundance. Ohio's downstream manufacturers have had to acquire these products primarily from petrochemical companies located on the Gulf Coast.

With the Appalachian area quickly developing into one of America's largest sources of natural gas and natural gas liquids, long-term hydrocarbon prices in the region have become attractive to petrochemical companies. Further, with a large market for commodity chemicals already located in the region, petrochemical companies also stand to gain from transportation cost savings. It is possible that some of these savings in costs will be passed along to markets downstream of the cracker facility, such as to distributors, compounders and converters. The savings for ethane transportation, together with the savings on shipping polyethylene from the

Gulf Coast back to the Midwest, has been projected to be around \$100 million per year for each prospective local large scale cracker.

In light of this opportunity, by the summer of 2015 four petrochemical companies had publicly announced that they were considering building ethane crackers in the Appalachian Basin. None of the four have yet reached a “Final Investment Decision.” However they have advanced far enough to choose potential sites and to project likely required ethane feedstock requirements. Sites have been selected along the Ohio River, which is necessary for ease of transportation of equipment. If all four crackers are built, it would require an ethane supply of about 223 mbb/d – roughly 1/3 of the anticipated total ethane locally available in 2020. With a projected take away capacity of about 430 mbb/d for the region in 2020, these two ethane markets would likely consume the regional ethane production, with 20% ethane rejection.

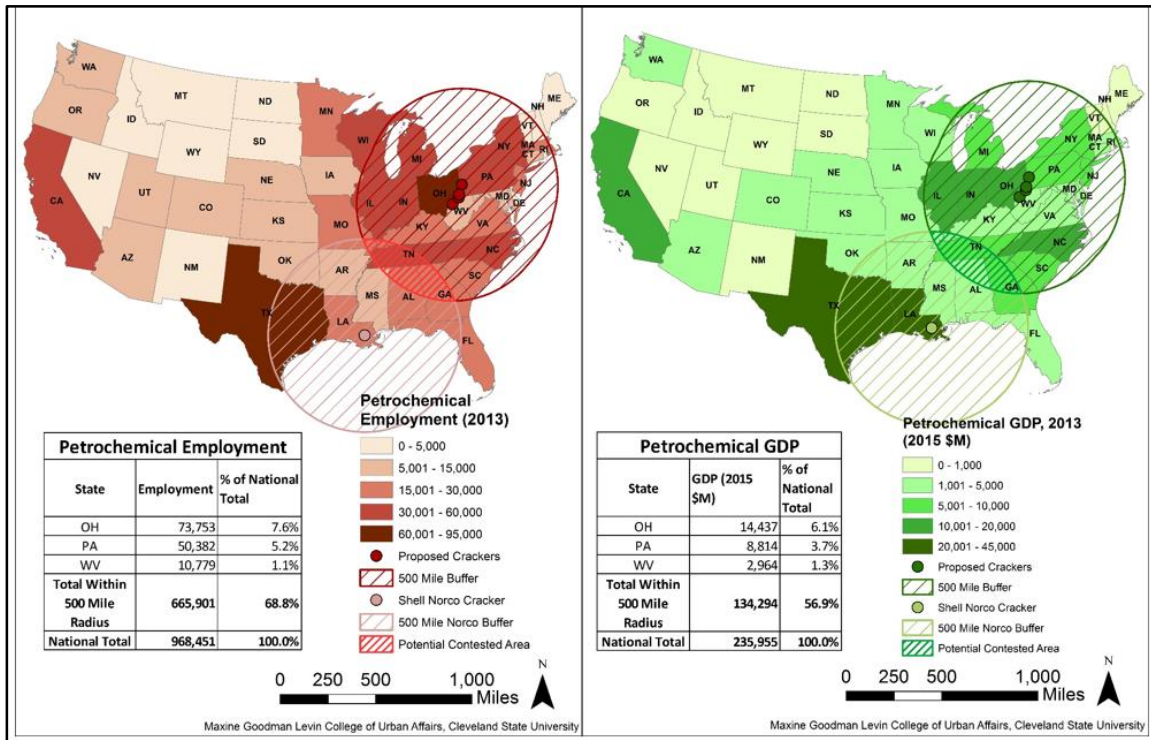
Obtaining firm commitments for ethane will be a critical step for the petrochemical companies. Currently two of the companies have announced at least tentative long-term contracts for delivery of ethane. The terms of the deals have not been released, however insofar as no Final Investment Decision has been made, the contracts are likely not firm commitments. Once the Final Investment Decision has been made, the contracts are likely to have components of both “take and pay” and “warranty” commitments. This means that the petrochemical company will have to commit to take, and the producing company to deliver, a range of ethane volumes.

One cost advantage the Gulf Coast has over Appalachia relates to storage capacity. Ethane is volatile at atmospheric temperatures and pressures, and as such cannot be easily stored. Storage is principally located underground in salt caverns or in permeable sandstone reservoirs. All such storage in the Appalachian region is already being used by natural gas. Accordingly, Appalachian petrochemical companies must develop other strategies for storage.

There are multiple strategies for dealing with storage challenges. The most common strategy is pipeline packing – whereby the line pressure is increased, enabling additional ethane to be stored in the line. This is done commonly for natural gas lines, and can be a short-term solution for ethane storage. Long-term solutions will require use of pipeline redundancy and back up contracts among petrochemical companies and upstream producers. For this reason, it is important that more than one cracker facility is located in the region; it provides both the cracker companies and the producers with flexibility to respond to ethane supply volatility.

Access to downstream consumers of ethylene and polyethylene is among the most important considerations for petrochemical companies. About 69% of all U.S. chemical commodity employment is located within a 500-mile radius from the Ohio Valley - an effective one day transportation distance. Likewise, around \$134 billion of Gross Regional Product was generated by 57% of the commodity chemical companies in this radius. Ohio accounts for about a 10% share of the national employment in this industry – second in the nation after Texas. Likewise, half the 26 states within the 500 mile radius have location quotients for Commodity Chemical Companies greater than 1.2 – meaning that this industry is considered to be a part of the economic base for that state’s economy.

Concentration of Commodity Chemicals Companies in the Tri-State Region



Final Investment Decisions are likely be made by some of the petrochemical companies in the next two years. From there it will take another several years to build each facility and begin operations. While ethane can be acquired on long term contracts, polyethylene cannot. Sales of polyethylene is short term, and based upon a manufacturers’ practice of maintaining a two month (or less) inventory. For this reason, ethylene/polyethylene are usually acquired by manufacturing companies on the spot market. Accordingly, petrochemical companies will have to speculate on their ability to sell polyethylene at a profit, given long term contracts for feedstock and short term sales of their products. Consumer companies willing to enter into longer-term contracts for ethylene/polyethylene may be able to negotiate a favorable price in return for their commitment. The cost of the price discounts required to secure long term contracts could be offset by the petrochemical companies from the transportation and local surplus cost advantages they have over competitors located along the Gulf Coast. It could also reflect a risk premium for the uncertainty petrochemical companies endure in selling their products prior to starting operations.

A surplus of natural gas, natural gas liquids and especially ethane has created an opportunity to grow the petrochemical industry in Ohio, Pennsylvania and West Virginia. Low cost, long-term feedstock supplies, together with an existing downstream chemical consumer market, make for a compelling investment opportunity. Building ethane crackers in the region will trigger additional growth in the distribution, compounding and converting of polyethylene into manufactured products. This, in turn, offers an opportunity to take shale development beyond extraction and use it as an economic development platform that creates local jobs, companies and wealth.

1. INTRODUCTION

1.1. Background, Issues Presented and Scope of Research.

In 2012 a research team from Cleveland State University, Ohio State University and Marietta College jointly published a projection of the likely economic impact from the development of the then nascent Utica/Point Pleasant (hereinafter Utica) Shale formation oil and gas play.¹ That report looked at job creation and the economic development value associated with upstream and portions of midstream oil and gas development. It did not undertake to look at the downstream potential for shale development.² While the report used the best data then available, the results were somewhat speculative, since at the time of publication, little was known about the nature or quantity of production from the Utica.

Today, three years later, we are still very much in the early stages of development of the Utica shale formation. However, a great deal more information is available now than was available in 2012. By the fall of 2014, some 584 Utica wells had reported production data to the Ohio Department of Natural Resources (ODNR). The data indicate that the projections from the 2012 study were generally accurate with regard to the likely number of wells to be drilled, but were low with regard to their rate of production. Technology improvements, together with a better understanding of the geology, have caused the industry to revise upward its original estimates of the likely production to come from the Utica.

One important change to the projections from 2012 relates to the production of natural gas liquids (NGLs)³ – those heavier, more complex, hydrocarbons that are held in suspension in natural gas streams. Some of these liquids fall out during production and transportation, with the reduction of temperature and pressure. Some are taken to processing plants to be removed from the natural gas stream. Interstate pipelines cannot take gas that contains a quantity of liquids exceeding a regulated threshold (btu content), thus requiring processing of gas streams rich in liquids (called “wet gas”). Further, some liquids tend to be more valuable than natural gas, so processing is usually well worth the cost if they are present in sufficient volumes. It was anticipated in 2012 that there would be zones within the Utica that produced large enough volumes of NGLs to justify investments in processing plant infrastructure in Ohio. Accordingly, a nascent gas gathering and processing (midstream) industry was already in the planning stage by late 2012.

However the volume of liquids that has been produced to date has been more robust than originally expected. Since then, there has been a rapid expansion in midstream infrastructure in Ohio, with investments of hundreds of millions of dollars already having taken place. What’s more, the Marcellus Shale formation also has a “wet gas” window, producing large amounts of

¹ See Thomas, A., Lendel, I., Hill, E. et al, “An Analysis of the Economic Potential for Shale Formations in Ohio” (2012), Urban Publications, Paper 453, http://engagedscholarship.csuohio.edu/urban_facpub/453. For purposes of this paper, “Utica Shale” shall mean both the Utica and the Point Pleasant formations, which formations occur together and are generally considered as one formation in reports.

² See section 1.2, *infra*, for an explanation of what industries fall in which streams of the oil and gas industry.

³ Natural Gas Liquids include the following: ethane (2 carbon chain, or C2), propane (C3), butane (C4), and natural gasoline (C5 and higher). Sometimes natural gasoline is also called “natural gas condensate” because it can separate in the field with the change in pressure and temperature upon production.

NGLs. This in turn has generated interest in the possibility of a petrochemical industry renaissance in the region.

With these developments in mind, the Study Team was asked to investigate the likely mid and downstream opportunities that may be arising in Ohio as a result of the Utica Shale drilling and infrastructure build out. The questions posed are summarized as follows:

- How has drilling in the Utica changed the picture with regard to anticipated production and throughput volumes?
- What does the midstream infrastructure look like in Ohio, and will it keep up with production?
- What amounts of NGLs are likely to be produced, what local markets for those liquids are available, and what is the value proposition for local industry in keeping those liquids in Ohio?
- What opportunities are there for downstream development of industry in Ohio both from natural gas and NGLs?
- What strategies might be deployed to capture these industries, and when should they be deployed?

The Study Team looked at these and other questions to guide its investigation. The study below sets forth the results of the Study Team's investigation.

1.2 Midstream Industries and Throughput Capacity.

Oil and gas industry activities are categorized by operation into upstream, midstream and downstream sectors. Upstream refers to the exploration and production end of the business: drilling, completing and producing wells. Midstream oil and gas operations occur subsequent to upstream operations. Midstream oil and gas activities include the gathering, compressing, transporting, storing, treating, separating, processing and fractionation of hydrocarbons.

Downstream refers to those activities that take place subsequent to midstream activities. Such activities include natural gas used in power generation, propane or methane used for home or industrial heating, and methane used in fertilizer manufacturing. They also include refining operations (e.g. reforming, cracking, or distillation) and all of those operations that subsequently occur within the petrochemical industry, such as compounding, distribution and conversion of petrochemicals. According to the North American Industry Classification System (NAICS), upstream companies are those found within the mineral extraction industries, while midstream companies are those found within the oil and gas transportation business. Companies engaged in downstream activities usually are included in NAICS as manufacturing industries, primarily in petroleum, petrochemical and chemical manufacturing.

Upstream operations require midstream infrastructure to take the production to market. Accordingly, midstream investment is critical to the success of the upstream business. In order to build sufficient infrastructure, midstream companies must estimate the likely volume of hydrocarbons to be produced. Pipelines and processing plants are built based upon an expected volume of production likely to be passing through their facilities ("throughput") on a daily basis.

Midstream investment costs hundreds of millions of dollars. The construction of some midstream facilities are secured by a contractually obligated delivery of production from certain

wells or fields to those facilities.⁴ Others are financed based on the likely needed midstream infrastructure in a given region, with the midstream company assuming all of the financial risk. Either way, midstream companies will be making, and have already made, major capital investment in their facilities, and their throughput estimates must be accurate.⁵

1.3 Refining of Natural Gas Liquids and the Petrochemical Industry

Downstream companies face a similar problem. These companies must make investments, often times in the billions of dollars, into their facilities based on the likely available throughput and the likely market for their refined or reformed products.

Investment into natural gas refining, such as for ethane crackers, requires not only a secure supply of the hydrocarbon raw products, it also requires a market for the product being refined. Accordingly, long-term supply contracts either from producers or from those midstream companies that take title to the liquids after processing is critical to enabling downstream facility investment. Of course long-term contracts for sales of refined products from the facility would likewise be important to obtaining investment capital. However, much of the market for refined products made from NGLs today is spot, rather than long term. Accordingly, we can expect that downstream refiners will have to assume the sales risk.

Natural gas liquid refineries take segregated liquids derived from the natural gas stream (“pure products”) and, using processes like catalytic cracking, reform the liquid into a new product that can be compounded, distributed and consumed by various operations further downstream. The most common example of this is refining ethane into ethylene, which is then polymerized into polyethylene pellets. Polyethylene is then distributed to various converter companies for molding into plastics that are consumed in an assortment of commercial applications.

Investment by chemical companies into crackers and other refineries in the Utica Shale region will be determined by a number of factors, including access to markets, transportation costs, labor costs, and storage capacity. But the first and most important factor will be the likelihood of production of large volumes of NGLs and condensate in the region. Regional production volumes for liquids and condensate will, however, be controlled as much by the Marcellus production as it will be by Utica Shale production.

1.4 Research Methodology

The research methods used for this study include several undertakings. The first relates to the assessment of likely upstream development and throughput scenarios. This was accomplished through the collection of ODNR well production data, together with assessing likely drilling and production scenarios based upon rig count, drilling times, and likely decline rates. Industry projections for development and throughput were acquired through literature searches,

⁴ Sales of natural gas are usually based upon a “daily contract quantity,” and contracts to sell natural gas tend to be far more complex than those for sales of liquids due to the difficulty in storing natural gas. Industry trade associations, such as the Association of International Petroleum Negotiators, have developed forms for gas sales agreements.

⁵ The midstream industry has introduced flexibility to its planning by building pipelines that can increase capacity with pressure, and by making processing facilities modular. Most processing plants can be built on skids – standard capacity units - and installed or uninstalled for redeployment elsewhere.

interviews, and conference presentations. These projections were then compared to the ODNR data.

A second undertaking relates to the assessment of the status of the midstream oil and gas infrastructure in Ohio. To obtain this data, the Study Team conducted both a literature search and conducted interviews of the major midstream companies working in Ohio, together with some of the major producers.

A similar investigation was undertaken to determine the downstream markets for natural gas and NGLs, with a principal focus on ethane. For this the Study Team undertook literature searches, attended industry conferences, and conducted interviews with downstream companies, especially those in the petrochemical business downstream of the refinery.

Because the downstream industry takes into account regional projections of throughput and does not differentiate Marcellus production from Utica production (both being in the same region), the Study Team was required to look broadly at prospects for production, infrastructure build out, and regional downstream development.

Finally, during the last phases of this study, hydrocarbon prices, especially for oil, dropped dramatically, calling into question some of the industry projections for production and infrastructure build out. The Study Team looked at a range of production scenarios that has likely captured the effects of this downturn. However at the time of publication, publicly available industry projections for production and infrastructure had not yet been materially altered – notwithstanding industry-wide cut backs in capital expenditures in the upstream business. In the coming months, this is likely to change. The Study Team has, where appropriate and possible, commented throughout the study about the possible effects of this downturn.

2. UTICA SHALE PRODUCTION HISTORY AND PROJECTIONS

2.1. Factors Controlling Production

The pace at which the Utica shale resource develops depends upon factors reflecting regional, national and sometimes global considerations. Regional factors include such things as the availability of local labor, infrastructure, supplies and contractors, as well as the status of state regulations. National and global factors, on the other hand, are beyond the control of regional players; they have to react to the realities presented by market forces. In most cases, global tendencies in oil and gas development influence local conditions through adjustments in business strategies of multinational corporations. Global oil prices, for instance, affect the availability of capital for investment into regional drilling, production and infrastructure and determine if it is profitable to drill and process natural gas and its derivatives in the Appalachian basin.

In this study we accounted for the influence of five factors that control the regional production of dry gas and NGLs, including natural gas prices, the pace of construction in the region's midstream infrastructure, the availability of drilling rigs, the effect of unitization, stranded or expiring leases, and the 2014-2015 business strategies of the principal Utica upstream players. These factors are largely regional in nature. However the rate of production will also be influenced by national and global supply, demand, and geo-political factors germane to the oil and gas industry.

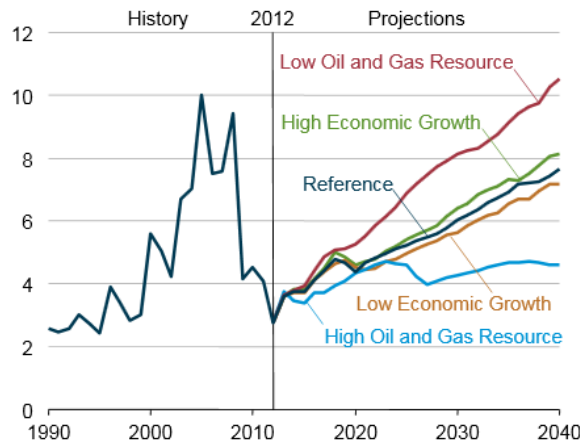
2.1.1. Natural Gas Prices

Geologists anticipate that the vast majority of hydrocarbons produced from the Utica and Marcellus region will be methane and ethane. Accordingly, prices for methane and ethane play a major role in determining the pace of development. Producing companies will of course drill and produce with alacrity when prices are high. The volume of natural gas produced from the Appalachian Basin has already been so significant that it is changing not only how we use gas, but also how we assess the natural gas market. Regional natural gas hubs have become, for the first time, more relevant than the traditional Gulf Coast trading locations in setting prices for the full range of products derived from natural gas, and for measuring regional supply and demand conditions and their relationships with global markets.

A number of private companies and government agencies generate projections for natural gas prices. The reports conducted by the U.S. Energy Information Agency (EIA), known as the "Annual Energy Outlook,"⁶ provide a reference case for future natural gas prices. The report also models the wedge in the projected prices due to macroeconomics growth rates and expected rates of resource recovery from natural gas wells (Figure 1). Higher rates of economic growth reflect increased consumption of natural gas due to their effects on housing starts, additional commercial floor space, and industrial output. According to EIA projections, in the case of high economic growth, natural gas prices will rise by 4.0% a year beginning in 2012; in the case of low economic growth, natural gas prices will increase by 3.5% a year.

⁶ US EIA, Annual Energy Outlook 2014 with Projections to 2040. DOE/EIA-0383, April 2014. <http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf>

Figure 1. Annual average Hub spot prices for natural gas in five cases, 1990-2014 (2012 dollars per million btu)



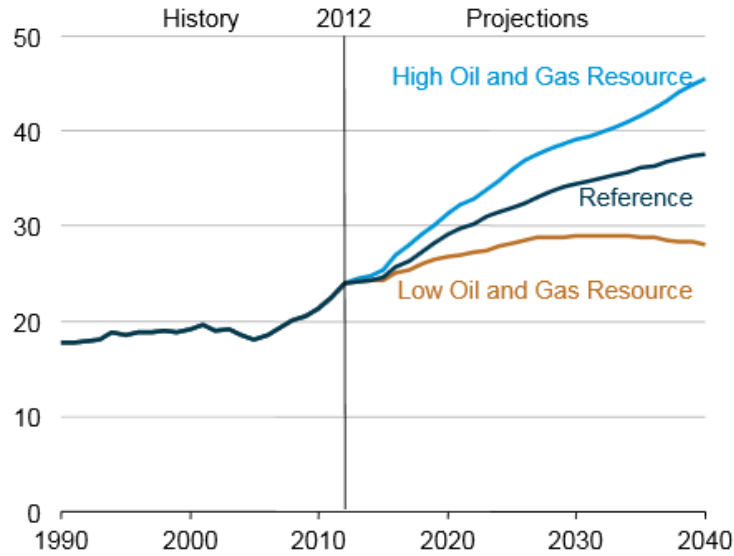
Source: Annual Energy Outlook 2014 with projections to 2014. EIA, DOE/EIA-0383, April 2014, p. MT-23.

According to EIA projections, the high and low rate of resource recovery from oil and natural gas wells may increase Henry Hub spot natural gas prices by 4.9% and 1.8% a year, respectively. Henry Hub spot price projections for natural gas increase by an average 3.7% a year in the “reference” case (in between high and low), from \$2.75/mmbtu (million British Thermal Units)⁷ in 2012 to \$7.65/mmbtu in 2040 (in 2012\$). Lower natural gas prices may lead to an increase in natural gas exports and, in turn, create an upward pressure on the price. The 2014 EIA reference case assumes that natural gas production will grow by an average 1.6% annually from 2012 to 2040 and projects that, as a result, by 2020 the U.S. will become a net exporter of natural gas. Based upon the assumed production growth, the reference case projects an increase in natural gas production from the Marcellus Shale from 1.9 trillion cubic feet (tcf) in 2012 to about 5.0 tcf per year (13.7 billion cubic feet per day (bcf/d)) from 2022 to 2025.

Projected growth in liquefied natural gas exports depends on a number of factors, including price convergence in global natural gas markets, competition of natural gas with oil in international gas markets, and the growth of the natural gas supply outside the U.S. In the event of high oil prices, LNG exports are projected by EIA to increase to 6.7 tcf in 2028 and remain at that level through 2040. In the event of low oil prices, EIA projects LNG exports to grow to only 0.8 tcf in 2018 and remain at this level the rest of projected time period (Figure 2).

⁷ British Thermal Units are the common method of determining energy content (heating value) contained in a natural gas production stream.

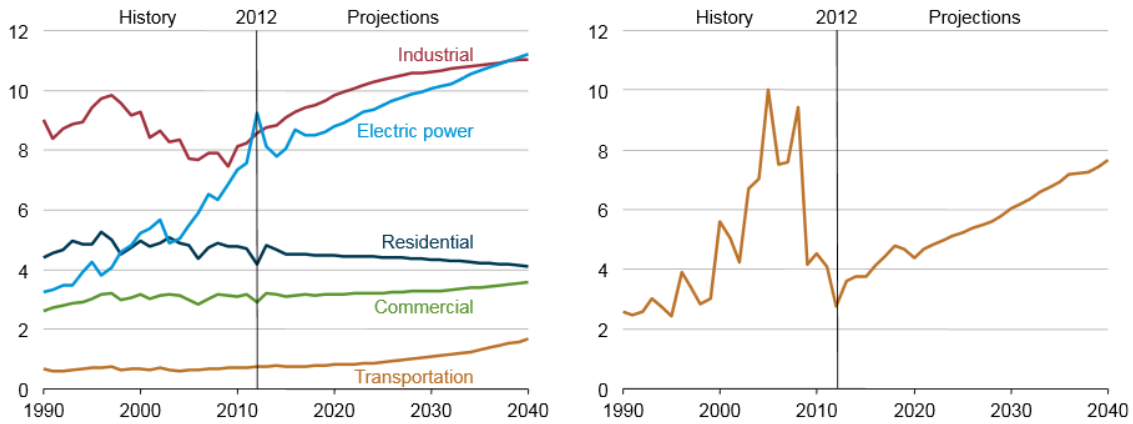
Figure 2. U.S. natural gas production, three scenarios, 1990-2040 (tcf per year)



Source: Annual Energy Outlook 2014 with projections to 2014. EIA, DOE/EIA-0383, April 2014, p. MT-25.

The EIA projections account not only for the factors affecting the supply of natural gas but also for changes in natural gas demand driven by consumption, especially that in the electric power generation, industrial, and transportation sectors (Figure 3). U.S. total natural gas consumption is projected to grow from 25.64 tcf in 2012 to 31.63 tcf in 2040. Consumption of natural gas for electric power generation is anticipated to grow by 2 tcf/year and to constitute about 33% of the increase in total 2040 consumption. About 2.5 tcf of consumption growth is due to increased industrial sector use. Consumption of natural gas as a transportation fuel is projected to grow from 40 bcf/year in 2012 to 850 bcf/year in 2040.

Figure 3. EIA projected and historical natural gas consumption by sector (tcf) and annual Henry Hub spot prices (2012\$ per mmbtu) (for the reference case after 2012; 1990-2040).



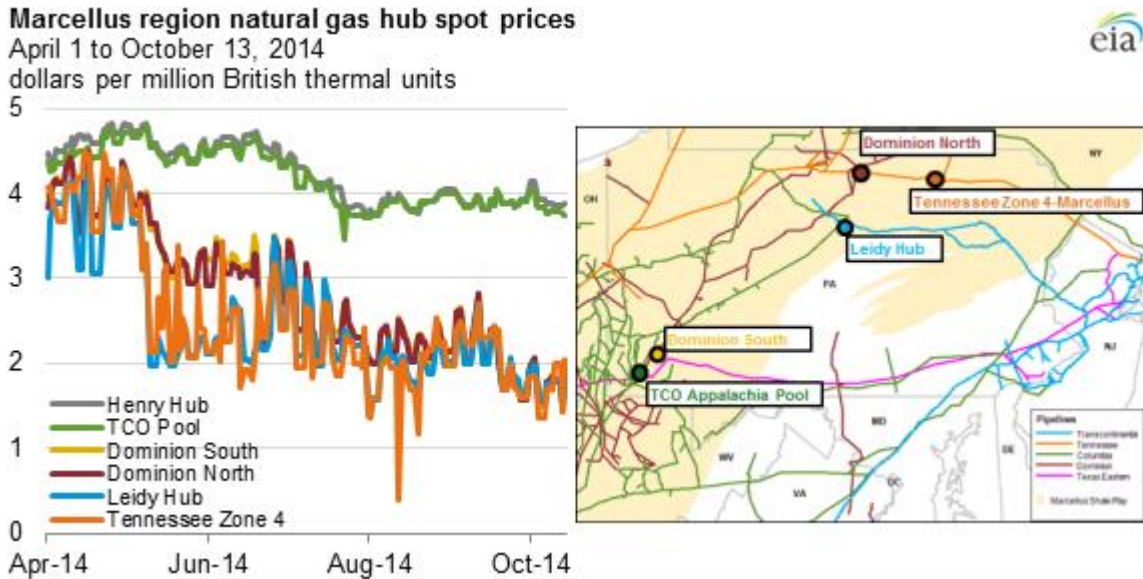
Source: EIA Annual Energy Outlook 2014

According to EIA projections for the cost of natural gas, growth in demand for natural gas, as mitigated by increases in supply, will result in a net upward trend on prices, especially from 2015-2018. EIA’s projected natural gas price for the Henry Hub spot market (reference case) calls for an increase over the next 5 years, ultimately reaching \$5.23/mmbtu by 2025 (Appendix A Table A-1). Comparable forecasts by other agencies and private companies project prices that vary between \$3.92 and \$5.69/mmbtu by 2025. All projections suggest that over the next five years, natural gas prices will not become a principal factor in stimulating upstream and midstream business activity on Utica shale development. The recent decline of oil prices may also indirectly affect the regional gas market, insofar as LNG project economics rely on a “generous spread” between oil-linked LNG and natural gas feedstock prices. Spread volatility such as currently exists in the oil markets may “challenge favorable long-term assumptions driving development of additional U.S. liquefaction capacity.”⁸

Moreover the Henry Hub index price is becoming increasingly irrelevant to the spot market price for natural gas in the Appalachian region, as natural gas production from that region continues to increase in comparison to the Gulf Coast. Indeed, as production in the Appalachian region continues to overwhelm regional consumption, regional hub prices have dropped consistently below the spot price of natural gas at Henry Hub in Louisiana (Figure 4). In the fall of 2014, natural gas produced from the Utica was traded locally nearly \$2/mmbtu below the Henry Hub price, notwithstanding that purchases from these hubs may include some additional transmission costs for some users.

⁸ See “Oil Drop May Slow U.S. LNG. Weaken Economics”, Fitch Ratings, December 22, 2014, found at: https://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Oil-Drop-May?pr_id=959975. The same concerns exist for the spread necessary to displace oil-based plastic feedstock with ethane-base feedstock.

Figure 4. Marcellus Regional Gas Prices and Henry Hub Spot Price and Map of Main Natural Gas Regional Trading Hubs.



For instance the Dominion Transmission Inc. indices (DTI or Dominion North and South hubs) have historically traded natural gas at higher prices than Henry Hub to account for the extra cost of transmission. But due to the surplus production of natural gas from the Utica and Marcellus, the DTI hubs have been trading at well below Henry Hub since May 2013. The regional differences with Henry Hub natural gas prices reflect an oversupply of natural gas from the Marcellus and Utica Shale plays, attributable to a regional shortfall of consumption relative to demand combined with a constrained pipeline take-away capacity.⁹ Without additional new consumption or take away infrastructure, prices in the regional hubs will remain relatively depressed, and eventually lead to a slowdown in drilling.

On the other hand, Columbia Gas Transmission Corporation’s Appalachian Index (TCO Appalachia Pool) – another traded location of Marcellus and Utica natural gas (Figure A-1, Appendix A) – has maintained prices that are comparable to those found at the Henry Hub, notwithstanding the surplus (Figure 4). This is most likely due to fewer pipeline restrictions coming out of the TCO Appalachian Pool. For instance, Columbia Gas was able to back out of obligations to take natural gas from Gulf Coast production to accommodate its West Virginia and Southwest Pennsylvania gas production.¹⁰ By February 2015, Henry Hub,¹¹ TCO Pool, and

⁹ This isn’t the first time that regional indices have fallen below Henry Hub prices. In July 2012 the phenomena of lower regional prices was observed when regional prices at Tennessee Gas Pipeline Zone 4 diverged from Henry Hub prices due to constraints in Marcellus midstream take-away pipeline capacity (Figure A-3, Appendix A). Marcellus production had jumped from 2.9 bcf/d in June 2011 to 5.7 bcf/d a year later. Without significant new take away infrastructure or local consumption, regional natural gas prices dropped to half of Henry Hub spot prices.

¹⁰ See, “Some Appalachian Natural Gas Spot Prices Are Well Below the Henry Hub National Benchmark,” *Today in Energy*, U.S. Energy Information Administration, October 15, 2014, found at: <http://www.eia.gov/todayinenergy/detail.cfm?id=18391>

Dominion South were trading around \$3.00/thousand cubic feet of gas (mcf), while Dominion North was trading around \$2.00/mcf.¹²

In addition to the threat to shale development from sustained low prices for natural gas, the current decline in global oil prices is indirectly affecting national and regional natural gas pricing due to the likely decrease in demand for liquefied natural gas (LNG) on the international markets. Internationally, where shale development has not fundamentally altered natural gas markets like they have in America, natural gas prices are more closely tied to oil prices. With falling oil prices, exporting LNG from the United States to Europe and Asia becomes less attractive, notwithstanding the relatively low cost of making LNG in America. Although the low regional prices will still increase domestic demand from the electricity generation, chemical, and transportation industries, some expansion projects might be slowed down or revisited.

Sustained low oil prices may affect natural gas production in the Appalachian basin in two other ways. First reduced oil production as a result of low prices will lead to a reduction in the production of inexpensive associated natural gas, a by-product of oil production. Second, low profits from oil production may constrain the availability of capital for drilling new non-associated gas wells. Both of these trends could lead to an overall decrease of natural gas supply and, as a result, will eventually lift natural gas prices.

Natural gas liquid prices will also have an effect on drilling in the Utica. Propane, butane and natural gasoline all have local markets and usually retrieve prices that are higher than methane on an mmbtu-basis. However ethane makes up the largest portion of NGLs, and it may or may not retrieve a higher price than methane; it all depends on demand relative to supply. Ethane and methane prices tend to be closely related, since both exist as gas at normal temperatures and pressures, and as such can be mixed together when delivered to a natural gas interstate pipeline. The decision to not remove ethane from the natural gas stream is known in the industry as “ethane rejection.” Ethane separation is rejected whenever the price of methane is higher than ethane, and if the pipelines are able to take it. Ethane is also rejected when there is no available de-ethanization facility or when there is no take-away infrastructure to deliver the ethane to a market.

In wet gas production areas, not all ethane can be rejected if it causes the btu content of the gas stream to exceed pipeline specifications. Interstate pipelines have limits to how much ethane can be placed into the gas stream. In such instances, ethane may have to be sold into lower revenue, or inferior, markets. These instances provide the most advantageous circumstances for a refiner looking to lock up supplies of ethane.

The decision to build a natural gas liquid catalytic cracking facility, however, will not rest on near-term methane or ethane prices. Both the size of the investment and the lead-time for construction require price projections many years out. Accordingly, chemical companies looking

¹¹ “Henry Hub Natural Gas Spot Price” U.S. Energy Information Administration 2/25/15.

<http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

¹² “Northeast Natural Gas Prices” NGI Data 2/15.

http://www.naturalgasintel.com/data/data_products/daily?region_id=northeast&location_id=NEACNGNP

at investing in a cracking facility will be contemplating long-term natural gas and natural gas liquid pricing prospects.

Another way that declining oil prices may affect natural gas markets is that there may be diminishing opportunities to substitute natural gas for oil as a feedstock for petrochemical products or as a fuel for transportation. Some plastics can be made from either refined ethane or from naphtha – a light component of crude oil. The former strategy is favored in the United States, while the latter is generally used in Europe. Cheaper naphtha may slow down investment projects in the U.S. petrochemical industry especially if their target markets are overseas buyers of ethylene or polyethylene. This illustrates the growing competition between lower-priced oil and gas for both fuel and feedstock uses, which in turn might lead to a decrease in demand for natural gas.

U.S. produced Ethane can also be sold on international markets to relieve U.S. market oversupply problems. Earlier this year Enterprise Products Partners estimated that Europe could provide an incremental 415,000 barrels per day (bbl/d) ethane demand.¹³ However, this market could also be supplied by ethane derived from naphtha.

2.1.2. Midstream Infrastructure Catch Up

Planning natural gas marketing today in America is relatively simple. Market planning does not normally begin in earnest until after a discovery. It wasn't always this way, and it is certainly not this way in most other oil and gas provinces around the world. In the 1950s and 60s in America, large volumes of natural gas were flared because there was no market for it. Much of this was because most natural gas was associated with and a by-product of oil production, and could not be shut in pending the development of a market. Markets for natural gas did not fully develop in America until the build out of the petrochemical industry in Texas and Louisiana in the late 1960s. Eventually, as interstate transportation and local distribution systems were built, it became possible to defer marketing decisions until after a discovery.

However even with today's mature American natural gas markets, new natural gas provinces such as the Utica require major new investment into a midstream infrastructure. Without that infrastructure in place, production must be shut in. Operators prefer to not expend resources on drilling and completing wells when there is no expectation of immediately selling the hydrocarbons that are produced.

Midstream companies also have to be careful to not overbuild. So investment into the midstream infrastructure has to be careful and deliberate. To date, the infrastructure in the Utica has been lagging discovery, but not by much. The midstream industry has already invested heavily in the region, and the lag has been less than a year. Throughput projections for the wet gas regions of the Utica and Marcellus shale basin are not expected to exceed

¹³ Marcellus/Utica produced ethane to reach USGC markets in January: Enterprise. Houston (Platts)-- 5Dec2013/437 pm EST/2137 GMT. <http://www.platts.com/latest-news/natural-gas/houston/marcellusutica-produced-ethane-to-reach-usgc-21914284>

processing or take away capacity before 2020. Total Utica and Marcellus midstream investments are projected to exceed \$30 billion.¹⁴

2.1.3. Drilling Rig Availability and Technology Improvements

Counting the number of drilling rigs that are at work in an oil and gas development play is an important tool to track domestic development of oil and gas resources. Rig counts fluctuate with drilling activity and are often used to project relevant employment trends in the United States. Drilling followed the global economic downturn on energy prices in 2008, with rig activity declining from a high of 2,031 active rotary drilling rigs in September 2008 to a low of 875 rigs in June 2009.¹⁵ Although rig counts follow economic trends, and does not predict them, the sensitivity of the number of drilling rigs to changes in regional markets is a useful indicator of the development path in the Utica.

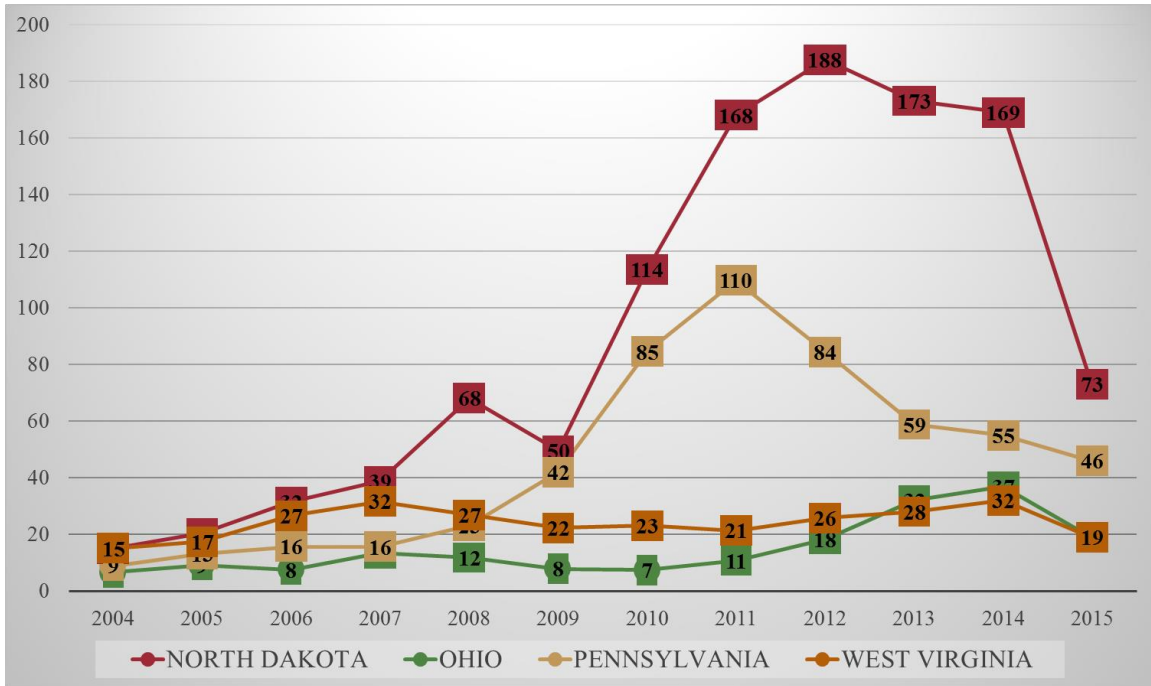
The Study Team tested several hypotheses regarding the count of drilling rigs in Utica region. We considered whether the number of drilling rigs will be increasing in the region due to the approaching end of land leasing cycles and whether sufficient rigs will be available to respond to this possible surge. The Study Team also considered the possibility of a decline in rig count and a consequent reduction in drilling activity due to plunging oil prices.

To answer these questions, the Study Team examined historical trends in numbers of drilling rigs in the principal states located within the regional Marcellus-Utica basin – Ohio, Pennsylvania and West Virginia. We compared the drilling rig counts in these states to the trend of drilling rig counts in North Dakota – home to the Bakken Shale, which is a predominantly oil rich play. North Dakota's rig count has, since 2008, served as a useful benchmark for overall economic growth, and as an example of the dynamic that exists between drilling activity and leasing cycles (Figure 5).

¹⁴ J. Lafield, "From Importer to Exporter," Blue Racer Investor Presentation, 1/30/14, found at: <http://www.caimanenergy.com/sites/default/files/resources/resources0114Presentation.pdf>

¹⁵ Headquarters Economics. Drilling Rig Activity Nears Twenty-Year High Price and Technology Remain Key Drivers of Oil and Gas Drilling Activity. June 20, 2011. <http://headwaterseconomics.org/wphw/wp-content/uploads/RigCounts.pdf>

Figure 5. Dynamic of Rotary Drilling Rigs Count in Selected States. 2004-2015.



Source: Baker Hughes. U.S. Rig Count Data, 2015 data is based on July averages

Just before the global recession, the number of drilling rigs in the Bakken increased from 39 in 2007 to 68 in 2008, and this trend generally continued despite the recession, ultimately reaching 188 rigs in 2012. Since most oil and gas leases contain five-year primary terms, we can speculate that oil prices and production in the Bakken was likely fueled by intense leasing activity in the 2007-2012 time frame. With low oil prices, operators are now facing a decision whether to continue drilling or to release acreage.

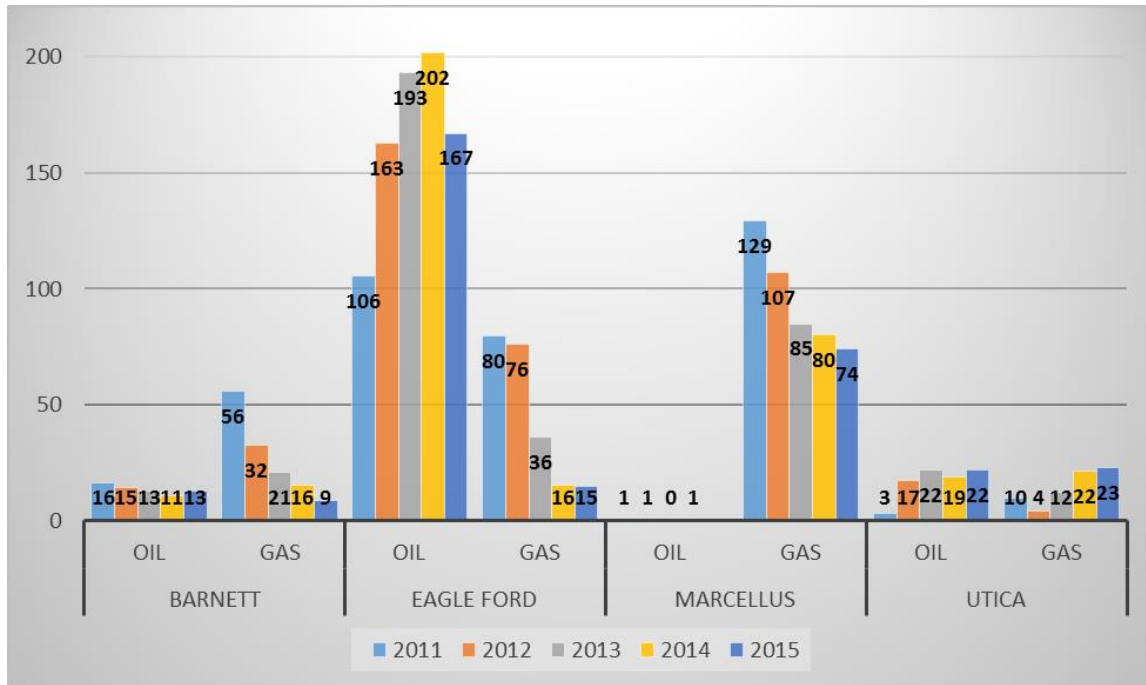
A rapid increase of drilled wells in the Marcellus formation in Pennsylvania occurred between 2007 and 2009, rising from 27 to 785 per year. It is likely that leasing activity in the Marcellus was heaviest in the 2006-2009 time frame, which would suggest that primary lease term expiration would drive an increase drilling activity in 2012-2014. However, it appears from the drilling rig count in Pennsylvania (dropping by around 50 rigs between 2011 and 2013) that shale development there was influenced more by natural gas prices than by the leasing cycle. Likewise, while we might expect that expiring leases in the Utica would cause a surge in drilling in 2015-2016, it appears that such a surge, will not significantly influence the overall development of Utica play. Prices for the gas and access to midstream infrastructure will have a greater influence on the development of the Utica than will expiring land leases.

Moreover, from an analysis of the rig counts across four shale plays (Figure 6), it is evident that the total rig count in the Utica play has been growing, while the total number of rigs in the

Barnett, Eagle Ford, and Marcellus plays have been declining.¹⁶ The decline may be caused by a decreasing number of rigs drilling for “dry” natural gas. The drilling in recent years in the Utica has targeted the “wet gas” portion of that play.

Of course, the recent price collapse for oil may well be changing this. Lower oil prices have also caused a price reduction for liquids, and as a result, we are now also seeing a reduction of drilling rigs in the areas targeting NGLs, such as the Utica. According to Rigdata, the rig count for the Utica (in Ohio) has dropped from 52 in October 2014 to 19 as of June 2015.

Figure 6. Rig Count by Type of Wells in Selected Basins. 2011-2015



Source: Baker Hughes. U.S. Rig Count Data, 2015. 2015 data are based on the average of January and February 2015.

Improving technology is another factor that has caused a drop in the number of drilling rigs in shale basins. One such technology improvement has been a decrease in the “spud to spud” drilling time for wells.¹⁷ This means fewer rigs are needed to do the same work. Longer completion zones in the horizontal laterals also have reduced the number of required wells, and therefore rigs. Likewise, better knowledge of a basin’s geological conditions, together with improving skills within operating and service companies, has reduced the risk of both mechanical and commercial failure. Indeed, shale drilling has become more like a factory

¹⁶ Count of rigs in Utica Shale by Baker Hughes differs from the number of rigs listed by Ohio Department of Natural Resources. Being aware of under count in number of rigs by Baker Hughes data, this analysis aim to show the dynamic of rigs across time and geographies.

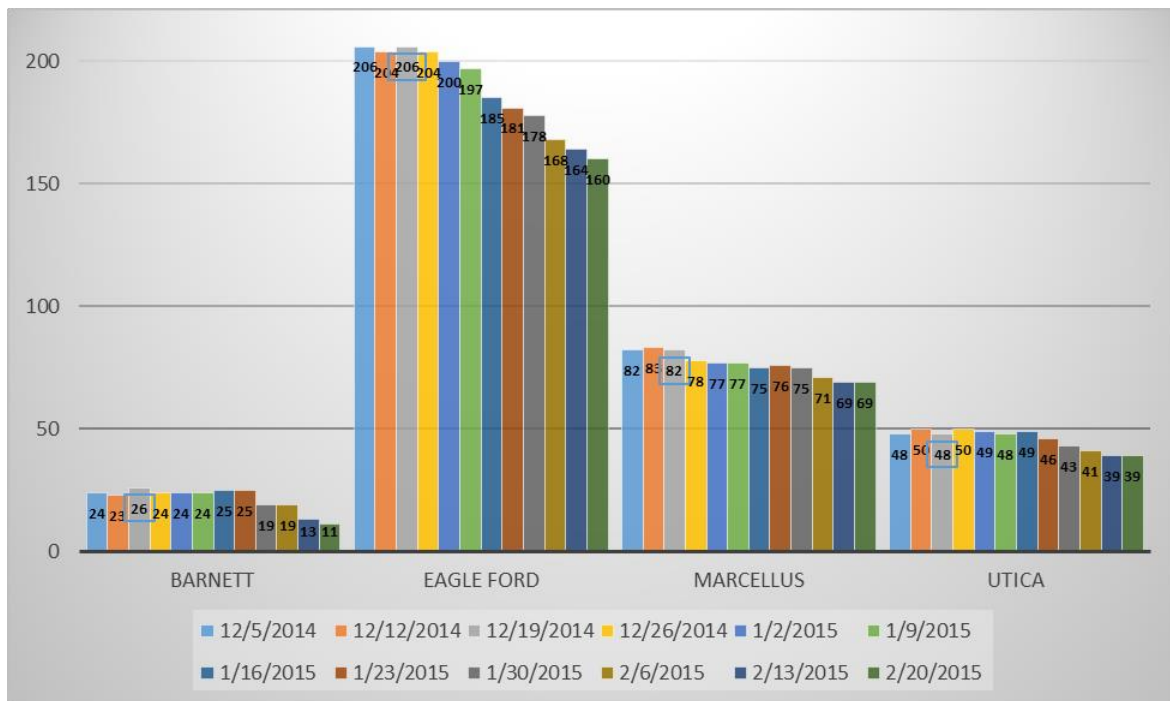
¹⁷ “Spud” refers to the actual time when the drilling bit penetrates the surface. Spud to spud refers to the time from the beginning of one well to the beginning of the next well.

process than the traditional “high risk-high reward” strategy used for exploration.¹⁸ The emphasis of shale drilling is on process optimization rather than on risk control. Drilling plans and “authorities for expenditure” (cost estimates) are predictable and reproducible from well to well. This approach has improved efficiencies and reduced the need for as many rigs.

The total number of rigs within Marcellus-Utica basins has been stable between 2012 and 2014. This followed a slight decline in the number of rigs from 2011 to 2012, caused by an outflow of rigs in response to low regional natural gas prices. Utica producing companies interviewed do not anticipate any problems with drilling rig availability. With about half of their active rigs in the dry gas corridor and half in the wet gas/condensate corridor, Utica producers should be able to retain mineral rights through production by moving the rigs between wells, depending on commodity pricing, availability of infrastructure and the exigencies of leasehold requirements.

As a result of falling oil prices in the winter of 2014-15, some analysts have projected that 500 drilling rigs may be taken off the market in 2015. These projections are based upon announcements from producers that they anticipate capital budget cuts ranging from 20% to 40% for 2015. Companies making public announcements that reflect budget reductions include Laredo Petroleum, Range Resources Corp., Oasis Petroleum, among others.

Figure 7. Rig Count by Basin: 12 Weeks December 2014 – February 2015



Source: Baker Hughes. U.S. Rig Count Data, 2015

¹⁸ See e.g. S. Rahim, “Focus on Well Efficiency Keeps Marcellus Shale Pumping Despite Low Prices, *E&E Publishing*, February 5, 2014, found at: <http://www.eenews.net/stories/1059994007>.

Over the 12 weeks between December 2014 and February 2015, the Marcellus-Utica region lost fewer rigs on a percentage basis than the more crude-intensive Eagle Ford and Barnett basins (Figure 7). Utica dropped 9 rigs, decreasing its count by 18.8%, while the Marcellus parked 13 rigs (15.9%). The Eagle Ford decreased its rigs by 22.3% and Barnett lost 54.2% of its rig count. The enduring Marcellus-Utica rig count, in the face of falling oil and gas prices, suggests a leaner cost of development in that region compared to other shale plays.

2.1.4. Effects of Unitization and Stranded Leases

One potential threat to the rapid development of the Utica relates to the rate and availability of statutory (forced) unitization. Operators cannot begin drilling until a unit has been established for the area to be drained, and often times the operators are unable to get all the mineral rights leased within a proposed unit. When this happens, the operators may deploy a legal procedure that enables them to “force-unitize” unleased acreage.¹⁹ If unitization approval through this process is delayed, operators may not be able to proceed to drill with the speed they might otherwise have.

Currently, under Ohio Department of Natural Resources procedures, there is a 120-day notice period required before a hearing on a forced unit is set.²⁰ Moreover, a decision on the hearing can take up to another 90-120 days before an order is issued. The result is that an operator may have to wait 8 months to get a unitization order. This lengthy waiting period can create difficulties for operators looking to efficiently develop their leaseholds.

However the Ohio General Assembly is in the process of considering a bill – House Bill 8 -- that will reduce the notice period to 45 days. As of September 2015, HB 8 was still under evaluation by the Ohio Senate. Other states, such as West Virginia and North Dakota, have considerably shorter notice periods than does Ohio.²¹

It is impossible to know exactly how this will play out over time, but there is no doubt that delays in statutorily created units will impact drilling strategies in some fashion. This in turn could lead to the creation of inefficient units, the use of sub-optimal drilling locations, and ultimately to the stranding of leases. The last will occur when operators are forced to abandon leases because they are either unable to fit them into a voluntary unit, or because they do not have the necessary 65% leasehold to force a unit.

¹⁹ See ORC §1509.28. At least 65% of the acreage contained in the unit must be voluntary. When mineral rights are forced into a unit, they are typically treated as though it were a mixture of leasing rights (royalty percentage) and working interest rights (net profit share).

²⁰ The 120 day notice period policy is set forth in an Ohio Department of Natural Resources, Oil and Gas Division, “Guidance Letter.” Under the traditional forced pooling strategy in Ohio – a far less complex and controversial procedure than forced unitization – the guidance letter required 45 days. See http://oilandgas.ohiodnr.gov/portals/oilgas/pdf/Unitization%20Application%20Guidelines_E050914.pdf.

²¹ The most common notice period is 45 days. See, e.g. North Dakota (NDCC Section 38-08-09.5).

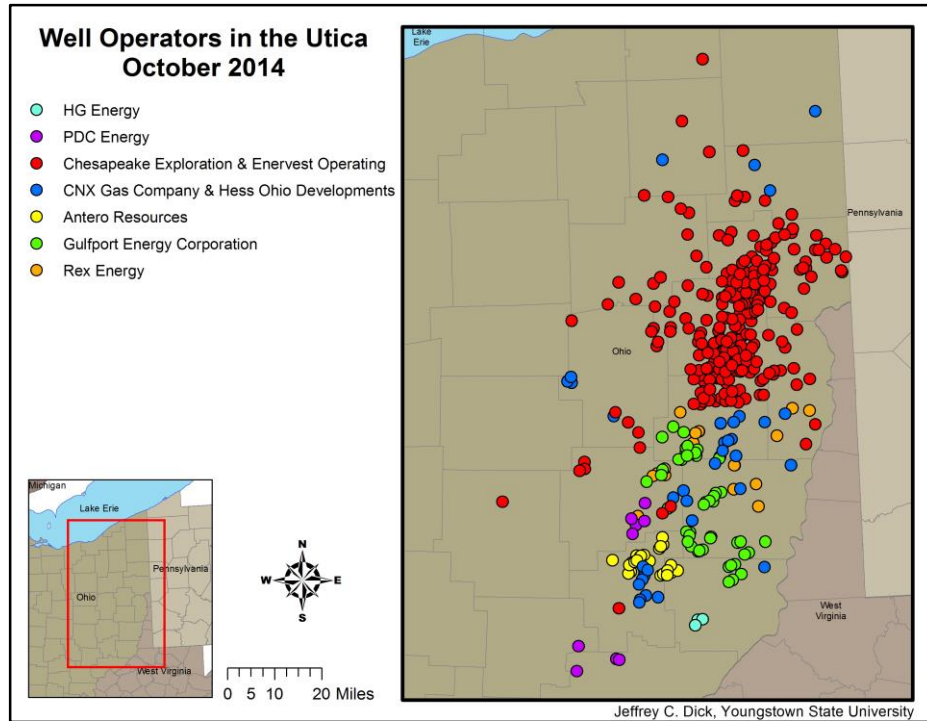
2.1.5. Strategies of Principal Utica Upstream Players

The development of the Utica shale formation within the state of Ohio will depend principally upon the investment strategies of a handful of key oil and gas operating companies. Most large and mid-size oil and gas producers mitigate their risk by investing in multiple plays. Some will also invest in midstream and even downstream projects to further mitigate risk, and also to ensure that there will be a market for their production. Companies investing into the Utica are no different in this regard; they all have investments that cross multiple regions and markets, and that compete internally for financial resources.

The Study Team examined historical ODNR data for drilling permits and actual drilling to identify the principal Utica players, resulting in a list of seven companies that have, to date, performed over 80% of operations in the Utica basin. Based on the data over six quarters during 2013-2014, the top producers ranked by the number of drilled and permitted wells, are the following companies (Figure 8):

- Chesapeake
- Gulfport
- Antero
- Hess and CNX Gas
- Rex Energy
- HG Energy
- PDC Energy

Figure 8. Spatial Distribution of Permitted, Drilled and Producing Wells of Main 7 Utica Operators



Over time, Chesapeake and Gulfport have remained as leaders in drilling Utica wells, with a few others, Hess, Rex Energy, and more recently Antero increasing their activities (Table 1).

Table 1. Leading Utica Drilling Companies in Ohio, 2013-2014

	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2
Chesapeake	Chesapeake	Chesapeake	Chesapeake	Chesapeake	Chesapeake	Chesapeake
Gulfport	Gulfport	Gulfport	Gulfport	Gulfport	Gulfport	Gulfport
Hess	Hess	Hess	Antero	Antero	Antero	Antero
Anadarko	Rex Energy	Rex Energy	Rex Energy	Rex Energy	Rex Energy	Hess
PDC Energy	Hilcorp	Hilcorp	Hess	Hess	Hess	Rex Energy
Enervest	Anadarko	Anadarko	Hilcorp	HG Energy	HG Energy	HG Energy
Rex Energy	Enervest	Enervest	Anadarko	PDC Energy	Eclipse Resources	Eclipse Resources

Source: ODNR

Chesapeake remains the biggest Utica developer, holding about 70% of all land leases,²² including 250,000 acres in wet gas, 300,000 in oil and 540,000 acres in dry gas.²³ The company

²² Seeley, Rachel. "Chesapeake Energy leads the pack in Utica" Oil and Gas Journal 8/13/14. <http://www.ogj.com/articles/uogr/print/volume-2/issue-4/chesapeake-energy-leads-the-pack-in-utica.html>

²³ According to Magnum Hunter analysis, Chesapeake is the #4 leveraged producer in Utica. The leverage is measured by the size of Utica share in company's total leased acreage in all shale plays.

has been drilling over 70% of all Utica wells.²⁴ By the end of the first quarter of 2014, Chesapeake was operating, on average, 8 rigs in Ohio's Utica play, accounting for 485 drilled wells and 274 producing wells. At the time, 211 of Chesapeake's drilled wells were shut in awaiting connection to the midstream take away system. This number decreased to 172 by September 30, 2014. The company identified its Estimated Ultimate Recovery (EUR) per well at 1,325 mboe (thousand-barrel oil equivalent), with production of 67 mboe per day as the expected per well average in the second quarter, rising to 85.5 mboe per day during the third quarter of 2014. Over 2013-2014, the company estimated its production growth in the Utica play at 300%, after seeing 400% growth in 2012-2013. The company's strategy within the Utica has been to increase its drilling efficiency. Chesapeake's average completed well cost rose from \$6.7 M in 2013 to \$7.1 M in 2014; however in those same two years, it improved its efficiency substantially through longer completed lateral well lengths (5,150 to 6,300 feet) and by increasing the number of fracturing stages (from 17 to 32).

Chesapeake shifted its emphasis in the Utica from dry gas production to wet gas, growing its wet gas segment by 65% in 2013-2014. Chesapeake formed two joint ventures, with French TOTAL and Houston-based EnerVest (EV). The company's plans to unlock an oil window may prove to be less appealing if prices remain as low as they were in the winter of 2014-2015. Chesapeake Energy recently sold its assets in the South Marcellus Shale and part of its assets in the Eastern Utica Shale to Southwestern Energy. This was followed by a recent announcement of the company's plans to repurchase \$1 billion worth of its own shares.²⁵ However there is nothing in these moves that suggests that Chesapeake will discontinue its bullish strategy in the Utica.

EnerVest Energy (EV) is the most leveraged producer in Utica²⁶ and operates through its joint venture with Chesapeake (Figure 9). The company operates primarily within the wet gas window and also has invested in midstream capacity through joint ventures in the Cardinal (9%) and Utica East Ohio (21%) pipeline systems. Although EV has significant Utica acreage and midstream assets, it also sells acreage when it suits its financial needs. In December 2014, the company was considering increasing its investment into the condensate²⁷ portion of the Utica, among other opportunities, such as expanding its investment into the wet gas window and ramping up its Utica midstream presence. The company has a diversified portfolio of assets across 10 basins with commitments to spend 11% of its exploration and production capital in

²⁴ The analysis of the main Utica producers' strategies is based on the analysis of Q1 and Q3 2014 investor presentations, press releases and producer presentations in multiple public events.

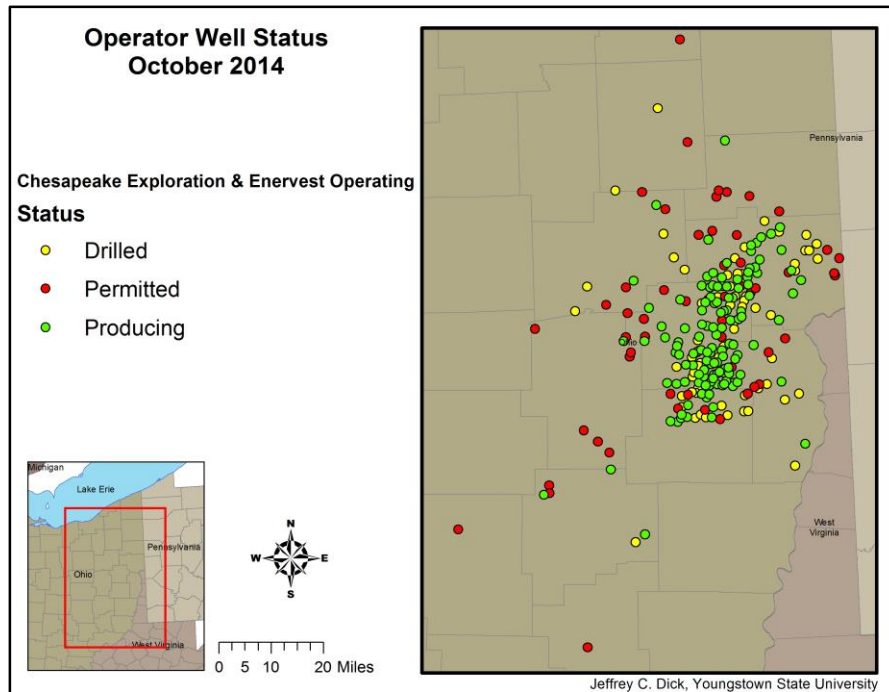
²⁵ Fukushima, Kurumi. "Chesapeake Energy (CHK) Stock Closed Up Today on \$1 Billion Share Buyback Following Asset Sale" The Street 12/23/14. <http://www.thestreet.com/story/12994764/1/chesapeake-energy-chk-stock-closed-up-today-on-1-billion-share-buyback-following-asset-sale.html>

²⁶ "2014 Louisiana Energy Conference" Magnum Hunter Resources 6/14. <http://www.louisianaenergyconference.com/webdocs/Magnum%20Hunter-LEC%20Panel-2.pdf>

²⁷ Condensate, also known as volatile oil, is oil that is in a gaseous state under reservoir conditions, but separates out (condenses) as a liquid with production at surface conditions. It has a relatively high API rating (upper 30s to low 40s) compared to conventional oil. API is a reference which compares a liquid hydrocarbon density (specific gravity) to that of water. Anything with a higher API rating than 10 is less dense than water, and will float on it. Most hydrocarbon liquids range in API gravity ratings from 10-70, with heavy crude anything below 22, and light crude anything above 31. Condensate falls into the light crude category.

the Appalachian basin. Its 2014 capital spending was split about 50/50 between midstream and upstream (exploration & production) investments.²⁸

Figure 9. Distribution of Drilled, Permitted and Producing Wells of Chesapeake and EnerVest



EnerVest plans to continue participation in the Chesapeake joint venture, and intends to gather, process and fractionate wet gas through its joint ventures. EnerVest has an interest in 600 mmcf/d (million cubic feet per day) of processing capacity and 90 mbbbl/d (thousands of barrels per day) of fractionation capacity in its Kensington and Leesville plants in Carroll County, Ohio. EnerVest plans to develop additional acreage commitments through its joint venture, and also owns a 145,000 acre “area of mutual interest” with American Energy Partners (AEP), pursuant to which it can further acquire and develop acreage within the Utica. The company originally planned to continue with its joint ventures to: build an additional 200 mmcf/d processing capacity at its Leesville facility; construct a high pressure pipeline from the Harrison Hub (Harrison County, Ohio) to the Cardinal Compression facility; develop a downstream liquids interconnect and expand propane and butane storage at Harrison Hub; and provide gathering, compression, and dehydration services in Utica acreage.²⁹ In April 2015, however, Williams Partners announced that it would be acquiring EV’s 21% stake in the Utica East Ohio system for \$575 million, with the deal potentially being finalized by July 2015.³⁰

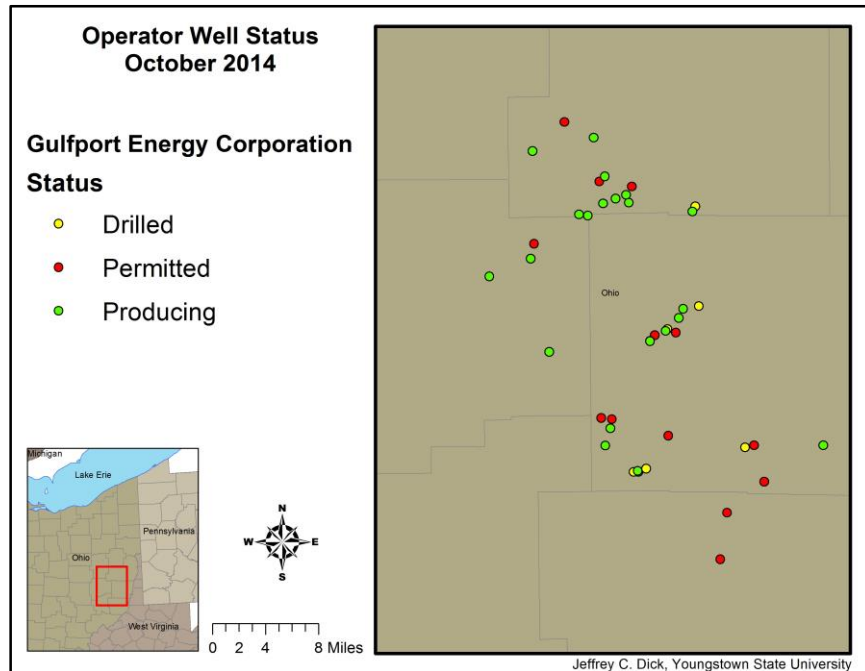
²⁸ EV Energy Partners. Well Fargo Energy Symposium presentation, December 9-10, 2014. Source: http://files.shareholder.com/downloads/EVEP/3799421390x0x798411/40114F7E-5314-42FC-B143-A474934544E4/EV_Energy_Partners_Wells_Fargo_Presentation_120914.pdf

²⁹ *Id.*

³⁰ Carr, Housley “Join Together With Demand-Five Marcellus/Utica Midstream Players” RBN Energy LLC 4/12/15. <https://rbnenergy.com/join-together-with-demand-five-Marcellus-utica-midstream-players>

Gulfport Energy Corporation (Gulfport) is ranked #2 in drilling and #3 in leased acreage in the Utica formation. With 4 rigs and 184,000 net leased acres, Gulfport expected to have 73 wells producing with a net production of 87.7 bcfe (billions of cubic feet equivalent) by year end 2014. With midstream investments and knowledge, Gulfport has the ability to develop wells and to market its production. The company plans to continue to be aggressive both in its drilling and its midstream activities, the latter through an expansion in takeaway capacity through the ET Rover pipeline agreement, which will take production from the field to Defiance, Ohio and then on to Michigan and Ontario. Gulfport also conducts operations through a joint venture with Rice Energy in the dry gas window (Figure 10).

Figure 10. Gulfport Permitted, Drilled and Producing Wells in Utica.



Gulfport, however, is different from many Utica players insofar as the Utica is its primary investment play. More than 82% (\$547.5 million) of Gulfport’s capital expenditures are devoted to the Utica project area. The company experienced record production growth in 2014 primarily due to the Utica, and the company has optimized its production by implementing pressure management strategies, flow optimization and hybrid gel fracturing of its wells. Gulfport also achieved significant improvements in its drilling times (reaching 22 days spud to spud drilling time per well). Gulfport plans to continue its active drilling in the Utica, and to maintain an interest in developing the region’s midstream infrastructure, thereby ensuring transportation and sales outlets, and to continue to increase its drilling efficiency through its suppliers and the aggressive use of new technologies.³¹

³¹ “Investor Presentation” Gulfport Energy Corporation 2/15.
http://files.shareholder.com/downloads/GPOR/3799629047x0x793305/C87014E8-0408-4F7B-A019-A92FADEEAC11/GPOR_InvestorPres_vFinal4_Website.pdf

Other significant players in the Utica include Antero Resources, Hess, Rex Energy, Range Resources, HG Energy, PDC Energy, and American Energy Partners. Each has had a significant, but, as of 2014, a less decisive impact on the development of the Utica play. These companies will likely continue to orient their portfolios in the Utica towards natural gas production (wet and dry) and to optimize their investments through mid and possibly even downstream activities.

2.2. Volumes and Throughput Projections

2.2.1. Projections Based Upon Publicly Available Data

2.2.1.1. Production data

Projecting the likely midstream and downstream opportunities from shale development begins with projecting likely total production over a given time frame. For purposes of estimating likely construction, mid and downstream industries use “throughput” to estimate the amount of infrastructure required to accommodate a particular volume of hydrocarbons. For natural gas, this throughput is commonly expressed as millions or billions of cubic feet per day (mmcf/d or bcf/d) that pass through the pipelines or processing facilities. For NGLs or condensate, throughput is typically expressed in terms of thousands of barrels per day (mbbl/d).

In order to project likely throughput from the Utica formation over the next five years (2015-2019) it was necessary to make several determinations about the nature of drilling and production performance from the Utica over its relatively short production history. The principal factors controlling the throughput estimates are: (1) average initial production from each well, (2) expected decline in production thereafter from each well, and (3) the number of likely wells in production.

The Ohio Department of Natural Resources Division of Oil and Gas Resource Management provides production reports on an annual basis for 2011 and 2012 and on a quarterly basis for 2013 (Q1 – Q4) and 2014 (Q1 and Q2). The quarterly production reports are generally released three months after the end of the production period. At the time the production study was prepared, only the first and second quarters of production were available for 2014.³² The production reports provide wellhead production values for barrels of oil (bbl) (one barrel equals 42 U.S. gallons), thousands of cubic feet of gas (mcf), barrels of produced water (brine and flowback) and the number of production days for each well. Since the natural gas liquid components are produced with the gas stream at the wellhead and typically separated at off-site cryogenic and fractionation facilities, the NGLs components (ethane, propane, butane, etc.) are not included in the ODNR production reports.

In order to estimate liquids throughput an additional analysis was required to estimate the volume of NGLs that could be gleaned from natural gas processing. This undertaking required a spatial analysis of Utica production, as well as an examination of the makeup of liquids recovered at the processing plants. Ultimately, areas classified as natural gas (dry gas), NGLs (wet gas), condensate, and oil were identified as occurring in distinct zones, and mapped as such.

³² The third quarter 2014 production report was issued just before the release of this study, however there was insufficient time to evaluate that report.

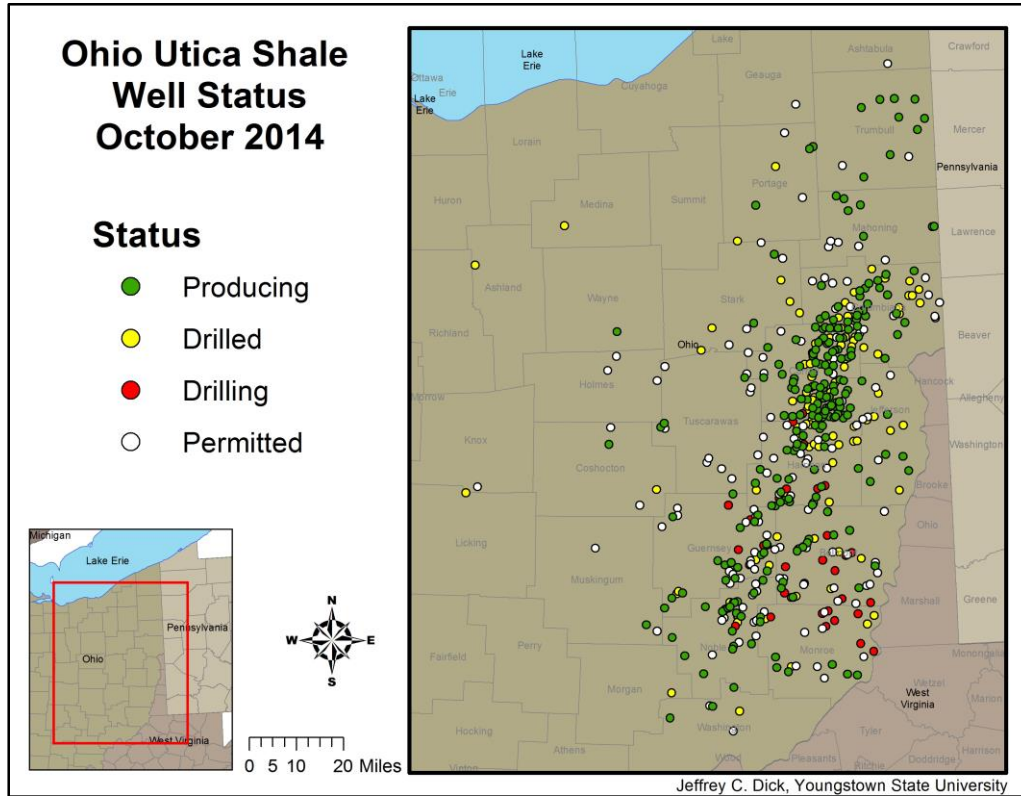
Accordingly, an analysis was undertaken for the Utica based upon a review of 573 producing wells as reported by the Ohio Department of Natural Resources (ODNR) in its October 11, 2014 Utica/Point Pleasant Shale Cumulative Permitting Activity Report. In addition, the following data were examined in reaching estimates for throughput:

- ODNR annual production reports for 2011-2012,
- ODNR quarterly production reports for 2013,
- ODNR production reports for the first two quarters of 2014,
- Rigdata Locations and Operators' reports,
- Calculated Initial gas/oil ratios (first quarter production for individual wells), and
- Publicly released initial production and test rate information.

2.2.1.2. Well Status

The ODNR provides Utica/Point Pleasant Shale Cumulative Permitting Activity Reports on a weekly basis. Individual wells are classified as “drilled,” “drilling,” “permitted” and “producing.” Additional information on well status is available from commercial reporting agencies such as Rigdata. The combination of these two sources provides a reasonably accurate assessment of well status. Figure 11 identifies individual well pads as producing, drilled, drilling, and permitted as of October 11, 2014. A total of 573 producing wells from 241 drilling pads (identified in green) were used in the study to estimate throughput. Although producing wells can be found throughout most of the Utica Shale region, the majority of producing wells are clustered along a rough line starting in Columbiana County and extending south-southwest through Carroll, Harrison, Guernsey and Noble Counties. Drilling activities in October 2014 were concentrated within Carroll, Harrison, Guernsey, Belmont, Noble and Monroe Counties. Many wells identified as “drilled” are waiting on the construction of gathering lines for natural gas and NGL production. The drilled wells along the western edge of drilling activity in Ashland, Knox and Medina Counties are presumably non-productive due to the shallow nature of the Utica Shale and likely low formation pressure and/or insufficient dissolved gas content.

Figure 11. Ohio Utica Shale Well Status.



2.2.1.3. Production Type Zones

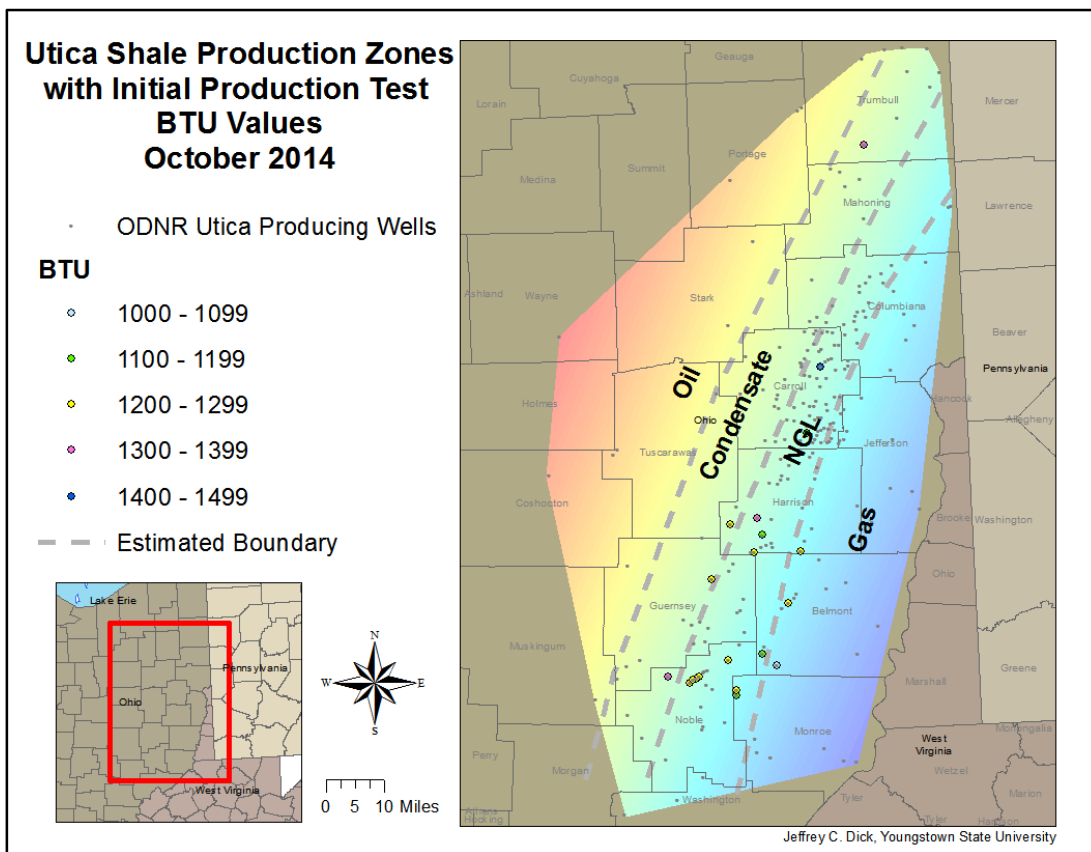
Production areas of oil, condensate, NGLs (wet gas) and dry gas (methane) in the Utica Shale tend to correspond to increasing depth or thermal maturity of the shale. The structure map on top of the Trenton Limestone³³ represents the structure of the Utica Shale as the Trenton Limestone directly underlies the Utica (Point Pleasant Formation). The Utica Shale structure is such that it dips at a general rate of approximately fifty feet per mile in an east – south east direction. The base of the Utica Shale can be found at a depth of approximately 3,600 feet in eastern Ashland County and decreases to a depth of approximately 8,500 feet along the Ohio River in northeastern Jefferson County. The result is the Utica Shale having zones of production that mimic or correspond to the rock structure. The eastern side of the Utica, with the greatest thermal maturity, tends to produce dry methane gas. The western side, with the lowest thermal maturity, tends to produce crude oil and condensate.

The Utica Shale Production Areas map (Figure 12) depicts the estimated locations of oil, condensate, NGL (wet gas) and gas (methane or dry gas). The map was constructed using the quarterly production histories of 573 Utica wells, along with calculated initial gas (mcf) to oil (bbl) ratios, subsurface elevation (based on Trenton Limestone structure) and media reports on initial production and energy content (in British Thermal Units). The btu measurement was available from media reports for initial production of thirty-one Utica wells.

³³ Patchen, D.G. et al, 2006, A geologic play book for Trenton-Black River Appalachian Basin exploration: Morgantown, W. Va., US Department of Energy Report, DOE Award Number DE-FC26-03NT41856, 601 p.

The Production Areas Map (Figure 12) map shows an association of production type with increasing depth. Natural gas is found in the eastern region of the Utica Shale play where the shale is deeper and likely to have a greater thermal maturity. This gas zone transitions to an NGL zone as the formation becomes shallower up-dip to the west. The boundary between the two zones is estimated based on btu content and to a lesser extent on initial production gas to oil ratio (mcf/bbl). The NGL zone has the greatest number of drilled and producing wells and the btu content ranges between 1100 and 1499. The estimated boundary between the condensate and NGL zones is based almost entirely on gas to oil ratio calculated from ODNR production reports. Wells having gas to oil ratios between 1 and 10 are considered condensate producers and wells with gas to oil ratios equaling zero (no recorded gas production) are considered oil producers. The geographic extent of the oil zone is still uncertain as few wells have been drilled in the western portion of the play. To date, most activity in the Utica has been focused in the “NGL” zone, where returns on investment have been the most predictable.

Figure 12. Ohio Utica Shale Production Areas with Initial Production Test btu Values, October 2014



2.2.1.4. Production Distribution

Similar to production type, production rate is dependent on geological attributes that influence pressure as well as dissolved gas content (reservoir management strategies may also control production rate). It is not within the scope of this report to study geological attributes, however it is useful to create production maps that illustrate areas of greatest production and greatest production potential. Accordingly, two different maps, Utica Shale Total Production (Figure 13) and Utica Shale Peak Average Daily Production (Figure 14), were created using ODNR annual and quarterly production reports.

The production map information was drawn from the production reports of 573 individual wells that have reported production histories of at least one full quarter during the six production quarters of 2013 – 2014. Production maps depict combined oil and gas production reported in Barrels of Oil Equivalent (boe) or Barrels of Oil Equivalent per Day (boepd). The accepted industry formula for calculation of individual well production in Barrels of Oil equivalent is:

$$\text{Barrels Oil Equivalent (boe)} = \text{barrels of oil} + \text{mcf gas}/6.0 \text{ (mcf gas/ barrel of oil)}$$

Barrels of oil Equivalent per Day is calculated by dividing the boe production for individual wells by the number of days over which the production occurred.

The Utica Shale Total Production map (Figure 13) depicts the total production (in boe) using contoured areas in incremental amounts of 50,000 bbl. The map clearly defines an area having total production greater than 200,000 boe with Belmont, Noble and Monroe Counties and a small part of Guernsey County. The map by itself is not all that useful since the individual wells have produced for varying amounts of time.

The Utica Peak Average Daily Production map (Figure 14) overcomes the problem of varying number of production quarters and total production days by mapping the single greatest production quarter for individual wells using the units of Barrels of Oil Equivalent per Day. The quarter of greatest production is typically the first quarter of production. The map depicts production in boepd using contoured areas having increments of 200 boepd and 1,000 boepd. Similar to the Total Production map, Belmont, Noble and Monroe Counties, Southern Harrison County and a small part of Guernsey County have the greatest peak average daily production greater than 1000 boepd with southern Belmont County exceeding 2000 boepd. These areas correspond to the area of current drilling activity identified in Figure 11.

Figure 13. Ohio Utica Shale Total Production Barrels of Oil Equivalent (boe), October 2014

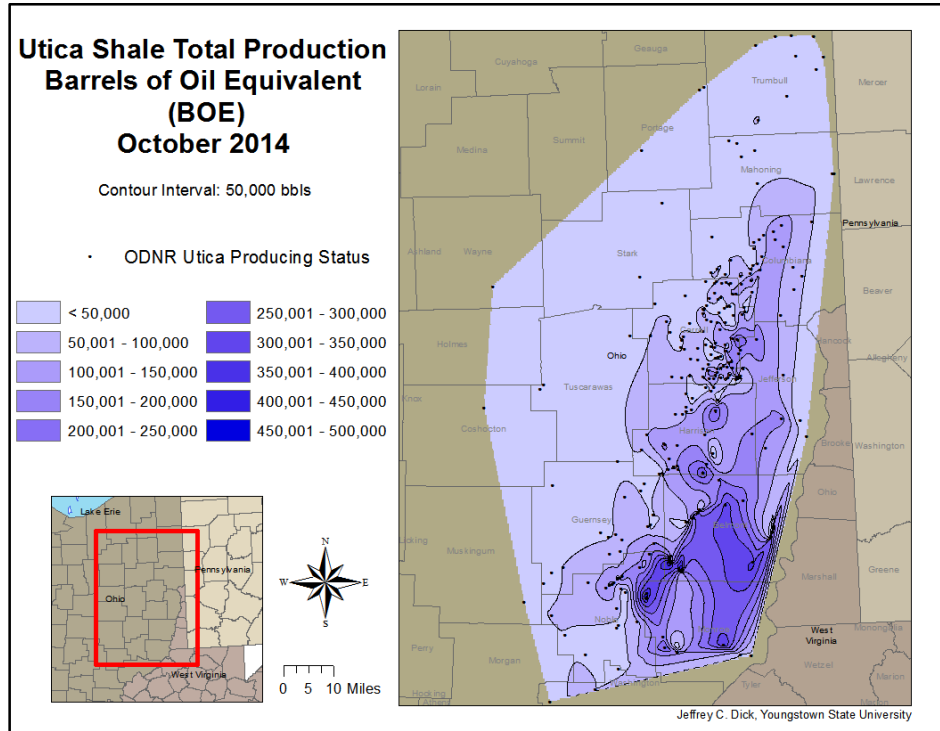
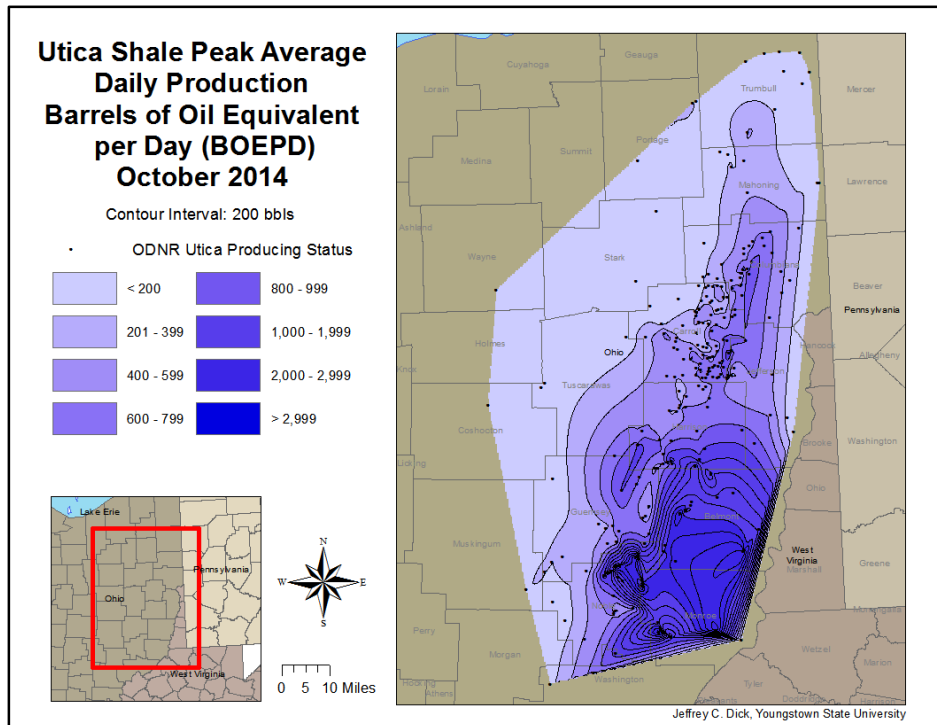


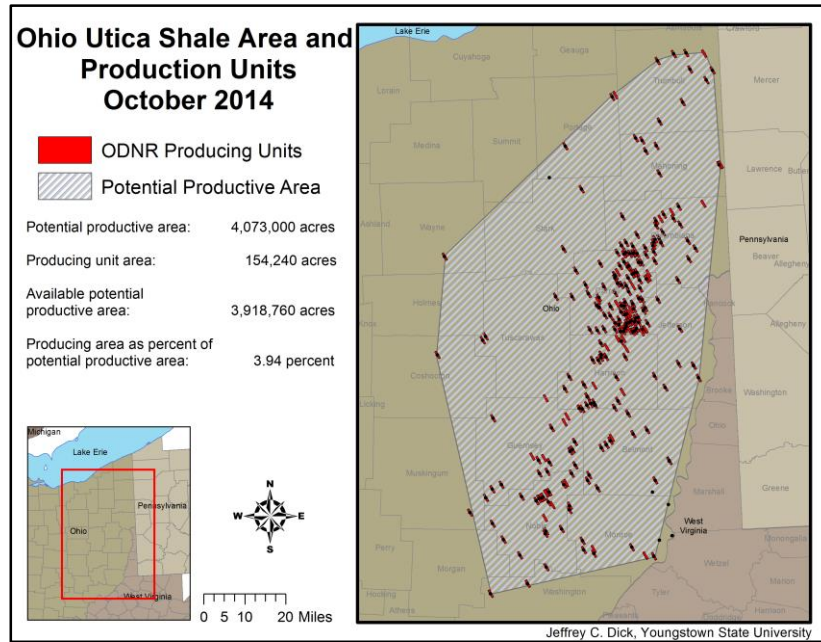
Figure 14. Ohio Utica Shale Peak Average Daily Production Barrels of Oil Equivalent Per Day (boepd), October 2014



2.2.1.5. Potential Productive Acreage

A useful measure of future drilling potential is a map depicting the total potential productive area of the Utica Shale and the amount of productive acreage currently drilled (Figure 15). The Potential Productive Area is an estimate of the gross area (includes cities, municipalities and other areas not likely to be drilled) within the geographic footprint of Utica wells identified by the ODNR as “producing,”³⁴ and equals four million and seventy three thousand (4,073,000) acres. This area is simply the productive Utica Shale area defined by established production and used in the maps of Figure 12, Figure 13, and Figure 14. The red polygons identified as ODNR Producing Units assume a standard 640-acre unit associated with each drill pad. Although the actual acreage may be more or less depending on the number of producing wells drilled on each pad, it is a reasonable assumption for early drilling, which often targets holding a unit with one or two wells from each pad.³⁵ The total producing unit area is one hundred fifty-four thousand two hundred and forty (154,240) acres constituting two hundred and forty one (241) separate well pads. This leaves approximately 3.9 million acres of remaining potential productive area. This analysis leads to the conclusion that in approximately four years’ time, 3.9 percent of the total potentially productive area of the Utica Shale has been drilled.

Figure 15. Ohio Utica Shale Area and Production Units, October 2014



³⁴ The status of wells as producing or otherwise are listed on the ODNR, Division of Oil and Gas, website (found at: <http://oilandgas.ohiodnr.gov/>). The actual geographic extent of the Utica will not be known until after wells are drilled along the frontier borders of current production, and those wells have been fully evaluated. Moreover, some wells that are not currently producing do not necessarily determine the boundaries of the Utica; wells that are currently not economical may become so later as prices and technology change.

³⁵ A more common strategy for unitization in 2014 is the creation of two units, once facing north or northwest of the drilling pad, and a second facing south or southeast of the pad. As completion zones within wells have increased laterally in the wellbores, the size of the units has also increased. Commonly there will be two units of 700-900 acres each associated with one pad.

2.2.1.6. Drilling Estimates

Rate of drilling is controlled by a combination of factors that include petroleum commodity prices, production rates, rig availability, rig counts, drilling efficiency, and strategies of the exploration and production companies. Commodity prices include NGLs, which have remained relatively high in recent years for the C3 (propane) and greater liquids. Lower commodity prices for methane may have contributed to rigs being moved from the dry gas region to the wet gas region in recent years.

The number of rigs moving on to site, drilling or moving off site is referred to as rig count. Rig count for the state of Ohio is monitored by the ODNR and reported by several industry reporting entities such as Rigdata. According to weekly Rigdata reports³⁶, the rig count increased from 40 in January 2014 to its peak of 56 in November 2014. However, Ohio rig counts have declined to 19 by June 2015.³⁷ Based on drill rate information determined from ODNR records in October 2014, it was estimated that a total of 593 Utica wells would be drilled in 2014. The actual number of Utica wells drilled and completed in 2014 was 391.³⁸

Rate of drilling is dependent on drilling efficiency and the number of available rigs. This rate can increase both due to the addition of drill rigs and to the improvement in drilling efficiencies. Indeed, drilling efficiency has improved considerably in recent years, as operators improve their understanding of the Utica Shale and as operations shift from exploration activities to development activities. Spud-to-spud time is the amount of days required to set up a rig, drill a well and then move to a new site. Based on ODNR cumulative permitting activity reports for 2014, the average spud-to-spud time for 2014 was 28.4 days. Drilling efficiency will continue to improve, however; spud-to-spud times will most likely be impacted by an emphasis on development drilling wherein rigs drill multiple wells on individual pads before tearing down and moving to a different pad.

It can be reasonably assumed that the rig count will increase slightly in the next several years in response to the high production volumes being delivered from the Utica. The “Most Likely” scenario throughput projections made in this study assumes that Utica rig count will rise by around 3 rigs per year, from 45 in 2014 to 53 in 2017. The study also assumes drilling efficiency will continue to improve, reaching spud-to-spud times of 22 days during this same time period.

The projected rig count and spud-to-spud times can be used to project future drilling rates (wells/year) and the cumulative number of wells. Nevertheless, production on a per well basis continues to increase in the Utica as a result of longer laterals and more completion stages in each well. Accordingly, for purposes of projecting throughput volumes between 2015 and 2019, the “most likely” drilling estimate is still projected to provide the best estimate.

³⁶ “The Rig Count by State & District: Weekly Average for Each Month, January 2014-December 2014” RigData 1/15. http://www.rigdata.com/counts_rankings/rig_count.aspx

³⁷ “The Rig Count by State & District: Weekly Average for Each Month, January 2015-June 2015” RigData 7/15. http://www.rigdata.com/counts_rankings/rig_count.aspx

³⁸ The total number of unconventional wells drilled and completed in 2014 was 401, including wells drilled into the Marcellus formation. See “The Debrosse Memorial Report 2014,” Ohio Oil and Gas Association 68th Annual Winter Meeting, http://c.ymcdn.com/sites/www.ooga.org/resource/resmgr/Docs/The_Debrosse_Memorial_Report.pdf

Table 2 shows the estimated most likely drilling rates for the next five years (2015 through 2019). The increase in the number of rigs coupled with improved spud-to-spud times has the drill rate increasing to 879 wells per year in 2017 and holding steady thereafter. The total number of wells drilled by the end of 2019 is 5,141. The projected rig counts and drill times for the low and high estimates for production are set forth in Appendix B as Tables B-1 and B-2. Under the low estimate, it is anticipated that the Utica will be drilling at a rate of 664 wells per year with a total of 4,197 wells by 2019. Under the high estimate, drilling will be at a rate of 995 wells per year with a total of 5,585 wells by 2019.

With the drop in oil and gas prices in the second half of 2014 and early 2015, drilling activity is likely to be somewhat curtailed, although apparently less than for other shale basins. Indeed, drilling rates in the Utica in early 2015 suggest that the “low estimate” scenario for drilling may be on its way to becoming the “most likely” scenario. The Ohio Oil and Gas Division for the Department of Natural Resources projected in April 2015 that roughly 600 permits would be issued in Ohio in 2015, down from the 702 issued in 2014.³⁹ Likewise, drilling rigs in Ohio dropped from a peak of 59 in December 2014 to 24 in early April 2015.⁴⁰ Nevertheless, production on a per well basis continues to increase in the Utica as a result of longer laterals and more completion zones in each well. Accordingly, for purposes of projecting throughput volumes between 2015 and 2019, the “most likely” drilling estimate is still projected to provide the best estimate possible.

Table 2. Five-Year Most Likely Drilling Rate Estimate

Year	Rig Count	Drill Time	Wells/Year	Total Wells
2011-2013				364
2014	45	28.4	593	957
2015	48	25	701	1,658
2016	51	22	846	2,504
2017	53	22	879	3,383
2018	53	22	879	4,262
2019	53	22	879	5,141

2.2.1.7. Decline Projections

A reasonable estimation of Utica production throughput requires an analysis of production decline. Production decline estimates for this study were based in part upon quarterly ODNR production reports. One must exercise great care when calculating decline rates as the ODNR production information does not necessarily provide a complete picture. For example: wells may produce intermittently, not all of the gas production may be reported due to flaring, or gas production may be constrained to aid in the production of condensate or NGLs. Therefore, forty-four wells were selected that had been in production a minimum of eighty percent of the

³⁹ S. Hoover, “State: Fewer Horizontal Drilling Permits this Year,” Canton Repository, April 8, 2015 (quoting Oil and Gas Division Chief Rick Simmers), found at:

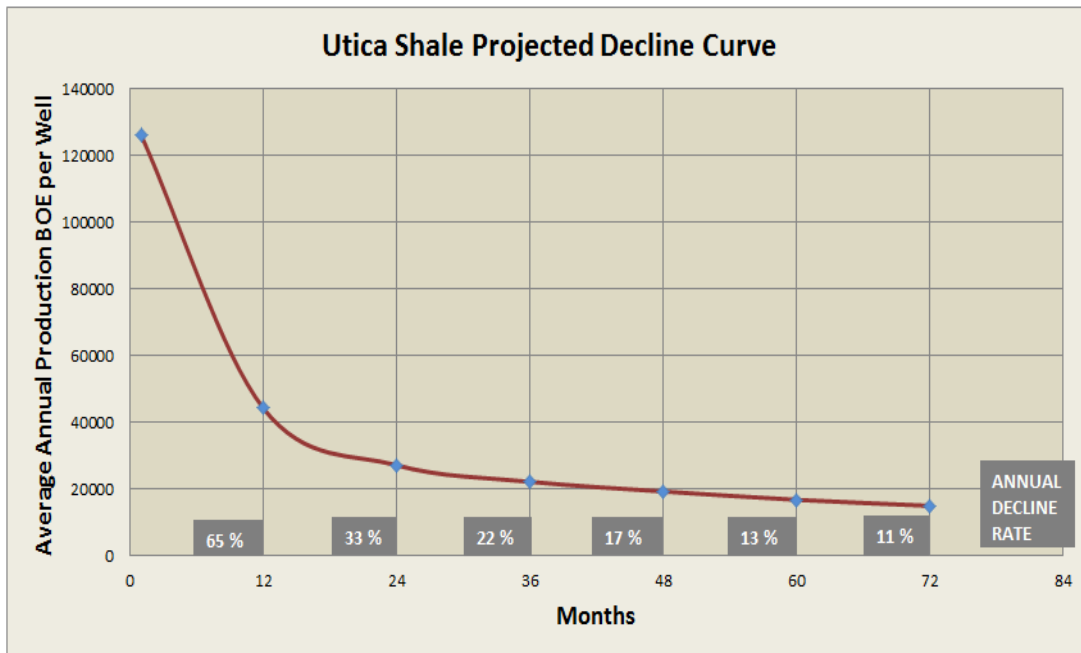
<http://www.cantonrep.com/article/20150408/NEWS/150409363>

⁴⁰ *Id.*

production days during 2013 and the first quarter of 2014. The average production decline for the forty-four wells was calculated at sixty-five percent over the first four quarters of reported production. The calculated decline was quite variable, with a standard deviation of twenty percent. Nonetheless, a sixty-five percent decline rate is consistent with various published decline rates for the Barnett, Haynesville and Marcellus formations.

Since there are insufficient long-term production data available for the Utica Shale, and since the calculated average production decline rate is consistent with early decline rates for the Barnett, Haynesville and Marcellus formations, Utica production decline for the years 2015 through 2019 (months 24 through 72) was estimated from various published long-term production decline curves for these same three shale plays. The resulting decline curve is shown in Figure 16. The initial average annual production in barrels of oil equivalent per well of 126,000 is based on ODNR production results for 2013 quarters 3 and 4 and 2014 quarters 1 and 2.

Figure 16. Utica Shale Projected Decline Curve



2.2.1.8. Throughput Projections

Based upon initial production rates, rig counts, spud-to-spud estimates and projected decline rates, the Study Team was able to project likely throughput projections. For purposes of projecting liquids and ethane throughput, the Study Team made certain assumptions based upon broad observations, industry “rules of thumb” and interviews with midstream executives. Among these assumptions are the following:

- About half the production will be wet gas;
- Wet gas will average 30% shrinkage;
- Wet gas produces about 6 gallons of liquids per mcf of wet gas, and 42 gallons of liquids per barrel; and
- Ethane make up will be about 60% of the liquids produced.

The “most likely,” “low” and “high-end” throughput estimates were determined based upon probable drilling, producing and decline rate estimates. The assumptions made for the most likely, low-end and high-end projections along with annual throughput determinations are set forth in Appendix B, Tables B-3, B-4, and B-5.

Finally, not all ethane can be economically recovered from a natural gas stream, even if the fractionation facilities are available. NGLS can be extracted either through Cryogenic Expansion processes or through the Absorption Method. The latter method is used more commonly for heavier NGLS, and employs adsorbing oils that have an affinity for attaching to and picking up NGLs. Cryogenic Expansion, on the other hand, is used for lighter NGLs such as ethane. For this process, temperatures are dropped to around minus 120 degrees Fahrenheit. The process allows for around 90 to 95% recovery of ethane.⁴¹ However industry projections tend to be more conservative than this, usually using the 20% rejection as the best estimate of the likely available ethane.⁴²

Assuming 20% ethane rejection, throughput projections for 2014 and 2019 are as follows:

Table 3. 2014 Throughput Projections

	Low	Most Likely	High
Natural Gas (bcf/d)	1.23	1.23	1.23
NG Liquids (bcf/d)	0.62	0.62	0.62
Ethane (mmbbl/d) (1)	42.4	42.4	42.4

(1) Assuming 20% ethane rejection

Table 4. 2019 Throughput Projections

	Low	Most Likely	High
Natural Gas (bcf/d)	3.67	4.75	5.30
NG Liquids (bcf/d)	1.84	2.36	2.65
Ethane (mmbbl/d) (1)	126.4	161.6	181.6

(1) Assuming 20% ethane rejection

⁴¹ “Processing Natural Gas,” *NaturalGas.org*, September 25, 2013, found at: <http://naturalgas.org/naturalgas/processing-ng/>

⁴² See, e.g. Blue Racer Investor Presentation, found at <http://www.blueracermidstream.com/sites/default/files/resources0114Presentation.pdf>.

2.2.2. Midstream and Other Industry Throughput Projections

To justify their large investments into infrastructure to serve the upstream industry, midstream companies have been making their own projections. These projections, along with those of industry analysts, are often presented at conferences and for investors. Moreover, most midstream companies are creating one integrated infrastructure for the Utica-Marcellus region. Often, as a result, they aggregate volume projections from both shale deposits. The Study Team reviewed publicly available literature and presentations made by midstream companies projecting throughput. This section compiles the various views provided by industry experts as to the likely production to be found from the Utica Shale over the next five years.

Due to the value received from NGLs, early development of the Utica is expected to be primarily in the “wet gas” corridor. The same assumptions that were made for the Study Team production scenarios were used here to estimate throughput: according to midstream and upstream companies operating in the region, a typical Utica natural gas well producing in the wet gas corridor has about 30% shrinkage after processing, or approximately 6 gallons of liquids per mcf of produced wet natural gas. Of these liquids, the typical make up is approximately:

- 60% ethane,
- 22% propane,
- 11% butane, and
- 7% other, more complex hydrocarbons.⁴³

A 2014 study from Tudor, Pickering & Holt projected 8.1 bcf/d of production from the Utica by the year 2020, a substantial increase from the 6.0 bcf/d projections made by that firm earlier.⁴⁴ Using this natural gas throughput volume, we can generate a very rough estimate of the amount of ethane likely to be produced from the Utica on a daily basis. Assuming that half of this production volume is wet gas (assumes that drilling in the dry gas area will pick up by 2020 to preserve leaseholds), and assuming 6 gallons of NGL/mcf and 60% of every gallon of NGL in ethane, the projected 8.1 bcf/d of Utica’s natural gas converts to 347 mbbl/d of ethane by 2020.⁴⁵

Of course, the downstream companies acquiring ethane supplies don’t concern themselves as to whether the ethane comes from the Marcellus or the Utica production. So for purposes of assessing regional ethane supply, the Utica and Marcellus production should be combined. According to midstream company Blue Racer, 2014 natural gas production will be around 13 bcf/d for the two shale plays.⁴⁶ Industry analysts at Wood MacKenzie project this will increase to about 25 bcf/d by 2020.⁴⁷ Blue Racer projects total “wet gas” production from the basin in

⁴³ The Study Team interviewed a number of major midstream and upstream companies during the course of the research. Based upon these interviews ethane content was found to be around 60% of the NGLs produced, and this number was used for the “rule of thumb” ethane throughput calculation.

⁴⁴ 2015 Tudor, Pickering, Holt & Co. 11th Annual Hotter ‘N Hell Energy Conference. 6/16/15.

⁴⁵ A coefficient of 42 is used to convert American gallons to barrels of oil.

⁴⁶ “From Importer to Exporter” Blue Racer 1/30/14.

⁴⁷ C. Davis, “Eagle Ford to Rival North Slope Output at its Peak, Says Wood Mackenzie,” NGI’s Shale Daily 6/6/14. <http://www.naturalgasintel.com/articles/98627-eagle-ford-to-rival-north-slope-output-at-its-peak-says-wood-mackenzie>

2020 to be around 9.3 bcf/d. Of this, Blue Racer projects about 3.6 bcf/d will be from the Utica, and about 5.7 bcf/d from the Marcellus.⁴⁸

Using the same formula as before (but without adjusting for dry gas), we obtain from Blue Racer’s projections a throughput of approximately 247 mbbbl/d by 2020 from the Utica formation plus another 391 mbbbl/d (both assuming 20% ethane rejection) from the Marcellus formation, for a total ethane output of 638 mbbbl/d from the combined Utica/Marcellus basin.

The anticipated industry throughput projections compared to those from the Study Team are as follows:

Table 5. Comparison of Study Derived Throughput to Public Industry Projections

	Total Throughput (bcf/d)	Wet Gas Throughput (bcf/d)	Ethane Throughput (mbbl/d) (1)
Study Projections (“most likely” scenario)	4.75	2.36	162
Industry Projections	8.1 ⁴⁹	3.6 ⁵⁰	247

(1) Assuming 20% ethane rejection

2.3. Midstream Company Activities

2.3.1. Gathering Lines

The midstream operations in the Utica region consist of gathering lines to bring the gas to either an interstate pipeline (if the gas is dry) or to a processing plant (if the gas is wet). These activities are often the specialty of companies that have particular skills in transportation, processing, or both. The result is that many of the midstream activities in the Utica are carried out by joint ventures (JV) between companies that pool together expertise and capital. A common partner to the JV might be a producing company. By joining the venture, producing companies may have more control over midstream infrastructure development and, accordingly, more control over development of markets for their production. After the take-away process is constructed and the market ensured, the producer may sell its interests in the JV to other partners so that it may reinvest the capital into exploration and production.

Because midstream infrastructure is so capital intensive, one of the co-venturers may also be the party that brings capital to the project. The JVs are also usually structured based upon the geography of the producer leaseholds owned by the principal producers and of any pre-existing gathering lines owned by the midstream company.

There are two principal JV business models for marketing of liquids that may affect downstream industry development. Both models are employed in the Utica. One model envisions

⁴⁸ Blue Racer, January 2014.

⁴⁹ Tudor, Pickering and Holt projection, Fall 2014.

⁵⁰ Blue Racer projection, Fall 2014. Ethane projections are based upon the same assumptions set forth earlier: 6 gallons/mcf, 60% ethane and 42 gallons/bbl.

transporting and processing natural gas on a “fee” basis, tying the fee to the volume of gas transported or processed. The other model allows the midstream company to take title to the NGLs upon processing. In this case, the midstream company assumes the risk of marketing or any loss of the liquids. Which model is deployed depends largely upon what expertise the JV participants may have. Normally, whoever has the most expertise at marketing liquids will take title to the production after processing. In some instances this may be the producing company; in other cases, it may be the midstream company. In some cases a JV may deploy both models.

The Appalachian basin had a significant gathering line infrastructure that pre-existed the development of the shale formations. Dominion, for instance, contributed almost 600 miles of gathering lines (with a capacity of 1.5 bcf/d) to its Blue Racer joint venture with Caiman Energy, much of which predates the Utica development.⁵¹ However Dominion’s pre-existing infrastructure was insufficient to support the significant new production coming into Blue Racer’s processing facilities, so new gathering lines are being built.

In addition to Dominion, other midstream companies that have gathering line capacity include: MarkWest (385 mmcf/d)⁵² and Access (1.1 bcf/d).⁵³ Companies that report gathering lines in miles include: NiSource (55 miles)⁵⁴ and Antero (105 miles).⁵⁵ While it appears that there is or will be sufficient gathering trunk line capacity to ensure continued growth in the Utica, there is a possibility that gathering line build out from the trunk lines to the respective fields will lag gas discovery. This could slow production growth.

⁵¹ “From Importer to Exporter” Blue Racer 1/30/14.

⁵² “2014 Morgan Stanley Marcellus-Utica Summit” MarkWest 9/17/14.

<http://investor.markwest.com/phoenix.zhtml?c=135034&p=irol-presentations>

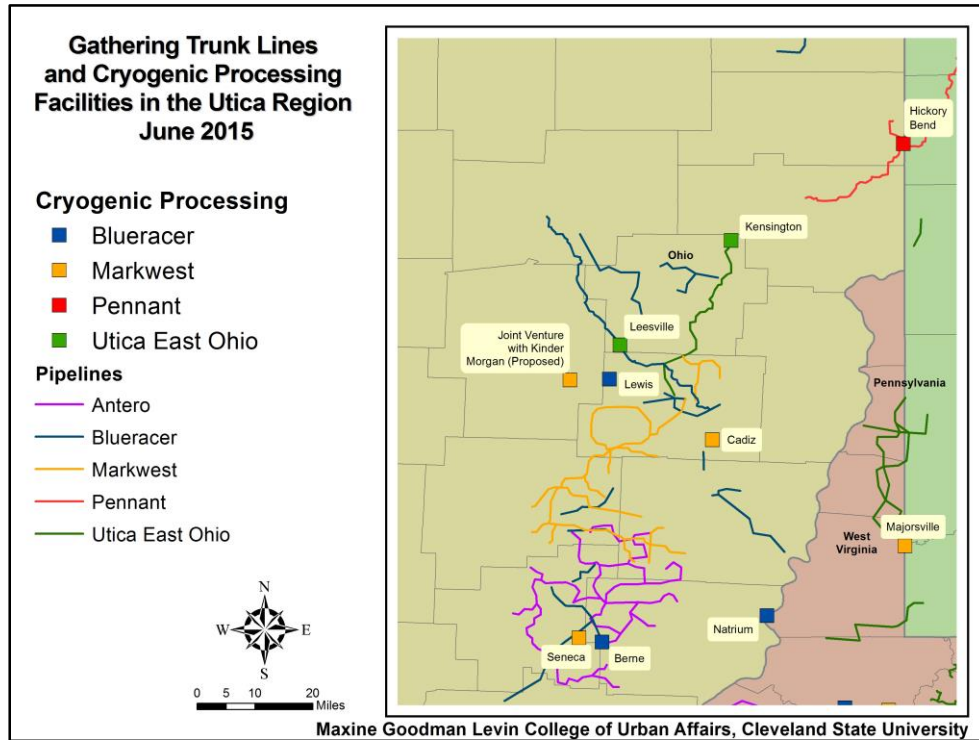
⁵³ Industry interviews

⁵⁴ “Pennant Midstream Hickory Bend Processing Plant and Gathering System Project” Columbia Pipeline Group 2014. <https://www.columbiapipelinegroup.com/current-projects/pennant-midstream-hickory-bend-processing-plant-and-gathering-system>

⁵⁵ “Company Overview October 2014” Antero Resources 10/14.

<http://investors.anteroresources.com/investors-relations/events-and-presentations/company-presentation/default.aspx>

Figure 17. Gathering Trunk Lines and Cryogenic Processing Facilities in the Utica Region, June 2015



Source: Midstream company investor presentations and other public sources

2.3.2. Cryogenic Processing and Fractionation Capacity

As of 2015, there were four major processing companies (several of which operate through joint ventures) in the Utica region:⁵⁶

- M3-Momentum (Utica East Ohio Midstream),
- MarkWest,
- Caiman (Blue Racer Midstream), and
- NiSource (Pennant Midstream).

M3-Momentum has collaborated with Access Midstream (acquired by Williams in 2014) and EnerVest to create Utica East Ohio Midstream. The joint venture gathers, compresses, dehydrates, processes and fractionates natural gas and NGLs. Utica East Ohio Midstream has 1.0 bcf/d cryogenic processing capacity, available at its Kensington and Leesville plant locations. Utica East Ohio Midstream also has 135 mbb/d of C2+ fractionation,⁵⁷ 90 mbb/d of C3+

⁵⁶ There is additional processing capacity in the Marcellus region that may, with some additional infrastructure, be used to process Utica wet gas.

⁵⁷ C2 fractionators, or de-ethanizers, separate out ethane from the NGL stream, while C2+ fractionators have the ability to remove propane, butane, isobutane, and natural gasoline in addition to ethane. C3+ fractionators can separate propane, butane, isobutane, and natural gasoline from the NGL stream. For

fractionation, 1 million barrels of NGL storage, a high capacity rail and truck terminal, and multiple purity product pipelines to distribute NGLs to the premium markets in the region. Utica East Ohio Midstream producers include Chesapeake, Total, Hilcorp, Halcon, and Atlas.⁵⁸

Caiman has partnered with Dominion to create Blue Racer. It processes gas for such operators as Hess, Consol, Rex and Chesapeake. Caiman may choose to take title to and market the liquids it processes, or it may choose to process liquids for a fee. As of April 2015 it had cryogenic processing capability of 400 mmcf/d in Natrium, West Virginia and 400 mmcf/d in Berne, Ohio. Blue Racer has a C2+ fractionation capacity of 46 mbbbl/d in Natrium, with another 80 mbbbl/d under construction.⁵⁹ Blue Racer also had 200 mmcf/d of cryogenic processing planned for a new facility in Petersburg, Ohio. Due to poor production in the northern portion of the Utica, however, the plans for this facility have been cancelled.⁶⁰

MarkWest (acquired by Marathon in 2015) has midstream operations in Ohio, West Virginia, New York and Pennsylvania. It takes production from Gulfport, Antero, Chesapeake, Range, Chevron, Consol and others. MarkWest may undertake fee-based processing or it may take title to the liquids and market them. Its 2014 processing capacity for the Utica was 925 mmcf/d, 600 of which were at the Seneca, Ohio facility and 325 at the Cadiz, Ohio facility. In 2014, the Seneca and Cadiz facilities were about 56% in use. MarkWest's C3+ fractionation capacity in April 2015 was 120 mbbbl/d (located at the Hopedale, Ohio complex), with another 40 mbbbl/d of de-ethanization (C2) located at its Cadiz facility. MarkWest anticipates expansions to 1,525 mmcf/d of processing capacity and 180 mbbbl/d of C3+ fractionation.⁶¹ In August of 2013, MarkWest announced that it plans to pursue a joint venture with Kinder Morgan to construct a cryogenic processing facility in Tuscarawas County, Ohio. This plant will have an initial capacity of 200 mmcf/d, with a planned expansion to 400 mmcf/d.⁶²

NiSource operates midstream gathering and a processing plant as Pennant in a joint venture with Hilcorp at the Hickory Bend facility in Mahoning County, Ohio. Pennant has processing capacity of 200 mmcf/d⁶³ and plans to add another 200 mmcf/d.⁶⁴

more information, refer to: <https://rbnenergy.com/adding-fractionation-capacity-and-rationalizing-in-the-utica-marcellus>

⁵⁸ Industry interviews

⁵⁹ "From Importer to Exporter" Blue Racer 1/30/14.

⁶⁰ "Blue Racer Shelves Petersburg Gas Project" The Business Journal 1/30/15.

<http://businessjournaldaily.com/blue-racer-shelves-petersburg-gas-project/>

⁶¹ "Fourth Quarter 2014 Conference Call Presentation" MarkWest 2/25/15.

<http://investor.markwest.com/phoenix.zhtml?c=135034&p=irol-presentations>

⁶² "Kinder Morgan, MarkWest Utica EMG Announce Plans to Form Joint Venture to Support Northern Ohio Rich-Gas Development and NGL Takeaway from the Utica and Marcellus Shale Resource Plays" Business Wire 8/7/13. <http://www.businesswire.com/news/home/20130807006090/en/Kinder-Morgan-MarkWest-Utica-EMG-Announce-Plans#.VHzHwcnzi1g>

⁶³ "Pennant Midstream Announces Hickory Bend Cryogenic Processing Plant Ready for Service" Columbia Pipeline Group 1/6/14. <https://www.columbiapipelinegroup.com/about-us/news-room/2014/01/06/pennant-midstream-announces-hickory-bend-cryogenic-processing-plant-ready-for-service>

⁶⁴ "Pennant Midstream Hickory Bend Processing Plant and Gathering System Project" Columbia Pipeline Group 2014.

As of June 2015, M3 Momentum had the largest cryogenic processing capacity in the Utica with 1.0 bcf/d, and plans to add at least 500 mmcf/d of additional processing capacity with the timing dependent upon its customers' production growth over the next few years.⁶⁵ Caiman had a total of 800 mmcf/d in cryogenic processing capacity, with plans to add an additional 600 mmcf/d planned at either its Natrium or Lewis facilities. MarkWest plans to greatly increase its processing capacity by 2020, expanding from 925 mmcf/d in 2014 to 1,525 mmcf/d. Its joint venture with Kinder Morgan will add an additional 400 mmcf/d, once both phases are complete.⁶⁶ With Hickory Bend as its only current processing facility, NiSource will increase its capacity from 200 mmcf/d to 400 mmcf/d by 2020. As of April 2015, the total cryogenic processing capacity for the Utica is 2,925 mmcf/d, which is expected to increase to 5,225 mmcf/d by 2020.

Projected wet gas production from Utica by 2020, according to Blue Racer, will be about 3,600 mmcf/d.⁶⁷ Based upon this projection, it appears that there will be ample processing capacity for the Utica in 2020. However, much of this processing capacity will also be handling Marcellus wet gas, so total capacity for the region must be compared to total wet gas for the region. That analysis is set forth in Section 2.3.4, below.

⁶⁵ Industry interviews

⁶⁶ "Kinder Morgan/MarkWest Joint Venture in Utica and Marcellus Shale" Mazurek Alford & Holliday 2/18/14. <http://www.mahenergy.com/news/the-kinder-morgan-markwest-joint-venture-in-utica-and-marcellus-shale/>

⁶⁷ "From Importer to Exporter" Blue Racer 1/30/14.

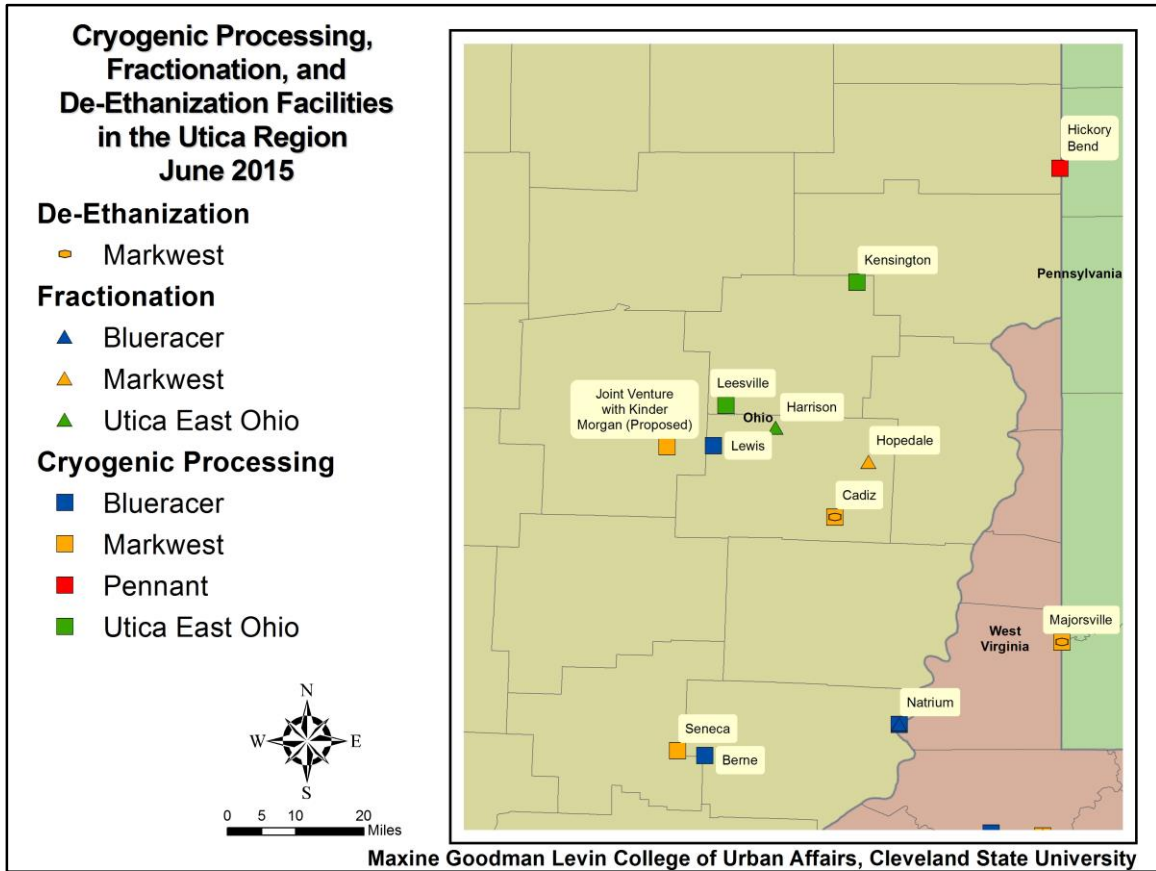
Table 6. Existing Processing Capacity in the Utica, June 2015

Location	Type of Processing			
	Cryogenic Processing (mmcf/d)	C3+ Fractionation (mdbl/d)	C2+ Fractionation (mdbl/d)	De-Ethanization (C2) (mdbl/d)
M3 Momentum				
Kensington	750			
Leesville	250			
Harrison		90	135	
Total	1,000	90	135	0
Caiman				
Natrium	400		46	
Berne	400			
Total	800	0	46	0
MarkWest				
Seneca	600			
Cadiz	325			40
Hopedale		120		
Total	925	120	0	40
NiSource				
Hickory Bend	200			
Total	200	0	0	0
Grand Total				
Grand Total	2,925	210	181	40

Table 7. Planned Processing Capacity Expansions in the Utica, June 2015

Location	Type of Processing			
	Cryogenic Processing (mmcf/d)	C3+ Fractionation (mmbbl/d)	C2+ Fractionation (mmbbl/d)	De-Ethanization (C2) (mmbbl/d)
M3 Momentum				
Existing	1,000	90	135	0
Total After Expansion	1,500	90	135	0
Caiman				
Natrium	600		80	
Existing	800	0	46	0
Total After Expansion	1,400	0	126	0
MarkWest				
Seneca	200			
Cadiz	400			
Hopedale		60		
Joint Venture with Kinder Morgan (new facility)	400			
Existing	925	120		40
Total After Expansion	1,925	180	0	40
NiSource				
Hickory Bend	200			
Existing	200			
Total After Expansion	400	0	0	0
Grand Total After	5,225	270	261	40

Figure 18. Cryogenic Processing, Fractionation, and De-Ethanization in the Utica Region, June 2015



Source: Midstream company investor presentations and other public sources

2.3.3. Natural Gas Liquids Take Away Capacity

Another important midstream activity occurs downstream of the cryogenic or fractionation activities. In addition to transporting natural gas, interstate pipeline companies also have lines dedicated to NGLs and oil. These lines can carry undifferentiated NGLs or carry pure product. Unlike natural gas, NGLs have alternative take away transportation strategies available: truck, rail and barge. Ethane, however, is the exception to this: pure product ethane normally requires a pipeline for take away.

There are four pipelines located within three major pipeline systems with natural gas liquid take away capacity. The first system is the ATEX pipeline, owned by Enterprise Products Partners, which has the ability to transport 125 mbb/d of ethane to the American Gulf Coast. The ATEX line can be expanded to 265 mbb/d.⁶⁸ The second system, owned by Sunoco, includes the Mariner East and West lines. The Mariner East 1 pipeline (East Coast) has a 70 mbb/d ethane and propane capacity, and an additional 275 mbb/d of propane, butane, and ethane capacity is planned for Mariner East 2. The pipeline, scheduled to come online in 2016, will be primarily

⁶⁸ "Citi MLP/ Midstream Infrastructure Conference" Enterprise Products Partners 8/20/14. <http://phx.corporate-ir.net/phoenix.zhtml?c=80547&p=irol-presentations2014>

used for propane transportation.⁶⁹ The Mariner West line (Sarnia, Ontario) has a 50 mbb/d ethane capacity.⁷⁰ Additional expansion is planned for the west to Sarnia through the proposed Kinder Morgan Utopia line (50 mbb/d ethane and propane capacity, expandable to 75 mbb/d) in 2018.⁷¹

Another pipeline operated by Enterprise Products Partners, TEPPCO, runs from the Gulf Coast to the northeastern United States. This line has the ability to ship propane and refined products northward, as well as from the Utica/Marcellus region.⁷² Adjusting for seasonal differences, the TEPPCO system has a design capacity of 60 mbb/d.⁷³

In addition to this, there is around 200 mbb/d railroad take-away capacity.⁷⁴ However railroad capacity, as is the case for trucking capacity, is principally limited to those NGLs that are easy to transport in a liquid state, such as propane. Ethane is normally not transported as a liquid.

There is also a robust local demand for propane, which is a popular fuel used for residential heating, as well as a feedstock for the petrochemical industry. As of 2014, most produced propane from the Utica/Marcellus region was consumed locally. Local propane demand in the Appalachian basin is around 100 mbb/d.⁷⁵

New natural gas liquid pipelines have been under consideration since the Utica began to show prolific wet gas production. The Mariner East 2 pipeline is projected to provide additional NGL capacity by 2016.⁷⁶ One system that was contemplated, but has been since suspended, was the William's Bluegrass NGL pipeline, which was to have around 200 mbb/d capacity.⁷⁷ Kinder Morgan, however, plans to build a batched system pipeline, (the Utica-Marcellus Texas Pipeline) to transport propane, butane, natural gasoline, γ -grade, and condensate with an initial capacity of 150 mbb/d.⁷⁸ The project will convert 964 miles of Kinder Morgan's Tennessee Gas Pipeline for NGL service, in addition to the construction of 200 miles of new pipeline along the Gulf Coast

⁶⁹ "About Sunoco Logistics and the Mariner East Project" Sunoco Logistics 11/14.

http://sxlpipelineprojects.com/wp-content/uploads/2014/11/SXL_Frequently_Asked_Questions.pdf

⁷⁰ "Citi MLP/ Midstream Infrastructure Conference" Sunoco Logistics Partners L.P. 8/20/14.

<http://www.sunocologistics.com/SiteData/docs/August2014/b68372a93583dc3e/August%202014%20Investor%20Presentation%20-%20v3.pdf>

⁷¹ "Kinder Morgan Announces Binding Open Season for Ethane/Propane Movements Out of the Utica Shale" Kinder Morgan 9/4/14. http://www.kindermorgan.com/content/docs/UtopiaPress_Release.pdf

⁷² "Enterprise increasing TEPPCO propane shipments following US FERC order" Platts 2/10/14.

<http://www.platts.com/latest-news/oil/houston/enterprise-increasing-teppco-propane-shipments-21198473>

⁷³ "Northeast Propane Infrastructure, Supply Shortages & High Cost to Consumers" Crestwood 4/15.

http://energy.gov/sites/prod/files/2014/04/f15/Remarksof_AndyRonald_Crestwood_ppt_April21_0.pdf

⁷⁴ "Credit Suisse 2014 Energy Summit" Williams 2/11/14.

<http://www.energy.williams.com/Profiles/Investor/Investor.asp?BzID=630&from=du&ID=64367&myID=13611&L=I&Validate=3&I=>

⁷⁵ *Id.*

⁷⁶ "Citi MLP/ Midstream Infrastructure Conference" Sunoco Logistics Partners L.P. 8/20/14.

⁷⁷ "From Importer to Exporter" Blue Racer 1/30/14.

⁷⁸ "Kinder Morgan Energy Partners- Targa Resources Partners to Expand Fractionation Capacity in Texas to Support the Utica Marcellus Texas NGL Pipeline" Kinder Morgan 12/20/13.

http://www.kindermorgan.com/content/docs/KMP_Targa_Ext_Open_Season.pdf

and 120 miles of new laterals. The Utica Marcellus Texas Pipeline will have a maximum capacity of 430 mbbbl/d and will be in service by the end of 2018.⁷⁹

Total liquids projected for 2020 from the combined Marcellus and Utica formations is around 1,400 mbbbl/d.⁸⁰ Including the railroad capacity (which won't work well for ethane), 2014 capacity was around 605 mbbbl/d. Assuming the Enterprise Products Kinder Morgan, and Sunoco expansions occur, take away capacity plus local usage for the basin could reach 1,525 mbbbl/d. This suggests that the total NGL production from the Utica and Marcellus will be comparable to the total NGL take away capacity plus local demand in 2020.

For ethane, however, there may be no local demand and there may be limitations in take away capacity. Projected take-away pipeline capacity for ethane in the region for 2020 will range between 315 and 735 mbbbl/d, depending upon how Mariner East and Utopia allocate capacity for ethane. A best guess capacity is about 460 mbbbl/d, based upon the assumption that the Mariner East 2 pipeline will be primarily used for propane.⁸¹ This will be sufficient for industry projections for the Utica, which is 247.2 mbbbl/d. However industry projections call for another 391.2 mbbbl/d by 2020 from the Marcellus wet gas window. Based upon industry projections for wet gas production, a local market for ethane will be required by 2020 to take up product that cannot be shipped out of the region. The alternative will be significant ethane rejection in the Utica and Marcellus wet gas windows.

⁷⁹ "Kinder Morgan Announces Binding Open Season for Utica Marcellus Texas Pipeline" Business Wire 6/17/15. <http://www.businesswire.com/news/home/20150617005877/en/Kinder-Morgan-Announces-Binding-Open-Season-Utica#.VYlcFhDzi1g>

⁸⁰ "Credit Suisse 2014 Energy Summit" Williams 2/11/14.

⁸¹ This figure does not include the Mariner East 2 pipeline (with 275 mbbbl/d of propane, ethane, and butane capacity) because the pipeline will primarily be used for propane transportation (see Sunoco Logistics, footnote 69). However, this figure does include the Mariner East 1 and Utopia pipelines with a combined 145 mbbbl/d of ethane and propane capacity. Because of this, ethane take away capacity for the Utica and Marcellus could theoretically range from 315 mbbbl/d (if no Mariner East 1, Mariner East 2, and Utopia capacity is dedicated for ethane) to 735 mbbbl/d (if all Mariner East 1, Mariner East 2, and Utopia capacity is dedicated for ethane).

Table 8. Utica NGL Take Away Capacity, June 2015 (Including Selected Utica/ Marcellus NGL Take Away Capacity)

Pipeline	Company	Type	Existing 2014 (mmbbl/d)	Projected (mmbbl/d)
ATEX	Enterprise Products	Ethane	125	265
Mariner East	Sunoco	Ethane and Propane	70 after completion of Mariner East 1 in 2015	345*
Mariner West	Sunoco	Ethane	50	50
Utopia	Kinder Morgan	Ethane and Propane	0	75
Ethane Total			245	460
TEPPCO	Enterprise Products	Propane	60	0
Utica Marcellus Texas	Kinder Morgan	Y-grade	0	430
Total			305	1,225
Grand Total			605 including local demand and rail capacity	1,525 including local demand and rail capacity

* The Mariner East 2 pipeline will have a capacity of 275 mmbbl/d of mixed NGLs, including propane, ethane, and butane. Because of this, its capacity is not included in the “Ethane Total” figure, but is included in the “Grand Total” figure.

2.3.4. Regional Production Compared to Regional Processing and Take Away Capacity

Because natural gas processing and take away facilities do not necessarily differentiate between the shale plays where their gas is sourced from, it is important to note processing and take away capacity in a regional context. It is very likely that facilities in the region will process and take away gas from both the Utica and Marcellus plays. It is also important to compare regional production to regional processing and take away capacity. When the processing capacity of the facilities in Pennsylvania and West Virginia are added to those in Ohio as of April 2015, total capacities become 8,898 mmcf/d for cryogenic processing, 338.5 mmbbl/d for C3+ fractionation, 181 mmbbl/d for C2+ fractionation, and 174 mmbbl/d for de-ethanization. By 2020, these regional processing capacity totals are projected to increase to 11,998 mmcf/d for cryogenic processing, 447 mmbbl/d for C3+ fractionation, 261 mmbbl/d for C2+ fractionation, and 284 mmbbl/d for de-ethanization. These amounts are broken down by company in Table 9 and Table 10.

By 2020, the industry projects that total ethane production for the Utica and Marcellus will be 638.4 mmbbl/d (assuming 20% rejection). In order to calculate regional ethane processing, de-ethanization (C2 fractionation) capacity must be added to the amount of C2+ fractionation capacity that is designated for ethane-specific processing. To calculate this C2+ value, an industry rule of thumb is used: one third of C2+ fractionation is reserved for ethane processing

(C2).⁸² Therefore, total regional ethane processing capacity is projected to reach 371 mbb/d (combining de-ethanization and one third of C2+ fractionation). These ethane processing capacities may well be sufficient, since ethane rejection can probably accommodate the processing shortfall. However, the same cannot be said for ethane take away capacity. It is only projected to expand to 460 mbb/d by 2020. This projected disparity between production/processing capacity and take away capacity, as seen in (Table 11), will mean that some additional local use must be developed to avoid large scale ethane rejection.

Table 9. Existing Processing Capacity in the Utica and Marcellus, June 2015

Company	Type of Processing			
	Cryogenic Processing (mmcf/d)	C3+ Fractionation (mbbl/d)	C2+ Fractionation (mbbl/d)	De-Ethanization (C2) (mbbl/d)
M3 Momentum	1,000	90	135	0
Caiman	1,088	14	46	0
MarkWest	4,345	192	0	134
NiSource	200	0	0	0
Williams	920	42.5	0	40
XTO	125	0	0	0
Grand Total	7,898	338.5	181	174

⁸² Industry interviews

Table 10. Planned Processing Capacity Expansions in the Utica and Marcellus, June 2015

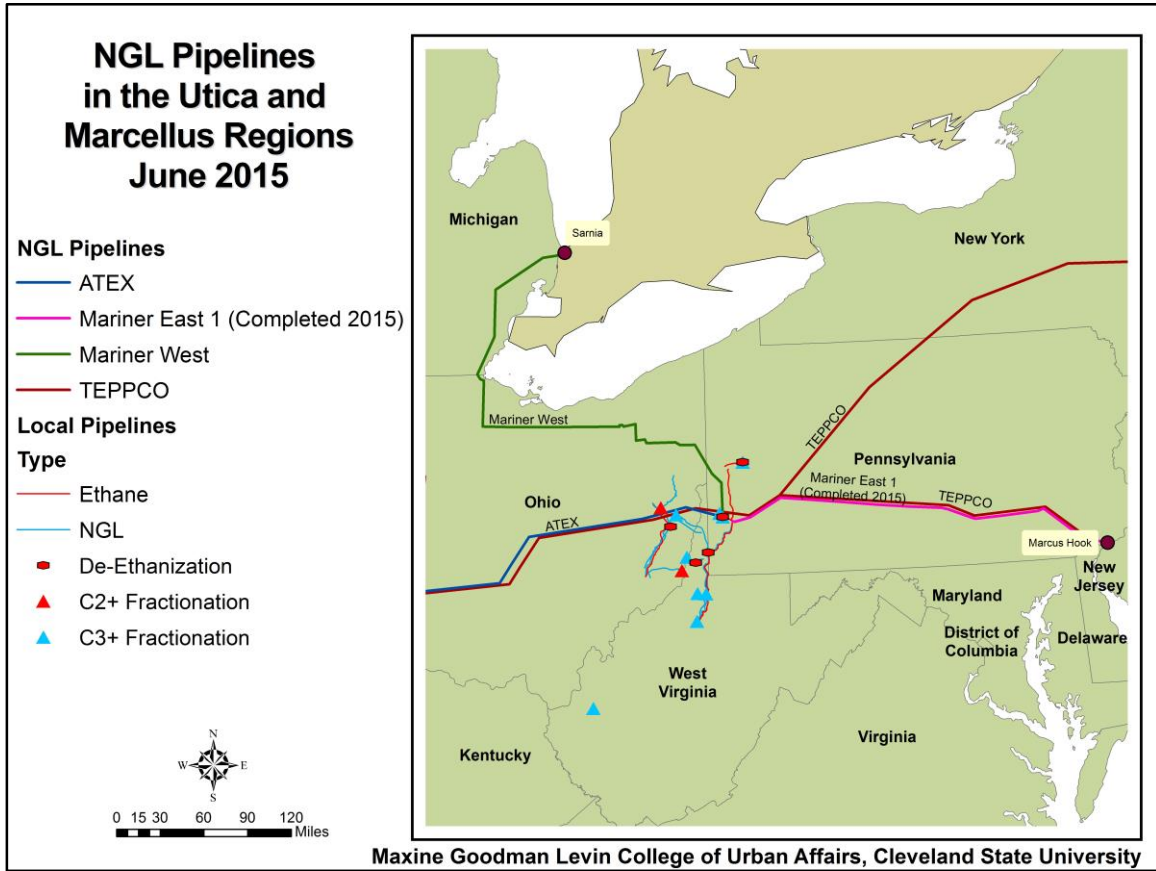
Company	Type of Processing			
	Cryogenic Processing (mmcf/d)	C3+ Fractionation (mmbbl/d)	C2+ Fractionation (mmbbl/d)	De-Ethanization (C2) (mmbbl/d)
M3 Momentum				
Existing	1,000	90	135	0
Total After Expansion	1,500	90	135	0
Caiman				
Existing	1,088	14	46	0
Total After Expansion	1,688	14	126	0
MarkWest				
Existing	4,345	192	0	134
Total After Expansion	7,145	283	0	244
NiSource				
Existing	200	0	0	0
Total After Expansion	400	0	0	0
Williams				
Existing	920	42.5	0	40
Total After Expansion	920	60	0	40
XTO				
Existing	125	0	0	0
Total After Expansion	125	0	0	0
Grand Total After Expansion	11,998	447	261	284

Table 11. Utica and Marcellus Projected Production Compared to Fractionation Capacity, 2020

	Total NGL Volume	Ethane (mmbbl/d)
Industry Projected Production – wet gas	9.3 bcf/d (3.6 Utica + 5.7 Marcellus) (1)	638 (2)
Industry Projected Processing Capacity	12 bcf/d	371 (3)
Industry Projected NGL Take Away Capacity, plus local use	1,525 mmbbl/d	460 (4)

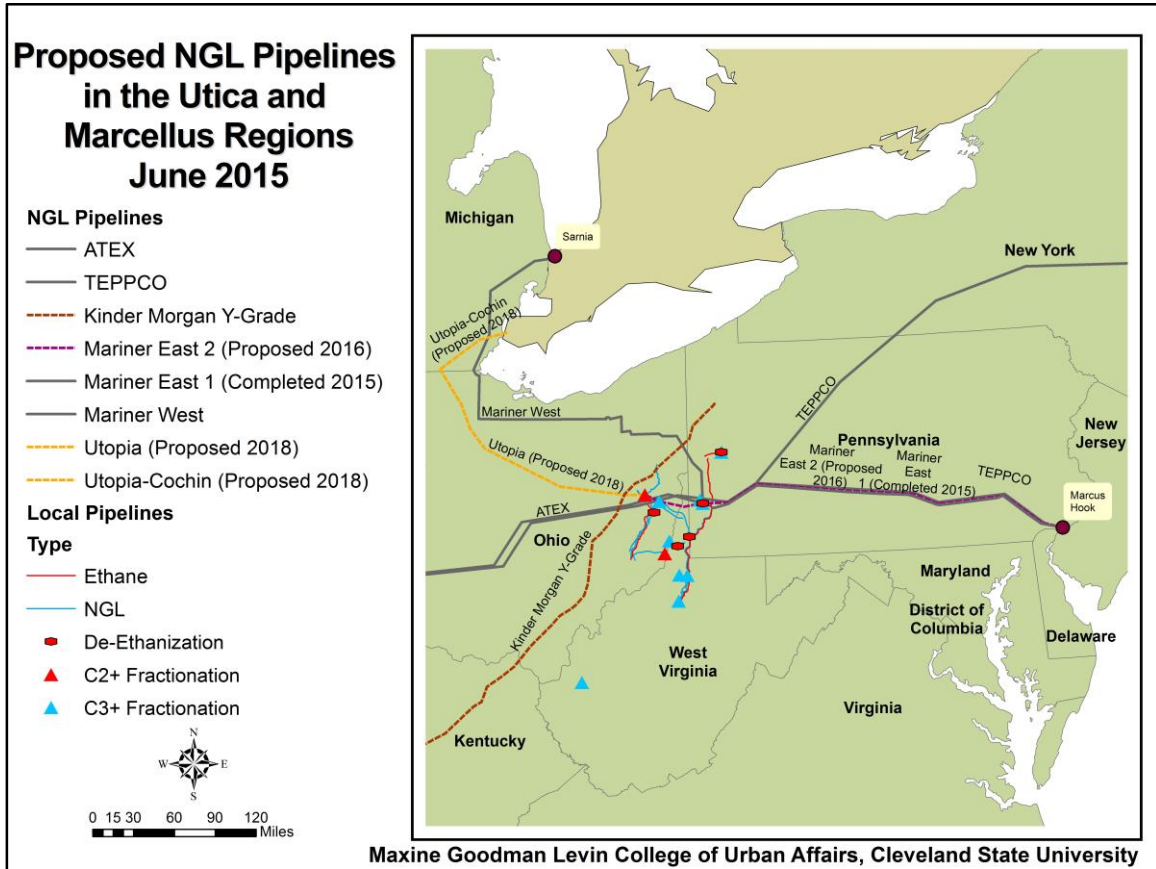
- (1) Blue Racer Investor Presentation – Fall 2014; Williams projects 1,400 mmbbl/d
- (2) Assumes 60% ethane, 6 gal/mcf, 42 gal/bbl, and 20% rejection
- (3) One third of C2+ fractionation (87 mmbbl/d) plus de-ethanization (C2) (284 mmbbl/d)
- (4) The Mariner East 1 and Utopia pipelines are dedicated to ethane and propane, with capacities of 70 and 75 mmbbl/d, respectively. The Mariner East 2 pipeline expansion is projected to be 275 mmbbl/d, however most of this pipeline’s capacity is anticipated to be used for propane. Accordingly, all 145 mmbbl/d of the propane/ethane capacity is used to make this number, but none of the 275 mmbbl/d. The range of possible ethane capacity is between 315 and 735 mmbbl/d.

Figure 19. NGL Pipelines in the Utica and Marcellus Regions, June 2015



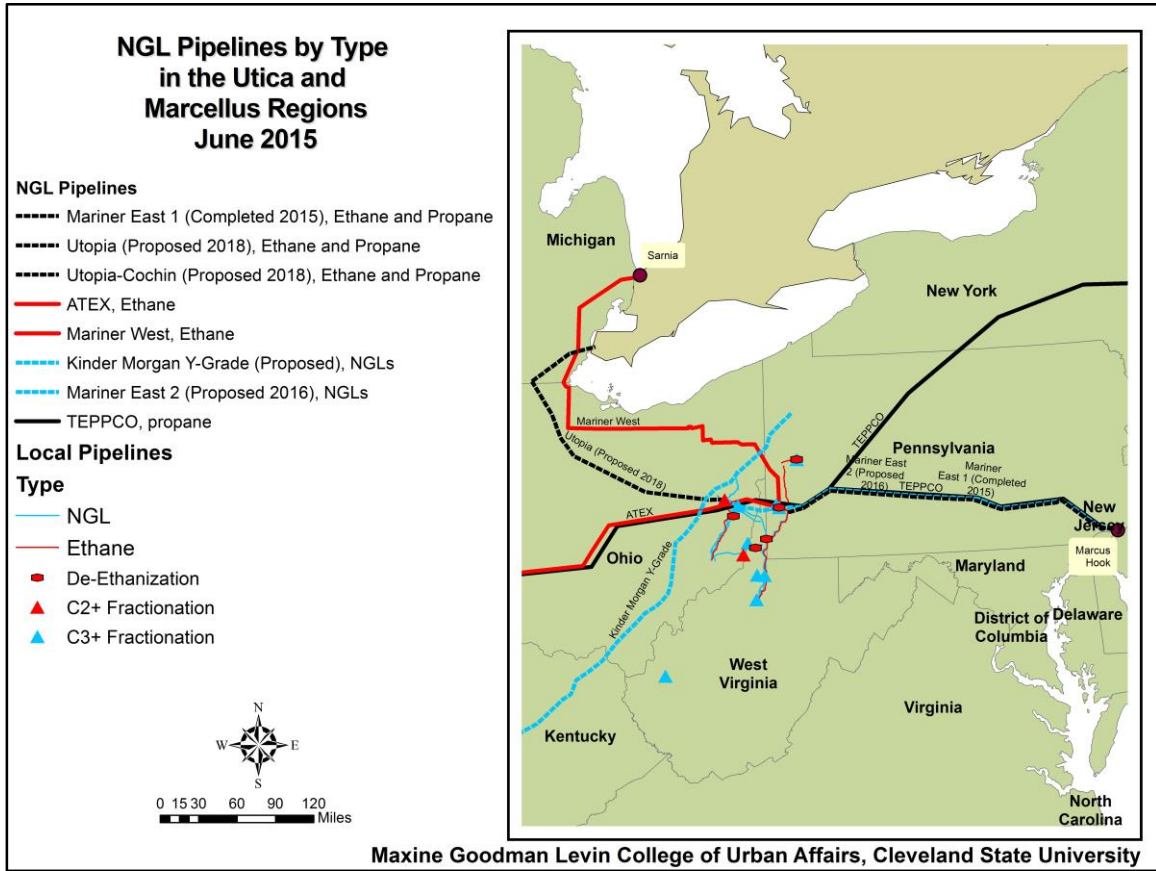
Source: Midstream company investor presentations and other public sources

Figure 20. Proposed NGL Pipelines in the Utica and Marcellus Regions, June 2015



Source: Midstream company investor presentations and other public sources

Figure 21. NGL Pipelines by Type in the Utica and Marcellus Regions, June 2015



Source: Midstream company investor presentations and other public sources

2.3.5. Natural Gas Take Away Capacity

By 2013, the Appalachian basin, including Ohio, Pennsylvania, and West Virginia, had become a major exporter of natural gas. According to the United States Energy Information Administration (EIA), the natural gas outflow (i.e. “take away”) capacity from those three states to areas outside the region was slightly less than the inflow capacity from outside the region. The outflow capacity from the three states totaled 34.57 bcf/d in 2013, with 19.37 bcf/d traveling outside the region and 15.2 bcf/d transferring within the region. The inflow capacity from outside of the region totaled 20.25 bcf/d in 2013.⁸³

Table 12. Outflow Capacity from Ohio, Pennsylvania, and West Virginia, 2013

State	To Outside Region (bcf/d)	Within Region (bcf/d)	Total Outflow Capacity (bcf/d)
Ohio	2.58	5.5	8.08
Pennsylvania	14.55	2.2	16.75
West Virginia	2.24	7.5	9.74
Total	19.37	15.2	34.57

Source: EIA, 2013

As of October 2014, there were several key interstate natural gas projects involving new pipeline construction scheduled to come online by 2020. EQT, a midstream company, has begun a joint venture with NextEra Energy and will construct the Mountain Valley Pipeline. This pipeline, which is scheduled for completion in 2018, will run from Mobley, West Virginia to south central Virginia, and have a capacity of 2 bcf/d.⁸⁴ Another project by EQT, the Ohio Valley Connector, will link Marion County, West Virginia to Monroe County, Ohio. This project has a capacity of 1 bcf/d and a projected startup of 2016.⁸⁵

Spectra Energy also has two projects planned in the region: NEXUS and OPEN. The NEXUS pipeline will run for 250 miles between Kensington, Ohio and southeastern Michigan, where it will interconnect with other natural gas pipelines for transport further north, west, and east into Canada. It will have a capacity that is scalable to 2 bcf/d⁸⁶ and is projected to come online in 2017. The OPEN (Ohio Pipeline Energy Network) project will run for 76 miles across eastern Ohio

⁸³ “U.S. State-to-State Capacity” U.S. Energy Information Administration 1/16/14. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls

⁸⁴ “EQT Analyst Presentation” EQT 10/14. http://ir.eqt.com/sites/eqt.investorhq.businesswire.com/files/doc_library/file/EQT_Analyst_Presentation_October_final.pdf

⁸⁵ “EQT Midstream: 2 Major Pipeline Projects Advance, 1 Doesn’t” Marcellus Drilling News 7/25/14. <http://marcellusdrilling.com/2014/07/eqt-midstream-2-major-pipeline-projects-advance-1-doesnt/>

⁸⁶ “NEXUS Gas Transmission” Spectra Energy 2014. <http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/NEXUS-Gas-Transmission/>

from Kensington to Clarington, providing access to points in the southern United States. This pipeline will have a capacity of 0.55 bcf/d and is scheduled for a 2015 startup.⁸⁷

TransCanada, through its ANR pipeline network, is planning to construct a 320 mile, 2 bcf/d natural gas pipeline from Cadiz, Ohio to ANR's Joliet Hub. Adopting a strategy comparable to Spectra for its NEXUS pipeline, the proposed ANR East Pipeline will take gas from receipt points in eastern Ohio and deliver it to points further west and south via the greater ANR Pipeline network. Depending on interest in the project, the pipeline may be extended southeast to Clarington, Ohio.⁸⁸ The ANR East Pipeline is scheduled for completion in 2017.⁸⁹

Dominion is planning to construct the 550 mile Atlantic Coast Pipeline, traversing a route from north central West Virginia to southeastern North Carolina, with a lateral to the Hampton Roads region of Virginia. This project, set for completion in 2018, will have a capacity of 1.5 bcf/d, which is expandable to 2 bcf/d.⁹⁰

Energy Transfer created the ET Rover Pipeline LLC in order to build the Rover Pipeline between the Utica region and Midwest market interconnects in Defiance, Ohio. The pipeline will also continue on to points in southern Ontario, Canada. The Rover pipeline will be built with a capacity of 3.25 bcf/d and will begin service in 2017.⁹¹

The Columbia Pipeline Group, affiliated with NiSource, plans to construct the Leach Xpress, a 160 mile pipeline running from northern West Virginia to central and southern Ohio. This pipeline will allow for 1.5 bcf/d of new capacity and will have connections to the greater Columbia Pipeline network.⁹² The Leach Xpress project will coincide with Columbia's Rayne Xpress project which will involve the addition of 1 bcf/d of capacity on its CGT mainline, connecting to points along the Gulf Coast. Both are scheduled for completion in 2017.⁹³

Williams is planning to construct the 400 mile Western Marcellus Pipeline from its Ohio Valley Midstream processing and gathering network in northern West Virginia to its Transco mainline in Virginia. The Western Marcellus Pipeline will be able to distribute up to 2 bcf/d of natural gas

⁸⁷ "Supplemental Information Appendix" Spectra Energy 11/5/14.

<http://investors.spectraenergy.com/phoenix.zhtml?c=204494&p=irol-calendarPast>

⁸⁸ "TransCanada ANR East Pipeline Project" TransCanada 7/4/14.

https://www.anrpl.com/documents/CMA/WhatsNew/ANR%20East%20Pipeline%20Project_Brochure.pdf

⁸⁹ "Several pipeline projects are underway" U.S. Energy Information Administration 10/24/14.

<http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB4QFjAA&url=http%3A%2F%2Fwww.eia.gov%2Ftodayinenergy%2Fimages%2F2014.10.15%2FEIA%2520pipeline%2520table.xls&ei=pp2ZVPu7H8GbyATNI4GgAw&usg=AFQjCNEBBynoiVzF4eoSAYEkWRavFLS-CA&sig2=eeG-gD1Y897MkCNPz-cGEw&bvm=bv.82001339,d.aWw>

⁹⁰ "Barclays Capital CEO Energy-Power Conference" Dominion 9/3/14.

<http://investors.dom.com/phoenix.zhtml?c=110481&p=irol-EventDetails&EventId=5168270>

⁹¹ "ET Rover Pipeline LLC" Energy Transfer 2014. http://www.energytransfer.com/ops_etrover.aspx

⁹² "Leach Xpress Project" Columbia Pipeline Group 2014.

<https://www.columbiapipelinegroup.com/current-projects/leach-xpress-project>

⁹³ "Several pipeline projects are underway" U.S. Energy Information Administration 10/24/14.

from the Utica and western Marcellus region to the north and the south via the Transco mainline by the end of 2018.⁹⁴

In addition to the new natural gas pipelines being constructed, several existing interstate lines are being enhanced so as to allow for bi-directional flow by 2020. The majority of these pipelines run between the Utica region and the Gulf Coast, with the exception being Tallgrass Energy's Rockies Express Pipeline (REX). Projects along TransCanada's ANR Southeast Mainline, Kinder Morgan's Tennessee Gas Pipeline, Boardwalk's Texas Gas Pipeline network, and Spectra's Texas Eastern Pipeline network will add 3.93 bcf/d of natural gas take away capacity from the Utica to points along the Gulf of Mexico. Bi-directional projects along Tallgrass' REX Pipeline will add 4.2 bcf/d of take away capacity to points further west.⁹⁵

Existing natural gas interstate pipelines will also see new capacity additions come online by 2020. Columbia Pipeline Group will add up to 2.44 bcf/d of capacity to its pipeline network in West Virginia to better move gas produced in eastern Ohio, northern West Virginia, and western Pennsylvania. Spectra Energy is planning to add 1.8 bcf/d to its Texas Eastern Pipeline system, 1 bcf/d of which heading northeast and 0.8 bcf/d heading south. Kinder Morgan will add 0.73 bcf/d to its Gulf Coast Mainline while enhancing connections with the REX. Columbia Pipeline Group and Dominion will add a total of 0.73 bcf/d to their respective pipeline networks through upgrading interconnects with interstate pipelines in Ohio.⁹⁶

According to the U.S. Department of Energy, natural gas interstate pipeline infrastructure projects across the United States are projected to total \$42 billion in capital expenditures between 2015 and 2030. Between 2015 and 2020, capital expenditures for these projects are predicted to roughly total \$15 billion. Interstate pipeline projects within the Marcellus alone will be \$10.5 billion of the \$42 billion in expenditures between 2015 and 2030, projected to have the largest activity of any region in the country.⁹⁷

⁹⁴Zeits, Richard. "Natural Gas: Marcellus Pipeline Boom Sets Stage for A 30 bcf A Day Tsunami," Zeits Energy Analytics 10/10/14. <http://seekingalpha.com/article/2554655-natural-gas-marcellus-pipeline-boom-sets-stage-for-a-30-bcf-a-day-tsunami?page=2>

⁹⁵ "Several pipeline projects are underway" U.S. Energy Information Administration 10/24/14.

⁹⁶ "Several pipeline projects are underway" U.S. Energy Information Administration 10/24/14.

⁹⁷ "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector" U.S. Department of Energy 2/15, pp.27-28.

http://energy.gov/sites/prod/files/2015/02/f19/dOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf

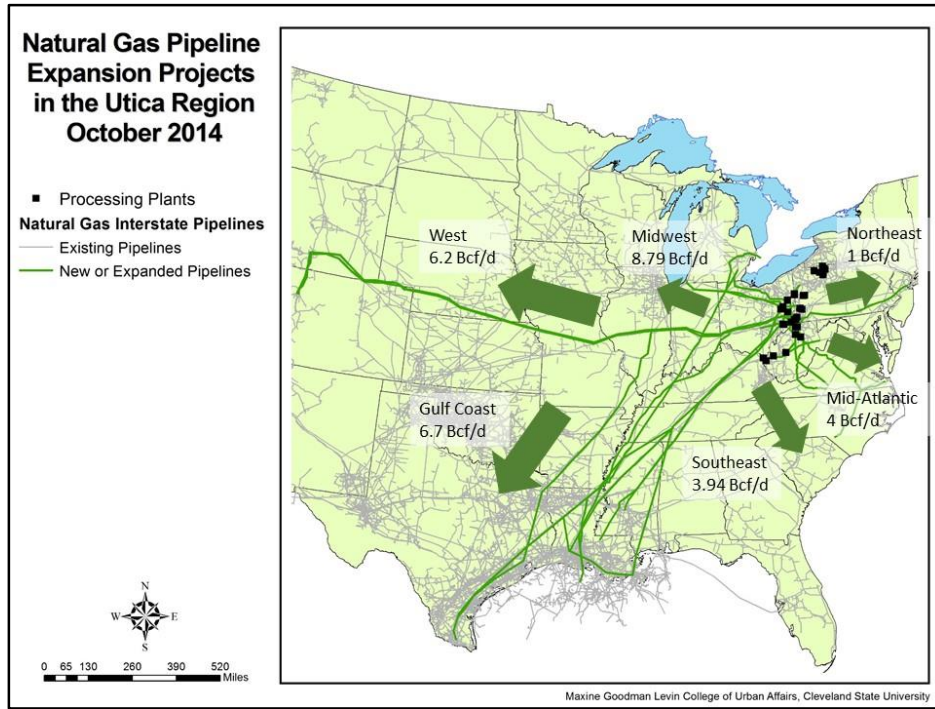
Mapping the Opportunities for Shale Development in Ohio

Table 13. Planned Utica Natural Gas Take Away Capacity Additions, October 2014 (Note: Some of the listed projects service both Utica and Marcellus shale. Additional takeaway capacity not listed below exists for the Marcellus shale only.)

Pipeline	Company	Capacity (bcf/d)	In-Service	Market	Capacity Addition Type
Mountain Valley	EQT	2	2018	Mid Atlantic	New
Ohio Valley Connector	EQT	1	2016	Midwest; Gulf Coast	New
NEXUS	Spectra Energy	2	2017	Midwest	New
OPEN	Spectra Energy	0.55	2015	Midwest; Southeast; Gulf Coast	New
Atlantic Coast	Dominion	1.5	2018	Southeast	New
Rover	Energy Transfer	3.25	2017	Midwest	New
Leach Xpress	Columbia	1.5	2017	Midwest; Gulf Coast	New
Western Marcellus	Williams	2	2018	Mid Atlantic; Southeast	New
Southeast Mainline Expansions	ANR Pipeline	2	2015	Gulf Coast; North	Bi-directional
REX Zone 3 East to West Project/Seneca Lateral	Tallgrass Energy	1.8	2015	West	Bi-directional
Tennessee Gas Pipeline Utica Backhaul	Kinder Morgan	0.49	2014	Gulf Coast	Bi-directional
Clarington Project	Dominion	0.24	2016	Gulf Coast; West	Expansion
Clarington West Project	Tallgrass Energy	2.4	2017	West	Bi-directional
ANR East Pipeline	ANR Pipeline	2	2017	West; South	New
Mountaineer Xpress	Columbia	2.44	2018	Southeast	Expansion
Appalachia to Market Project	Spectra Energy	1	2018	Northeast	Expansion
QuickLink Project	Columbia	0.49	2015	Midwest; Gulf Coast; West	Expansion
TEAM South Expansion Project	Spectra Energy	0.29	2014	Gulf Coast	Expansion
Ohio to Louisiana Access Project	Boardwalk	0.63	2016	Gulf Coast	Bi-directional
Gulf Coast Mainline Expansion	Kinder Morgan	0.73	2016	Gulf Coast	Expansion
Northern Supply Access Project	Boardwalk	0.18	2017	Gulf Coast	Bi-directional
Rayne Express	Columbia	1	2017	Gulf Coast	Expansion
Gulf Markets Expansion	Spectra Energy	0.63	2017	Gulf Coast	Bi-directional
Access South Project	Spectra Energy	0.31	2017	Gulf Coast	Expansion
Adair Southwest Project	Spectra Energy	0.2	2017	Gulf Coast	Expansion
Total New Take Away Capacity from the Utica		30.63 bcf/d			

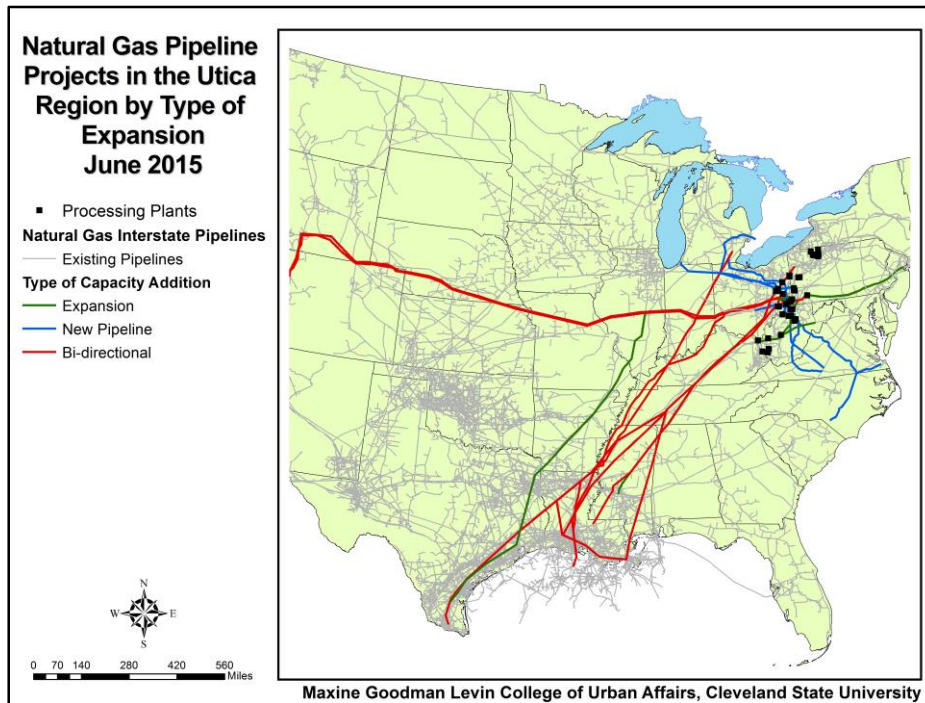
Source: "Several pipeline projects are underway" U.S. Energy Information Administration 10/24/14.

Figure 22. Natural Gas Interstate Pipeline Expansion Projects in the Utica, Announced as of October 2014



Source: Midstream company investor presentations and other public sources

Figure 23. Natural Gas Interstate Expansion Projects by Type, Announced as of June 2015



Source: Midstream company investor presentations and other public sources

2.3.6. Condensate Midstream Infrastructure

There are two main crude oil pipeline systems in Ohio: the Mid Valley Pipeline and the Patoka-Martinsville pipeline. Sunoco Logistics operates the Mid Valley Pipeline, which carries crude oil between Texas and Michigan, and runs through the western portion of Ohio, connecting to refineries in Lima and Toledo.⁹⁸ Marathon Petroleum Corporation operates the Patoka-Martinsville line, which transports crude imported from points west via refineries in Lima and Canton. BP Husky's Toledo refinery is currently designed primarily for heavy crude imported from Canada and other locations, while Marathon's Canton, PBF's Toledo, and Husky's Lima facilities are designed for light crude.^{99 100}

Marathon is in the planning stages of creating a new \$140 million¹⁰¹ pipeline which will bring condensate from Harrison County, Ohio and other locations in the Utica to its Canton refinery by late 2016, and eventually to points further westward. Called the Cornerstone Pipeline, its build out will traverse one of three potential routes which seek to use existing right-of-ways, and all of which will require a new pipeline running from the Utica region to Canton. The three strategies include: (1) terminating the new Utica pipeline at the refinery in Canton, (2) an addition to the new Utica pipeline running parallel to an existing crude line from Canton to Lima, and (3) an addition to the new Utica pipeline running parallel to Marathon's existing products pipeline between Canton and Findlay, and then south to Lima. Depending on the circumstances, pipeline capacity will range from 25-180 mbb/d. These build outs would give Marathon the ability to ship condensate from the Utica to locations further north or west.¹⁰²

In 2013, Marathon completed the construction of a truck-to-barge facility in Wellsville, Columbiana County, Ohio, with a capacity of 50,000 bbl/d, as well as a project with Harvest Pipeline Company that increased truck unloading capacity to 24,000 bbl/d. By 2015, Marathon will have completed the installation of condensate splitters at its refineries in Canton and Catlettsburg, Kentucky, allowing it to process 60,000 bbl/d of condensate. The company has \$345 million of capital projects planned for the Utica infrastructure expansion, \$225 million of which was budgeted for 2014.¹⁰³

Another midstream company that transports condensate is Enlink, a company that was recently formed with the support of Devon Energy. Enlink operates over 200 miles of pipelines in the Utica and Marcellus regions, including a system of crude pipelines that extends from Holmes County, Ohio to central West Virginia. The system infrastructure also includes crude stations,

⁹⁸ "Crude Oil Pipeline System" Sunoco Logistics 2014.

<http://www.sunocologistics.com/Customers/Business-Lines/Crude-Oil-Pipeline-System/55/>

⁹⁹ "Refineries" PBF Energy 2015. <http://www.pbfenergy.com/refineries>

¹⁰⁰ "U.S. Refineries" Husky Energy 2015.

<http://www.huskyenergy.com/operations/downstream/facilities/usrefineries.asp>

¹⁰¹ "2013 Annual Report" Marathon Petroleum Corporation 2013.

http://www.marathonpetroleum.com/content/documents/investor_center/annual_reports/MPC_Annual_Report_2013_with10-K.pdf

¹⁰² "Cornerstone Pipeline & Utica Build-Out Projects: Notice of Non-Binding Open Season" Marathon Pipe Line LLC 2013.

http://www.marathonpipeline.com/Shippers/Cornerstone_PipelinUtica_BuildOut_Projects_NonBinding_Open_Season/

¹⁰³ "2013 Annual Report" Marathon Petroleum Corporation 2013.

condensate stabilization stations,¹⁰⁴ and natural gas compression stations located at points along the lines.¹⁰⁵ Enlink has the capability to ship crude and condensate through its Black Run rail terminal in Muskingham County, Ohio, and also its Bells Run barge facility along the Ohio River in Washington County, Ohio. The company also transports crude and condensate via truck.

Enlink is currently in the process of adding a 45 mile condensate pipeline with a capacity of 50,000 bbl/d extending from Guernsey County, Ohio to its existing pipeline in Washington County. This pipeline will be complemented by the addition of 6 condensate stabilization and natural gas compression stations, increasing its system capacity to 60,000 bbl/d of condensate stabilization and 1.2 bcf/d of natural gas compression. These infrastructure improvements are scheduled to be online by the second half of 2015.¹⁰⁶

Blue Racer also operates condensate infrastructure in the Utica region. Gathering lines are currently being built which will transport condensate to its Berne processing plant, and connect to its Natrium processing plant along the Ohio River by a 30 mile pipeline. The condensate will be stabilized at either location, and can be further transported via barge or rail from the Natrium facility.¹⁰⁷

Utica East Ohio Midstream owns and operates condensate stabilization facilities in the Utica. Utica East Ohio currently has a 6,000 bbl/d condensate stabilizer capacity available at its Kensington site and is constructing a new 30,000 bbl/d condensate stabilizer at its Harrison Hub facility. Both facilities are capable of receiving Utica and Marcellus condensate from truck haulers in the region. Each facility is design to remove the light end NGLs from the condensate in order to make the product marketable and will provide its customers with options to load the stabilized condensate onto trucks or rail cars. Utica East Ohio also plans to be able to deliver into the Marathon Cornerstone pipeline beginning in late 2016.¹⁰⁸

MarkWest operates a 23,000 bbl/d condensate stabilization facility near Cadiz, Ohio, from which Marathon's Cornerstone Pipeline will originate. The company also has rail infrastructure at its Hopedale, Houston, Keystone, and Siloam (Kentucky) facilities. MarkWest's rail operations include 3 rail terminals, sidings for 835 rail cars, and 108 loading racks.¹⁰⁹ MarkWest is in the process of completing a \$15.8 billion merger with MPLX LP, a master limited partnership it formed with Marathon Petroleum Corporation in 2012. The merger, which is expected to close by the end of 2015, will combine MarkWest's gathering and processing operations with MPLX's refined products logistics.¹¹⁰

¹⁰⁴ Condensate stabilization refers to a process that gives condensate the ability to be transported or used downstream. See "Condensate Stabilization" Frames 2014. <http://www.frames-group.com/systems-solutions/lpg-c5-fractionation/condensate-stabilization>

¹⁰⁵ "Citi One-On-One MLP/ Midstream Infrastructure Conference" Enlink Midstream 8/20/14. http://enlk.enlink.com/files/doc_presentations/2014/Citi-ConferencePresentation-Final-8-20-14.pdf.

¹⁰⁶ "Citi One-On-One MLP/ Midstream Infrastructure Conference" Enlink Midstream 8/20/14.

¹⁰⁷ "From Importer to Exporter" Blue Racer 1/30/14.

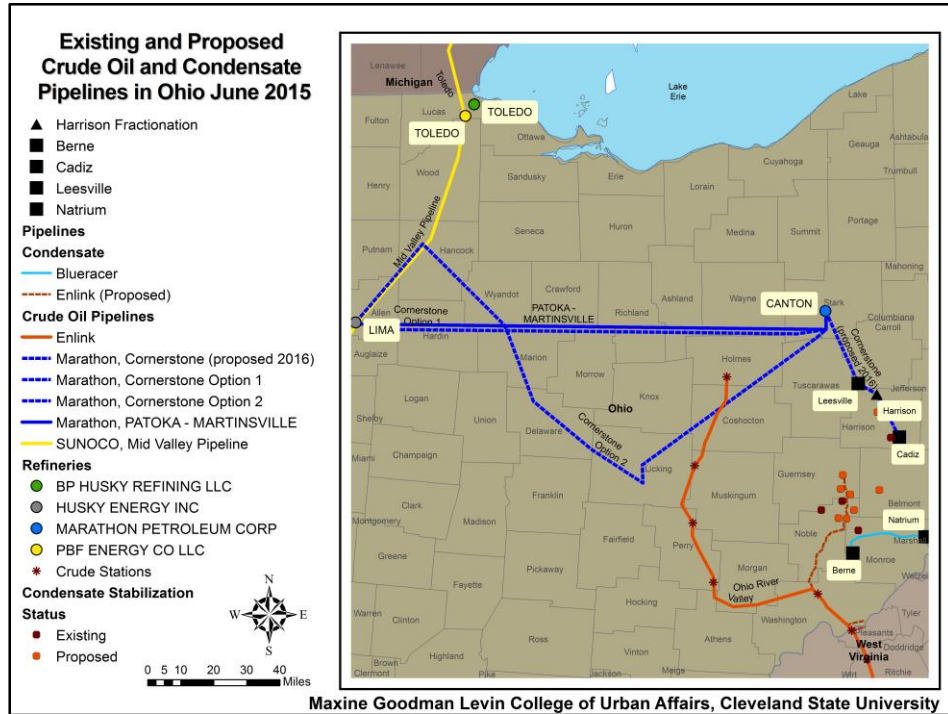
¹⁰⁸ Industry interviews

¹⁰⁹ "2015 Investor & Analyst Day" MarkWest 6/3/15.

<http://investor.markwest.com/phoenix.zhtml?c=135034&p=irol-presentations>

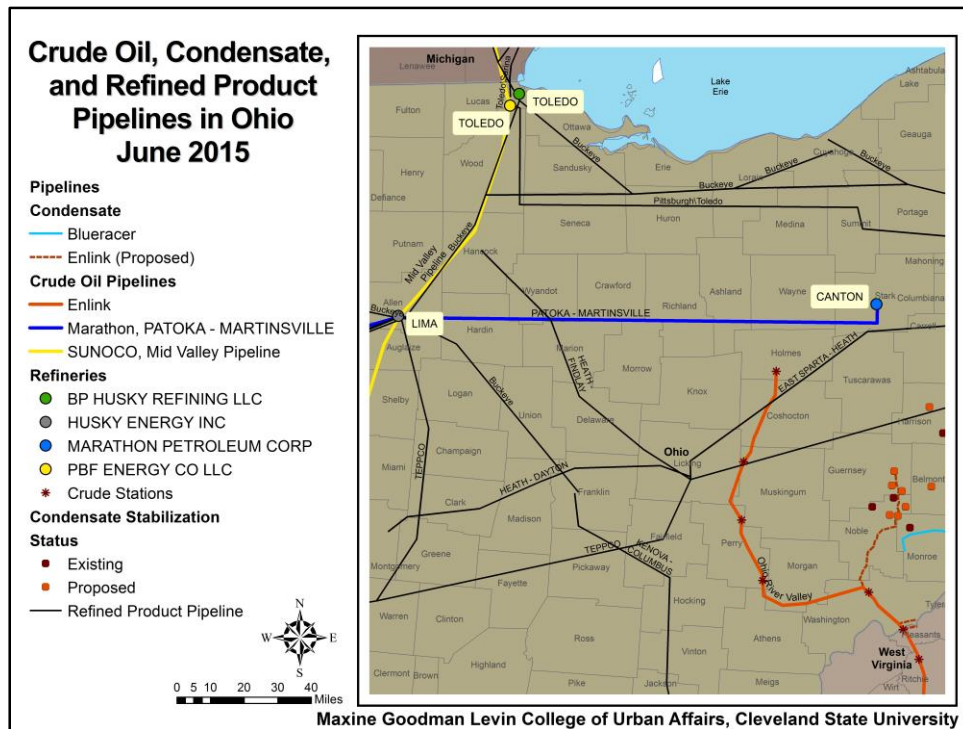
¹¹⁰ "MPLX, MarkWest to merge in \$15.8 billion deal" Oil and Gas Journal 7/13/15.

Figure 24. Existing and Proposed Crude Oil and Condensate Pipelines in Ohio, June 2015



Source: Midstream company investor presentations and other public sources

Figure 25. Crude Oil, Condensate, and Refined Product Pipelines in Ohio, June 2015



Source: Midstream company investor presentations and other public sources

3. PROSPECTS FOR UTICA-MARCELLUS PRODUCTS IN OHIO.

3.1. Demand for the Natural Gas Uses

The previous sections of this report highlighted the supply of natural gas coming from Marcellus and Utica Shale basin. However, the recent collapse of crude oil prices and a simultaneous decline in prices for natural gas and LNGs highlights the importance of estimating the demand for these products. This is especially true for anticipating development in the end-user markets and markets of interim products where dry gas, NGLs and especially ethane can be used as feedstock.

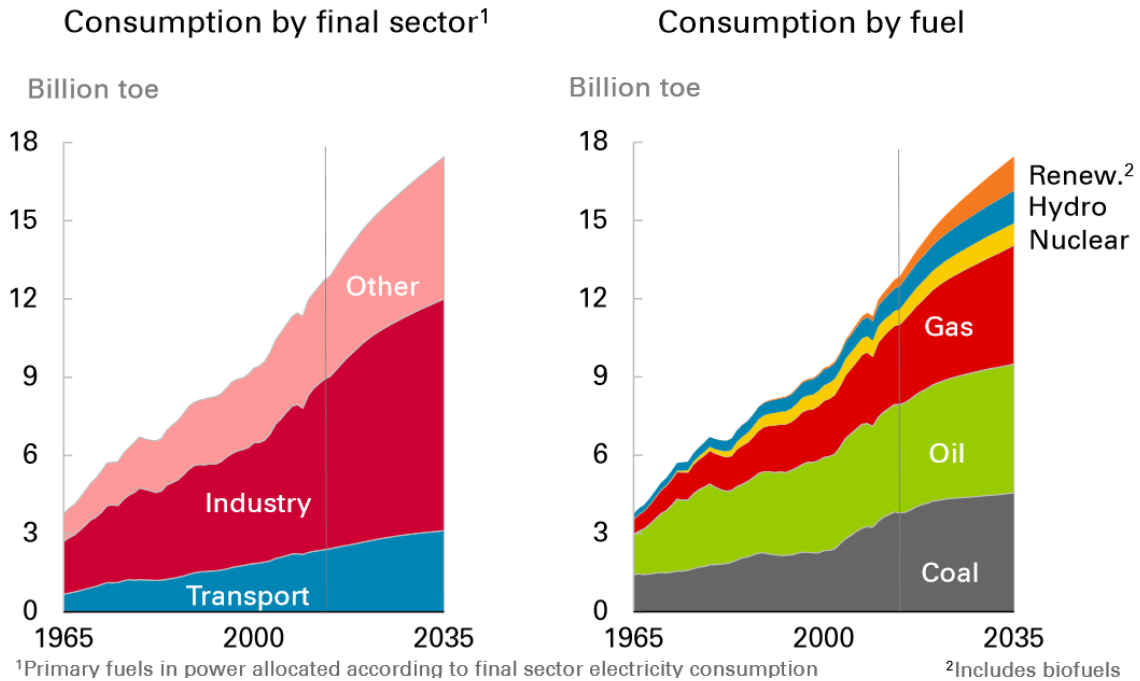
Prior to the collapse of the crude oil prices in the fall of 2014, natural gas supplies (dry and wet) were significantly surpassing consumption needs, both in the Appalachian region and in the U.S. generally. This section will describe the status of natural gas and natural gas liquid uses. This will help to assess potential growth of the natural gas demand and the equilibrium in the gas market.

According to BP's Energy Outlook, two-thirds of the anticipated worldwide increased energy demand in 2035 will be met by fossil fuels. With the energy generation mix shifting towards renewable and unconventional sources. Natural gas has been acknowledged as the fastest growing and the cleanest among fossil fuels. Although the largest growth for energy consumption is coming from non-OECD¹¹¹ markets, the anticipated growth in GDP worldwide is expected to continue to be closely connected to energy consumption. China and India are expected to contribute 60% to all non-OECD growth, and these countries are projected to be the largest consumers of dry natural gas and of NGLs, both as a feedstock for further petrochemical transformation and as a consumer of imported plastic products made from NGLs.

The current rate of Asian growth in particular is expected to slow down by 2035 due to the end of their energy-driven industrialization and electrification. There is also an expectation that non-OECD consumption of energy will diminish due to economic growth becoming less dependent on heavy industry and being driven more by innovation and knowledge. There is speculation that an accelerated reduction of energy intensity might end the close correlation between energy consumption and Gross Domestic Product, however, we are not likely to see this come to pass before 2030-2035 (Figure 26 and Appendix Figure C-1).

¹¹¹ The OECD, or the Organisation for Economic Co-operation and Development, is an international forum where member governments can discuss common economic, social, and environmental issues and find solutions. The majority of the OECD's members are located in Europe and North America.

Figure 26. Projected Energy Demand, 2035



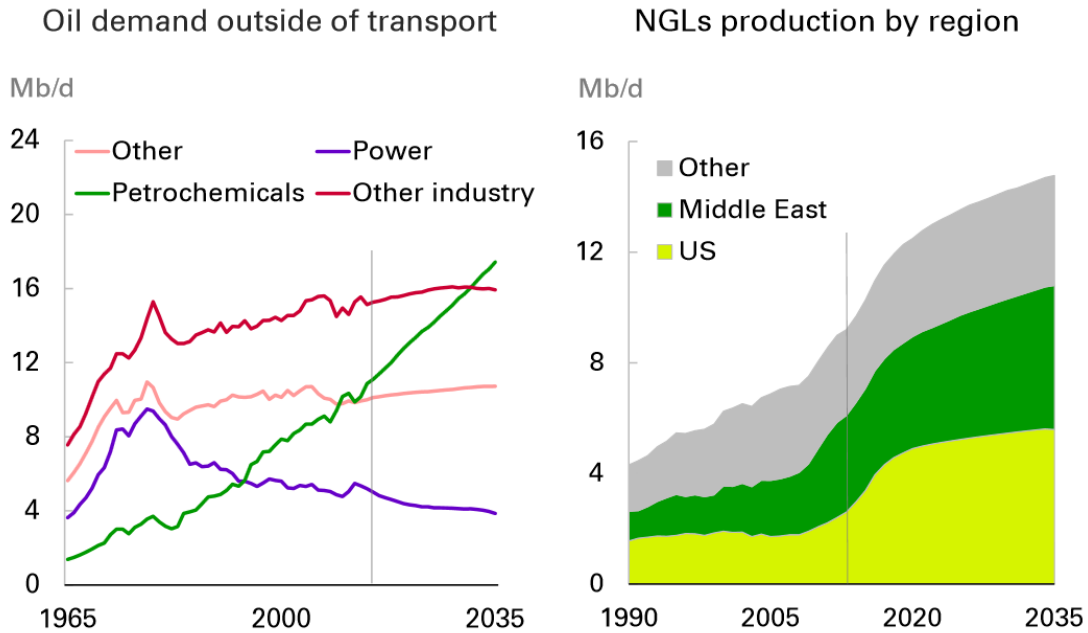
Source: BP

The global picture of energy demand is commonly defined by the consumption of oil. Transportation accounts for more than half (55%) of total liquid demand.¹¹² The growth in this portion of the oil sector comes exclusively from Asia (i.e. China); demand for transportation liquids from OECD countries is declining. Increased demand in other liquid-consuming sectors is also anticipated to come principally from non-OECD countries. Non-OPEC unconventional sources, largely from the U.S., Canada, and Brazil, are projected to be the initial hydrocarbon source used to satisfy this demand. OPEC production is expected to grow to meet this demand thereafter, especially through production of NGLs and crude oil in Iraq.

The other key driver of liquids demand is the petrochemical sector. Due to limited feedstock substitution capability for crude oil and in particular NGLs and due to limited room for efficiency gains in technological process, petrochemicals are projected to grow by 2.5% a year between 2013 and 2035 and consequently increase demand for oil and NGLs. (Figure 27). This growth projection is supported by cheap feedstock of NGLs from unconventional sources, gains in costs for energy-intensive chemical transformations, and growing demand for final plastic products, especially from Asia. Interestingly enough, growth of OPEC liquids supply is projected to come largely from NGLs. Transportation and petrochemicals are two major sectors constituting likely future growth of global consumption of energy, and the growth of the demand will be coming largely from Asia.

¹¹² Liquid fuel includes oil (from conventional and unconventional production), NGLs, and biofuels.

Figure 27. Growth of Oil and NGLs Demand by 2035



Source: BP

Similar projections have been made for the liquefied natural gas (LNG) demand. The largest growth in demand will likely come from Asia and Europe, while the supply therefore will likely be shared by the U.S., Australia, Africa, and Qatar.¹¹³

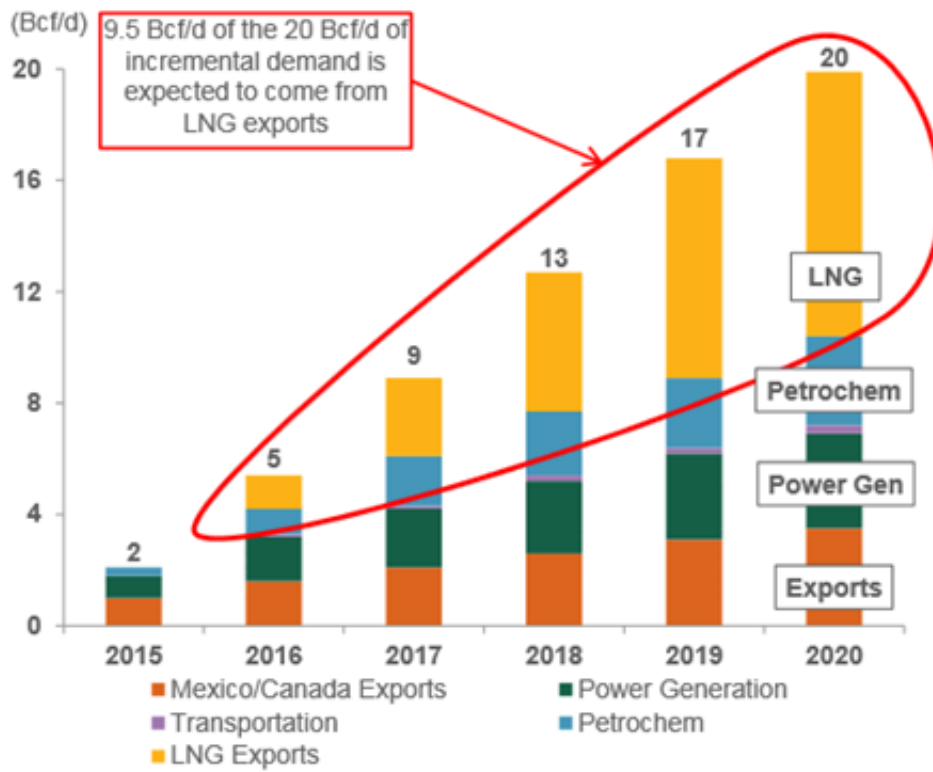
Since EIA projections of U.S. total energy consumption are also based on oil prices before the recent crash, it is difficult to predict whether the projected trends to 2040 will hold unless the oil and gas industry quickly recovers from the current decline. Sources of growth in U.S. production will be influenced by increased domestic demand from the power generation, transportation and petrochemical industries, as well as increases in global demand.

According to Antero Resources, incremental demand for U.S. natural gas is projected to grow rapidly from just 2 bcf/d in 2015 to 20 bcf/d by 2020 (Figure 28). This increase is due in large part to exports, through LNG and by pipeline to Canada and Mexico, which are projected to account for over 65% of U.S. natural gas demand by as early as 2020. Antero projects that LNG exports alone will account for almost 50% of projected natural gas demand by 2020. The majority of the last third of the natural gas demand will stem from industrial uses, including petrochemical growth and heat and power generation purposes. Transportation use will also likely increase to 1% of total natural gas demand by 2020.¹¹⁴

¹¹³ BP Energy Outlook 2035. February 2015. http://www.bp.com/content/dam/bp/pdf/Energy-economics/energy-outlook-2015/Energy_Outlook_2035_booklet.pdf

¹¹⁴ "Company Overview" Antero Resources 1/15. http://investors.anteroresources.com/files/doc_presentations/2015/JanB/Company-Website-Presentation-b-January-2015.pdf

Figure 28. Projected Incremental Natural Gas Demand, 2020



Source: Antero. Company Overview. January 2015.

The following sections 3.2 – 3.6 address each of the consumption sectors outlining projections for the regional growth of demand.

3.2. Wet Gas as a Feedstock for the Petrochemical and Chemical Industries

According to American Chemistry Council, the global market of petrochemicals is dominated by top multinational corporations and concentrated in a handful of industrialized nations (Figure 29). U.S. chemical exports surpassed \$190 billion in 2014 and is projected to expand about 8% annually with shipments growing almost 25% through 2019.¹¹⁵ While the global petrochemical market was valued at \$558.61 billion in 2013, it is expected to reach \$885.07 billion by 2020, growing by 6.8%¹¹⁶ annually.¹¹⁷

Asian markets, largely as the result of growing demand in China and India, are driving worldwide petrochemical consumption. The growth of demand for petrochemical products in OECD countries is expected to reflect any increase in Gross Domestic Product (GDP) and most likely will consist of single digit percentage increases. However continued growth in Asia will likely

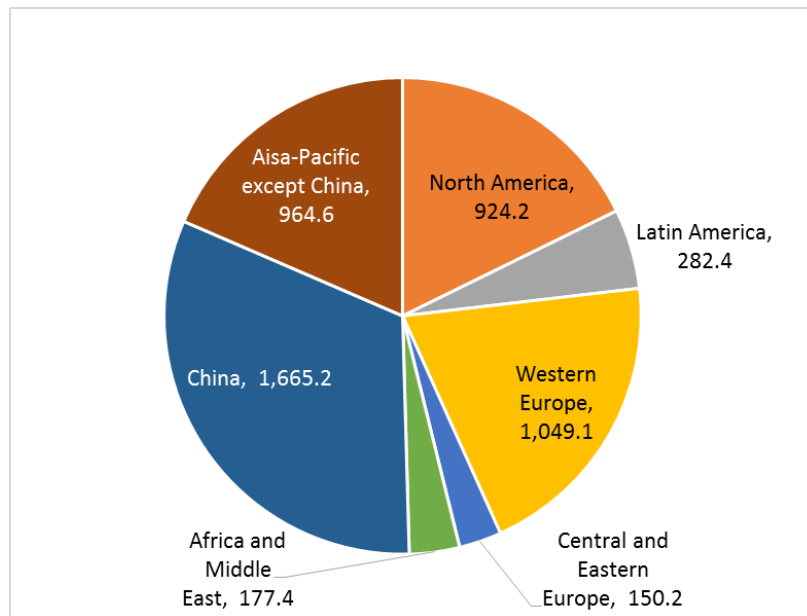
¹¹⁵ American Chemistry Council (ACC), U.S. chemicals trade by the numbers. January 2015. <http://www.americanchemistry.com/Policy/Trade/US-Chemicals-Trade-by-the-Numbers.pdf>

¹¹⁶ Percentage is calculated as Compound Annual Growth Rate (CAGR).

¹¹⁷ Petrochemical Markets – Global Industry Analysis, Size, Share, Growth Trends and Forecast 2014-2020. Transparency Market Research. November 2014. <http://www.transparencymarketresearch.com/pressrelease/petrochemicals-market.htm>

lead to growth over and above the GDP rate. Likewise, overall demand for plastics, including those derived from ethane, may be modified by upward pressure due to innovation and increased international demand for plastics, primarily from Asian markets. The likely reason for a spike in petrochemical demand from the Asian markets would be from increasing demand for polyethylene, which can be compounded or converted at factories in Asia. Indeed, experts speculate that for this reason finished plastics products in the U.S. will likely see no more growth than that realized by the GDP. The forecast for the domestic consumer demand of end products has been identified to likely fall within the range of 1%-2% for the next 10 years. Innovation leading to substitution of ethane-derived chemicals for chemicals derived from more complex petrochemicals might double these end product growth numbers, however it is unlikely to lead to double-digit increases of demand in the final domestic markets.

Figure 29. Global Chemical Shipments by Region (billions of dollars)



Source: ABIQUIM, ANIQ, Bureau of the Census, CEFIC, Statistics Canada, United Nations, VCI, and American Chemistry Council Estimates

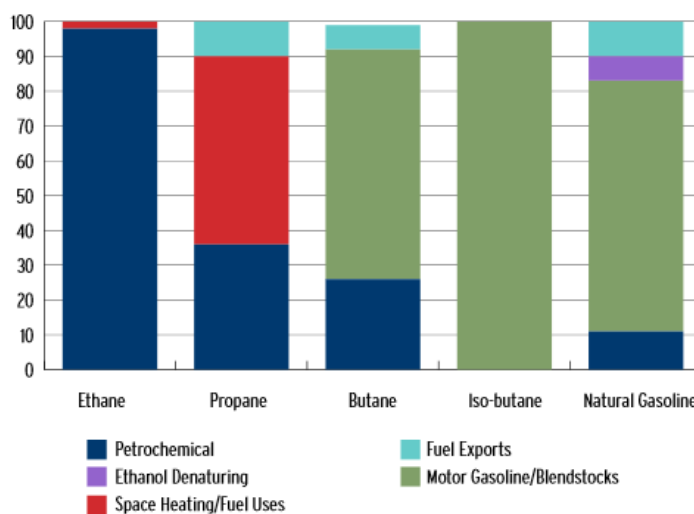
The chemical industry transforms wet gas into four main components: methane, ethane, propane, and butane. There are several processes involved in this transformation, ranging from cryogenic expansion removing methane from the stream of the “wet” components in the gas, to temperature-based refining (fractionation) that separates the remaining NGLs from one another, and further to “cracking,” which separates the large hydrocarbon chains into smaller and more useful bits. The fractionation process “boils off” hydrocarbon products one by one, starting with removal of the lighter NGLs from the stream, through processes known as de-ethanization, de-propanization, and de-butanization. Pentanes and heavier hydrocarbon chains, if any, are left behind in the stream. Finally, iso- and normal butanes are separated from each other through a butane splitter or through de-isobutanizing. In addition to separation of the

different NGLs into pure products, sulfur and carbon dioxide need to be removed as a part of the fractionation process.

All the transformation processes are energy-intensive. In petrochemical and chemical manufacturing, hydrocarbons are used as fuel for operations and as a raw material (called feedstock). The price of hydrocarbons influences the selection of the chemical process, which in turn can lead to volatility in prices and supplies of the hydrocarbons. Derived “pure products” -- ethane, propane, butane and isobutene – can be further transformed through refining into basic and specialty chemicals.¹¹⁸

The petrochemical sector consumes large amounts of NGLs, especially ethane and propane for the production of ethylene and propylene compounds, ultimately for use in the plastics industry (Figure 30). Space heating is another large portion of propane consumption.

Figure 30. NGL Consumption by Sector and Source, 2013



Source: Brookings Institute, 2013.¹¹⁹

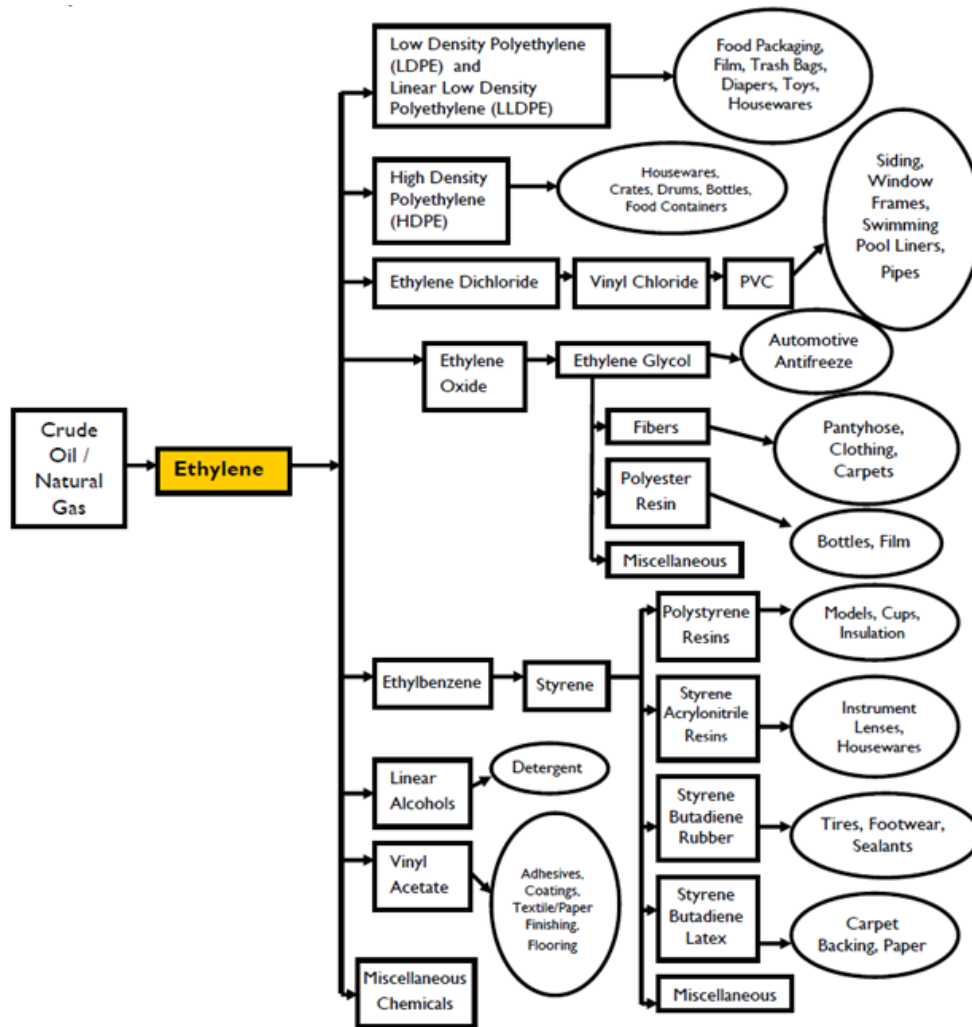
¹¹⁸ There are many classifications used by the chemical industry to help understand and organize the various chemical processes and products. One of them uses five thematic groups: industrial processes, materials and applications, basic chemicals, polymers and metals (Petrochemical Science of the University of York, <http://essentialchemicalindustry.org/materials-and-applications.html>). European Chemical Industry Council (CEFIC) includes different five groups: petrochemicals, basic inorganics, polymers, specialty chemicals and consumer chemicals. American Chemistry Council classify groups of chemicals to pharmaceuticals, basic chemicals, specialty chemicals, agricultural chemicals, and consumer products. Under the ACC scheme, basic chemicals are mainly sold within the chemical industry and to other industries before becoming products for the general consumer. They include inorganic chemicals, bulk petrochemicals, organic chemical intermediates, plastic resins, synthetic rubber, man-made fibers, dyes and pigments, printing inks, etc. Also called commodity chemicals, these chemicals are produced in large volumes. **Specialty chemicals** are low-volume, high-value compounds sold on the basis of what they do, not what they are. Also known as performance chemicals, some examples include paint, adhesives, electronic chemicals, water management chemicals, oilfield chemicals, flavors & fragrances, rubber processing additives, paper additives, industrial cleaners, and fine chemicals. See, <http://www.americanchemistry.com/Jobs/EconomicStatistics/Industry-Profile/Business-of-Chemistry-Segments>

¹¹⁹ *Id.*

Ethylene is one of the most widely used organic compounds in the chemical industry. This petrochemical is often converted into one of three types of plastics: low-density polyethylene (LDPE), linear low-density polyethylene (LLDPE) and high-density polyethylene (HDPE) (Figure 31).¹²⁰

LDPE is frequently used in plastic bags, food packaging, housewares, trash bags, films, toys, and diapers. HDPE is used in the production of food containers, crates, and drum bottles. LLDPE is used to make plastic bags and sheets, plastic wrap, stretch wrap, toys, lids, pipes, containers, cable covering, and flexible tubing. Polyethylene also accounts for about 3.9% of use in light vehicles.¹²¹

Figure 31. Ethylene Chain to Final Products



Source: American Chemistry Council, Guide to Business of Chemistry, 2014.

¹²⁰ Tom S. Witt, PhD, Managing Director and Chief Economist Witt Economics LLC “Building Value from Shale Gas: The Promise of Expanding Petrochemicals in West Virginia,” December 2013

¹²¹ “Chemistry and Light Vehicles,” Economics and Statistics Department, American Chemistry Council, July 2013.

Ethylene is also as a building block to create polyvinyl chloride (PVC) or vinyl. PVC is an important thermoplastic used to make building materials such as window frames, pipe cables and coating, siding, flooring, and swimming pool liners.¹²² Ethylene can further be converted into ethylene oxide, which can be used to synthesize ethylene glycol, polyester resin, and fibers. Ethylene glycol is an essential ingredient of automotive antifreeze. Polyester resins are used in sheet molding, bottles and films. The fibers from ethylene can be used for carpets and clothing.

Ethylene benzene is another important intermediate chemical, used primarily for the production of styrene. Polystyrene (PS) resins are important plastics for the production of various materials like building insulation, protective packaging (such as CD and DVD cases), lids, bottles, and disposable trays, cups, plates, and cutlery. Other important types of styrene derivatives produced are styrene butadiene rubber, styrene acrylonitrile resins, and styrene butadiene latex. Styrene butadiene rubber is used to produce tires, footwear, and sealants. Styrene acrylonitrile resins are used in housewares and instrument lenses and styrene butadiene latex is used in carpet backing and paper. Still another ethylene-based product is linear alcohol, which is used in detergent and vinyl acetate. Vinyl acetate is used in the production of adhesives, coatings, and textile/paper finishing.¹²³

As the second-largest component of natural gas, ethane is an important petrochemical feedstock and is primarily used in production of ethylene. Ethylene is usually produced by steam cracking of not only ethane, but also other petrochemicals, including naphtha¹²⁴. Steam-cracking is an endothermic process leading to the breaking up of large molecules into smaller ones. Naphtha, a crude oil fraction, is the most important petrochemical feedstock in Europe. In other regions, steam crackers also use ethane, propane and butane as a feedstock, depending on the pricing of the different feeds and the desired product mix.¹²⁵

The choice of feedstock is an important economic decision as it influences other costs as well. Subject to availability, ethane is probably the best feedstock, as it has higher yield and selectivity of ethylene than heavier feedstock and its processing is relatively simple, involving lower capital costs. Ethylene production margins have reached record highs due to the availability inexpensive ethane, reaching \$0.33/lb in 2014.¹²⁶ As a result, North American steam crackers were switching back to ethane feedstock, and by 2012 60% used ethane and only 12% used naphtha.¹²⁷

Until recently, for U.S. cracker expansions in the chemical industry, ethane has been chosen as the only feedstock for producing ethylene. Most recently, however, ethylene-naphtha crackers

¹²² *Guide to the Business of Chemistry 2014*, American Chemistry Council.

¹²³ "Vinyl Acetate" United States Environmental Protection Agency 10/18/13.
<http://www.epa.gov/ttnatw01/hlthef/vinylace.html>

¹²⁴ Naphtha is a hydrocarbon that contains mostly molecules with 5–12 carbon atoms, one of the lighter components produced by refining crude oil. It is a much heavier feedstock than ethane or propane, which respectively consist of hydrocarbon molecules with 2 or 3 carbon atoms.

¹²⁵ The average energy demand of currently operating naphtha crackers is 18 giga-joules (GJ)/tonne of cracker products. State of the art naphtha crackers use 11 GJ/tonne of cracker products. *Id.*

¹²⁶ ICIS Consulting. Presentation "U.S. shale gas, the project boom and impact on global petrochemicals." May 27, 2014.

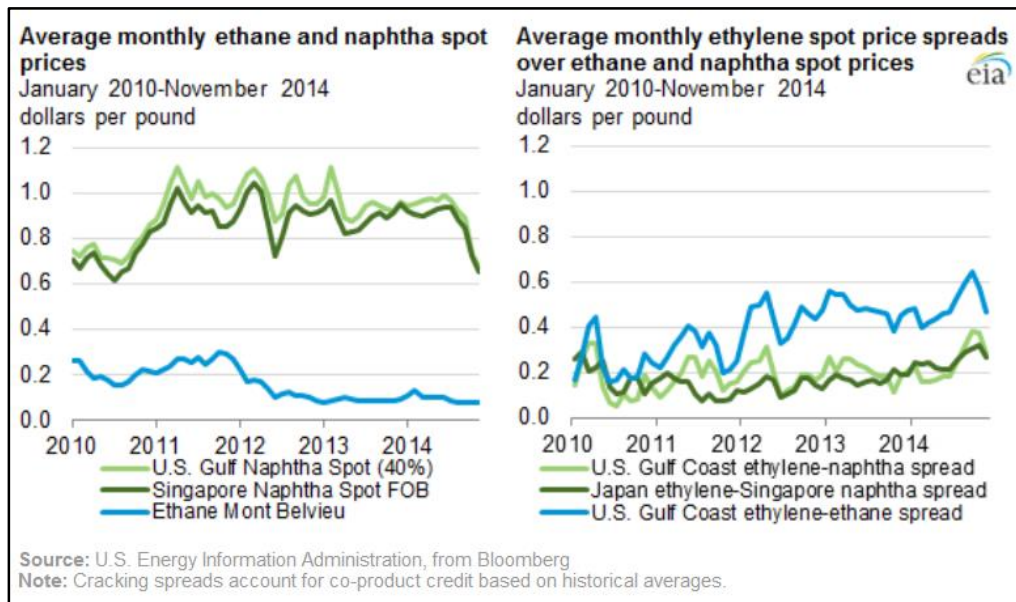
¹²⁷ *Id.*

are being considered in response to decreased naphtha prices. Increasing propane supplies have also recently increased expansion of propylene crackers. The decision to expand cracker capacity in the U.S. has been made based on the difference between the value of raw materials (ethane and propane) and the chemical products derived therefrom (ethylene and propylene) (Figure 32 and Figure 33).

As of January 2015, ethane remained a significantly lower-priced raw material compared to naphtha, and as such continued to be the highest margin-yielding feedstock in producing ethylene. Based upon November 2014 naphtha prices, the average profit margin for making ethylene was \$0.65/lb, (see Appendix Table C-2),¹²⁸ while producing ethylene from ethane delivered a \$0.48/lb margin between the feedstock and the final product.¹²⁹

Propane prices at the liquids hub of Mont Belvieu (\$0.10/lb) also surpassed its price competitors in delivering the profit margins of \$0.50/lb from cracking propylene from propane. In 2012, PwC and TopAnalytics each projected that refiners would realize a fivefold reduction in cost of production by using U.S. ethane to make ethylene as opposed to Asian naphtha (316 \$/ton vs. 1,717 \$/ton). This analysis was based upon a price of \$3.00/mmbtu for natural gas and \$100/bbl of crude oil.¹³⁰ Of course the price of oil has since substantially fallen. However there continues to be a significant advantage to using U.S. based ethane as the principal feedstock for ethylene, although with a smaller margin.

Figure 32. Average Monthly Ethane, Naphtha, Ethylene and Their Spreads, 2010 – 2014.¹³¹



¹²⁸ Naphtha prices correlate closely to crude oil price.

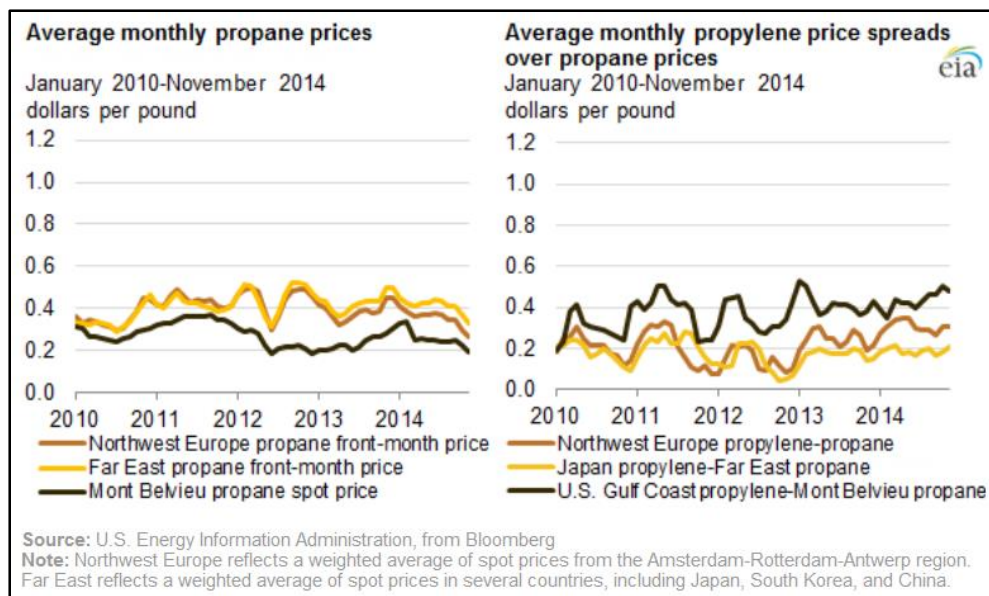
¹²⁹ "Growing U.S. HGL production spurs petrochemical industry investment" U.S. Energy Information Administration 1/29/15. http://www.eia.gov/todayinenergy/detail.cfm?id=19771#tabs_SpotPriceSlider-1

¹³⁰ Shale Gas Reshaping the U.S. Chemical Industry. PwC. October 2012.

http://www.pwc.com/en_US/us/industrial-products/publications/assets/pwc-shale-gas-chemicals-industry-potential.pdf

¹³¹ Source for Figures 32 and 33: "Growing U.S. HGL production spurs petrochemical industry investment" EIA.

Figure 33. Average Monthly Propane, Propylene, and Their Spreads, 2010 – 2014.



The ethane molecules follow a series of complex paths after being refined into ethylene, with the finished product depending upon which path is taken. When ethane is converted to ethylene in crackers and then to polyethylene, it takes a form of a commodity chemical that might go through another transformation (becoming a secondary commodity chemical) before it will be compounded into a plastic mixture (physical mixing of resins with performance-enhancing additives). Compounding companies and other intermediaries thereafter either produce final plastic products or send the mixture to plastic manufacturers for molding and stamping into final consumer goods, industrial parts and other products. Polyethylene produced at or near the cracker facility by the petrochemical company may be sold directly to compounders or to distribution companies.

Consumer products maintain a traditional segment in the market of chemicals and these compete for customers by using brands, different distribution channels, demographic niches and geographies. The economic markets are segmented by such types of final chemical product as hygiene products, hair care, skin care, cosmetics, body care, perfumes, and packaging. The *Bulk Petrochemicals* and *Intermediates* (including ethane derivatives) occupy 17% of global chemical shipments; the *Consumer Products* hold about 9% of global shipments.¹³²

Polyethylene consumption growth can also be analyzed in light of the specific types of compounds generated. Low Density Polyethylene (LDPE), first developed in 1935, has a density in the range of 0.910 g/cc (grams per cubic centimeter) to 0.940 g/cc, which results in a relatively low tensile strength and a relatively high ductility. LDPE tends to be translucent,

¹³² American Chemistry Council. Guide to Business of Chemistry. 2014.

making it useful in film applications such in food packaging, which requires high transparency and moderate strength.¹³³

The major sectors that consume Linear Low Density Polyethylene (LLDPE) are packaging, construction and automotive, accounting for 80% of the global LDPE demand in 2010. LLDPE is gradually replacing LDPE in many applications due to its lower cost and higher strength, but LDPE is still used widely in extrusion coating because of its ease of processing. Demand for LDPE has been slowing, with a compound annual growth rate (CAGR) of only 2.5% for the period 2000-2010. The growth of LDPE demand can be attributed solely to the Chinese market, which accounted for 32% of demand in 2010.¹³⁴

The global market for LLDPE demand, on the other hand, has been moving steadily forward - its growth driven largely by the developing plastics industries in the Asia-Pacific and Eastern European countries.¹³⁵ Global consumption of LLDPE is projected to increase by 4-4.5% annually through 2017. The Asian region makes up approximately 42% of forecasted total demand, while the more mature markets of North America and Europe, apparently approaching market saturation, have experienced a more limited LLDPE demand increase. Accordingly, we might expect restricted LLDPE capacity additions in these regions. Demand increase is anticipated to come from the packaging and construction industries. Indeed, capacity additions already scheduled for the developing markets are likely to further drive the LLDPE industry growth.¹³⁶

3.3. Natural Gas as Fuel for Transportation

In the United States, 0.01% of natural gas produced is used as fuel for transportation. As an alternative to gasoline or diesel fuel, natural gas can act as a transportation fuel in a compressed (CNG) or liquefied (LNG) state. CNG is stored on vehicles in high-pressure cylinders, achieving comparable fuel economy to a gasoline-powered automobile. LNG is created by super-cooling natural gas and storing it at cold temperatures while under pressure. While CNG can be used for a wide variety of applications, LNG is better suited for long-distance travel because of its greater storage efficiency.¹³⁷ Because of this, EIA believes that LNG may become a more viable fuel for freight rail, predicting that it will control 35% of the rail fuel market by 2040.¹³⁸

As of 2012, there are 15 million NG vehicles operating around the world, 250,000 of which are operating in the United States. The majority of these vehicles are part of transportation fleets, but new technology is increasing the potential for individual NG vehicles. The largest barrier to more widespread NG use in the U.S. is a lack of CNG and LNG refueling stations. NatGasCar, a Cleveland, Ohio-based company, has developed both a conversion system that allows gasoline-powered vehicles to operate with CNG, and a home CNG vehicle refueling system. The vehicle

¹³³ *Id.*

¹³⁴ Western Plastics (final product distribution company), <http://www.wplastics.com/article2853.asp>

¹³⁵ Merchant Research & Consulting Ltd.

¹³⁶ Plastemart, http://www.plastemart.com/plastic-facts-information.asp?news_id=21390&news=Global-LLDPE-demand-is-moving-steadily-forward

¹³⁷ "Natural Gas Fuel Basics" U.S. Department of Energy 11/4/13.
http://www.afdc.energy.gov/fuels/natural_gas_basics.html

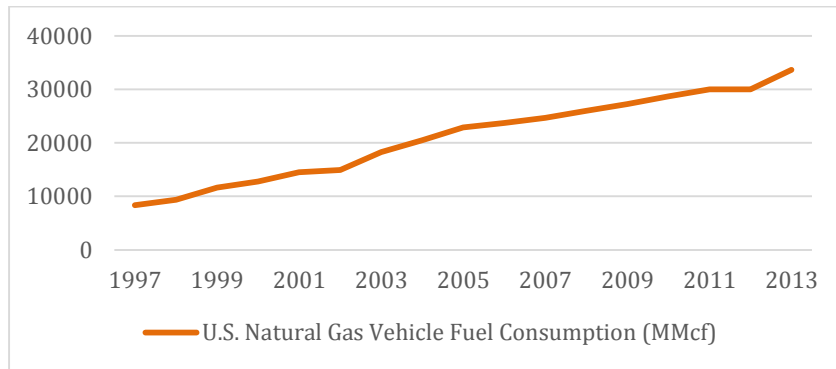
¹³⁸ "Annual Energy Outlook 2014" U.S. Energy Information Administration 4/14.
<http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf>

conversion system can be used to completely or partially switch a vehicle’s fuel source to CNG, and is designed for use in either vehicle fleets or by individual vehicles. The home refueling system was developed to minimize refueling duration, a common impediment to CNG use in individual vehicles.¹³⁹

The U.S. Energy Information Administration shows that natural gas vehicle fuel consumption in the United States has increased from 8.33 bcf in 1997 to 33.62 bcf in 2013, an over 300% increase (Figure 34).¹⁴⁰ In their 2014 Annual Energy Outlook, EIA projects that this upward trend of natural gas consumption by transportation uses will increase to 850 bcf (2.33 bcf/d) in 2040. Much of this increase in transportation consumption will be driven by fleet vehicles, both land and sea.¹⁴¹

As of 2014, there are 12,000 CNG stations available worldwide for public use, 500 of which are located in the United States.¹⁴² According to Clean Fuels Ohio, there are 20 public CNG stations located in Ohio with 5 more under construction, and 20 more planned. In addition, there are 13 privately operated CNG stations and 3 such LNG stations in Ohio.¹⁴³ Because of the abundance of inexpensive natural gas produced domestically, and the lower emissions associated with CNG, use of natural gas as a transportation fuel is increasing. CNG use in the United States has grown 3.7% per year since 2000, while global increase of the fuel has been 30.6% during this same period.¹⁴⁴ Companies such as Smith Dairy in Orrville, Ohio have begun to transition their trucking fleets from conventional gasoline to CNG. Smith Dairy operates over 400 vehicles and plans to completely convert its fleet to CNG by 2030. It began this process in 2012 with the construction of a publicly available CNG station in Orrville.¹⁴⁵

Figure 34. U.S. Natural Gas Vehicle Fuel Consumption, mmcf



Source: EIA

¹³⁹ “Natural Gas Vehicle Conversion and Refueling Systems for Residential and Commercial Use” NatGasCar 2011. <http://www.natgascar.com/>

¹⁴⁰ “U.S. Natural Gas Vehicle Fuel Consumption” U.S. Energy Information Administration 1/30/15. <http://www.eia.gov/dnav/ng/hist/n3025us2A.htm>

¹⁴¹ “Annual Energy Outlook 2014” U.S. Energy Information Administration 4/14. <http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf>

¹⁴² “What is CNG?” CNG Now! 2014. <http://www.cngnow.com/what-is-cng/Pages/default.aspx>

¹⁴³ “Ohio CNG Stations Map” Clean Fuels Ohio: Ohio NGV Partnership 2014. <http://ohiongv.cleanfuelsohio.org/cng-stations/>

¹⁴⁴ “What is CNG?” CNG Now!

¹⁴⁵ “Smith Dairy Deploys Natural Gas Vehicles and Fueling Infrastructure in the Midwest” U.S. Department of Energy 10/17/13. <http://www.afdc.energy.gov/case/1543>

Transit agencies represent another opportunity for growing CNG and LNG use. As of 2014, 12-15% of public transit buses operate using CNG or LNG, and 20% of new vehicle orders are CNG or LNG.¹⁴⁶ Of the public transportation authorities in the five largest cities in Ohio, three have purchased CNG vehicles: COTA in Columbus¹⁴⁷, GCRTA in Cleveland¹⁴⁸, and METRO RTA in Akron (Figure 35).¹⁴⁹

The price differential between oil, which is used to make gasoline and diesel fuel, and natural gas, has a large effect on the viability of natural gas use as a transportation fuel. When the price of oil is high and natural gas low, as has been the case for the past five years, there is an incentive for fleets to convert to natural gas. However, if the price of oil drops, so will the incentive to convert. Under these circumstances, the payout for conversions is too long, and the inconvenience too great.

Such a drop in price in oil occurred in the fall of 2014. If low oil prices prove to be sustainable, it will have a chilling effect on the development of natural gas as a transportation fuel in Ohio and the nation. Gasoline and diesel price volatility creates uncertainty both for companies looking to convert fleets and for investors looking to build CNG/LNG refueling stations. The result is that the government incentives may be required to get such investment.¹⁵⁰

¹⁴⁶ "Vehicles" CNG Now! 2014. <http://www.cngnow.com/vehicles/Pages/information.aspx>

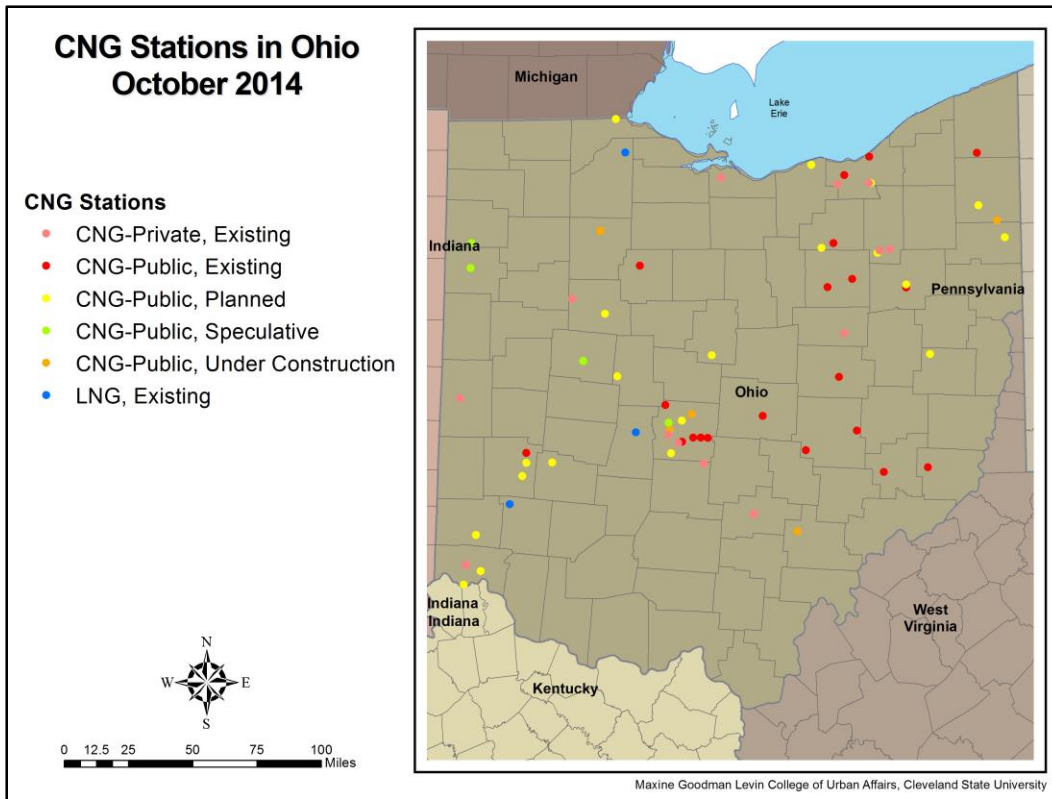
¹⁴⁷ Rouan, Rick. "COTA's cheap-fuel buses roll out today" The Columbus Dispatch 5/6/13. <http://www.dispatch.com/content/stories/local/2013/05/06/cotas-cheap-fuel-buses-roll-out-today.html>

¹⁴⁸ Shaffer, Mary. "RTA to purchase 60 buses powered by CNG" Greater Cleveland Regional Transit Authority 11/19/13. <http://www.riderta.com/news/nov-19-rta-purchase-60-buses-powered-cng>

¹⁴⁹ Thomas, Christine. "Akron, Ohio Transit Agency Selects Clean Energy to Operate its CNG Bus Fueling Facility; Station Serves 45-Bus Natural Gas Fleet" Clean Energy 7/3/08. <http://investors.cleanenergyfuels.com/releasedetail.cfm?releaseid=319488>

¹⁵⁰ The United States excise tax for gasoline and diesel fuel at the pump is far below other western countries. An increase in such taxes could be one way to incent private investment into CNG/LNG refueling stations.

Figure 35. CNG Stations in Ohio, October 2014



Source: <http://ohiongv.cleanfuelsohio.org/cng-stations/>

3.4. Power Production and Heat Generation

Natural gas can be used to produce electricity in one of three ways: (1) steam production from burning gas, which then generates electricity through a steam turbine; (2) electricity generation by burning gas in a combustion turbine; or (3) burning gas in a combustion turbine, using the heat to make steam which will be used by a steam turbine to generate electricity (combined cycle).¹⁵¹ In 2013 natural gas accounted for 27% of total electricity generation in the United States – second only to coal.¹⁵² However, EIA projects that by 2035 natural gas generation will surpass all other forms of electricity generation in the United States. Natural gas power plants have been replacing coal-fired plants in recent years due a combination of low natural gas prices, coal plant inefficiencies and new emission constraints from environmental regulation. If coal-fired plants are retired at an increasing pace, EIA predicts that natural gas electricity generation could overtake coal as early as 2019.¹⁵³

¹⁵¹ “Natural Gas” U.S. Environmental Protection Agency 9/25/13.

<http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html>

¹⁵² “What is U.S. electricity generation by energy source?” U.S. Energy Information Administration 6/13/14. <http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3>

¹⁵³ “Annual Energy Outlook 2014” U.S. Energy Information Administration 4/14.

As of the first quarter of 2014, 11 states were using natural gas as their primary source of electricity generation, with Texas, Florida, and California the leaders. Ohio is 12th in the nation in natural gas electricity generation, with over 6,000,000 megawatt-hours. This represents a substantial increase since the first quarter of 2001, when Ohio was 36th in the nation with only 115,000 megawatt-hours.¹⁵⁴ As of 2012, there were 30 natural gas power-generating facilities in Ohio.¹⁵⁵ Using an EIA fuel-to-electricity conversion chart, pursuant to which 0.00786 mcf of natural gas is required to generate one kilowatt-hour of electricity, Ohio required over 47 bcf of natural gas for electricity generation during the first quarter of 2014.¹⁵⁶

During the first six months of 2014, natural gas power generation made up over 50% of new generating capacity added in the United States. The majority of this growth was seen in Florida, with substantial natural gas power generation capacity also added in Utah and Texas. 2,179 megawatts of combined cycle electricity generation capacity were added in the first six months of 2014, representing a 60% increase versus 2013. Overall, however, natural gas power generation additions were 50% less than the same period in 2013.¹⁵⁷ EIA predicts that 73% of electricity generation capacity additions added by 2040 will be natural gas plants. Natural gas consumption for electricity generation purposes are projected to increase by 2 tcf during this time period.¹⁵⁸ The number and capacities of coal-fired electricity generating power facilities that are being retired have been growing each year (Figure 36).

According to the EIA, 29 of these facilities were retired in 2010, with a total net summer capacity of 1,418 MW. By 2012, 85 facilities were being retired with a total capacity of 10,214 MW, or 3.2% of total coal-fired power generation in the United States in 2011. The EIA predicts that these numbers will continue to grow and that 60,000 MW of capacity will be retired by 2020, or nearly 20% of coal-fired capacity in 2012. The overwhelming majority of these retirements are projected to take place before 2016, when the EPA's Mercury and Air Toxics Standards come into effect.

¹⁵⁴ Molla, Rani. "Coal Still Is Top Source of Electricity in U.S.; Where Does Your State Stand?" The Wall Street Journal 8/14/14. <http://blogs.wsj.com/numbers/most-electricity-in-u-s-still-comes-from-coal-where-does-your-state-stand-1705/>

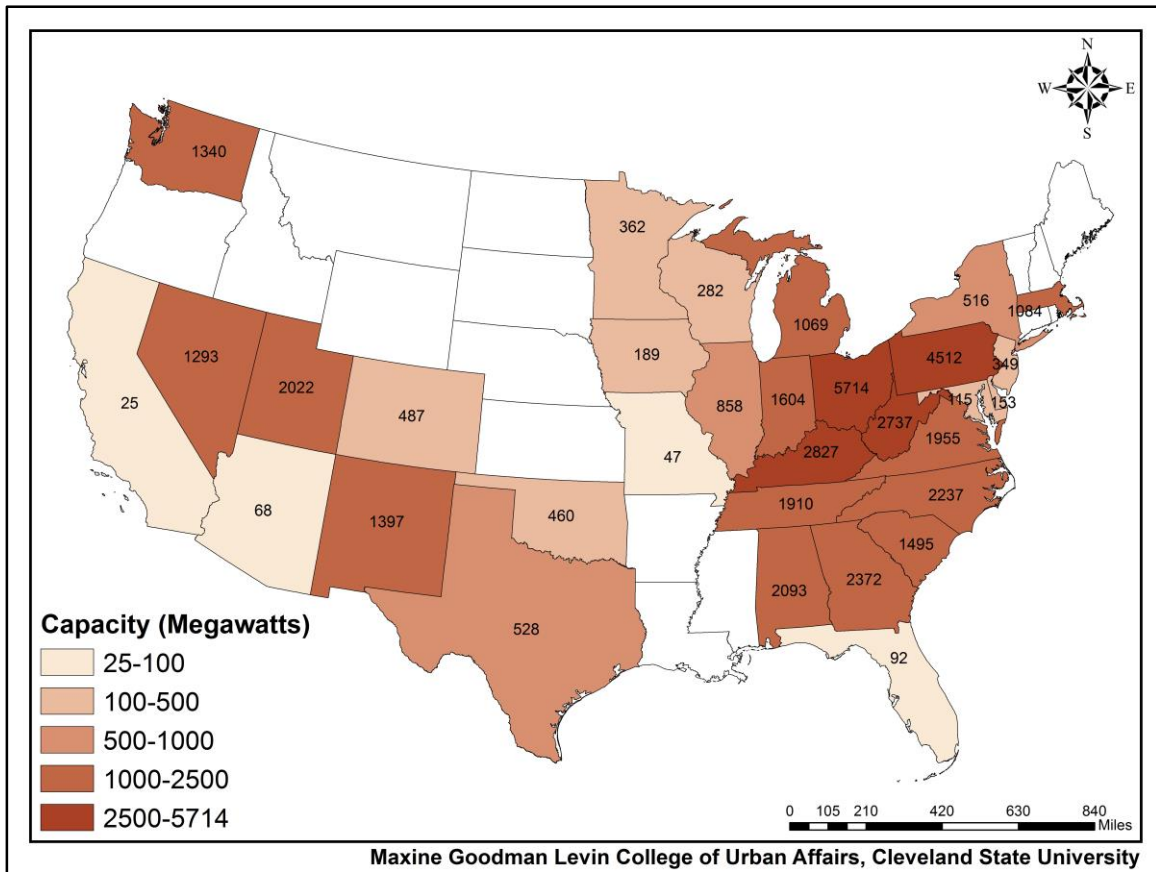
¹⁵⁵ "Ohio: State Profile and Energy Estimates" U.S. Energy Information Administration 9/14. <http://www.eia.gov/state/?sid=oh#tabs-4>

¹⁵⁶ "How much coal, natural gas, or petroleum is used to generate a kilowatt-hour of electricity?" U.S. Energy Information Administration 1/15/14. <http://www.eia.gov/tools/faqs/faq.cfm?id=667&t=3>

¹⁵⁷ Lee, April. "Today in Energy: Natural gas, solar, and wind lead power plant capacity additions in first-half 2014" U.S. Energy Information Administration 9/9/14. <http://www.eia.gov/todayinenergy/detail.cfm?id=17891>

¹⁵⁸ "Annual Energy Outlook 2014" U.S. Energy Information Administration 4/14.

Figure 36. Capacity of Coal-Fired Power Generation Plants Planned to Retire, 2012 – 2025



The United States Government Accountability Office states that the total capacity of coal-fired facilities retired between 2012 and 2025 will be 42,192 MW. These facilities are not spread evenly geographically, however: the majority of capacity retirements are in the eastern half of the United States, and specifically in the Appalachian region. Ohio accounts for the largest capacity drop, with 5,714 MW planned to be retired by 2025.¹⁵⁹

Natural gas is also the top choice of heating fuel for the majority of households in the United States: 56 million households, or 49%, use natural gas as a fuel for space heating. In the Midwest, roughly 66% of households are heated with natural gas, in the West 56%, in the Northeast 54%, and in the South 30%. These numbers have been declining slightly since 2005, however, in every region except for the Northeast.¹⁶⁰ According to EIA’s 2009 Residential Energy Consumption Survey, 2,873 bcf of natural gas was used for space heating and an additional

¹⁵⁹ “EPA Regulations and Electricity: Update on Agencies’ Monitoring Efforts and Coal-Fueled Generating Unit Retirements” U.S. Government Accountability Office 8/14.

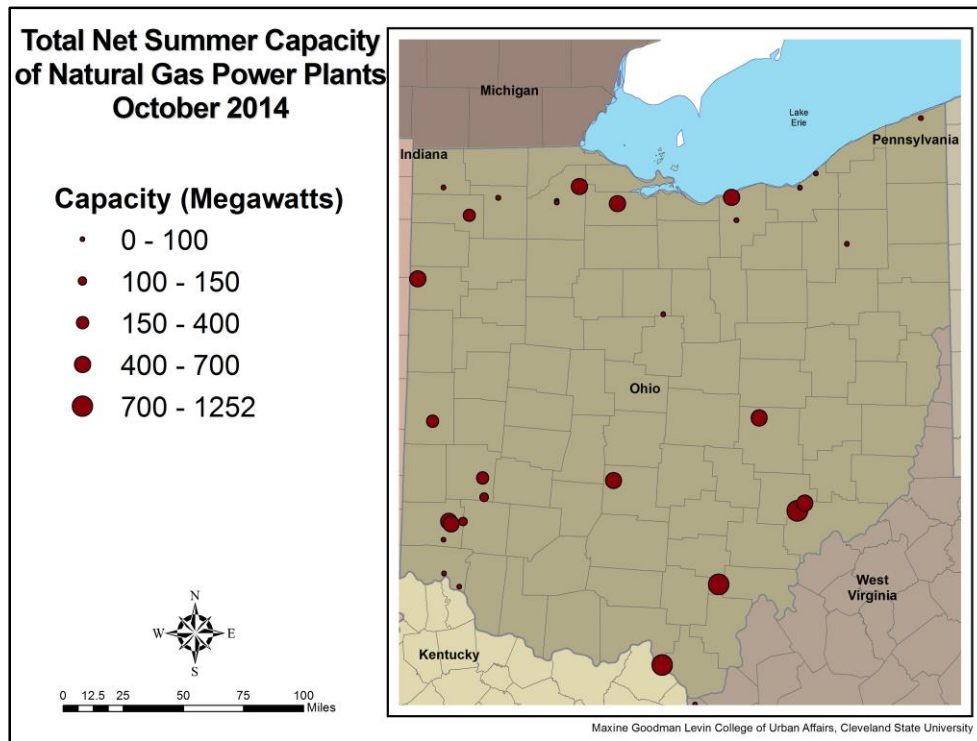
<http://www.gao.gov/assets/670/665325.pdf>

¹⁶⁰ Comstock, Owen. “Everywhere but Northeast, fewer homes choose natural gas as heating fuel” U.S. Energy Information Administration 9/25/14. <http://www.eia.gov/todayinenergy/detail.cfm?id=18131>

1,196 bcf for water heating in households in the United States. In the Midwest region, 1,189 bcf was used for space heating and 371 bcf was used for water heating.¹⁶¹

Demand for space heating is also a main contributor for the rise in residential and commercial sector natural gas consumption during the winter months. Between April 2009 and March 2014, residential consumption has risen, on average, from 5.5 bcf/d during the summer to 20.5 bcf/d during the winter. For the same time period, commercial consumption fluctuates between 5 bcf/d in the summer and 12.2 bcf/d in the winter. Stock of natural gas is built during the summer months and is drawn during the winter months, allowing for this large swing in consumption. The largest swing was seen between the summer of 2013 and the winter of 2013-2014 where combined residential and commercial consumption rose by 25.9 bcf/d.¹⁶² Natural gas consumption for the industrial sector, including that which is used for space heating, was around 8.5 tcf in 2012. This amount is predicted to grow by 2.5 tcf by 2040, and makes up 26% of the total increase in natural gas consumption over that period.¹⁶³

Figure 37. Total Net Summer Capacity of Natural Gas Power Plants in Ohio, October 2014



Source: EIA

¹⁶¹ "2009 RECS Survey Data: Table CE4.1 Household Site End-Use Consumption by Fuel in the U.S., Totals, 2009" U.S. Energy Information Administration 2009.

<http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=consumption>

¹⁶² "Short-Term Energy Outlook Supplement: Weather Sensitivity in Natural Gas Markets" U.S. Energy Information Administration 10/14. http://www.eia.gov/forecasts/steo/special/pdf/2014_sp_03.pdf

¹⁶³ "Annual Energy Outlook 2014" U.S. Energy Information Administration 4/14.

3.5. Gas to Liquids Technology Development

Gas to liquids (GTL) is a process by which natural gas is converted into synthetic liquid fuels, such as diesel fuel and gasoline. New technology, including the use of advanced catalysts, has increased the efficacy of GTL plants and has allowed for the creation of products of a higher caliber. Through 2014, the abundant supply of domestically produced natural gas through shale development, the rise in the price ratio between crude oil and natural gas up to early 2015, and the need for high-quality, low-emission products had enabled GTL to become a viable endeavor. However, in 2015 the price ratio between crude oil and natural gas has declined, making GTL less attractive.

Gas to liquids can be established at several points along the gas value chain. It can be complementary to or replace midstream natural gas processing, or it can be sold in the downstream markets.¹⁶⁴ A study from the International Journal of Alternative Propulsion has expressed the view that GTL processes not only have lower emissions than those of coal to liquid (CTL) or biomass to liquid (BTL), but also represent a more economically feasible alternative in regions where natural gas is abundant.¹⁶⁵ The Louisiana Department of Natural Resources is predicting that there will be a market for more than 10 new GTL plants, each valued at \$12-20 billion.¹⁶⁶ However, the U.S. Energy Information Administration does not believe that GTL will have much of an effect on the total amount of liquids produced domestically. The EIA has expressed the view that due to high costs and price competition with crude oil production, gas to liquids will remain only a small portion of domestic liquids production.¹⁶⁷ Recent drops in oil prices have further eroded the near term economic opportunity associated with GTL plants.

Historically, gas-to-liquid facilities have been constructed in locations abroad, due either to an abundance of very inexpensive natural gas (Qatar, Malaysia, and Nigeria) or to historic political isolation (South Africa). Due to the success of the majority of these facilities, and especially Shell's Pearl GTL project in Qatar, and due to the abundance of inexpensive shale gas, North America is now becoming a focus in the implementation of GTL. The international energy company Sasol is planning to construct an \$11-14 billion 96,000 bbl/d GTL facility in Louisiana by 2016.¹⁶⁸ Shell initially expressed interest in constructing a similar facility in Louisiana, however the plans were discontinued, citing high costs and market uncertainty.¹⁶⁹

¹⁶⁴ Hobbs, H. O. Jr. "Gas-To-Liquids Plants Offer Great ROI" The American Oil & Gas Reporter 5/12.

¹⁶⁵ Bertucco, Alberto and Sudiro, Maria. "Production of synthetic gasoline and diesel fuels by alternative processes using natural gas, coal and biomass: process simulation and economic analysis" International Journal of Alternative Propulsion 2008. <http://www.inderscience.com/storage/f635491187110212.pdf>

¹⁶⁶ O'Brien, Edward. "Gas to Liquids Plants: Turning Louisiana Natural Gas into Marketable Liquid Fuels" Louisiana Department of Natural Resources/ Technology Assessment Division 11/13. http://dnr.louisiana.gov/assets/TAD/newsletters/2013/2013-11_topic_1.pdf

¹⁶⁷ "Annual Energy Outlook 2014" U.S. Energy Information Administration 4/14.

¹⁶⁸ Forbes, Alex. "Gas-to-Liquids- on the threshold of a new era?" GasTechNews 9/18/13.

<http://www.gastechnews.com/processing-technology/gas-to-liquids-on-the-threshold-of-a-new-era/>

¹⁶⁹ Mallik, Arup and Mantri, Vishakh. "Gas-to-liquids plants face challenges in the U.S. market" U.S. Energy Information Administration 2/19/14.

Smaller companies, such as Velocys, are also in the process of GTL and Biomass to Liquid (BTL) research and development. The Central Ohio-based company has begun constructing and selling small-scale GTL modules, or reactors, which can create diesel fuel on-site, using a natural gas feedstock.¹⁷⁰ These small operations represent a lower-cost and potentially lower-risk GTL alternative to the large-scale facility that Sasol is planning. Small-scale operations may also match better with the scattered way shale gas is distributed geographically. When infrastructure cannot keep up with production in these areas, the natural gas could potentially be converted to fuel using small-scale GTL facilities.¹⁷¹

Velocys anticipates it will be supplying Calumet Specialty Products with 1,000 bbl/d of fuel on-site in Karns City in Central Pennsylvania.¹⁷² In June 2014 Velocys also announced that it had acquired Houston-based Pinto Energy and with it, Pinto's plans to construct a \$300 million GTL facility in Ashtabula, Ohio, capable of producing at least 10,000 bbl/d of fuel.¹⁷³ The plant is scheduled for completion in 2016. Additional expansions of up to 7,000 bbl/d of fuel and industrial wax production at this facility will be possible.¹⁷⁴

3.6. International Export of Natural Gas

The Natural Gas Act of 1938 states that authorization from the United States Department of Energy must be granted in order to export or import natural gas to or from a foreign country.¹⁷⁵ Shale gas development, and the associated drop in natural gas price due to an oversupply, is spurring a push to export natural gas to locations abroad. LNG terminals that were intended to import natural gas just a few years ago are now being converted to export it. The EIA projects that the U.S. will become a net exporter of natural gas by 2020, and that net exports of natural gas will total 5.8 tcf in 2040.¹⁷⁶ For the first nine months of 2014, natural gas averaged \$4.47 per mmbtu in the United States. Through the process of liquefaction and shipping, final prices for exported natural gas would rise to \$9.14 per mmbtu in the Americas, \$9.64 in Europe, and \$11.64 in Asia. For example, Cheniere's Sabine Pass LNG export facility charges a liquefaction fee of \$3.50 per mmbtu, adds a 15% markup (\$5.14), and then charges a transport fee dependent upon destination (\$.50 to the Americas, \$1.00 to Europe, and \$3.00 to Asia).¹⁷⁷ The main method of exporting natural gas is through a process in which the gas is converted into a liquid

¹⁷⁰ Gearino, Dan. "Battelle spinoff taps old idea to turn natural gas into diesel" The Columbus Dispatch 5/3/13. <http://www.dispatch.com/content/stories/business/2013/05/03/company-taps-old-idea-to-profit-on-natural-gas.html>

¹⁷¹ Kelly-Detwiler, Peter. "Small Gas-To-Liquids Plants Get a Huge Boost" Forbes 3/28/14.

¹⁷² Hargreaves, Neville. "Making Distributed Gas to Liquids a Reality" Oxford Catalysts/Velocys 10/4/12. http://www.velocys.com/arcv/press/ppt/SMI%204%20Oct%202012%20Velocys_rev1.pdf

¹⁷³ "Acquisition of Pinto Energy and Ashtabula GTL Project" Velocys 6/25/14. <http://www.velocys.com/financial/nr/nr140625.php>

¹⁷⁴ Shingler, Dan. "Ashtabula gas-to-liquids plant could be just the first for Ohio company and its Texas partner" Crain's Business Cleveland 10/4/13.

¹⁷⁵ "Natural Gas Regulation" Energy.gov. <http://energy.gov/fe/services/natural-gas-regulation>

¹⁷⁶ "Annual Energy Outlook 2014" U.S. Energy Information Administration 4/14.

¹⁷⁷ Shaik, Zain. "U.S. Natural Gas Exports Will Fire Up in 2015" Bloomberg Businessweek 11/6/14. <http://www.businessweek.com/articles/2014-11-06/u-dot-s-dot-natural-gas-exports-will-fire-up-in-2015>

through super cooling. This Liquefied Natural Gas (LNG) has a greatly reduced volume, making it easier to store and export via ship.¹⁷⁸

As of December 2014, four LNG export facilities had been approved by the United States Federal Energy Regulatory Commission (FERC). Three of these are located in the Gulf Coast region: Cheniere's Sabine Pass facility in Sabine, Louisiana, Sempra/Cameron's export terminal in Hackberry, Louisiana, and the Freeport LNG facility in Freeport, Texas. The first LNG export facility to receive approval outside of the Gulf Coast region was Dominion's Cove Point terminal in Maryland. Cove Point will have a capacity to export the equivalent of 0.82 bcf/d of natural gas¹⁷⁹, and will begin these shipments in 2017.¹⁸⁰ The export facility will draw gas from the Marcellus Shale using Dominion's existing interstate pipeline network.¹⁸¹

As is the case with natural gas' viability as a transportation fuel, the possibility of LNG exports greatly depends on the price of crude oil. As oil prices drop, so too does the likelihood of LNG exports. This is especially true for exports to Asia, where natural gas prices are frequently linked to crude oil prices. The LNG export facilities that have already been approved by FERC and are currently under construction are at an advantage because they have most likely already lined up long-term contracts with buyers abroad.¹⁸² However, United States producers of LNG may not suffer the same setbacks as producers elsewhere in the world because contracts signed by U.S. companies are generally linked with domestic natural gas prices in the U.S., not with oil. In addition, many current and proposed LNG facility projects in the United States involve the conversion or repurposing of existing LNG import terminals. By utilizing some of the existing infrastructure, LNG producers can begin exporting more inexpensively.¹⁸³ Nevertheless, the drop in oil global oil prices in the fall of 2014 threatens the near term viability of LNG export economics.

As of 2009, there were 31 locations in the United States where gas was exported to Canada or Mexico via pipeline. Export capacity to both countries has greatly increased since 1990, to 4.3 bcf/d and 3.6 bcf/d, respectively.¹⁸⁴ There are five export points located in the eastern half of the country: Sault Ste. Marie, Detroit, and St. Clair River (Sarnia) in Michigan; Niagara Falls in

¹⁷⁸ "Liquefied Natural Gas: Exports- America's Opportunity and Advantage" American Petroleum Institute 11/14. <http://www.api.org/~media/files/policy/lng-exports/lng-primer/liquefied-natural-gas-exports-highres.pdf>

¹⁷⁹ "North American LNG Import/Export Terminals: Approved" Federal Energy Regulatory Commission 12/3/14. <http://ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf>

¹⁸⁰ Chediak, Mark and Polson, Jim. "Dominion Cove Point LNG Terminal Wins Federal Approval" Bloomberg 9/30/14. <http://www.bloomberg.com/news/2014-09-30/dominion-cove-point-lng-terminal-wins-federal-approval.html>

¹⁸¹ "LNG exports: Marcellus Shale goes global" State Impact 12/18/12.

<http://stateimpact.npr.org/pennsylvania/tag/lng-exports/>

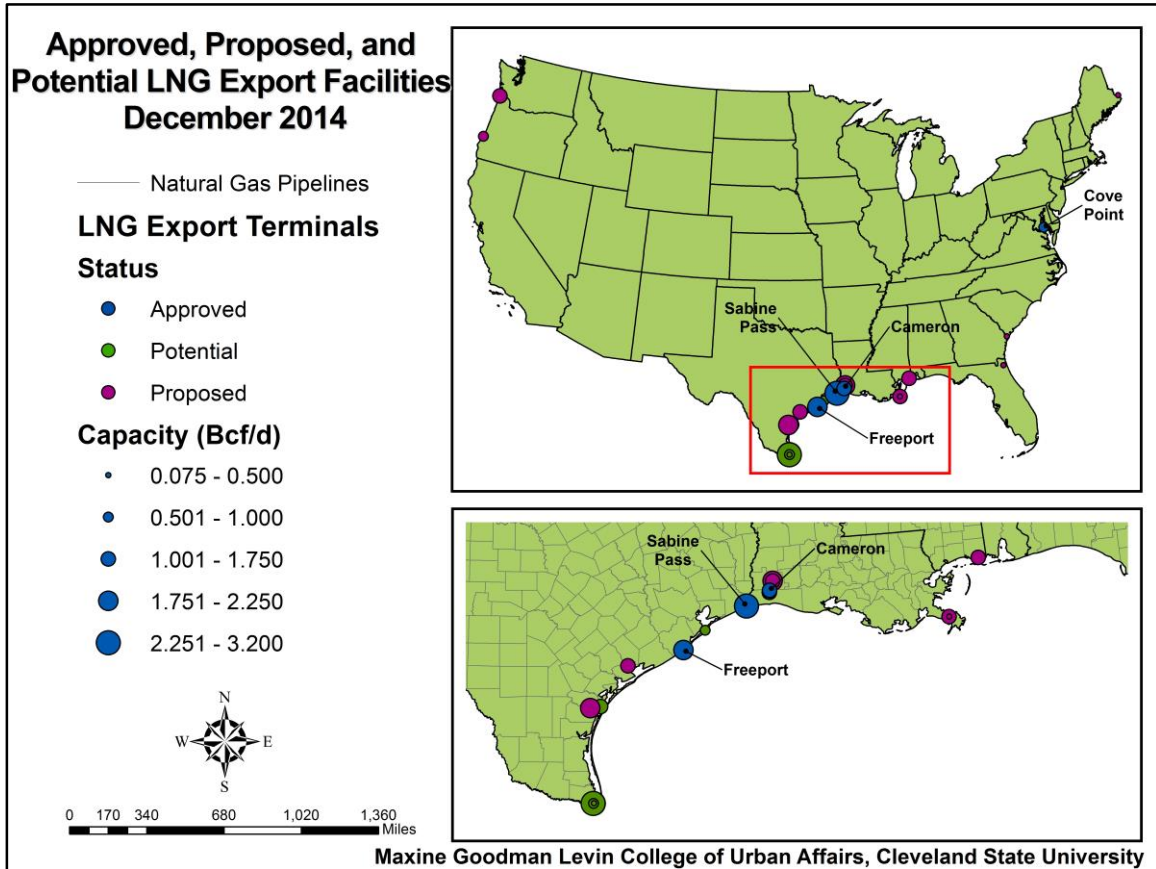
¹⁸² Dlouhy, Jennifer A. "Lower oil prices could pinch natural gas export plants" Houston Chronicle 12/17/14. <http://www.houstonchronicle.com/business/energy/article/Lower-oil-prices-could-pinch-natural-gas-export-5964433.php>

¹⁸³ Kelly, Ross. "Oil Plunge Dims Outlook for LNG Projects" NASDAQ 12/11/14. <http://www.nasdaq.com/article/oil-plunge-dims-outlook-for-lng-projects-20141211-00054>

¹⁸⁴ "Natural Gas Import/Export Pipelines" U.S. Energy Information Administration 2009. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/impex.html

New York; and Pittsburg in New Hampshire. These export points have a combined capacity of 5,153 mmcf/d.¹⁸⁵

Figure 38. Approved, Proposed, and Potential LNG Export Facilities, December 2014



Source: FERC

3.7. Methanol and Fertilizer Industries

Methanol is used as a feedstock in the production of many products that are used on a daily basis, including plastics, paints, and adhesives, as well as transportation fuels. While methanol can be produced from a variety of sources such as biomass, its primary feedstock is natural gas. Around the world there are 90 methanol plants producing up to 100 million metric tons per year.¹⁸⁶ Worldwide, another 65.9 million metric tons/year of methanol production capacity is slated to be operational by 2020. While relatively small (1.8 million metric tons/year), North America’s share in methanol production is expected to grow to a capacity of 6.5 million metric

¹⁸⁵ “Locations of U.S. Natural Gas Import & Export Points, 2009” U.S. Energy Information Administration 2009. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/impex_list.html

¹⁸⁶ “Methanol Basics” Methanol Institute 2011. <http://www.methanol.org/Methanol-Basics.aspx>

tons by 2020.¹⁸⁷ In 2012, the global methanol demand was 62 million tons, of which the United States made up 10%. With shale development causing an abundance of cheap natural gas, methanol production has become more profitable in North America. In addition, demand for methanol has increased, insofar as it is considered to be a cleaner-burning fuel.¹⁸⁸ The majority of methanol plants, both existing and proposed, in the United States are located in the Gulf Coast region.¹⁸⁹ As of October 2014 there are no methanol plants in Ohio, and no public announcements of plans to build any.

Fertilizer production is broken down into three categories by crop nutrients: nitrogen, phosphorus, and potash. Out of the three, nitrogen-based fertilizer requires natural gas as a feedstock during production.¹⁹⁰ Each ton of fertilizer (ammonia) that is produced requires roughly 34 mcf of natural gas. The supply of natural gas makes up the largest share of costs associated with fertilizer production.¹⁹¹ The American Oil & Gas Reporter states that shale gas development is creating a “renaissance” for nitrogen fertilizer production in the United States, contrasting the current situation to the period between 1999 and 2007, when capacity was almost cut in half. It is anticipated that 6 million tons of ammonia will be added to the United States’ capacity by 2016.¹⁹²

As of 2012 there were 53 nitrogen fertilizer production sites in 29 states across the U.S., represented by 30 companies. Three of these production sites are located in Ohio: Agrium U.S. Inc. in North Bend (near Cincinnati), PCS Nitrogen Fertilizer, L.P. in Lima, and USX Corporation in Lorain.¹⁹³ Agrium’s North Bend facility has a production capacity of 187,393 tons of nitric acid per year,¹⁹⁴ a material that is combined with ammonia to produce ammonium nitrate.¹⁹⁵ Because nitric acid production itself requires 0.32 tons of ammonia per ton of nitric acid, the creation of ammonium nitrate depends heavily on a supply of natural gas.¹⁹⁶ Using this figure, Agrium’s North Bend facility requires 2 bcf/year, or 5.5 mmcf/d of natural gas.

PCS’s facility in Lima has the capacity to produce 661,387 tons of ammonia, 330,693 tons of urea (a nitrogen fertilizer product that requires .64 tons of ammonia/ton of urea¹⁹⁷), 220,462 tons of nitrogen solutions, and 110,231 tons of nitric acid.¹⁹⁸ From ammonia, urea, and nitric acid

¹⁸⁷ Morris, Gregory DL. “U.S. Methanol on the Comeback” *The American Oil & Gas Reporter* 4/13. <http://www.aogr.com/web-exclusives/exclusive-story/u.s.-methanol-on-the-comeback>

¹⁸⁸ Krishnamurthy, Krithika and Mukhopadhyay, Bhaswati. “Analysis: Cheap gas fuels North American methanol expansion” *Reuters* 3/21/13. <http://www.reuters.com/article/2013/03/21/us-methanol-imports-idUSBRE92K14220130321>

¹⁸⁹ “U.S. Methanol on the Comeback” *The American Oil & Gas Reporter*.

¹⁹⁰ “U.S. Fertilizer Production and Mining Facilities at a Glance” *The Fertilizer Institute*.

¹⁹¹ “Key Fertilizer Products” *Fertilizer101* 2013. <http://www.fertilizer101.org/science/?storyid=9>

¹⁹² Morris, Gregory DL. “New Capacity Bolstering Gas Demand” *The American Oil & Gas Reporter* 2/13. <http://www.aogr.com/web-exclusives/exclusive-story/new-capacity-bolstering-gas-demand>

¹⁹³ “U.S. Fertilizer production and Mining Facilities at a Glance” *The Fertilizer Institute*

¹⁹⁴ “Fact Book 2013-2014” Agrium 1/14. http://www.agrium.com/includes/2014_Agrium_Fact_Book.pdf

¹⁹⁵ *Fertilizer101* “Key Fertilizer Products”

¹⁹⁶ “Fact Book 2013-2014” Agrium.

¹⁹⁷ “Fact Book 2013-2014” Agrium.

¹⁹⁸ “Facilities & Investments: Lima” *PotashCorp* 2/28/14.

<http://www.potashcorp.com/about/facilities/nitrogen/lima/>

production, the PCS Lima facility requires 30.9 bcf/year, or 84.6 mmcf/d of natural gas. The Lima facility is currently undergoing a \$190 million expansion, scheduled to come online by late 2015.¹⁹⁹ Spurred by the low cost of domestically-produced natural gas, this expansion will increase ammonia production by about 100,000 tonnes and urea production by 80,000 tonnes.²⁰⁰

4. PROSPECTS FOR OHIO DOWNSTREAM DEVELOPMENT

In the national chemical industry, Ohio is ranked #6 by volume of producing chemicals. The chemical industry comprises the second largest industry of the manufacturing base of Ohio, employing more than 44,000 people with average wages of \$73,950, exceeding the average manufacturing wage by 33%. Ohio ships \$6.5 billion in chemical products to customers outside the state.²⁰¹ Plastic products have become a major part of our daily life. We drive vehicles that, on average, contain 350 pounds of polymers. Each light vehicle in North America comes with about 18 pounds of polyethylene, which is more than 5% of total plastic/composites in a car. Our cellular phones are housed in plastic cases that never leave our side. Water bottles have become a part of our daily hydration routine. We are surrounded by microwaves, medical devices, pharmaceuticals, large appliances, food storage containers and wraps, small electronics, computers and a myriad of other products that contain plastics in their essential parts and structural covers. A strong economic base in the chemical industry positions Ohio to provide a large customer base for prospective downstream segments of the oil and gas industry, with a petrochemical cluster at its core.

U.S. Production of ethylene – a major component of plastic -- grew from 22,977 thousands of metric tons in 2003 to 25,035 thousands of metric tons in 2013. Just ethane production from U.S. gas plants alone almost doubled since shale development began, growing from 581 thousand barrels per day in December 2008 to 1,087 mbb/d in May 2015. Between 2014 and 2018, ethylene crackers using ethane will increase their feedstock capacity by nearly 600,000 barrels per day (not accounting for crackers announced in the Appalachian Region).²⁰²

¹⁹⁹ Brown, Trevor. "Lima, OH- PotashCorp" AmmoniaIndustry.com 1/31/14.

<http://ammoniaindustry.com/lima-oh-potashcorp/>

²⁰⁰ "Food Matters: 2013 Annual Integrated Report" PotashCorp 2013.

http://potashcorp.s3.amazonaws.com/2013_PotashCorp_Annual_Integrated_Report.pdf

²⁰¹ ACC. <http://ex.democracydata.com/ACHEMC/sites/ImpactChem/docs/Ohio.pdf>

²⁰² Growing U.S. HGL production spurs petrochemical industry investment. EIA. January 29, 2015.

<http://www.eia.gov/todayinenergy/detail.cfm?id=19771>

Figure 39. U.S. Gas Plant Production of Ethane-Ethylene



Source: U.S. Energy Information Administration

Abundant ethane produced from the Utica and Marcellus has created an opportunity to develop a petrochemical hub in Ohio River Valley. Downstream plastic manufacturers in Ohio and the Midwest, which rely on natural gas liquids like ethane, should enjoy modest cost reductions for polyethylene and other feedstock as a result of the Appalachian ethane surplus. This would be aided by potential transportation cost savings and sales advantages that can come from the presence of end-use customers, specialty chemical companies, refiners, and the natural resource in the same economic region.

The proximity of petrochemical refining to polyethylene distributors, converters and plastic manufacturers has the potential to enhance the competitive position of a regional ethane-derived chemical commodity market due to strong buyer-supplier relationships. Potential advantages that can be passed from the refinery to the primary chemical manufacturer include: shipment reliability, transportation cost savings and an ability to develop specific products in response to customer product requirements. All these advantages could catalyze the building of a petrochemical cluster in the Eastern and Midwestern portions of the United States, where it can easily connect to large numbers of plastic manufacturers located in that part of the country.

National oil markets may also influence decisions of petrochemical companies to invest in the Midwest downstream segment of the oil and gas industry. The ample supply of ethane in the regional market will influence downstream companies with regard to location and expansion of the petrochemical sector within the region. Demand for petrochemical products and proximity to the customer base will influence their cost of production and may create an attractive competitive advantage for Ohio and the Appalachian region.

The remainder of this report considers the availability of feedstock for downstream development, specifically for companies interested in building steam petrochemical crackers close to the Marcellus and Utica shale deposits. The advantages from transportation cost savings are discussed, as are strategies and technologies for storing feedstock and finished chemical products, and the necessity for pipeline redundancy. A separate section provides

information on the role of long term contracts in securing feedstock for downstream development. The discussion of the supply side of regional markets is complemented by addressing the potential regional demand for ethylene-based chemical manufacturing operations located in the region. This analysis is continued with an explanation of the economics of petrochemical feedstock in the oil and gas downstream sector. The section concludes by illustrating promising industry interactions that can foster development, and then by considering the timing of investment decisions required for Ohioans to see substantial benefits from the development of the state's oil and gas resources.

4.1 Regional Market for Oil and Gas Products

A number of supply and demand factors will affect further development of the Utica shale and the downstream segment of the oil and gas industry. An understanding of how decisions are made by companies looking to invest in mid and downstream businesses is the first step to evaluating the potential for the development of petrochemical industries in Ohio.

Prices for oil and its derivative products are set by supply and demand conditions on global markets. Those prices are influenced by a number of national oil companies as well as large transnational companies that refine and market oil, such as ExxonMobil, Shell, BP, Chevron, and TOTAL. The Utica and Marcellus, on the other hand, are being developed by a different group of mid-sized independent oil and gas companies. Moreover, the markets for natural gas and natural gas liquids, while being constrained by global price movements in both gas and oil, are more regional in terms of end-use markets. The Utica, being rich in natural gas and natural gas liquids, may provide these companies with an opportunity to mitigate the effects of falling oil prices by expanding their operations into natural gas development and into downstream market opportunities in heating, electricity generation, and industrial consumer plastics.

The regional nature of the natural gas market is primarily due to the reliance upon local infrastructure, which controls the cost and complexity of transporting natural gas. The most important market for local natural gas producers are spot markets. Even when long-term contracts can be negotiated, prices are commonly tied to some regional spot market.

The investment decisions of large vertically integrated international exploration and production (E&P) companies account for most of the product development chain (E&P, midstream, downstream and frequently product distribution) will often make decisions based upon the total profitability of the company. Accordingly, they could make investments that might not appear at first blush to be attractive based upon local factors alone. An integrated company may, for instance, find that low oil and gas prices benefit its downstream product prices. Smaller companies that operate only in E&P or are integrated only across E&P and midstream operations may be more affected by the falling oil prices. Moreover, with a smaller scale in operations, these companies typically have less equity and profit margin for price risk protection. Mid-sized companies can take advantage of the geographic proximity of the supply of NGLs in the Appalachian basin and end-users. The density of both population and industry in the industrial Northeast, Midwest, and upper South creates a regionalized pool of demand and potential competitive advantage. However, existing petrochemical hubs in the Gulf Coast region announced a number of expansion projects benefiting from existing pipeline and storage

infrastructure.²⁰³ At the same time, due to a significant amount of valuable petrochemical feedstock now being required in Northeastern United States, and due to the proximity to manufacturing customers therewith, a number of companies were targeting new ethane refining locations within the ethane-rich Marcellus-Utica region.

A few companies have decided that it might be feasible to locate petrochemical operations in the Appalachian basin region. The reasons for these decisions included an assessment of likely regional feedstock advantages and the existing regional petrochemical product demand. As of 2015, those companies include: Shell Chemical LP (a subsidiary of Royal Dutch Shell PLC); the Brazilian company Braskem together with The Appalachian Shale Cracker Enterprise LLC, a subsidiary of Brazilian-based Odebrecht; PTT Global, a company headquartered in Thailand, along with a Japanese investment company, Marubeni Corporation; and Houston-based Appalachian Resins, Inc. It is only after each company made its decision that a cracker may be feasible in the region, did the site-selection process come into play.

The petrochemical companies considered additional factors for the location of ethane crackers. While choosing a site for an ethane cracker, Shell indicated that it was looking “at various factors to select the preferred site, including good access to liquids-rich natural gas resources; water, road and rail transportation infrastructure; power grids; economics; and sufficient acreage to accommodate facilities for a world-scale petrochemical complex and potential future expansions.”²⁰⁴ The result was the selection of an industrial site on the Ohio River northwest of Pittsburgh. The following discussion addresses the more important of these factors.

4.2. Availability of Feedstock

Ethylene makes up approximately 80% of the products derived from ethane cracking. The availability of only one principal product on the back end of ethane crackers increases the investment risk because the investment is large, the plant is inflexible, and the company is selling into only one product market. Ethylene can also be produced from propane cracking, which renders a product consisting of approximately 30% ethylene. Ethane cracking is, as a result, the preferable procedure to produce ethylene, especially since cracking heavier feedstock (including oil) requires heavier, larger and more expensive equipment, producing smaller quantities of the products.

The four announced cracker construction projects in the tri-state region have envisioned ethylene production from ethane. Usually it takes about 5 years to build a cracker plant from the engineering phase to the starting date of operations. It takes from 1 to 3 years to identify the opportunity, undertake the financial and risk analysis, select a site, and engineer and design the plant. Common hindrances that run parallel with selection and assessment include securing the ethane supply, receiving some form of purchase commitments from customers, and

²⁰³ Comparably cheap and available capital during the recovery from the financial recession of 2007-2009 has enabled companies to commit to a number of new and expansion projects in the petrochemical industry. While ethane refining projects must compete with other oil and gas capital-intensive projects, the Study Team looked closely only at potential for expansions for ethane processing capacity, due to the potential for a large and long term supply of that product in the region. A list of committed projects as of the spring of 2005 are listed in Appendix Table C-1.

²⁰⁴ Adam Burns, Site Selection, March 2012, <http://www.siteselection.com/theEnergyReport/2012/mar/petrochemicals.cfm?s=ra>

obtaining all necessary permits. In addition, each company will regularly assess the market and adjust its plans in response to changes in the world market and the actions and investments of its competitors.

Royal Dutch Shell of Monaca (Beaver County, PA) has been developing plans to build a \$3 billion ethane cracker in that region for four years. In 2012, Shell announced it was considering a site at a former zinc smelter facility in Potter Township, Beaver County, for an ethane cracker. The State of Pennsylvania offered state tax credits and committed to pay the costs of cleaning up the site. The final investment decision on the project has not been announced as of early Fall 2015.²⁰⁵ If completed, the cracker is projected to take approximately 105 thousand barrels a day (mmbbl/d) of ethane and crack it into ethylene.²⁰⁶

Since the Pittsburgh area does not meet EPA clean air standards for particulate pollution and ground level ozone, Shell must demonstrate that its plant would not make the region's air quality worse. The company will have to purchase air pollution reduction credits from other facilities in the region and use the best available pollution control technologies to meet its permit requirements.²⁰⁷

Shell officials believe this project could create 10,000 construction jobs and 400 permanent operational jobs, while producing 1.6 million tons of polyethylene pellets per year to be used for manufacturing plastics, tires, antifreeze and other products.²⁰⁸

The Brazilian company Braskem and the Appalachian Shale Cracker Enterprise LLC, a subsidiary of Brazilian-based Odebrecht, have been planning to build an ethane cracker, three polyethylene plants (plus associated infrastructure for water treatment and energy co-generation) on a 363-acre property near Parkersburg, (Wood County), WV. If built, the \$5 billion²⁰⁹ ASCENT plant would use about 60 mmbbl/d of ethane, and would permanently employ about 325 operational workers.

²⁰⁵ Marcellus Drilling News, <http://marcellusdrilling.com/2014/11/shell-finally-buys-site-for-cracker-plant-in-beaver-county-pa/>

²⁰⁶ Anya Litvak, Pittsburgh Post-Gazette. November 7, 2014, <http://powersource.post-gazette.com/powersource/companies-powersource/2014/11/07/Shell-to-buy-Horsehead-plant-in-Beaver-County/stories/201411070073>.

²⁰⁷ According to Mark Gorog of DEP's Bureau of Air Quality. The plant will be permitted to release 30.5 tons of hazardous air pollutants, as well as hundreds of tons of particulate matter and volatile organic compounds, according to the DEP. The plant will be permitted to emit 2.248 million tons of carbon dioxide equivalent. Found in: "Shell's cracker air emissions plan gets hearing," *State Impact*, May 6, 2015. <http://stateimpact.npr.org/pennsylvania/2015/05/06/shells-cracker-air-emissions-plan-gets-hearing/>

²⁰⁸ "Shale Play, Pennsylvania to issue air permit for planned ethane cracker plant," March 29, 2015. <http://shaleplayohiovalley.com/page/content.detail/id/511204/Pennsylvania-to-Issue-Air-Permit-for-Planned-Ethane-Cracker-Plant.html?nav=5005#sthash.Zs4DeFZV.dpuf>, retrieved April 14, 2015.

²⁰⁹ "Some sources claim the cost of the project at \$3.8 billion," *The Business Journal*, Youngstown, Ohio, April 27, 2015, <http://businessjournaldaily.com/appalachian-resins-ceo-says-small-cracker-moving-forward/>

Lately, multiple publications have quoted Braskem America CEO Fernando Musa to the effect that Braskem is re-evaluating its plans for developing the proposed plant.²¹⁰ The steep decline in crude oil prices has made Appalachian ethane less attractive to chemical companies; the advantage of producing ethylene from NGL versus from naphtha was \$600 per metric ton before oil prices collapsed. In the spring of 2015 the spread was only \$150 per metric ton. One option for Braskem is that the company might reconfigure its plant to crack both ethane and propane as opposed to ethane only. Regardless, it is unlikely that a plant will start up before 2020, according to Mr. Musa.²¹¹

In spring 2015, Thailand's biggest chemical company, PTT Global, and a Japanese investment company, Marubeni Corp., confirmed their intentions to build a \$5.7 billion dollar ethane cracker in the Appalachian basin. Officials believe the project could create thousands of temporary jobs during the construction phase and hundreds of full-time permanent jobs once it is online. The partnership has selected a site in Belmont County, Ohio as the prospective site of a one-million-ton olefin cracker that will use ethane from the Marcellus and Utica shale as feedstock.

The Thai/Japanese partnership is expected to make a final investment decision on the Belmont County ethane cracker by 2016, spending about \$150 million over the next few years to determine the viability of the project. The company is looking to select one of five potential partners that are interested in the project to jointly invest in a propylene oxide project in Thailand with an estimated cost of about \$1 billion and capacity of 200,000 tons a year. PTT Global, one of the world's top 10 ethylene makers, has set an investment budget of \$4.5 billion for 2015-2019.²¹² If built, this facility may take approximately 35-40 mbb/d of ethane.

A fourth potential cracker for the Marcellus-Utica region has been announced by Houston-based Appalachian Resins, Inc. (AR). AR hopes to build a cracker in the Appalachian basin to take advantage of both the proximity of the feedstock and the polyethylene downstream market, much of which can be found within a 500-mile radius. As of May 2015, AR planned to lease approximately 50 acres of land in Salem Township (Monroe County), Ohio, to build an integrated 600 million pound-per-year ethylene/polyethylene production facility. AR would require about 18 mbb/d for this \$1.3 billion integrated facility, and would produce different grades of ethylene switching between HDPE and LLDPE. The company projects to permanently employ 125 people, and intends to improve regional rail facilities to facilitate a more efficient supply chain. AR positions this plant as "less than world-scale." AR's proposed financial model

²¹⁰ *HIS Chemical Week*, April 15, 2015. http://www.chemweek.com/home/top_of_the_news/69458.html; Energy Inc. April 21, 2015, http://www.bizjournals.com/pittsburgh/blog/energy/2015/04/west-virginia-ethane-cracker-project-postponed.html?ana=e_pit_nrg&u=/nn4SOaHmim+Om/Ks6Ga7Q019c0f34&t=1427828611

²¹¹ *Id.*

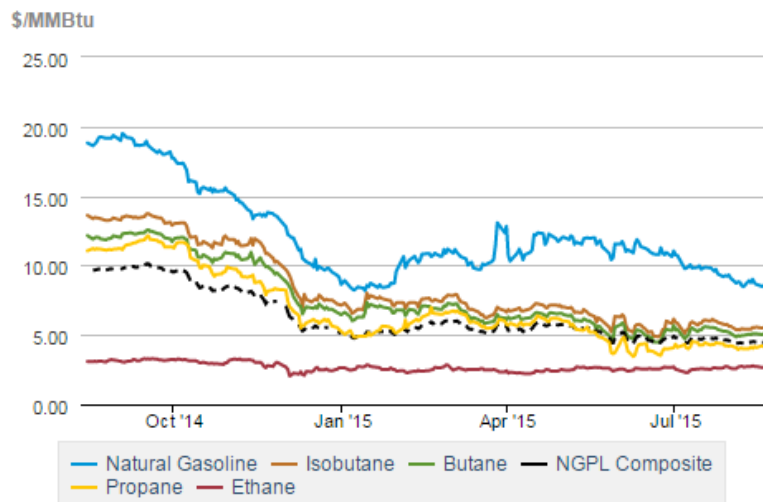
²¹² Columbus Business First, April 20, 2015, <http://www.bizjournals.com/columbus/blog/2015/04/exclusive-thai-company-has-eyes-on-ohio-for.html>; May 18, 2015, <http://www.bizjournals.com/columbus/blog/ohio-energy-inc/2015/05/ohio-cracker-plants-backers-seeking-3rd-partner.html>; Reuters Africa, May 15, 2015, <http://af.reuters.com/article/energyOilNews/idAFL3N0Y64QZ20150515>; Shale Play, April 30, 2015, <http://shaleplayohiovalley.com/page/content.detail/id/511238/Ethane-Cracker-Plant-in-Belmont-County-Would-Add-Pollution-to-Ohio-Valley.html#sthash.fkirHkHV.dpuf>.

resembles that used by pipeline companies, operating on a “tariff” basis. The \$400 million polyethylene plant will operate based on long-term contracts with the co-located ethylene plant.²¹³

The cumulative ethane cracking capacity of the four announced crackers adds up to about 223 mbbbl/d, as early as 2020. As set forth in Section 2 above, industry ethane production projections (spring 2015) for the wet gas regions of the Utica and the Marcellus for 2020 is anticipated to be around 638 mbbbl/d by 2020 (assuming 20% ethane rejection).²¹⁴ So the crackers, if all built, would use around one-third of the locally available ethane. Importantly, at least two of the prospective petrochemical companies have indicated that they have secured significant amounts of feedstock through long-term contracts with regional producing and midstream companies.²¹⁵ This speaks to the confidence producers and midstream companies have that Marcellus and Utica wet gas drilling and midstream infrastructure can be ramped up to accommodate greater volume requirements.

Ethane prices have been historically more closely associated with natural gas than with oil or gasoline prices, unlike other natural gas liquids (Figure 40). This is primarily due to the fact that the alternative market for ethane is usually rejection – meaning it is sold along with methane. It is also due to the fact that ethane has the same fundamental issues that methane has with regard to storage and transportation: marketing ethane requires more careful planning than other NGLs and an extensive pipeline system.

Figure 40. Natural Gas Liquids Spot Prices



Source: EIA. August 19, 2015.

²¹³ APAG, accessed 4/28/2015, <http://apeg.com/tag/appalachian-resins/> and Plastic News, 02/08/2013, <http://www.plasticsnews.com/article/20130208/NEWS/130209931/new-west-virginia-polyethylene-plant-would-target-shale-gas>.

²¹⁴ See *supra* p. 57. Note also that there may be processing and fractionation constraints on the total available production, and that there will also be around 460 mbbbl/d take away capacity. See following section.

²¹⁵ Oil and Gas Journal, March 28, 2014. <http://www.ogj.com/articles/2014/03/ethane-supply-secured-for-proposed-w-va-ethylene-cracker.html>

Almost 100% of the ethane production in the U.S. and Canada is processed from natural gas. About 75% of NGLs in the U.S. is produced from natural gas (about 60% is, globally). The rest comes from processing oil.

Since 2009, expanding shale development has brought much larger volumes of ethane to the marketplace. However comparatively modest growth in plastic manufacturing, the primary consumer of ethane, has not created significant new demand. Moreover, more efficient gas producing technologies have been deployed in shale basins, further increasing production, while operators have shifted away from dry gas into price-premium NGL plays, causing yet more ethane to be brought into the market. The result has been a significant decrease in ethane prices. This issue became more profound for Appalachian Basin producers who have been realizing a relatively high content of ethane in their production, no local outlet for ethane, and limited pipeline infrastructure for take-away capacity.

Technologies to process natural gas vary from the less efficient -- those deployed in "lean oil" plants -- to the ultra-efficient -- those that deploy cryogenic processes. Using oil plants to recover NGLs is the least efficient method for recovery of ethane; recovery is typically about 15-30% of available ethane. Oil plants are, however, more efficient for propane (65-75%), butanes and C5+ (99%) extraction from NGLs.

The most efficient strategy – and the one employed in the Appalachian basin – is the use of cryogenic plants. These plants can recover nearly 100% of propane, butane and C5+ hydrocarbons, and can also recover about 85-90% ethane. The latter plants are also the more expensive to build.

Natural gas liquids require special conditions for transportation and storage. The liquid state requires the maintenance of high pressure and low temperatures. The liquids are highly flammable and require special trucks, ships, and storage facilities made from enhanced steel and insulation.

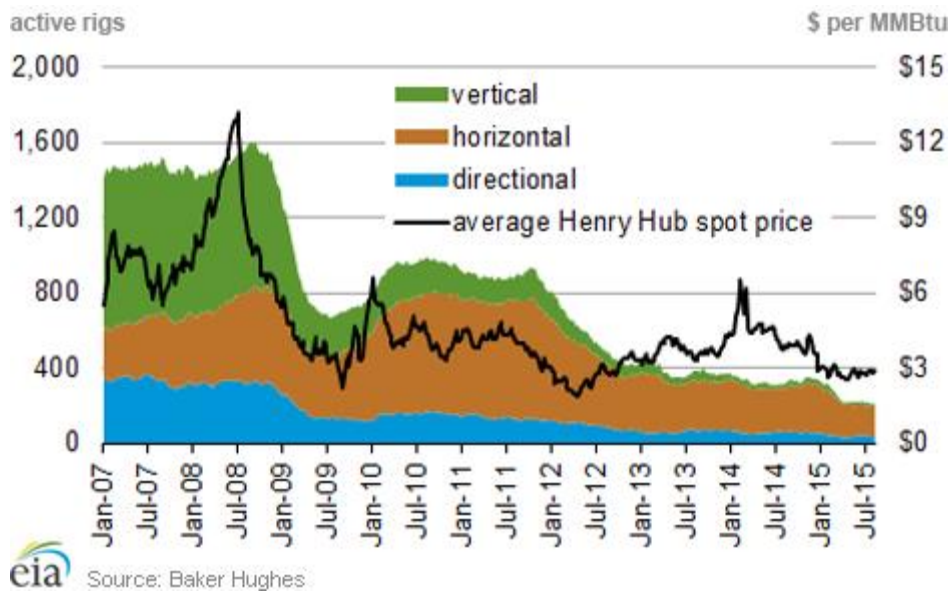
The decision to extract ethane must account for transportation and fractionation (T&F) costs incurred subsequent to cryogenic processing (extracting NGLs from the natural gas stream). The so-called "frac spread" (the difference between the revenue received from selling undifferentiated NGLs and the value received from selling purity products, such as ethane, propane, butane, and natural gasoline) may vary by as much as \$2/mmbtu. In 2012, for example, T&F costs reduced the actual price of ethane realized from \$2.50/mmbtu to \$0.59/mmbtu between Kansas and Wyoming.

Importantly, the largest T&F costs in the lower 48 states for delivery of ethane to the nearest hub is associated with the Marcellus and Utica: T&F costs from the Appalachian Basin to Mont Belvieu are around \$0.28-0.30/gal. Of this cost, transportation is most significant for the Utica/Marcellus. In 2013/14 the Marcellus and Utica basin had the highest ethane delivery cost to cracker facilities among U.S. shale plays (\$0.15/gal). Between transportation costs, a lack of pipeline take-away capacity, and a lack of local markets, ethane rejection will likely continue until at least 2018. Of course, saving these high transportation costs is a motive for building cracker facilities in the Appalachian Basin region and for serving the dense network of customers that are already located in the region.

Numerous reports have indicated that ethane rejection has indeed been the principal market for ethane in Appalachian region. Noting the 130% growth in regional gas processing capacity between 2013 and 2015, (3.8 bcf/d to 8.76 bcf/d), Bentek predicted that “by the end of 2015, [there] could be as much as 300 mbb/d of incremental dedicated ethane and propane pipeline capacity from the Williston, Marcellus and Utica.” However, the regional supply of ethane in the Appalachian basin may still overwhelm regional processing and take away capacity.

However, as outlined earlier in this report, the continuing increase of Utica natural gas production may be a necessary choice for producing companies looking to maintain leaseholds and to obtain a return on prior investments, rather than any strategic plan to maximize ethane profits. According to the EIA, in April 2015, despite the decline in the number of rigs, Utica Shale gas production reached 2.38 bcf/d, which was a 168% increase from March of the prior year. Ethane production may continue to be driven by increasing natural gas production, and the value of extracting higher carbon chain natural gas liquids may push drilling into the ethane rich regions.

Figure 41. Utica Natural Gas Production and Total Rigs



Ohio has seen \$3.5 billion in oil and gas-related investment in the final six months of 2014, and some \$22.3 billion in shale-related projects since 2013. This figure is up from \$18.8 billion since April 2013.²¹⁶

A recent Baker Hughes rig count indicated that Utica has 14 operating rigs operating in April 2015 compared to 23 at the same time last year, which was also down from the 2014 peak of over 40 rigs. However the dropping rig count can be a misleading indicator of production

²¹⁶ “Shale Development Overview (Spring 2015)” Bricker & Eckler 2015. http://www.bricker.com/documents/resources/Spring2015_%20Shale_Economic_Development_Chart.pdf

activity. A big reason for the decreased rig count is attributable to the marked increased Utica's drilling productivity. Producers have not only been optimizing production strategies as they learn about the Utica, they have also been drilling increasingly longer laterals in each well, thereby dramatically improving per well recovery rates. The typical well in the Utica was producing around 6.1 mmcf/d in April 2015 -- an improvement of 108% over the prior 12 months. This increasing supply of natural gas and ethane, together with a potential ethane take away capacity shortfall, have created a positive outlook for building new cracking capacity within the region.

HIS Chemical's experts have postulated that since Shell already owns and operates four U.S. steam crackers and associated plants in Deer Park (TX) and Norco (LA), Shell's cracker planned in Pennsylvania will be a commercial success. HIS Chemical has suggested that due to the absence of storage facilities in the region and a need for increased reliability of feedstock, there is a need for at least two Appalachian-based crackers. Their experts have indicated that the Appalachian basin represents the classical "trapped ethane problem" where solutions are to either build a cracker on site and ship derivatives, or to build new pipeline capacity to transport the ethane, or both.

While the ability to secure feedstock is an important factor in site selection decisions for cracking facilities, there are two other frequently-posed questions by suppliers, economic development organizations, and governments: 1) might the completion of multiple pipeline projects, which enhance the take-away capacity of ethane, jeopardize the supply of the feedstock for the prospective crackers? And, 2) how might the deficiency of traditional petrochemical industry infrastructure (i.e. storage facilities and connecting pipelines) affect the prospects of developing a petrochemical cluster?

4.3. Transportation, Storage, and Pipeline Redundancy

In the United States, the majority of Natural Gas Liquids are transported by pipeline. However, when pipeline capacity is limited, NGLs can be transported via truck or rail. Heavier NGLs are more likely to be transported in this manner. Ethane's high vapor pressure, on the other hand, inhibits its ability to be transported economically by truck or rail.²¹⁷ As a result, delivery of ethane can be problematic for both the producing companies and the end users that rely upon it. Neither the transportation nor the storage of ethane is simple.

The construction of a downstream oil and gas industry should enable the region to realize significant transportation cost advantages. As noted by PolymerOhio in a recent study, "[t]he logistic advantage for a regional cracker is based on avoiding the ethane pipeline transportation costs to the gulf coast and the subsequent freight cost of shipping the polymer back to the Ohio region."²¹⁸ This advantage will inure primarily to the owners of the crackers and presumably

²¹⁷ The process of transporting Marcellus produced ethane to the Gulf Coast on a converted LNG cargo ship is also being explored by midstream companies. See "Natural Gas Liquids (NGLs)" Resource & Supply Task Group 9/15/11.

²¹⁸ Impact Assessment of Shale Gas Development on Investment and Growth in Ohio's Polymer Industry. PolymerOhio Inc. September 2014. P.20.

some portion of this cost savings will be passed down to their customer chain as part of the cracker's competitive advantage over more distant companies. The annual transportation and logistics savings generated by one regional world-class cracker is anticipated to be in a range of \$100 million.²¹⁹ However this savings in transportation cost for ethane/ethylene may be offset in part by a lack of ethane storage facilities in the Midwest.

Storage and transportation of ethane ends up being similar to that for methane, except that there is much less infrastructure dedicated to ethane. The more commonly known strategies for storing natural gas involve pumping gas into natural gas storage facilities. Storage for ethane is needed for the same reasons it is needed for methane: it serves as an insurance against unexpected market events, such as interruptions in production, pipeline mechanical failure, and natural disasters, and, to a lesser extent, weather-related consumption spikes. Both capacity and location of the facility are important to avoid supply interruption.²²⁰

As of December 2013, total United States domestic natural gas storage capacity was over 9,100 bcf,²²¹ located in more than 400 facilities across the country.²²² There are three types of natural gas storage facilities: depleted natural gas reservoirs, aquifers, and salt caverns. Depleted natural gas reservoirs make up the largest share of storage in the United States, at over 80%, and also comprise the majority of facilities in the Appalachian region. Natural gas storage can be graded based on its rate of deliverability, or how fast gas can be withdrawn, and its cycling capability, or the speed at which natural gas can be injected into/ withdrawn from storage. Because gas generally flows through pipelines at 15 miles per hour, it can take days to reach an intended destination. For this reason, storage facilities located near market areas are the most valuable.²²³

²¹⁹ *Id.*

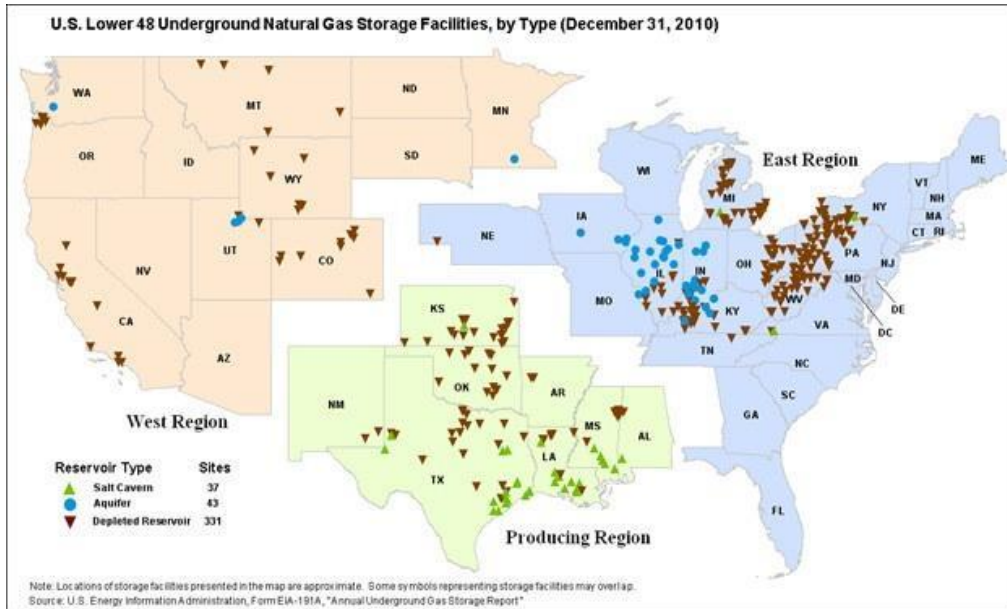
²²⁰ C. Mitchell, "Catch a Hydrocarbon, Put it in Your Cavern, Save It for a Wintry Day," RBN Energy, LLC, April 8, 2013, found at: <https://rbnenergy.com/catch-a-hydrocarbon-put-it-in-your-cavern-save-it-for-a-wintery-day-natural-gas-storage>

²²¹ "Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefits" IHS Global Inc. 12/13.

²²² "Energy: Securing Our Natural Gas Supply Chain" American Petroleum Institute.

²²³ "Energy Primer: A Handbook of Energy Market Basics" Office of Enforcement, Federal Energy Regulatory Commission 7/12. Salt cavern storage is also found in Ohio. Most aquifer storage in the United States exists west of Ohio. This type of storage is the most expensive of the three because the "base gas" required is over 50% of the total gas in storage. Base gas is that amount of gas permanently required in a reservoir to maintain adequate pressure and the ability to withdraw the "working" gas. *Id.*

Figure 42. Underground Natural Gas Storage Facilities in the United States, 2010.



Natural gas storage historically has followed a time-honored pattern: put gas in during the summer, and take it out during the winter. However it has recently become more complicated in the Appalachians due to shale development. Now storage is more than just a flywheel for gas usage fluctuation; with production overwhelming demand, storage may be needed to avoid flaring. Currently for the Appalachian region, all storage facilities are dedicated to methane storage. There is no existing ethane market in the Utica-Marcellus region, and there has been no reason to commit facilities for ethane storage. Currently, facility storage would have to be contained in refrigerated on-site storage tanks, similar to those used in shipping ethane overseas. Most petrochemical companies operating in the United States consider such on site storage to be too expensive.

However underground storage facilities are not the only way to store natural gas or ethane. Natural gas can also be stored for short-term purposes within pipelines through the process of “line packing.” In order to line pack, pipeline pressure is increased to “pack” a greater number of molecules into the same amount of space. A pipeline is “packed” when the withdrawal of gas is minimum and pressure is at a maximum (warmer months), and is unpacked when withdrawal is at a maximum and pressure is at a minimum (colder months). Therefore, the storage capacity of a natural gas pipeline is the difference between its packed condition and its unpacked condition.²²⁴

Gases that are used for heating fuel, such as propane, are stored on a seasonal basis: stocks are built during the warmer months in order to prepare for the greater demand during the winter.

²²⁴ “LP model uses line-pack to optimize gas pipeline operation” Oil & Gas Journal 2/24/03.
<http://www.ogj.com/articles/print/volume-101/issue-8/transportation/lp-model-uses-line-pack-to-optimize-gas-pipeline-operation.html>

Because it is not used as a fuel (unless rejected), ethane is not as affected by seasonality or by severe weather demands, and thus has a steadier rate of storage.²²⁵ In this way, ethane pipeline storage can act as a mechanism of redundancy that helps to moderate the price of natural gas in the face of geographic and seasonal constraints, as well as other rapid fluctuations of supply and demand. Storage, through both refrigerated tanks and through pipeline redundancy, will be a critical element to the success of crackers in the region. The American Institute of Chemical Engineers states that gas storage is a necessity for participation in the global natural gas market, as well as for the possibility of new or expanded ethane cracker facilities.²²⁶

4.4. Role of Long Term Contracts in Downstream Development

Due to the large amount of capital required to develop petrochemical plants, investors want assurances that there will be binding agreements from reputable companies in place to supply hydrocarbons (long term contracts to sell refined materials would also be welcome, but are generally more difficult to get). Unfortunately, the history of long-term contracts to sell hydrocarbons has been historically fraught with litigation. As a result, obtaining long-term hydrocarbon supply contracts are not simple.

The problem stems principally from the storage dilemma. Without storage, producers, pipeline companies and end-users are endlessly forced to juggle production and take obligations. There have traditionally been two types of contracts to sell natural gas: contracts to supply all the needs of the buyer (“requirements” contract) or contracts to take all the production supplied by the seller (“outputs” contract). The first sort of contract is often called a “warranty” contract, and it is usually the sort of contract a gas distribution company would enter into with an end user. However producing companies have, from time to time, and to stimulate the market, entered into long-time warranty contracts directly with end users, or with pipeline companies, often with catastrophic results.²²⁷ The more common gas sales contract used by producers, however, is the outputs contract – where the pipeline company agrees to take, or if they fail to take, to pay anyway for all production supplied by the pipeline company, usually from a particular field or reservoir. These contracts have become known in the industry as “take or pay” contracts.

Take or pay contracts have their own history of litigation, however. Take or pay-contracts cause problems when commodity markets rapidly shift, making litigation, a more attractive choice than continuing to pay above market rates. In markets as volatile as natural gas, this risk has been especially acute.

As a result, execution of new take or pay contracts became a significant hurdle for the development of downstream projects relying on methane or ethane as a feedstock. Eventually, the industry began to develop strategies for a compromise that could mitigate the problems associated with the uncertainty of long-term commitments. Today there remains risk and

²²⁵ “Natural Gas Liquids (NGLs)” Resource & Supply Task Group 9/15/11.

²²⁶ “Expanding the Shale Gas Infrastructure” American Institute of Chemical Engineers 2012.

²²⁷ Texaco, Inc., for instance, went into bankruptcy in the 1980s in part due to a system of long-term warranty contracts it entered into with petrochemical companies in Louisiana. For a general description of the problem Texaco faced see, A. Thomas and E. Belton, *Texaco v. State of Louisiana: An Analysis of and Solution to Market Value Litigation*, Oil & Gas Law and Taxation Review, London, England (Sweet & Maxwell) Vol. 13, Issue 3, March 1995.

uncertainty when tying any large capital project to a commodity market like natural gas. However principles of risk mitigation have found their way into modern long-term hydrocarbon sales agreements. Today the take or pay contract is the more common form of gas sales arrangements, although take obligations can be mitigated.

Overcoming the financial risks associated with such a project through take or pay contracts will be a critical step to locating crackers in the Ohio, Pennsylvania and West Virginia region. Some creativity in the design of take or pay contracts can allow for risk management for both the oil company and the end user. It can also enable each party to focus on its core competency – for producers, the extraction of hydrocarbons, for midstream companies, the storage and delivery of hydrocarbons, and for end users, the manufacturing of plastics feedstock.

The take-or-pay contract is today the primary mechanism for financing capital-intensive resource recovery projects. A properly constructed take-or-pay contract provides the seller with a revenue stream that ensures an adequate return on the significant project capital investment, including the risks to which it is exposed.²²⁸ However the take-or-pay contract remains, fundamentally, an outputs contract. As such, the refinery assumes most of the risk of supply failure, unless there is a warranty for delivery of product. It will be hard to finance a new cracker facility without *some* warranty of delivery. The parties must weigh the reward of certainty against the risk and flexibility of ambiguity. Producers also must also consider the possibility that without firm take obligations, they may be unable to reject ethane, causing them to either flare or to shut in production.

The most common tool to mitigate risk in a take or pay contract is price indexing. Other strategies include price reopeners, hedging, and call options. Caps on take obligations can also reduce risk, as can the use of back up sale agreements that kick in when the take obligation is not met.

Finally, those investing in crackers would, ideally, like to also have long-term contracts to sell their product, usually either ethylene or polyethylene, to distributors and plastics converters. However there is no evidence, at least domestically, that there is a market for long-term commitments to purchase either of these products. Polyethylene, like oil, is easily stored and transported, and as such, subject to a worldwide spot market. Ethylene is less easily transported than polyethylene, and for this reason is commonly converted to polyethylene on site. Accordingly, those who build crackers will do so largely speculating on the sales of the product being manufactured. Investors in this arena must have deep pockets to withstand this sort of risk. Those investing in new cracker facilities in the Appalachian region will certainly look carefully at potential sales markets, but it does not appear that long-term contractual commitments will be a necessary precondition to the building of these crackers.

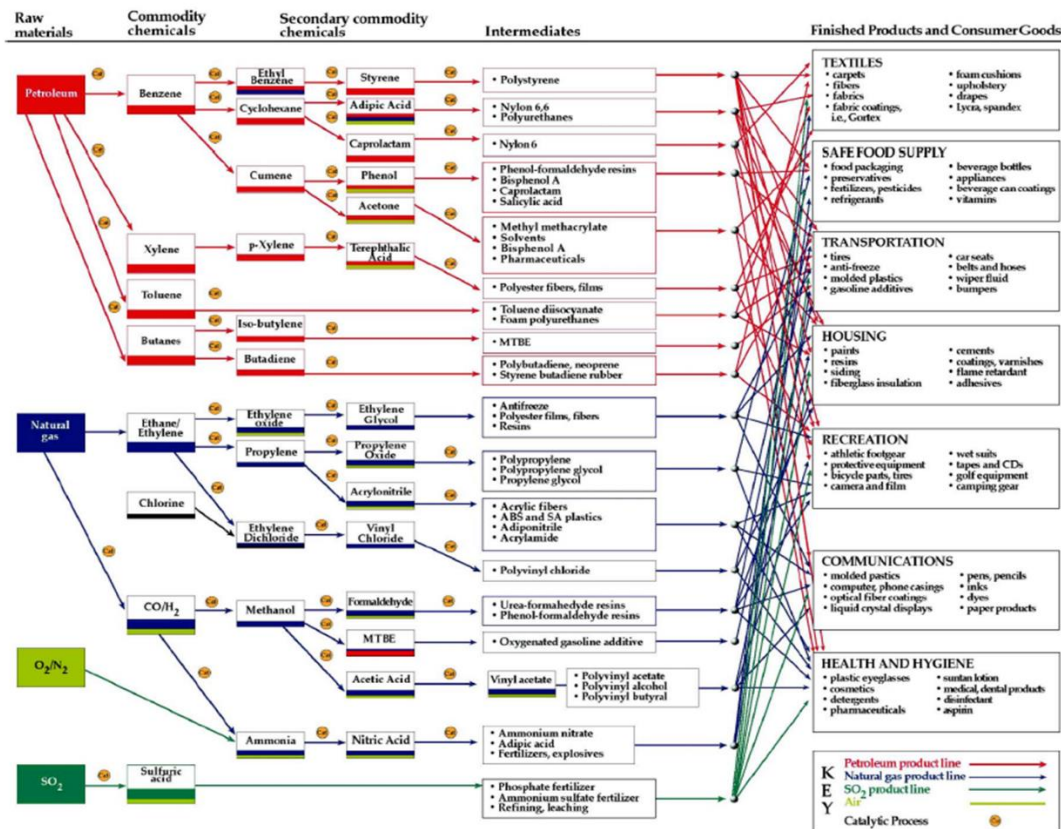
²²⁸<http://www.forbes.com/sites/richardlevick/2014/09/17/natural-gas-innovative-financing-breaks-distribution-barriers/>

4.5. Access to Downstream: Concentration of Existing Chemical Manufacturing

The second most important factor of a cracker site selection decision is access to consumers of ethylene or polyethylene. At least two crackers, Shell’s Beaver County plant and The Appalachian Shale Cracker Enterprise, announced building a number of polyethylene and monoethylene glycol production units adjacent to the ethane crackers. Their targeted market of consumers is identified as the Northeast region of the United States.

It is useful to understand who the immediate consumers of the cracker products are, and what the challenges are to securing a market of customers five to six years ahead of the first product production. Understanding of and appreciation for the complexity of the components of the final plastic products market come from examining the complex relationships illustrated in a Department of Energy chart, set forth herein as Figure 43. The finished products and consumer goods rarely use a single input from assorted petroleum feedstock. Noticeably missing from the DOE’s figure is polyethylene – the principal chemical ultimately made from ethane crackers. The diagram’s main utility is in understanding sequence of consumers located along the plastic product chains.

Figure 43. Products from Petroleum Feedstock



Source: Department of Energy.

Ethylene and polyethylene are produced and self-consumed by the primary and secondary commodity chemicals companies (which include the companies which operate crackers). These companies create an added value for ethane and ethylene by tailoring them to specific chemical commodities that can be used by compounding companies (“Intermediaries” in the figure). The compounders develop a creative solution for specific products used in the manufacturing and final consumer markets by combining different chemicals in quantities and proportions that secure the final product’s desired characteristics. In turn, these companies (or their manufacturing consumers) purchase these “recipe” produced plastic products that have final value on the market.

Many studies and companies’ investor communication materials suggest that 500 miles is the typical limit for cost effective transportation. Accordingly, we can expect that transportation of ethylene or polyethylene beyond this distance will likely generate a significant cost increase. A 500 radius from the wet gas region of the Utica and Marcellus completely encompasses OH, IN, KY, SC, NC, VA, WV, MD, DE, PA, NJ, NY, CT and RI. It also covers the majority of MI, IL, TN, GA, MA, NH and VT; and partially covers WI, IA, MO, MS and AL. See Figure 44 below.

The following analysis was developed from the U.S. Market’s top 47 commodity chemical companies to create a NAICS-based profile (Table 14) of the most probable ethylene/polyethylene consumers and service companies (Appendix Table C-2).

Table 14. NAICS Profile of the Top U.S. Commodity Chemicals Companies

Industry		Percentage of Top U.S. Commodity Chemicals Companies within this NAICS	Cumulative Percentage of Top U.S. Commodity Chemicals Companies within this NAICS
3251	Basic Chemical Manufacturing	37.8%	37.8%
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing	11.1%	48.9%
3255	Paint, Coating, and Adhesive Manufacturing	11.1%	60.0%
3261	Plastics Product Manufacturing	6.7%	66.7%
3259	Other Chemical Product and Preparation Manufacturing	6.7%	73.3%
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	4.4%	77.8%

Source: Moody’s Economy.com

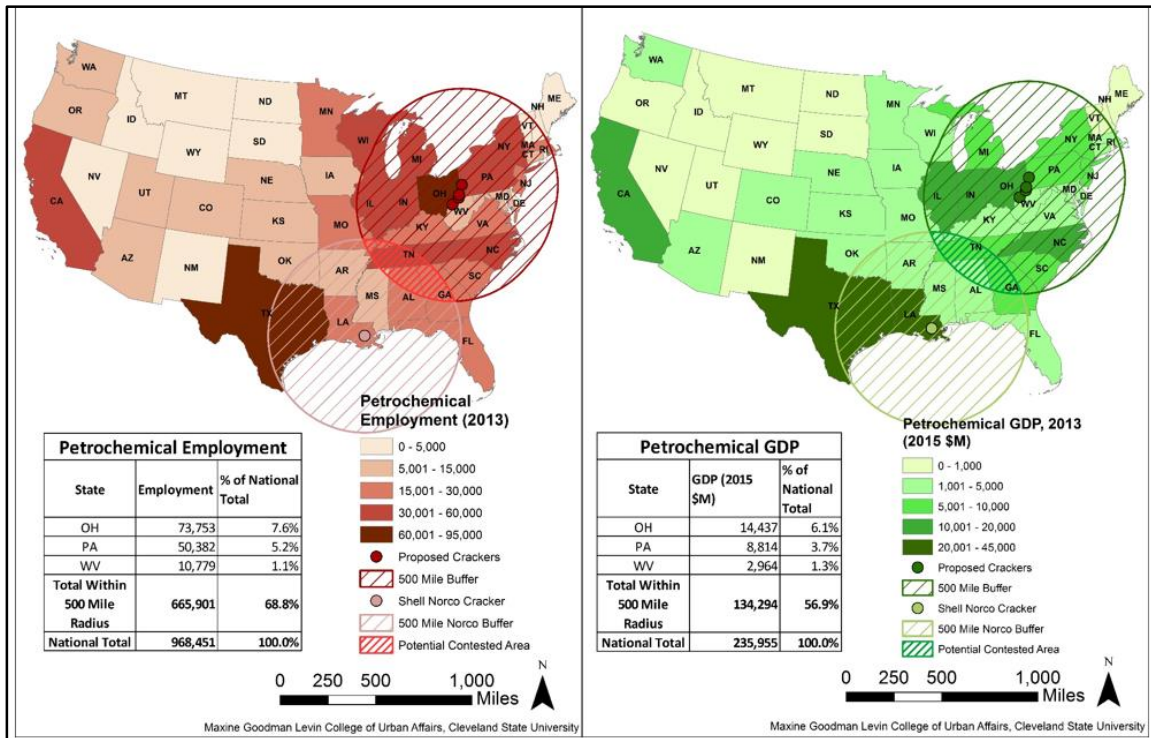
The largest concentration of these companies occurs within six 4-digit NAICS industries, therefore about 80% of all commodity chemicals companies falls within this NAICS-based profile. Using Moody’s Economy.com data, we observed that 665,901 employees of commodity chemicals companies classified in six NAICS-profile industries are located within 500-mile radius from the regional crackers. Considering that this employment accounts for 77.8% of all commodity chemicals companies, it is suggested that all 100% of commodity chemicals companies capture about 856,000 employees or more than 88% of the total U.S. employment in commodity chemicals companies.

Similarly, considering that \$134.3 billion of Gross Regional Product was generated by 77.8% of commodity chemicals companies located within the 500-mile radius from the regional crackers, we can approximate that all commodity chemicals companies located within this region produce a product worth about \$172.6 billion. This product consists of 73.1% of all commodity chemicals companies’ national GDP.

Mapping the Opportunities for Shale Development in Ohio

Two states that have the highest employment in the commodity chemicals industry group are Texas (118,567 employees or 12% of the national employment in this industry group) and Ohio (94,798 or about 10% of the national total). The next high-employment group in these industries includes Illinois, Pennsylvania, Michigan, Indiana, North Carolina, Wisconsin, New York and Tennessee, with South Carolina closely following them. All of these states except Tennessee appear to have a clear transportation advantage for consumption of ethylene and polyethylene delivered from the proposed tri-state regional crackers, compared to delivery from the closest cracker located in the Gulf Coast region.

Figure 44. Concentration of Commodity Chemicals Companies in the Tri-State Region



Although not all commodity chemicals companies are consumers of large volumes of ethylene and polyethylene, they interact based on providing multiple services one to other. Among those services are the creation of compounding solutions and the manufacturing of products based on solutions created by others. Other such services include the supply of specialty chemicals, testing product and chemical solutions for specific properties, indentifying chemical compositions of off-spec production and many others. The main benefit expected by small regional consumers of polyethylene is the addition of regional commodity chemicals companies that can provide all these services to a broader consumer base.

While there is, in 2015, no concentration of large consumers of polyethylene in the region, there are local companies that consume non-virgin polyethylene (recycled, scrap or off-spec). This market follows the virgin polyethylene market dynamic with about 6 months lag. The feedstock for the local secondary-polyethylene users is tightening due to increased volumes of recycled polyethylene exported to China.

One major challenge for cracker companies is in the time mismatch between building a new cracker and the ability of cracker companies to receive commitments from prospective consumers to buy their future product. These two events are about 5-6 years apart. Downstream chemicals companies normally buy their feedstock on the commodity markets and largely care only about total price with delivery. Further, they maintain a feedstock inventory at most for the next two months. No long-term commitments to purchase polyethylene from downstream distributors or converters will be forthcoming, leaving the petrochemical refiner to speculate on market conditions many years out.

However, according to cracker companies,²²⁹ petrochemical refiners will have an ability to tailor the quality of their products to specific Stock Keeping Units (SKUs – unique identifiers for each distinct product and service that can be purchased in business). There are hundreds of SKUs in the purchasing inventory of distribution and compounding companies and there may be high demand for specific products. Another advantage the cracker companies can provide while penetrating regional consumer market is to share the transportation cost advantage crackers will receive from midstream companies with them, by supplying ethane to crackers locally (e.g. a supply contract based upon a price below spot market prices). As of today, the transportation and fractionation (T&F) of ethane to existing hubs cost the midstream companies, on average, 18c/mcf, which often creates a negative base price for the regional producers. The negative price base is calculated as the T&F cost deducted from the hub selling on the btu-equivalent bases.²³⁰ They are forced to accept the negative base price after maxing out rejected ethane volume. However it is unlikely that any purchasers of polyethylene will commit 5-6 years out.

²²⁹ Interviews with representatives of regional cracker companies.

²³⁰ For example, if the hub price of ethane to natural gas based on btu ration is 1.03 then after adjustment for about 10 cents a gallon of F&T, this ratio drops to 0.6 of the btu equivalent price of natural gas at the plant tailgate. *Oil and Gas Financial Journal*, January 7, 2013.

Although the larger region accounts for a high concentration of commodity chemicals companies, for some states located within 500-mile radius from the proposed Appalachian crackers, these companies represent a part of their economic base.²³¹

Table 15. Employment and GRP Location Quotients of the Commodity Chemicals Companies within the 500 miles Radius from Proposed Regional Crackers

States within 500 mile area	Employment	Emp LQ	GRP, \$M	GRP LQ
Ohio	73,753	2.00	14,437	1.81
Illinois	55,727	1.37	10,370	1.02
Pennsylvania	50,382	1.25	8,814	0.97
Michigan	47,491	1.66	5,904	0.97
Indiana	44,501	2.15	10,434	2.33
North Carolina	37,788	1.29	12,770	1.92
Wisconsin	36,154	1.80	4,681	1.17
New York	32,909	0.53	6,978	0.38
Tennessee	32,632	1.67	6,063	1.49
Georgia	29,818	1.04	6,032	0.94
South Carolina	26,668	1.96	5,135	1.98
New Jersey	25,271	0.93	5,960	0.78
Virginia	23,426	0.86	4,740	0.74
Kentucky	23,093	1.70	3,784	1.46
Alabama	21,353	1.57	4,277	1.56
Missouri	20,846	1.06	4,109	1.05
Massachusetts	17,933	0.77	3,798	0.60
Iowa	12,860	1.15	3,848	1.64
Maryland	10,840	0.59	2,459	0.51
West Virginia	10,779	1.98	2,964	2.84
Connecticut	9,517	0.82	2,241	0.64
Mississippi	8,902	1.10	2,052	1.38
New Hampshire	4,763	1.07	464	0.48
Delaware	4,062	1.34	1,432	1.62
Rhode Island	3,688	1.12	481	0.64
Vermont	745	0.34	64	0.15
TOTAL	665,901		134,294	

Source: Moody’s Economy.com

Economic base measured by location quotients²³² of employment and GRP illustrate relative concentration of employment and GRP in six NAICS-profile commodity chemicals industries to

²³¹ Regional economic base is usually considered as industries and companies that produced products that will be exported outside of the regional boundaries bringing revenue into the region. Such industries often called “export” industries and they are commonly identified by the location quotient of employment or GRP.

²³² A location quotient (LQ) is an analytical statistic that measures a region’s industrial specialization relative to a larger geographic unit (usually the nation). An LQ is computed as an industry’s share of a regional total for some economic indicators (employment and GRP) divided by the industry’s share of the national total for the same statistic. For example, an LQ of 1.0 in the commodity chemicals industries means that the region and the nation are equally specialized in the commodity chemicals industries; while an LQ of 1.8 means that the region has a higher concentration in the commodity chemicals industries than the nation. For economic development analysis, usually an LQ of greater than 1.2 is an indicator of an economic base industry.

employment and GDP of these industries in the U.S. (Table 15). Half of the states on this list of 26 states within the 500 mile radius have the location quotient of the Commodity Chemicals Companies greater than 1.2, which indicates this industry is a part of that state's economic base. Indiana has the highest LQ of employment at 2.09, and Ohio and West Virginia follow with 1.94. These states also have the highest location quotients of produced GRP, (IN – 2.19, OH – 1.88 and WV – 1.71). Only 5 states (including the aforementioned three) have the location quotient of GRP above 1.2 and 5 more states have GRP LQ between 1.1 and 1.18, which is considered as a marginal evidence of industry's concentration due to a possible "noise" in the data. High employment and GRP LQs for commodity chemical industries in a large number of states indicate that there already exists an agglomeration effect for company co-location. Such agglomeration suggests the existence of common infrastructure, workforce, supply chains, and research services.

While the markets for polyethylene is very important to prospective crackers, falling oil prices have reduced the profit margin to produce ethylene/polyethylene from ethane compared to that produced from naphtha. The comparison between ethane and naphtha as a feedstock for ethylene is complicated by the differences in the percentage of produced ethylene per unit of ethane and comparable unit of naphtha. Moreover, additional naphtha-derived products and their growing U.S. demand further complicate the calculations. The result is that a straight comparison of the costs of natural gas and oil on an mmbtu basis may be not be fully indicative of the value proposition of ethane vs. naphtha.

4.6. Economics of Petrochemical Feedstock

Building ethane crackers in the tri-state region may significantly improve the economics of ethane recovery for local producers. However, building such plants is expensive and time consuming. To predict a successful capital cost recovery, petrochemical companies must estimate ethylene spot price spreads based upon ethane and naphtha spot prices. Since the collapse of oil prices in the last quarter of 2014, the economics of ethylene production costs for major feedstock has changed.

Feedstock flexibility and the ability to make fast feedstock adjustments are seen as major mitigating factors for the risk of price volatility of oil and related commodities.²³³ Ethane, as a feedstock for the petrochemical industry, is a simple molecule that primarily produces ethylene. "Roughly 80 percent of ethane fed into a cracker is converted to ethylene,"²³⁴ with the remainder turned into fuel gas including methane, hydrogen and carbon monoxide. More complex molecules, like gas oil and naphtha, cracks into a more complex variety of intermediate chemical by-products.

²³³ Dan Lippe. "Falling Oil Prices will Disrupt Feed Cost Differentials." Petral Consulting Co., 03/02/2015.

²³⁴ Thompson, Jesse. "Shale Revolution Feeds Petrochemical Profits as Production Adapts." Southwest Economy. Federal Reserve Bank of Dallas. Fourth Quarter. 2013. P.16.

Table 16. Estimates of Production from Different Feedstock

Refined Product	Feedstock			
	Ethane	Propane	Naphtha	Gas Oil
Hydrogen	5%	2%	1%	1%
Methane	9%	27%	15%	8%
Ethylene	78%	42%	35-25%	23-15%
Propylene	3%	19%	16%	14%
Butylene			5%	5%
Butadiene (-1,3)	2%	3%	5%	6%
Gasoline (RPG C5-C8)	3%	7%	19-29%	20%
Fuel Oil			4%	23-31%

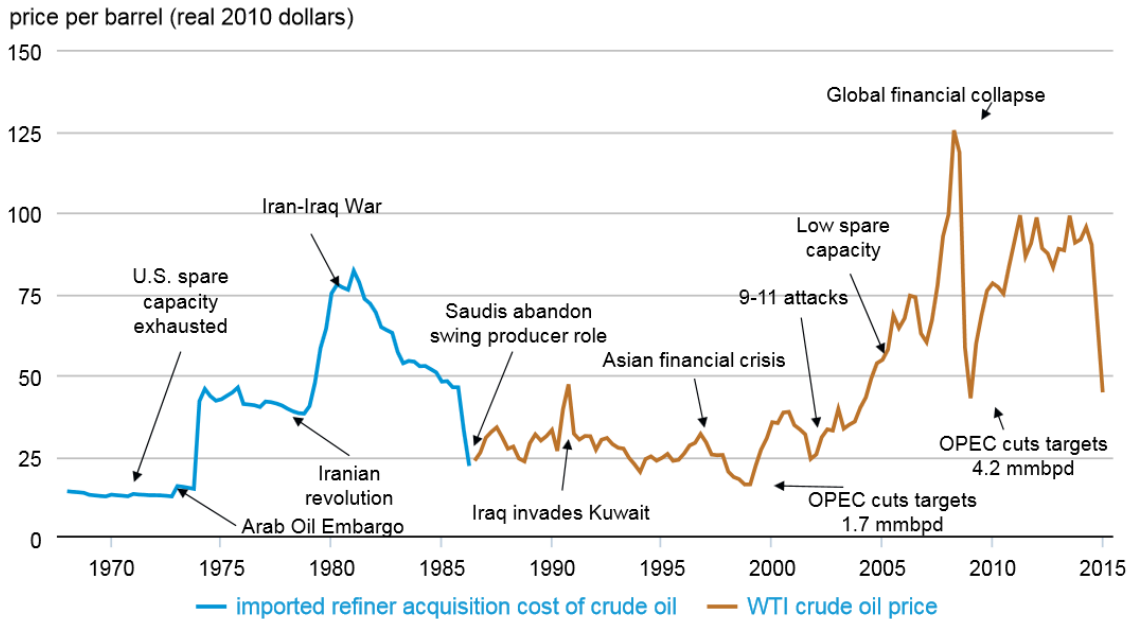
Source: The Essential Chemistry Industry

While 78% of ethylene is produced from a unit of ethane, only 42% of ethylene is produced from cracking a unit of propane. Even less, 25-35% of ethylene, is produced from a unit of naphtha. However, naphtha yields additional products from cracking, such as butylene (5%), fuel oil (4%) and significantly larger volumes of butadiene (5%) and gasoline C5-C8 (19-29%). As a result, ethylene can be considered as a byproduct of naphtha processing, and may be sold at a lower price as a result.

To understand the economics of cracking from two alternative feedstock, ethane and naphtha, several factors should be considered simultaneously: feedstock price, output product price, output product volume, and output product composition. The cost of processing and availability and the cost of energy and water are secondary, but important factors. Often, a simple comparison is made based on feedstock prices. Such short-sided judgments claim that when oil prices fall, naphtha, which is a derivative distilled from crude oil or condensate, becomes cheaper as a feedstock that then can produce ethylene, and the profit margin from selling ethylene cracked from naphtha becomes sustainable.

There is more to the economics of two feedstock comparisons than just feedstock prices. We can start with the strategic long-term view. Volatility of oil prices is not a new phenomenon in this industry (Figure 45). Every peak and trough of oil price volatility is accompanied/caused by underlying economic or political events. Historically, oil prices increased with growing political instability, especially in the oil-producing countries. However, the recent drop in oil prices occurred in spite of political unrest influenced by the overwhelming supply of oil resulting from the market share “war” of countries that are major oil producers. When OPEC did not cut the targets of oil production and that were producing more than their quota, the price of crude oil collapsed, hurting rapidly expanding shale production in the United States and delaying the expectation for fast growth in renewable energy technologies and their use.

Figure 45. Crude Oil Prices React to a Variety of Geopolitical and Economic Events



Sources: U.S. Energy Information Administration, Thomson Reuters

Source: EIA Presentation “What drives crude oil prices?” June 9, 2015. Washington, D.C., www.eia.gov.

In the past, when gas prices were high and the cost of NGLs was expected only to grow, U.S. cracker capacity fed by NGLs declined from 75.4% in 2001 to 67.9% in 2005. With the increase of NGLs produced from shale resources, NGL-fed U.S. cracker capacity increased to 90% in 2013.²³⁵ Three primary factors influenced this dynamic: (1) disengagement of NGLs prices from oil prices and closer association with cheap dry gas prices in the United States (Figure 40); (2) the abundance of ethane, cheap energy, and water in the United States enabling expansion of the petrochemical industry overall; and (3) economic and political stability married with free business enterprise spirit that enabled significant investments in this expansion.

The sharp decline in crude oil prices in the fourth quarter of 2014 affected nearly all feedstock, although each to a different degree. While natural gasoline fell 44%, normal butane prices declined 41%; propane dropped by 32% following the crude oil decline in 2014; and ethane prices declined by only 25%.²³⁶ Until the middle of 2014, the ethane prices at TX and LA hubs (at \$0.44/gallon of ethane), resulted in the production cost of ethylene at \$0.18/pound with the selling price of ethylene at about \$0.70/pound.²³⁷ At the end of 2014, ethane prices fell to \$0.18/gallon, making production of ethane \$0.092/pound with the selling price of ethylene at

²³⁵ Thompson, Jesse. “Shale Revolution Feeds Petrochemical Profits as Production Adapts.” Southwest Economy. Federal Reserve Bank of Dallas. Fourth Quarter. 2013. P.17.

²³⁶ Lippe, Dan. “Falling oil prices will disrupt feed cost differentials.” Petra Consulting Co. 03/02/2015.

²³⁷ The American Oil & Gas Reporter, June 17, 2014. <http://www.aogr.com/web-exclusives/exclusive-story/shale-gas-npls-fuel-large-scale-petrochemical-investments>

\$0.38/pound.²³⁸ Since the derivative products (propylene and butadiene) declined more slowly than their feedstock, this lag of price decline in co-products of naphtha processing pushed ethylene production cost from naphtha lower than ethylene production cost from ethane. Uneven decreases in production costs of ethylene from ethane and naphtha (Table 17) and the high price of benzene, toluene, and the three xylene isomers (BTX or aromatics also called C4+ aromatics) allowed naphtha feedstock to continue to yield good economics for steam crackers even at the end of 2014.

Table 17. Ethylene Production Costs from Different Feedstock, c/lb

2014-2015	Ethane	Propane	n-Butane	Naphtha, gas oil
July	11.2	20.0	12.7	45.9
August	10.3	18.7	10.9	39.9
September	10.7	21.2	13.1	40.6
October	10.4	15.7	9.1	30.3
November	10.8	12.1	10.3	25.3
December	9.2	5.0	2.6	16.9
January	9.3	2.9	3.9	12.0

Source: Lippe, Don. "Falling oil prices will disrupt feed cost differentials," Petral Consulting Co. 03/02/2015.

Another factor to be considered is the increased amount of recently-announced U.S. and Middle East condensate production. This production increase suggests that the shift from naphtha to ethane as a feedstock in the global market will be happening very gradually.²³⁹ Because oil produced from shale deposits is "lighter" than traditional imported U.S. oil, smaller volumes of condensate are required at oil refineries for use in the process of blending condensate with gasoline to meet a higher octane level – the traditional use of natural gasoline in the United States. The weak domestic demand for gasoline only increased the surplus of non-utilized condensate. To benefit from the excessive amounts of condensate, some midstream operators have opted to "split" condensate streams into processed oil products to circumvent the crude oil export ban. Once blended with refined products, the condensate can travel to and be sold on international markets, thereby avoiding the crude oil export ban. After this product is run through refineries, it yields 60-70% of naphtha-range materials, adding to an oversupply of cheap naphtha feedstock to steam crackers, which had already benefited from an oversupply stemming from Middle Eastern producers.²⁴⁰

²³⁸ Lippe, Dan. "Falling oil prices will disrupt feed cost differentials." Petra Consulting Co. 03/02/2015.

²³⁹ Fattough, Bassam and Craig Brown. "U.S. NGLs production and steam cracker substitution: What will the spillover effect be in global petrochemical markets?" The Oxford Institute for Energy Studies. September 2014. P.10.

²⁴⁰ *Id.* p.11.

Switching from naphtha to ethane feedstock in North America caused a shortage of the supply of propylene, butadiene, and other higher C-chain, C4+ aromatics. This shortage started even before the shale revolution in the United States, and was accompanied by a decreased amount of these already-in-short-supply chemicals. Moreover, lighter low-cost shale oil is an average 12.5% lower in aromatics content than the typical historical U.S. refinery mix. According to research conducted by Platts,²⁴¹ the total U.S. supply of aromatics has dropped an estimated 55% and caused a significant increase in prices for C4+ aromatics.

The market responded to the shortages of butadiene and BTX not only by price growth, but also by attracting more imports of these chemicals to the U.S. For the long run, there has been announcements of new construction and an expansion of propylene crackers that will yield greater amounts of higher C-chain chemicals in the United States.²⁴² Attractive prices for C4+ aromatics also encouraged competition for substitutes made from NGL-based ethylene.²⁴³ Cheap feedstock of naphtha produced from crude oil, the additional supply of condensate from the Middle East and the United States, and the attractiveness of C4+ aromatics' prices will continue to keep naphtha-based crackers profitable and accelerate the change from naphtha to ethane as a main feedstock for ethylene-producing crackers in the United States (but not globally).

While the naphtha crackers remain profitable due to the factors described above, a few points need to be made about the advantage North America has in the switch to ethane-based crackers. The yield of ethylene from different feedstock varies significantly by volume. To produce the same amount of ethylene, a smaller amount of ethane is required compared to naphtha. According to industry data, it takes about 1.302 metric tons of ethane to yield 1 ton of ethylene compared with 3.3 tons of naphtha to yield the same amount of ethylene.²⁴⁴ According to some industry specialists opinions,²⁴⁵ only a lack of sufficient NGLs resources outside of the Middle East and recently the U.S., made naphtha as a traditional steam crackers feedstock for ethylene production.

Another advantage of building ethane crackers in the United States, and in the Appalachian/Mid-Ohio Valley in particular, is the availability of relatively cheap electricity and the abundance of water, both for transportation and cooling in chemical processing. When discussing new Middle East, Chinese and Indian chemical processing facilities, the cost of energy

²⁴¹ Allen, Kevin. "Impact of shale plays on U.S. aromatics production and pricing." Platts U.S., January 10, 2013. P.2. <https://www.platts.com/IM.Platts.Content/InsightAnalysis/IndustrySolutionPapers/aromatics-shale-revolution.pdf>

²⁴² Six new propylene crackers and expansion construction projects were announced in Texas, including those by the following companies: Enterprise Products, C3 Petrochemicals, Dow Chemicals, Formosa Plastics and PetroLogistics. Williams Co. announced a propylene cracker in Canada.

²⁴³ Thompson, Jesse. "Shale Revolution Feeds Petrochemical Profits as Production Adapts." Southwest Economy. Federal Reserve Bank of Dallas. Fourth Quarter. 2013. P.17.

²⁴⁴ "Petrochemicals: Preparing for a super cycle". Morgan Stanley. October 18, 2010. In Fattough, Bassam and Craig Brown. "U.S. NGLs production and steam cracker substitution: What will the spillover effect be in global petrochemical markets?" The Oxford Institute for Energy Studies. September 2014. P.6.

²⁴⁵ Interviews with petrochemical and chemical companies in Ohio and West Virginia.

and water are often omitted. However, the chemical industry is one of heaviest users of electricity, heat, and water and these resources are expensive outside of the United States.²⁴⁶

Finally, while the fall of oil prices eased competitive pressure on naphtha-based crackers, especially in Europe, the decreased cost of crude oil will not last long. Alleviated competitive pressure may only delay a strategic decision to import U.S. ethane and refit naphtha-based crackers for ethane as a feedstock. Moreover, many naphtha-fed crackers are based on older technologies and use old equipment. What seems to be the significant advantage of low naphtha prices today might prove to be a disadvantage in the future.

Low ethane prices and sustained oil, gas, and NGL production during the first half of 2015 proved the resiliency of U.S. shale oil and gas producers. This resiliency is rooted in high productivity and continued innovation. Low ethane prices and sustained volumes of NGLs from Marcellus and Utica will attract petrochemical producers. The benefits of being the first mover will be significantly greater than for those who enter this region to crack ethane later. The advantage will be built through lower-cost feedstock, better availability of skilled labor, easier access to transportation contracts and greater pool of local customers for polyethylene. Greater flexibility of feedstock might be an answer for current changing economics of spread between the cost of ethylene production and the selling price of ethylene and polyethylene.

4.7. Main Nodes of Ohio Development and Critical Investment Decisions

There is a significant mismatch measured in time and cost that exists between building natural gas processing capacities connected to take away pipelines and building petrochemical production plants (i.e. crackers). The natural gas processing capacity can be built quickly and is closely aligned with pace of drilling and production. Indeed, gas processing facilities are often owned by producing companies, usually as part of a consortium with companies that specialize in processing or gas gathering. It takes between 12 to 18 months to construct a natural gas processing plant. Units arrive on skids in pre-made segments that have a processing capacity of 200,000 mcf/d per segment. The processing capacity is built ahead of the scheduled drilling and expected production, and can be closely coordinated to ensure it matches production volumes.

Likewise, fractionation plants downstream of the processing plants can also be quickly built and brought on line in response to production. Unlike gas processing, capacity for fractionation is measured in liquid volumes (usually 75 mbbbl/d as a standard unit), while costs are around \$250-\$260 million/unit.

However fractionation must be accompanied by the capability of taking the pure products (i.e. natural gas liquids separated into single chemicals) to market. For ethane, this means building a pipeline system, since ethane is a gas at normal temperatures and pressures. The demand for pure product pipelines in Utica/Marcellus basin soared in 2013-2014, especially for ethane.

²⁴⁶ Alexander, Serena E., Wendy A. Kellogg, Iryna V. Lendel, Andrew R. Thomas, Nicholas C. Zingale. "Water Resources Shaping Ohio's Future: Water Efficiency Manual for Industrial, Commercial, and Institutional Facilities. Prepared for the Ohio Lake Erie Commission and Ohio Department of Natural resources," Center for Economic Development, Cleveland State University. May 2014. Additional sources: Interviews of petrochemical and chemical companies.

The required construction time for take-away pipelines corresponds to the time needed to build natural gas processing and fractionation plants, or 18 to 24 months. Each pipeline project costs less than \$1 billion, varying significantly from project to project. For example, Sunoco's combined Mariner projects are expected to cost \$600 million. The bottom line is that all necessary midstream infrastructure to process, fractionate and take away ethane and other pure products can be brought on line within a few years of the time that a major new production basin has been identified.

An ethane cracker, on the other hand, might take 5 to 6 years to plan and build, with the cost varying from \$3 billion to \$6 billion. In addition, regulatory requirements may extend the timeline and/or incur additional costs. Herein lies the mismatch: those hoping to see a petrochemical cluster develop around ethane cracker facilities must hope that ethane production and processing continues to outpace take away capacity, and that petrochemical companies bet large amounts of money on this scenario continuing many years out. The best way to ensure that ethane is husbanded for local use is through firm long-term contracts between production and petrochemical companies.

Five pipeline projects are scheduled to come online by 2018 that will create significant additional take away capacity for Utica and Marcellus natural gas liquids, including ethane. The projects include: Sunoco Logistics' Mariner West, which will take ethane up to petrochemical plants in Sarnia, Canada; Sunoco's Mariner East, designed to take propane and eventually ethane to the Marcus Hook facility in Philadelphia; Appalachia to Texas Express (ATEX), built to transport ethane to petrochemical plants in Mont Belvieu, Texas; Kinder Morgan's Utopia pipeline to Windsor, Ontario; and a project by MarkWest Energy Partners and Kinder Morgan Inc. that will transport mixed Y-grade (C3 and up) liquids to Mont Belvieu. Moreover, having already-acquired right-of-ways permits, pipelines will have ability to expand capacity in the future.

Notwithstanding this risk, industry production projections through the spring of 2015 for ethane continue to indicate a strong capability of supplying multiple crackers in the Appalachian basin. Yet this does not end the inquiry for petrochemical companies. Falling oil prices have reduced feedstock spread between ethane and naphtha, and this may delay decisions to move forward with construction of these crackers. Tighter capital availability, a stronger U.S. dollar, and a drastic decrease in U.S. rig counts have added to market volatility. Market stability is a critical component to evaluating manufacturing expansion opportunities. Some experts suggest that if the crackers would be already built and running, they would be profitable even at the current low oil prices. However, a different equation is in play when these companies need to demonstrate a positive cash-flow for paying off capital investment to their investors.

It appears, then, that ethane volume and ethane prices will be an inducement for and not an impediment to building ethane crackers in the region. Moreover, with earlier announcements by Shell and other petrochemical companies confirming that significant amount of the necessary ethane supply may be under contract for delivery, availability feedstock should not be a consideration preventing companies from moving ahead with building processes. Delays (or cancellation) in building are more likely to be caused by the decreasing spread between

different ethylene feedstock and, as a result, a decreased margin between ethylene/polyethylene prices and ethylene cost, holding a constant processing cost.

Investment decisions for cracker plants and other petrochemical facilities that rely on feedstock from the Utica and Marcellus shale production must be made in time to ensure that available production is not committed to other out-of-region processing opportunities. Moreover, the petrochemical refiner would like to capture feedstock commitment during the point in time when the production is peaking, especially if it is in a surplus status, thereby ensuring it gets depressed prices. The refiner would also like to have its plant fully operational at such time that production exceeds the take-away capacity. For ethane, it should also be operating at a time when natural gas prices are also depressed, ensuring that the rejection market is not more attractive than the ethane market.

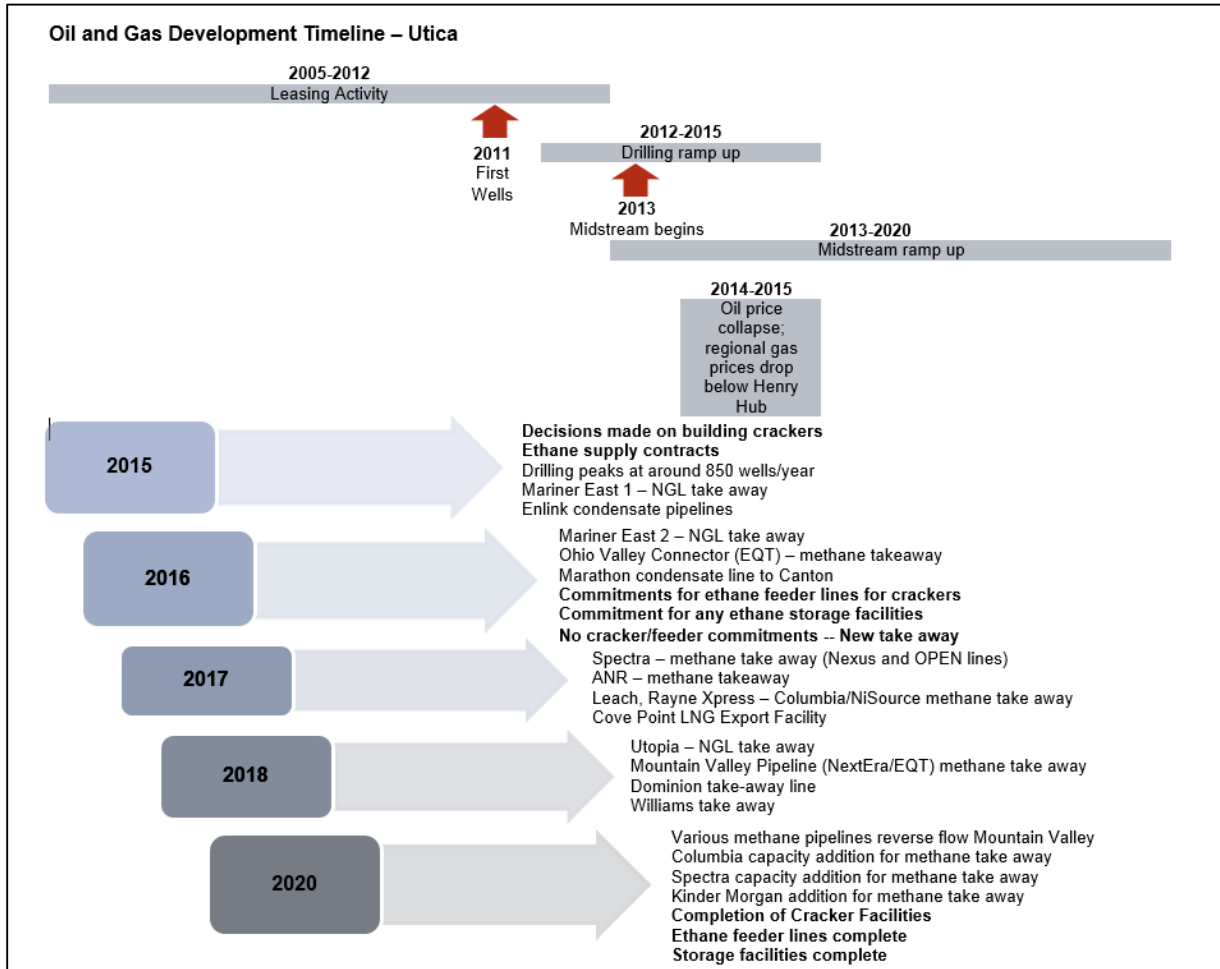
Those conditions generally exist now, for the Utica and the Marcellus region. Production will likely not peak until 2020, however, so there is a good chance they will continue to exist until then. More importantly, in 2020, barring any additional new take away capacity being built beyond that already planned, the ethane surplus will be at its peak. According to current industry projections, ethane production capability will be around 638.4 mbbbl/d in the basin (assuming 20% rejection), while take away capacity will be at only about 460 mbbbl/d.

For a large petrochemical plant to be fully operational by 2020, its owner will need to begin work on it no later than 2016. Estimates given to the Study Team for a new cracker facility have been around 4-5 years to be built and fully operational. One key moment required to justify the beginning of work will be when the petrochemical company obtains sufficient and firm feedstock supply commitments. It should trigger investment. Such commitments are also likely to head off additional pipeline take away infrastructure build out. Accordingly, acquisition of firm commitments should be fully developed by 2015-16.

If they are not, any time before contractual commitments are made to build or to supply new take away infrastructure should be sufficient. Once contractual commitments are made to take away the excess ethane, it will be increasingly difficult to get firm supply commitments for the petrochemical plant, and there will be increased competition for locally produced ethane.

A timeline of the key infrastructure events is set forth below, along with an estimate of key time frames for decision making on commitments to supply and build petrochemical facilities. An additional key consideration will be the timing and extent of the build out of natural gas take away capacity, which may, in turn, provide additional rejection capacity. In 2014, there was insufficient natural gas take away capacity in the Appalachian basin, leading to a discrepancy between local prices and Henry Hub prices. There are, however, a number of natural gas take away projects in process, including some pipeline reversals, which will alleviate this by 2020. So ethane rejection will become an increasingly viable alternative market for ethane over time. Accordingly, petrochemical companies that wish to head off additional natural gas take away development before 2020 may need to tie up ethane supplies by 2017-18.

Figure 46. Oil and Gas Development Timeline for the Utica



Abbreviation Glossary

Abbreviation	Description
bbl	Barrel
bbl/d	barrels per day
mdbl/d	thousand barrels per day
bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcfe	billions of cubic feet equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
tcf	trillion cubic feet
boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
mboe	thousand-barrel oil equivalent
btu	British Thermal Unit
mmbtu	million British Thermal Units
g/cc	grams per cubic centimeter
LDPE	low-density polyethylene
LLDPE	linear low-density polyethylene
HDPE	high-density polyethylene
PVC	polyvinyl chloride
PS	Polystyrene

APPENDIX A

Table A-1. Comparison of natural gas projections, 2025 (tcf)

Figure A-1. Marcellus Area Spot Natural Gas Trading Points.

Figure A-2. TCO Appalachia and Henry Hub Natural Gas Prices

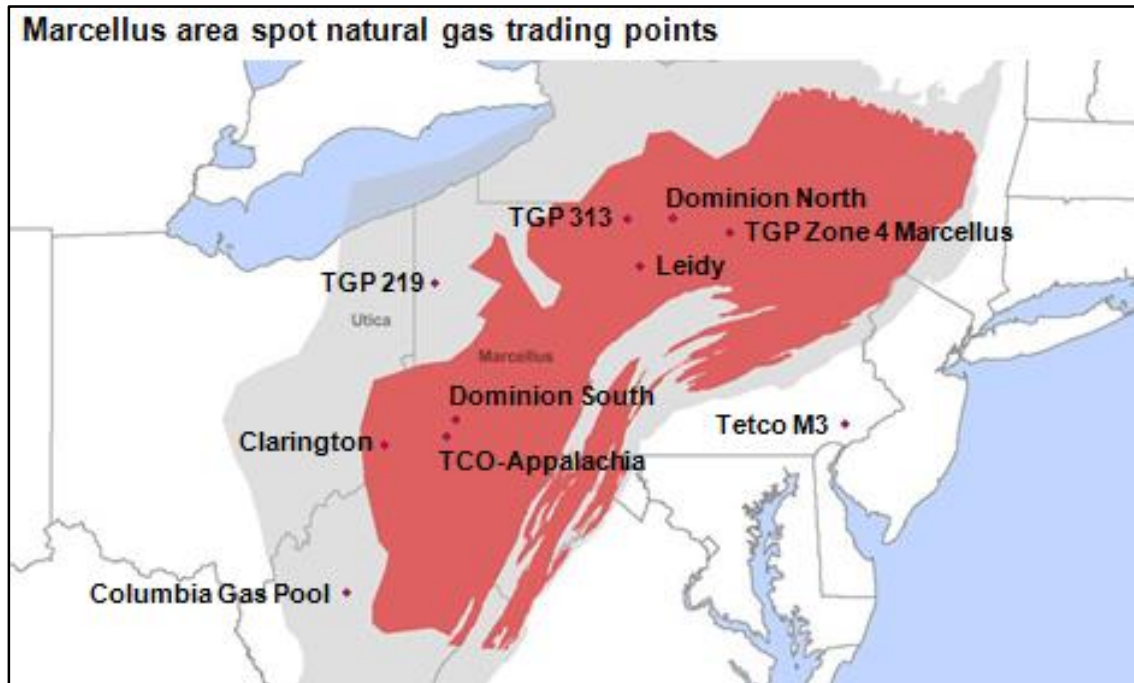
Figure A-3. Daily Spot Natural Gas Prices at the Tennessee Gas Pipeline Zone 4 Marcellus and Henry Hub Trading Points. 1/1/2012 – 7/23/2012.

Table A-1. Comparison of natural gas projections, 2025 (tcf)

Projection	2012	AEO2014	IHSGI	EVA	ICF	BP ^a	ExxonMobil	INFORUM
		Reference						
2025								
Dry gas production ^b	24.06	31.86	34.26	33.14	33.15	31.96	--	26.20
Net Imports	1.51	-3.41	-1.81	-2.34	-3.02	--	--	--
Pipeline	1.37	-0.84	--	0.64	-0.80	--	--	--
LNG	0.15	-2.57	--	-2.99	-2.22	--	--	--
Consumption	25.64	28.35	32.52	32.15	29.64	28.28	29.30 ^c	24.84 ^c
Residential	4.17	4.40	4.60	5.09	5.04	--	8.00 ^d	4.71
Commercial	2.90	3.22	3.24	3.55	3.11	--	--	3.38
Industrial ^e	7.14	8.41	7.96	9.56	7.96	--	9.00	7.82
Electric generators ^f	9.25	9.49	13.28	10.61	10.90	--	12.00	8.92
Others ^g	2.18	2.84	3.45	3.35	2.64	--	0.30	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	5.23	3.92	5.69	5.44 ^h	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	12.75	11.37	--	--	--	--	--
Commercial	8.29	10.51	9.26	--	--	--	--	--
Industrial ⁱ	3.85	6.46	6.18	--	--	--	--	--
Electricity generation	3.51	5.88	4.60	--	--	--	--	--

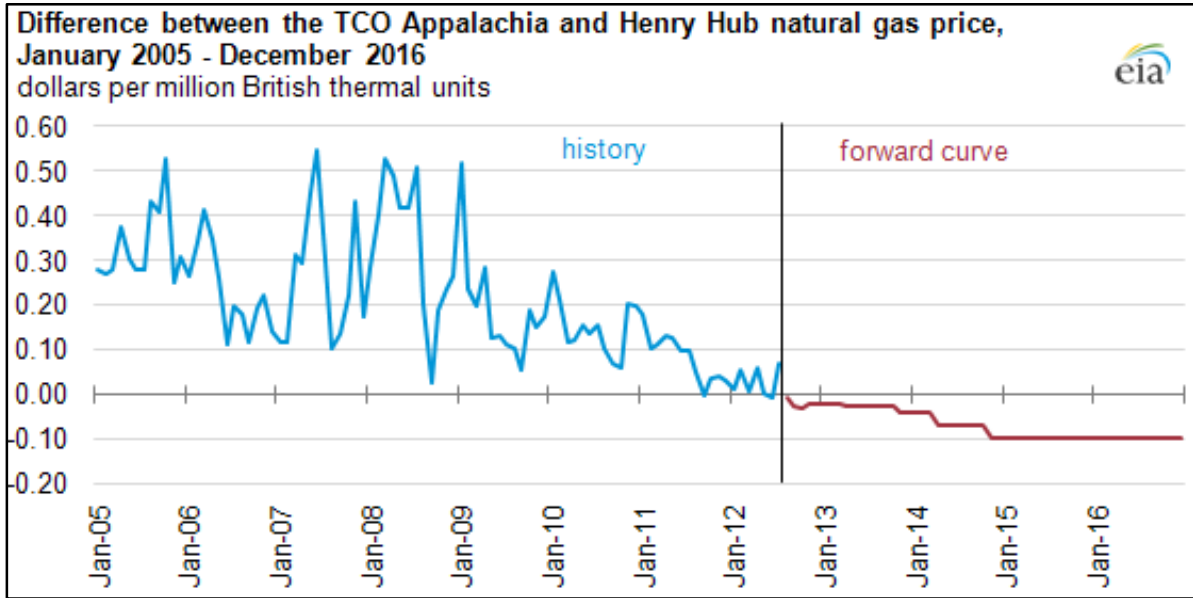
Note: IHSGI – IHS Global Insight, EVA – Energy Ventures Analysis.

Figure A-1. Marcellus Area Spot Natural Gas Trading Points.



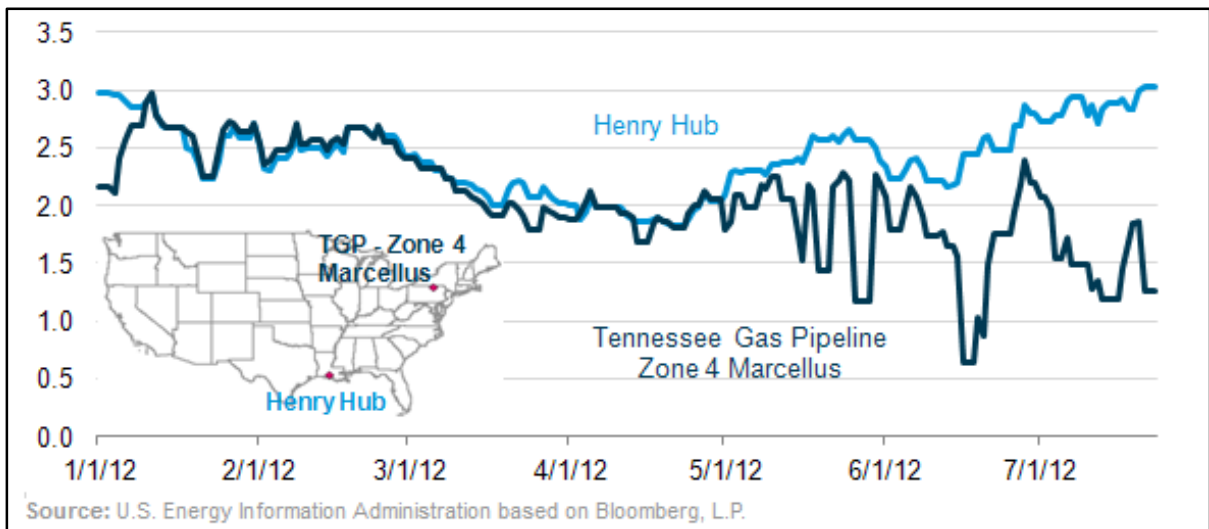
Source: U.S. EIA, <http://www.eia.gov/todayinenergy/detail.cfm?id=18391>

Figure A-2. TCO Appalachia and Henry Hub Natural Gas Prices



Source: U.S. EIA, <http://www.eia.gov/todayinenergy/detail.cfm?id=18391>

Figure A-3. Daily Spot Natural Gas Prices at the Tennessee Gas Pipeline Zone 4 Marcellus and Henry Hub Trading Points 1/1/2012 – 7/23/2012.



Source: "Spot natural gas prices at Marcellus trading point reflect pipeline constraints." U.S. Energy Information Administration. July 23, 2012. <http://www.eia.gov/todayinenergy/detail.cfm?id=7210>

APPENDIX B

Table B-1. Five Year Low Side Drilling Rate Estimate

Table B-2. Five Year High Side Drilling Rate Estimate

Table B-3. Most Likely Throughput Determination

Table B-4. Low Side Throughput Determination

Table B-5. High Side Throughput Determination

Table B-1. Five Year Low Side Drilling Rate Estimate

Year	Rig Count	Drill Time	Wells/Year	Total Wells
2011-2013				364
2014	45	28.4	593	957
2015	45	25	584	1541
2016	45	22	664	2205
2017	45	22	664	2869
2018	45	22	664	3533
2019	45	22	664	4197

Table B-2. Five Year High Side Drilling Rate Estimate

Year	Rig Count	Drill Time	Wells/Year	Total Wells
2011-2013				364
2014	45	28.4	593	957
2015	50	25	730	1687
2016	55	22	913	2600
2017	60	22	995	3595
2018	60	22	995	4590
2019	60	22	995	5585

Table B-3. Most Likely Throughput Determination

Assumptions:

- Spud-to-spud time increases from current average of 28.4 days to 25 days in 2015 and 22 days in 2016
- Rig count increases from 45 in 2014 by 3 rigs/year to a maximum of 54 rigs in 2017

	Average Production (BOE/well)	# Wells	Total Production (BOE)	Total Annual Production (BOE)	Total Annual Production MCF Equivalents	Daily Production MMCFEQ/Day
2011 - 2013 Total Production	55728	364	20285152	20285152	121710912	0.33
2014 projected Total Prod.	125983	593	74708000	74708000	448248000	1.23
2015 Est Production	168600	701	118188600			
65 % decline (2014)	44094	593	26147800	144336400	866018400	2.37
2016 Estimated Annual Prod	168600	846	142635600			
65 % decline (2015)	59010	701	41366010			
33 % decline (2014)	29543	593	17519026	201520636	1209123816	3.31
2017 Estimated Annual Prod	168600	879	148199400			
65 % decline (2016)	59010	846	49922460			
33 % decline (2015)	39537	701	27715227			
22 % decline (2014)	23044	593	13664840	239501927	1437011562	3.94
2018 Estimated Annual Prod	168600	879	148199400			
65 % decline (2017)	59010	879	51869790			
33 % decline (2016)	39537	846	33448048			
22 % decline (2015)	30839	701	21617877			
17 % decline (2014)	19126	593	11341817	266476932	1598861595	4.38
2019 Estimated Annual Prod	168600	879	148199400			
65 % decline (2018)	59010	879	51869790			
33 % decline (2017)	39537	879	34752759			
22 % decline (2016)	30839	846	26089478			
17 % decline (2015)	25596	701	17942838			
13 % decline (2014)	16640	593	9867381	288721646	1732329875	4.75
		TOTAL	1235550693	1235550693	7413304160	20.31

Table B-4. Low Side Throughput Determination

Assumptions:

- Spud-to-spud time increases from current average of 28.4 days to 25 days in 2015 and 22 days in 2016
- Rig count remains unchanged at 45 rigs

	Average Production (BOE/well)	# Wells	Total Production (BOE)	Total Annual Production (BOE)	Total Annual Production MCF Equivalents	Daily Production MMCFEQ/Day
2011 - 2013 Total Production	55728	364	20285152	20285152	121710912	0.33
2014 projected Total Prod.	125983	593	74708000	74708000	448248000	1.23
2015 Est Production	168600	584	98462400			
65 % decline (2014)	44094	593	26147800	124610200	747661200	2.05
2016 Estimated Annual Prod	168600	664	111950400			
65 % decline (2015)	59010	584	34461840			
33 % decline (2014)	29543	593	17519026	163931266	983587596	2.69
2017 Estimated Annual Prod	168600	664	111950400			
65 % decline (2016)	59010	664	39182640			
33 % decline (2015)	39537	584	23089433			
22 % decline (2014)	23044	593	13664840	187887313	1127323878	3.09
2018 Estimated Annual Prod	168600	664	111950400			
65 % decline (2017)	59010	664	39182640			
33 % decline (2016)	39537	664	26252369			
22 % decline (2015)	30839	584	18009758			
17 % decline (2014)	19126	593	11341817	206736984	1240421903	3.40
2019 Estimated Annual Prod	168600	664	111950400			
65 % decline (2018)	59010	664	39182640			
33 % decline (2017)	39537	664	26252369			
22 % decline (2016)	30839	664	20476848			
17 % decline (2015)	25596	584	14948099			
13 % decline (2014)	16640	593	9867381	222677736	1336066419	3.66
		TOTAL	1000836651	1000836651	6005019908	16.45

Table B-5. High Side Throughput Determination

Assumptions:

- Spud-to-spud time increases from current average of 28.4 days to 25 days in 2015 and 22 days in 2016
- Rig count increases from 45 in 2014 by 5 rigs/year to a maximum of 60 rigs in 2017

	Average Production (BOE/well)	# Wells	Total Production (BOE)	Total Annual Production (BOE)	Total Annual Production MCF Equivalents	Daily Production MMCFEQ/Day
2011 - 2013 Total Production	55576	365	20285152	20285152	121710912	0.33
2014 projected Total Prod.	125983	593	74708000	74708000	448248000	1.23
2015 Est Production	168600	730	123078000			
65 % decline (2014)	44094	593	26147800	149225800	895354800	2.45
2016 Estimated Annual Prod	168600	913	153931800			
65 % decline (2015)	59010	730	43077300			
33 % decline (2014)	29543	593	17519026	214528126	1287168756	3.53
2017 Estimated Annual Prod	168600	995	167757000			
65 % decline (2016)	59010	913	53876130			
33 % decline (2015)	39537	730	28861791			
22 % decline (2014)	23044	593	13664840	264159761	1584958568	4.34
2018 Estimated Annual Prod	168600	995	167757000			
65 % decline (2017)	59010	995	58714950			
33 % decline (2016)	39537	913	36097007			
22 % decline (2015)	30839	730	22512197			
17 % decline (2014)	19126	593	11341817	296422972	1778537829	4.87
2019 Estimated Annual Prod	168600	995	167757000			
65 % decline (2018)	59010	995	58714950			
33 % decline (2017)	39537	995	39339017			
22 % decline (2016)	30839	913	28155666			
17 % decline (2015)	25596	730	18685123			
13 % decline (2014)	16640	593	9867381	322519137	1935114820	5.30
		TOTAL	1341848947	1341848947	8051093685	22.06

APPENDIX C

Figure C-1. Industrialization and Growing Power Demand

Figure C-2. Average Monthly WE Crude Oil and Naphtha Prices, 2008-2014

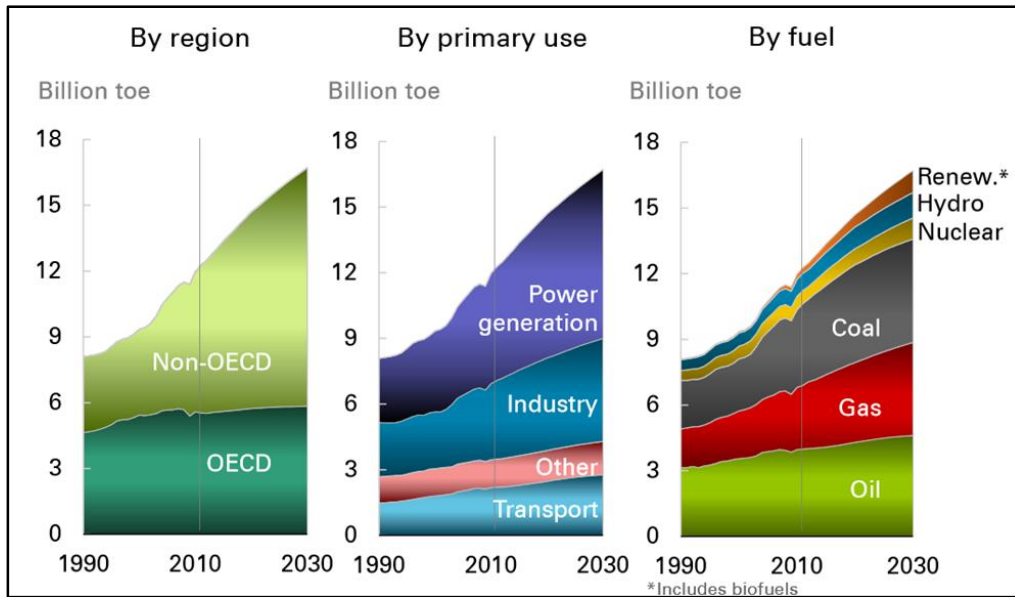
Figure C-3. Products from Petroleum Feedstock

Table C-1. Existing and Proposed Cracker Capacities in the United States, 2014

Figure C-4. European Polymer Prices, 2014-2015

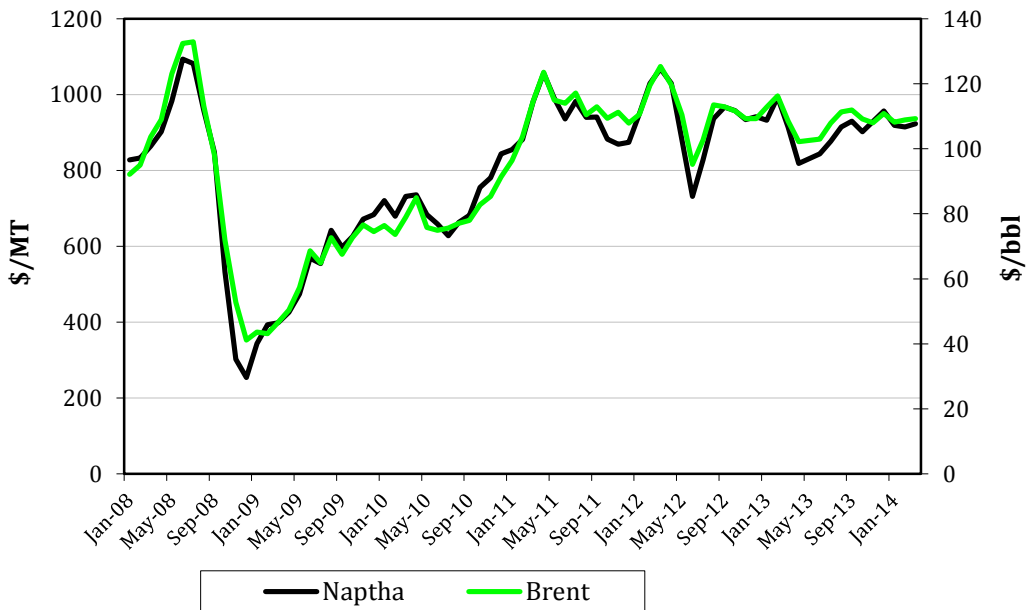
Table C-2. Top U.S. Commodity Chemicals Companies

Figure C-1. Industrialization and Growing Power Demand



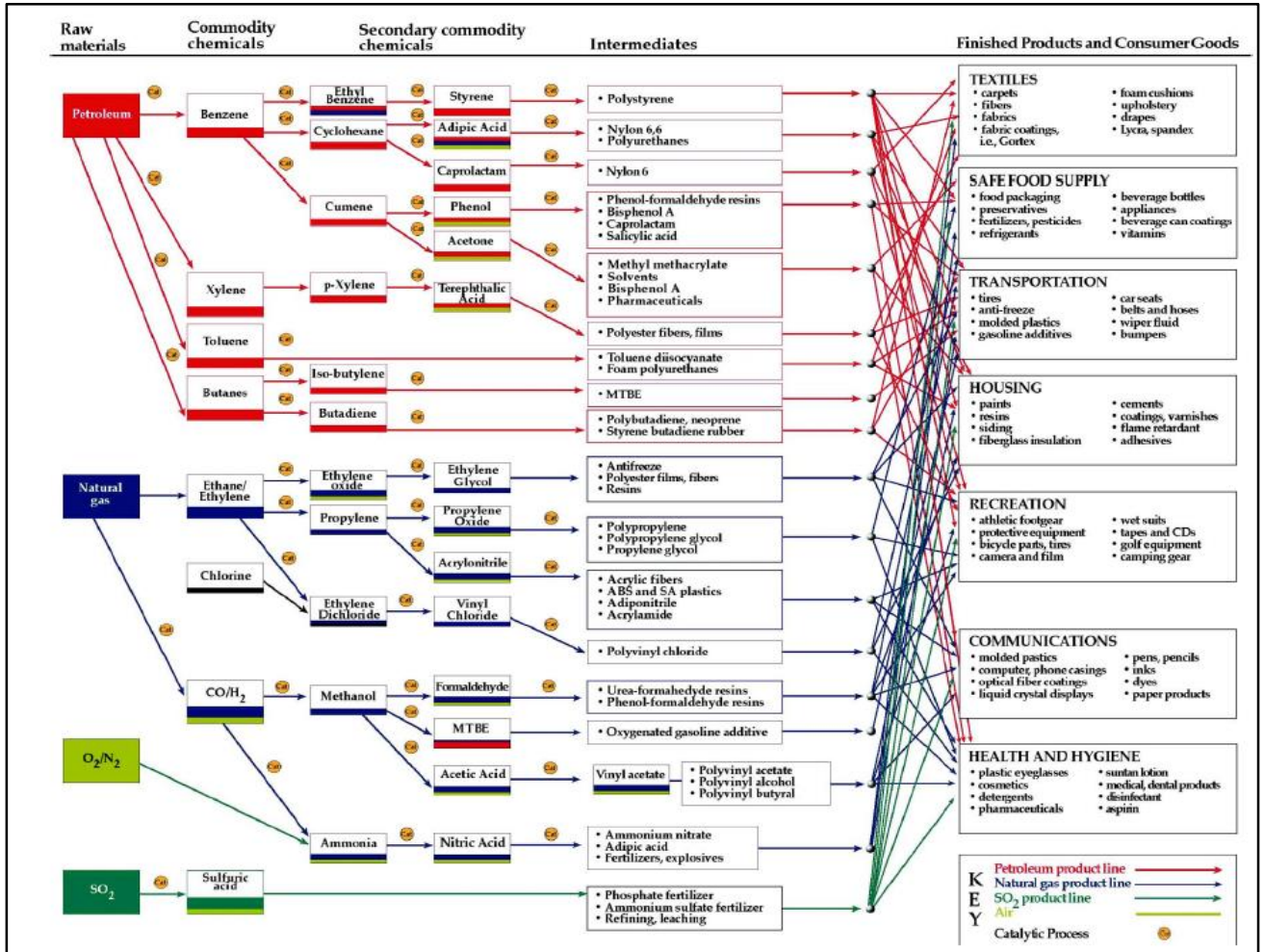
Source: BP Energy Outlook 2030, January 2013. http://www.bp.com/content/dam/bp/pdf/Energy-economics/Energy-Outlook/BP_Energy_Outlook_Booklet_2013.pdf

Figure C-2. Average of Monthly WE Crude Oil and Naphtha Prices, 2008 – 2014



Source: DeWitt & Company data, <http://www.dewittworld.com/portal/GraphAnalysis/Catalog.aspx?GraphID=333&ProductID=101&MainActiveTab=All&SubActiveTab=&PageIndex=0>

Figure C-3. Products from Petroleum Feedstock



Source: DOE

Mapping the Opportunities for Shale Development in Ohio

Table C-1. Existing and Proposed Cracker Capacities in the United States, 2014

Company	Location	Total Nameplate Capacity, tonnes/yr	Total Ethane Capacity, tonnes/yr	Expansion Capacity, tonnes/yr	Total Capacity by 2020, tonnes/yr
Appalachian Resins	Monroe County, OH	0	0	460,000	460,000
BASF Fina Petrochemicals	Port Arthur, TX	860,000	0	170,000	170,000
Chevron Phillips Chemical Co. LP	Cedar Bayou, TX	835,000	250,500	1,500,000	1,750,500
	Port Arthur, TX	855,000	684,000		684,000
	Sweeny, TX	945,000	359,100		359,100
	Sweeny, TX	665,000	498,750		498,750
	Sweeny, TX	255,000	216,750		216,750
Dow Chemical Co.	Freeport (LHC 7), TX	630,000	315,000	1,500,000	1,815,000
	Freeport (LHC 8), TX	1,010,000	101,000		101,000
	Plaquemine (LH 2), LA	520,000	390,000	220,000	610,000
	Plaquemine (LH 3), LA	740,000	518,000		518,000
	Taft 1, LA	590,000	118,000		118,000
	Taft 2, LA	410,000	0		0
Dupont	Orange, TX	680,000	680,000		680,000
Eastman Chemical Co.	Longview, TX	781,000	195,250		195,250
Equistar Chemicals LP (LyondellBasell)	Channelview, TX	875,000	43,750	1,112,000	1,155,750
	Channelview, TX	875,000	43,750		43,750
	Chocolate Bayou, TX	544,000	0		0
	Clinton, IA	476,000	380,800		380,800
	Corpus Christi, TX	771,000	77,100		77,100
	LaPorte, TX	789,000	473,400		473,400
	Morris, Illinois	550,000	440,000		440,000
ExxonMobil Chemical Co.	Baton Rouge, LA	975,000	87,750		87,750
	Baytown, TX	2,197,000	1,274,260	1,500,000	2,774,260
	Beaumont, TX	816,000	65,280		65,280
	Houston, TX	102,000	0		0
Flint Hills Corp.	Port Arthur, TX	634,921	0	100,000	100,000
Formosa Plastics Corp. USA	Point Comfort, TX	816,000	367,200	1,150,000	1,517,200
	Point Comfort, TX	725,000	326,250		326,250
Huntsman Corp.	Port Neches, TX	180,000	0		0
INEOS Olefins and Polymers USA	Chocolate Bayou, TX	1,752,000	876,000		876,000
Javelina Co.	Corpus Christi, TX	151,000	0		0
Occidental Chemical/Mexichem	Ingleside, TX	0	0	550,000	550,000
Odebrecht	Wood County, WV	0	0	1,400,000	1,400,000
PTT Global	Ohio	0	0	1,000,000	1,000,000
Sasol North America Inc.	Lake Charles, LA	471,655	471,655	1,550,000	2,021,655
Shell Chemicals Ltd.	Deer Park, TX	1,179,138	0		0
	Norco, LA	1,451,247	72,562		72,562
	Monaca, PA	0	0	3,100,000	3,100,000
Westlake Petrochemicals Corp.	Calvert City, KY	204,082	204,082	216,000	420,082
	Sulphur #1, LA	567,000	567,000		567,000
	Sulphur #2, LA	630,844	441,591		441,591
Williams Olefins	Geismar, LA	612,245	563,265	258,000	821,265
US Total		28,121,132	11,102,045	15,786,000	26,888,045

Sources: Oil and Gas Journal; IHS

Figure C-4. European Polymer Prices, 2014-2015

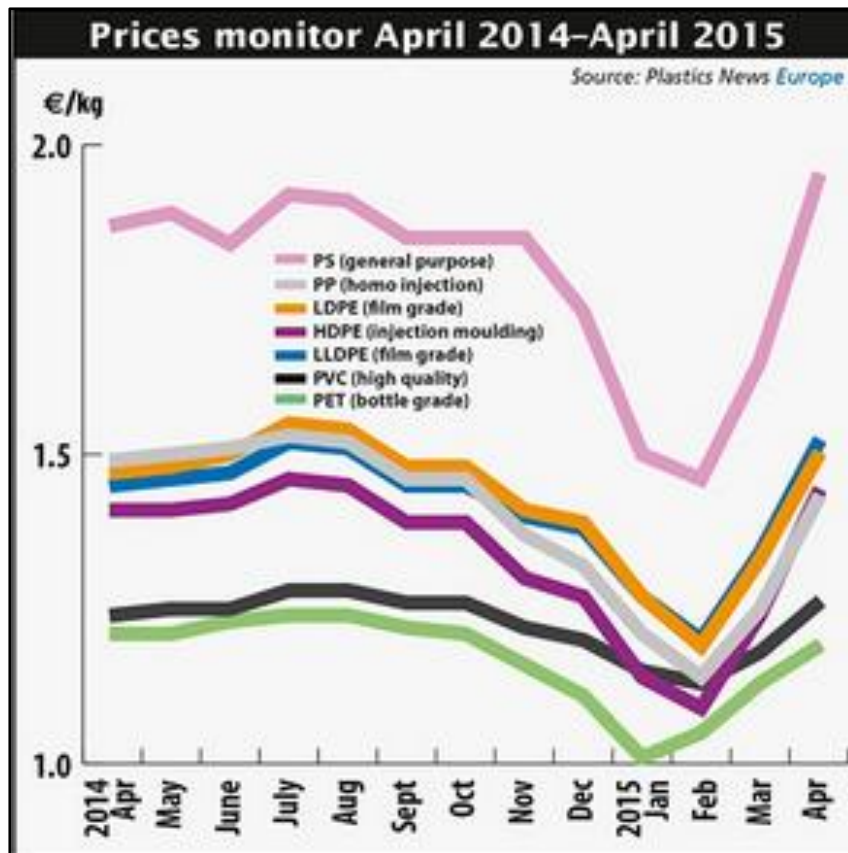


Table C-2. Top U.S. Commodity Chemicals Companies

Company Names
A. Schulman, Inc.
AIR PRODUCTS AND CHEMICALS, INC.
Airgas Inc.
Akzo Nobel N.V.
Albemarle Corp.
Axiall Corporation
Braskem S/A.
Celanese Corporation
Eastman Chemical Company
Enzymotec Ltd.
Innophos Holdings Inc.
Koninklijke DSM N.V.
Lyondellbasell Industries Naamloze Vennootschap
Methanex Corporation
Newmarket Corporation
Olin Corporation
Ppg Industries Inc.
Praxair Inc.
RPM International Inc.
Sherwin-Williams Company
Valspar Corporation
Westlake Chemical Corporation
Detrex Corporation
Gulf Resources Inc.
Koppers Holdings Inc.
Quaker Chemical Corporation
Taminco Corporation
UFP Technologies Inc.
Cheniere Energy Partners, L.P.
Diamant Art Corporation
FlameRet Inc.
FuelCell Energy Inc.
GEI Global Energy Corporation
GelTech Solutions Inc.
Green Earth Technologies Inc.
Hybrid Coating Technologies Inc.
Dynamic Nutra Enterprises Holdings, Inc.
Mobile Area Networks, Inc.
Plug Power Inc.
Rentech Inc.
Shiner International Inc.
United Energy Corporation
US Rare Earth Minerals Inc.
Asia Carbon Industries Inc.
BioLargo Inc.
Enertech Corporation
Keyuan Petrochemicals Inc.

Source: Markets Business Day, New York Times, October 10, 2014.