  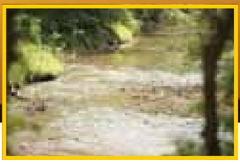

Expanding the Shale Gas Infrastructure

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Development of U.S. shale gas resources will require expansion of infrastructure assets ranging from roads and rails to pipelines and seaports to power-generation plants and ethane crackers, and more.

The Interstate Natural Gas Association of America (INGAA) estimates that over the next 25 years, the U.S. will need to add approximately 43 billion cubic feet per day (cfd) of natural-gas transmission pipeline capacity; 414,000 miles of new gas-gathering lines; 32.5 billion cfd of gas-processing capacity; 14,000 miles of new lateral pipelines to and from power plants, processing facilities, and storage fields; and 12,500 miles of transmission lines with a capacity of 2 million barrels per day (bpd) to transport natural gas liquids (NGLs) *(1)*. These infrastructure needs, however, are only part of the picture.

Virtually all portions of the shale gas value chain need new, expanded, and/or upgraded infrastructure. These needs are related to bringing shale gas resources to production, gathering the natural gas, midstream processing of the gas, and long-distance gas transmission, as well as getting the NGLs that are separated from the gas at the midstream facilities to market. Additional facilities will be needed to absorb the burgeoning supplies of natural gas (*e.g.,* compressed natural gas [CNG] infrastructure, liquefied natural gas [LNG] terminals, and additional gas-fired power-generation plants) and NGLs (*e.g.,* steam crackers).

This article provides an overview of key infrastructure needs and developments associated with the production of shale gas. Gerencser and Vital *(2)* provide a more-detailed assessment of the infrastructure gaps as well as practical suggestions on how to close them.

Enabling drilling and production

To unlock the value of shale gas, wells need to be drilled and brought into operation (completed). Drilling activity increases the local demand for concrete, steel, and site services such as excavation, hauling, and skilled construction (*e.g.,* for well completion and establishment of drilling pads). All of these demands strain the facilities that produce, distribute, and transport these goods and services.

Drilling also requires large quantities of water, sand, and equipment, which need to be transported into areas that are often remote. This, in turn, increases the burden on the region's infrastructure. The road systems in shale plays often require significant upgrading, which the gas industry generally undertakes voluntarily as a necessary cost of doing business. Even so, local highways tend to be insufficient to support the supply of goods and services related to shale gas activity.

Rail systems are similarly stressed. For example, regional railroads in northeastern Pennsylvania that were originally linked to the production of anthracite coal were reinvigorated by the Marcellus Shale boom. However, congestion has become a problem in some terminals and service yards, as has the need for more railcars to meet the increase in demand. This need for railcars has created pressure to turn over the cars faster, so the storage of sand and other materials in railcars is often not practical. This creates additional infrastructure needs for silos and storage to support the distribution network for sand and water.

The procurement and delivery of water to hydraulic fracturing activities is an evolving complex issue involving the management of water and other ecological resources. Additionally, the disposition of produced water (water present in the reservoir that flows to the surface with the gas) and spent water used in the fracturing process further stresses the transportation infrastructure and requires the development of a disposition infrastructure. Although the exact nature of the disposition infrastructure is in flux as regulators and the regulated entities debate the disposition options, the need for more facilities to treat and purify these waters is evident. Facilities to treat waters associated with shale production are more sophisticated and more capital intensive than typical municipal wastewater plants, and require unique designs and additional (independent) investment.

Gathering and processing

After natural gas is produced (brought to the surface), it must be gathered into the natural gas transmission and distribution network. This requires capital outlays for gathering lines (typically 6-in.- to 20-in.-dia. pipelines) to take the raw natural gas to processing facilities, as well as for the gas-processing facilities themselves. The investment can be substantial, and may even create an insurmountable barrier. For example, the capital expenditures associated with separations and gathering lines have made it uneconomical to recover the natural gas associated with oil production in the Bakken play, leading to considerable flaring of natural gas in that region.

Water and condensate (higher-hydrocarbon liquids) are typically removed from the raw natural gas at or near the wellhead. Gathering lines then carry the remaining natural gas to a gas-processing facility that removes other constituents so that the processed gas meets pipeline specifications and so maximum value can be obtained for constituents such as NGLs.

The construction of gathering lines requires complex negotiations of rights of way. An enforcement infrastructure (inspectors) is also needed to enforce local codes, since these are usually intrastate pipelines with limited (or no) federal oversight.

Gathering lines are typically considered the demarcation between upstream production and midstream processing and transmission to market.

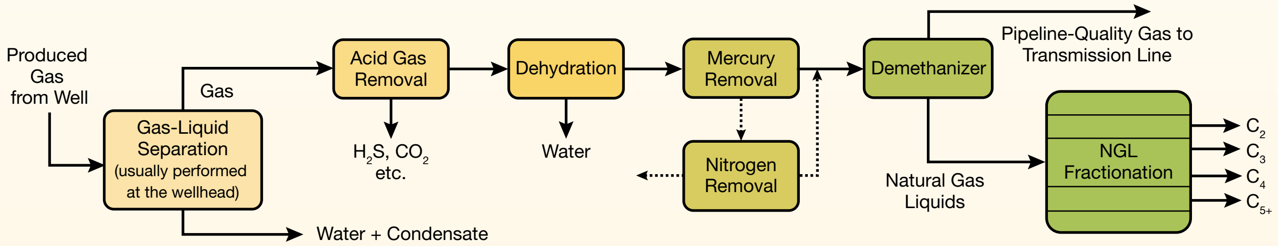
The natural-gas-processing facility (Figure 1) is a dedicated separations train that begins with the removal of acid gases (carbon dioxide, hydrogen sulfide, and organosulfur compounds). Elemental sulfur is often recovered from treatment of the offgas stream from this process. The natural gas stream is then subjected to dehydration and mercury removal, and occasionally nitrogen is removed if warranted. The gas stream is then sent to a demethanizer, which separates NGLs from the pipeline-quality natural gas that is injected into the transmission lines.

If economically feasible, the NGLs may be further separated into high-value ethane, propane, butanes, and a C_{5+} stream. The extent of NGL separation and recovery depends on the quantities of the produced gas, the values of these products, and whether or not they need to be removed from the gas in order to meet pipeline specifications.

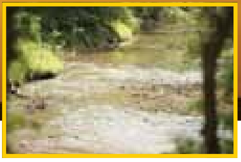
Energy companies have been increasing the capacity of midstream assets in active shale plays. Recent activity in the wet portion of the Marcellus play exemplifies this trend. (The adjectives wet and dry indicate the amount of natural gas liquids and condensate co-produced with the natural gas. Wet regions contain substantial amounts of light hydrocarbons, often to the extent that recovering them is economically justifiable. In dry regions, NGLs are only minor contaminants. The terms are generally used in a relative manner and do not have strict thresholds. The western portion of the Marcellus Shale play has been found to be wet, whereas northeastern Pennsylvania developments have been found to be dry.)

For its Liberty operations in southwestern Pennsylvania and northern West Virginia, Mark West Energy Partners has built 325 million cfd of gathering capacity, 1.15 billion cfd of cryogenic gas processing capacity, 60,000 bpd of C_{3+} fractionation capacity, and 75,000 bpd of de-ethanization capacity. Last year, energy company Dominion augmented its existing assets with the addition of a propane terminal in Charleroi, PA, and the upgrading of its processing facilities in Hastings, Lightburn, and Shultz, WV, and it plans to open 400 million cfd of processing capacity in Natrium, WV, by the end of 2013. Caiman Energy anticipates spending approximately $1.2 billion from 2010 through 2014 on

▼ **Figure 1.** Before it is transported to the end user, natural gas undergoes a series of processing steps at the wellhead and at a processing plant.







its Fort Beeler operations in northern West Virginia, split almost equally between gathering and NGL infrastructure.

The development of these assets in relatively close proximity within the wet region of the Marcellus play demonstrates the rapid response of the market to provide the infrastructure required for the production of shale gas.

After midstream processing, the value chain splits into two components: the processed natural gas value chain, and the NGL value chain.

Getting natural gas to market

Transmission pipelines (typically 20–48 in. diameter) take the processed natural gas from the processing facilities to market centers, where they tie into existing local distribution networks. Although these localized transmission and distribution networks are well established, they will need to adjust to increases in natural gas demand (for heat, power, and transportation) spurred by low natural gas prices.

Activity related to the Marcellus Shale (Figure 2) is typical of the adjustments and augmentation of infrastructure required to support an active shale play.

Spectra Energy announced the construction of a pipeline to move 60 million cfd of natural gas from Oakford, PA, to Station 195 of the Transco pipeline (a distance of about 85 miles, at a cost of $700 million); a pipeline to carry 200 million cfd of natural gas from southwestern Pennsylvania to the eastern half of the state ($200 million); and an expansion of the Texas Eastern Transmission pipeline that extends its reach into the New York City area. These pipeline expansions complement Spectra's natural gas storage assets. Storage assets are required for a more-global natural gas market, as they enable the system to respond to pricing volatility and to arbitrage based on locational and temporal pricing differences.

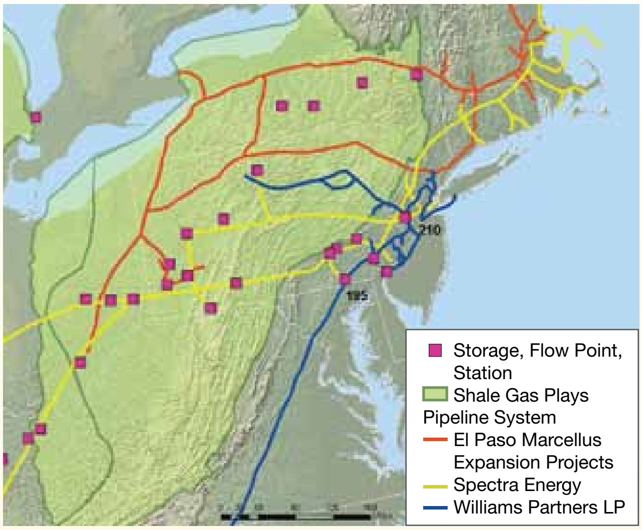
The Tennessee Gas pipeline, similarly, undertook four projects in the eastern U.S. that are coming online between 2011 and 2013 to handle the flow of 14,876,000 dekatherms per day (Dth/day) of natural gas from the Marcellus Shale to northeast markets. (Dekatherm is the unit commonly used for natural gas flowrates and sales. One dekatherm is equal to 10 therms. One dekatherm of natural gas contains one million Btu [1 MMBtu] of energy.)

Growth in demand for pipeline capacity to move gas from Marcellus production sites to market centers has also spurred Oklahoma-based energy company Williams to expand its Transco pipeline system. Projects on its southern section (south of Station 195 in southeastern Pennsylvania), include the 142 MDth/day Mid-Atlantic Connector through Virginia and Maryland (in service in 2012); the 199 MDth/day Cardinal Expansion in North Carolina (in service in 2012); and the 225 MDth/day Mid-South Expansion in Alabama, Georgia, South Carolina, and North Carolina (in service 2012–2013).

Most projects in the northeast U.S. are aimed primarily at either improving the Transco pipeline system's access to northeast markets or adding supply from Marcellus Shale producers to the Transco system. Market access projects include the Northeast Connector in Pennsylvania and New Jersey, as well as the Bayonne Lateral in New Jersey and the Rockaway Delivery Lateral in southeastern New York. The supply of Marcellus Shale gas will be enabled by the Northeast Supply Link and the Atlantic Access pipeline. The Northeast Supply Link, with a capacity of 250 MDth/day, will supply gas from the Leidy hub in north-central Pennsylvania to pipelines in central New Jersey. The 1,100 MDth/day Atlantic Access pipeline, due onstream in 2014, will supply the East Coast with natural gas from the western Marcellus region (including new natural gas processing facilities in Fort Beeler and Natrium, WV).

The industry responded quickly to these opportunities; however, as natural gas prices fall, it is unclear how quickly it will respond to support transmission from dry-gas regions. Dry-gas projects might not provide the return on investment necessary to support their development, whereas wet-gas development can be justified based on the value of both the gas and the NGLs and condensate associated with their development.

Completing the value chain of natural gas is the development of assets that will use the increased supply of natural gas. The conversion of existing coal-fired power plants to natural-gas-fired and the construction of new gas-fired plants will take time, and is complicated by the need to be optimally interfaced with environmental and other permitting requirements, the natural gas supply system, electricity demand, and the nation's bulk electric power system (*i.e.,* the grid). LNG



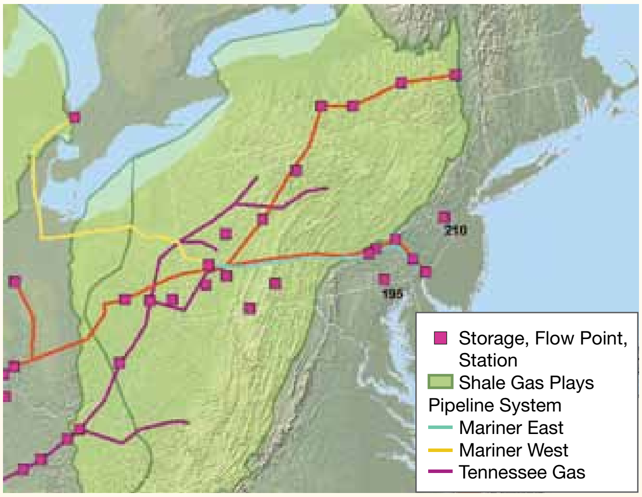
▲ **Figure 2.** Extensive natural gas pipeline infrastructure has been built to enable development of the Marcellus Shale play. Map prepared by Chung Shih.

export terminals need to be built to facilitate trade of U.S.-sourced natural gas on the world market. The development of a compressed natural gas (CNG) vehicle infrastructure, including expanded distribution systems and filling stations as well as the vehicles themselves, will take even longer. (The challenges associated with developing these capital assets are complex and beyond the scope of this article.)

Taking advantage of the liquids

The natural gas liquids that are co-produced with many shale gases have different downstream infrastructure requirements. As mentioned earlier, the co-production of these higher-value, but lower-volume, components requires additional capital investment in natural-gas-processing facilities (beyond that required to upgrade the gas itself). Once separated from the raw natural gas, the NGLs need to be transported to their own markets, and new assets to consume them may need to be built to absorb the increased supply. (The discussion of NGLs in this article focuses on ethane, since it is typically the largest component of NGLs and is the preferred feedstock for producing ethylene, a major petrochemical building block).

A small amount of NGLs can remain in the natural gas (typically less than 10%), but some must be removed from the raw gas in order to meet pipeline specifications. This level of ethane recovery, known as the mandatory portion, is achieved by the gas-processing operation discussed earlier. Ethane removed from the raw gas above and beyond the mandatory level required to meet the pipeline specification is often referred to as discretionary ethane. The quantity of discretionary ethane produced depends on economic conditions, which determine whether it is cost-effective to seek the full value of the ethane as a product (*i.e.,* petrochemical feedstock) or simply capture its heat content. Once removed, the ethane must be delivered to the markets in which it is consumed.



▲ **Figure 3.** Ethane pipeline infrastructure has been developed to transport ethane produced in the Marcellus Shale to established ethane markets. Map prepared by Chung Shih.

The vast majority of ethane is consumed by the chemical industry, mainly in steam cracking units to produce olefins such as ethylene and propylene. In addition to enjoying a price advantage due to the availability of feedstock from shale gas, ethane steam cracking has a much less intense separations train than the cracking of liquid feeds such as naphtha. This translates into lower capital and operating costs (especially with respect to energy consumption). Hence, a strong push has been made to convert existing domestic steam cracking facilities to ethane. Furthermore, capacity increases are being achieved with new ethane cracking facilities (either expansions or entire new plants). These expansions and/or grassroots facilities will take time to come on-stream, and they will require extensive supporting infrastructure, including transportation access, storage, offsites, electricity and other utilities, etc. Olefin-derivative plants (*e.g.,* to manufacture such products as polyethylene and polypropylene) will also be needed for the stable consumption of ethane co-produced with natural gas.

Approximately 95% of domestic steam cracking capacity (including crackers that use liquid feeds) is located in Texas and Louisiana, making transport of ethane to the U.S. Gulf Coast a paramount infrastructure requirement for the disposition of ethane. Ethane can be delivered to the Gulf Coast by pipeline, or by Jones-Act-compliant vessels from a seaport. (The Merchant Marine Act of 1920, better known as the Jones Act, restricts domestic shipping to vessels that are domestically built, staffed, and owned. This puts constraints on the available shipping capacity between domestic ports.)

Shipping through a seaport that is reasonably close to the shale play also opens up access for exporting ethane to foreign markets (*e.g.,* Europe). Sarnia, Ontario's steam cracking capacity of approximately 1.4 million ton/yr makes it a potential market for U.S. ethane.

Five options for disposing of ethane from the wet portion of the Marcellus region have been identified. Four of these involve pipeline transport (Figure 3) of the ethane out of the region:

• The Mariner West pipeline is slated to draw 50,000 bpd (expandable to 65,000 bpd) from Mark West's Liberty processing facility near Houston, PA, for transport to Sarnia, ON.

• The Mariner East pipeline is slated to transport 65,000 bpd to Energy Transfer Partners' storage and shipping terminal assets near Marcus Hook, PA, by the middle of 2013.

• The Marcellus Ethane Pipeline System (MEPS) will connect Mark West's Liberty processing facility and Dominion's Natrium processing facility to the Gulf Coast with a capacity of at least 60,000 bpd (expandable to 100,000 bpd) by November 2014.

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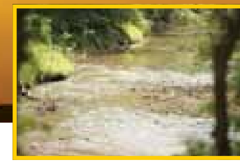

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• By January 2014, Enterprise Products Partners will begin moving a minimum of 75,000 bpd (expandable to 175,000 bpd) by pipeline to Baton Rouge, LA, and Mount Belvieu, TX.

These pipelines would transmit ethane to existing markets in Sarnia and along the U.S. Gulf Coast, and enable shipment of ethane to other parts of the world.

• A fifth option for the disposition of ethane from the Marcellus and Utica shale plays is a local ethane cracker. Shell has signaled its intent to build an ethane cracker in the Appalachian region, and has preliminarily selected a site in Monaca, PA (near Pittsburgh).

It appears the market has responded quickly to develop the infrastructure required to capture the full value of the NGL portion of the Marcellus and Utica shale gas. Once the ethane has been transformed into ethylene, the latter is a fungible product easily absorbed by the robust domestic chemical industry.

Closing thoughts

The aggregate capital needed to establish the infrastructure for the Marcellus play alone is staggering — in the billions of dollars. Success will be contingent on highly efficient capital markets and an entrepreneurial culture willing to take the large risks that accompany the potential for large rewards. It is unclear whether the focus necessary for the massive development of infrastructure assets exists and, if so, can be sustained. CEP

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Acknowledgments

The author thanks Chung Shih of Booz Allen Hamilton, who prepared the maps of the natural gas and ethane pipelines (Figures 2 and 3).

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