Cathy Kunkel, Energy Finance Analyst
Clark Williams-Derry, Energy Finance Analyst
Suzanne Mattei, Energy Policy Analyst
March 2021

Institute for Energy Economics and Financial Analysis
IEEFA.org

Mountain Valley Pipeline Faces Uphill Struggle to Financial Viability

Lower Gas Demand, Risks to LNG Exports Undermine Need for Project

Executive Summary

The Mountain Valley Pipeline was proposed in 2014 as a 303-mile pipeline to transport natural gas from northern West Virginia to Pittsylvania County, Va. Seven years later, the project's costs have increased by more than 60 percent. Developers now aim to have the project in service by late 2021, three years behind schedule.

In the seven years since the project was first proposed, the rationale for the Mountain Valley Pipeline has largely disappeared. In this report, IEEFA finds:

- Forecasts for natural gas demand in the Mountain Valley Pipeline region have been revised and are substantially lower than projections that pipeline sponsors used as justification for the project. Indeed, the U.S. Energy Information Administration (EIA) predicts natural gas demand will decline from 2019 to 2030 in the southeastern and mid-Atlantic regions.

- One of the shippers has likely lost its entire rationale for the project. If an appeals court upholds a North Carolina decision to deny a permit for an extension designed to bring natural gas into the state, Public Service Company of North Carolina's rationale for contracting for capacity on the pipeline will have completely evaporated.

- Utilities that signed up to ship gas on the pipeline face a high risk that Mountain Valley will not provide their customers with less-expensive gas. Two utilities that have contracted for Mountain Valley capacity would not receive natural gas directly from pipeline but would use it to bring natural gas from northern West Virginia into Virginia. The gas then would be shipped to the utilities on the Transco pipeline. But with the erosion of price differentials between northern West Virginia gas and gas purchased from elsewhere on Transco, the utility customers face an increasing risk that buying into Mountain Valley's capacity will not result in lower gas prices.

- Appalachian Basin pipeline capacity currently exceeds production, and prospects for greater production increasingly depend on a growing export market for Appalachian gas. This prospect is fraught with significant risks, including the likely possibilities that: (1) Asian liquefied natural gas (LNG) demand growth may be lower than expected; (2) lower-cost LNG-exporting nations may undermine U.S. export ambitions; (3) new proposals for U.S. LNG export terminals may face challenges in securing financing; and (4) new U.S. LNG terminals may obtain gas from suppliers outside Appalachia.

This combination of factors increases the risk that Mountain Valley Pipeline's capacity will be underutilized. This risk has not yet been analyzed by the Federal Energy Regulatory Commission (FERC), which has persisted in its outdated process for evaluating pipeline need that does not consider a rapidly changing domestic natural gas market or the risks associated with growing LNG exports on the domestic gas market. FERC has recently reopened a review of its pipeline policy. The vanishing need for the Mountain Valley Pipeline highlights the urgent need for reform of FERC policy and practices.

Background: Failure To Scrutinize Project Need and the Project's Current Status

The Mountain Valley Pipeline, first proposed in 2014, would transport as much as 2 billion cubic feet per day (bcf/d) of natural gas along a 303-mile route from north-central West Virginia to Pittsylvania County, Va. The project is a joint venture of EQM Midstream Partners, LP (which split off from Mountain Valley's original lead sponsor, EQT, in 2018); NextEra US Gas Assets LLC; Con Edison Gas Pipeline and Storage LLC; RGC Midstream LLC; and WGL Midstream Inc. Con Edison recently exercised an option to cap its share of the project, giving EQM a slightly larger stake in the venture. The pipeline is fully subscribed, meaning that it has entered into long-term contracts with shippers for the entire capacity of the pipeline, as shown in Table 1. All but one of these shippers are corporate affiliates of the project's sponsors.

Table 1: MVP Project Owners and Shippers

Owner	Owner Parent	Ownership Stake		Shipper	Shipper Parent	Contracted Capacity (dth/d)	Percent of Total
EQM Midstream Partners, LP	Equitrans Midstream	48%		EQT Energy LLC	EQT Corporation	1,165,000	58%
NextEra US Gas Assets LLC	NextEra Energy	31%		USG Properties Marcellus Holdings LLC	NextEra Energy	125,000	6%
Con Edison Gas Pipeline and Storage, LLC	Consolidated Edison	10%		Consolidated Edison Company of New York	Consolidated Edison	250,000	12.5%
WGL Midstream LLC	AltaGas	10%		WGL Midstream Inc	AltaGas	200,000	10%
RGC Midstream LLC	RGC Resources	1%		Roanoke Gas Company	RGC Resources	10,000	0.5%
				Public Service Company of North Carolina	Dominion Energy	250,000	12.5%

FERC's Process for Determining "Need" Is Flawed

FERC approved the Mountain Valley Pipeline in October 2017 and a related project, the Southgate Extension,[1] in June 2020. Both orders found the pipelines to be necessary, according to the agency's standards. Also, FERC reaffirmed its finding of need when it granted an extension of time for the construction of the Mountain Valley Pipeline in 2020.

FERC based its determination of need on the existence of long-term contracts to ship gas. In its October 2017 order, FERC stated, "We find that the contracts entered into by the shippers are the best evidence that additional gas will be needed in the markets that the MVP … [is] intended to serve. We find that Mountain Valley has sufficiently demonstrated that there is market demand for its Project." The 2020 order approving an extension of the time for the pipeline noted that the long-term contracts extended well beyond the two-year extension of time and that there was "no evidence demonstrating that any shipper intends to cancel its transportation contract." Similarly, the order approving Southgate relied on the existence of a long-term contract accounting for 80% of the pipeline's capacity.

Companies may have many reasons to enter into shipping contracts that are perfectly rational decisions for corporations but not in the public interest.

The orders were consistent with FERC's longstanding practice of assuming that a pipeline is needed so long as its developers have signed contracts with shippers for most of the pipeline's capacity. In the rare instance that FERC has rejected a pipeline based on need, it has been because the pipeline did not show evidence of long-term shipping contracts.[2]

Companies may have many reasons to enter into shipping contracts that are perfectly rational decisions for corporations but not in the public interest. This is particularly the case when pipeline developers and shippers are corporate affiliates, as frequently occurs. For example, a natural gas producer may seek to build its own

---

[1] The Southgate Extension is a 73-mile extension of the Mountain Valley Pipeline that was proposed in 2018. Southgate would transport 0.36 bcf/d from Pittsylvania County, Va., to Alamance County, N.C. The project is sponsored by the same corporations as Mountain Valley, minus Con Edison.

[2] IEEFA is only aware of one instance when this has occurred, the Pacific Connector Gas Pipeline. In its March 2016 order, FERC stated, "Pacific Connector has presented little or no evidence of need for the Pacific Connector Pipeline. Pacific Connector has neither entered into any precedent agreements for its project, nor conducted an open season, which might (or might not) have resulted in "expressions of interest" the company could have claimed as indicia of demand." (154 FERC ¶ 61,190). The project was later approved in 2020, after the company reapplied with 96% of its capacity under long-term contract. (170 FERC ¶ 61,202).

pipeline to bring gas to market and capture an arbitrage opportunity sooner than competing companies, resulting in multiple pipelines along similar routes to meet the same "need." A utility holding company may seek to develop a pipeline knowing that the return on equity is typically higher than can be earned in regulated transmission, electric or gas utility sectors; entering into a contract with an affiliated electric or gas utility company to ship gas on the pipeline ensures that the risk of underutilized pipeline capacity will be passed off to its customers. The result is that the natural gas industry has a well-recognized tendency to overbuild pipelines.

By relying on precedent contracts to determine need, FERC has essentially abdicated its responsibility to facilitate a rational deployment of capital to build pipelines in the public interest.

Figure 1: Projected Route of Mountain Valley Pipeline

Source: IEEFA.
Note: The Mountain Valley Pipeline (red) would carry gas from northern West Virginia to an intersection with the Transco pipeline in Virginia.

As a result of existing FERC policy, the agency conducted no regulatory evaluation of the need for the Mountain Valley Pipeline beyond the existence of shipping contracts. That approach is particularly inappropriate in the case of the Mountain Valley because it is a supplier-driven pipeline. The project is driven by natural gas producers who plan to ship gas on the pipeline and sell it to customers downstream. The pipeline terminates at an interconnection with the interstate Transco pipeline, which extends from Texas to New York City. Natural gas shipped on the Mountain Valley Pipeline could ultimately reach customers throughout the Southeast and mid-Atlantic, and could also reach export markets. Two of the four utilities that have contracted to ship gas on Mountain Valley would not receive natural gas directly from the Mountain Valley Pipeline. Instead, they would continue to receive gas from their existing interconnections to the Transco pipeline. By entering into a shipping contract on Mountain Valley, they are betting that sourcing gas from northern West Virginia will be less expensive than purchasing gas from elsewhere on Transco. Thus, an evaluation of the "need" for the Mountain Valley Pipeline should consider both the physical need for natural gas to meet demand in the Southeast and mid-

Atlantic, and whether the Mountain Valley Pipeline truly represents an opportunity to provide downstream consumers with cheaper gas.

Under the new leadership of Chairman Richard Glick, FERC has announced it will revisit its policy on pipeline need. In February 2021, FERC reopened a notice of inquiry soliciting comments from stakeholders on FERC pipeline policy, including the question of FERC's policy on determining need.[3] The extent to which any FERC action to revise the commission's need policy might affect proceedings on the Mountain Valley Pipeline remains to be seen.

The Project's Current Status

The Mountain Valley Pipeline has experienced numerous delays due to permitting challenges. In a Dec. 1, 2020, decision, the U.S. Fourth Circuit Court of Appeals stayed the Army Corps of Engineers' authorization of the project's proposed water crossings in Virginia and most of West Virginia. The authorization had been issued under a broad regional permit without the opportunity for public comment on specific impacts, pending the outcome of an appeal.[4] In January 2021, FERC failed to gain a majority vote to approve the sponsors' attempt to redesign the project to bore under certain water bodies, which might have circumvented the Fourth Circuit Court's stay order.[5] As a result, the sponsors' company informed FERC that it will now seek individual permits for the water body and wetland crossings, which will involve new federal and state reviews.[6] Also, legal challenges are pending to the U.S. Forest Service's decision to allow the pipeline to cross through the Jefferson National Forest and to the U.S. Fish and Wildlife Service's determination under the Endangered Species Act.[7,8]

---

[3] 174 FERC ¶ 61,125 (February 18, 2021).

[4] *Sierra Club. v. U.S. Army Corps of Engineers*, 981 f.3d 251 (4th Cir. 2020). The authorizations had been granted pursuant to "Nationwide Permit 12," a broad, generic permit under which a project's activities to construct a utility line, such as a gas pipeline, may be approved. The court granted the stay pending the outcome of the appeal because it determined the plaintiffs would likely succeed in the argument that the Army Corps Division Engineer lacked the authority to modify Nationwide Permit 12 by changing a special condition to allow the project to proceed without an individual Clean Water Act § 401 water quality certification.

[5] S&P Global Market Intelligence. Natural gas project orders stall at FERC on eve of presidential inauguration. January 19, 2021. Also see: The Roanoke Times. In a rare rebuke, FERC fails to approve Mountain Valley Pipeline's proposal. January 19, 2021.

[6] Mountain Valley Pipeline LLC. Letter to FERC and service list, FERC Dockets Nos. CP16-10 and CP21-12. January 26, 2021. Also see: S&P Global Market Intelligence. Mountain Valley Pipeline adjusts permit approach after setbacks at FERC, court. January 27, 2021.

[7] See Petition in *Wild Virginia v. United States Forest Service*, No. 21-1039 (4th Cir., filed January 11, 2021).

[8] See Petition in *Appalachian Voices v. U.S. Department of the Interior*, No. 20-2159 (4th Cir., filed October 28, 2020), challenging the agency's Biological Opinion and Incidental Take Statement for the project

The sponsors hoped to put the pipeline in service by November 2018.[9] But delays have pushed the opening date back to the second half of 2021.[10]

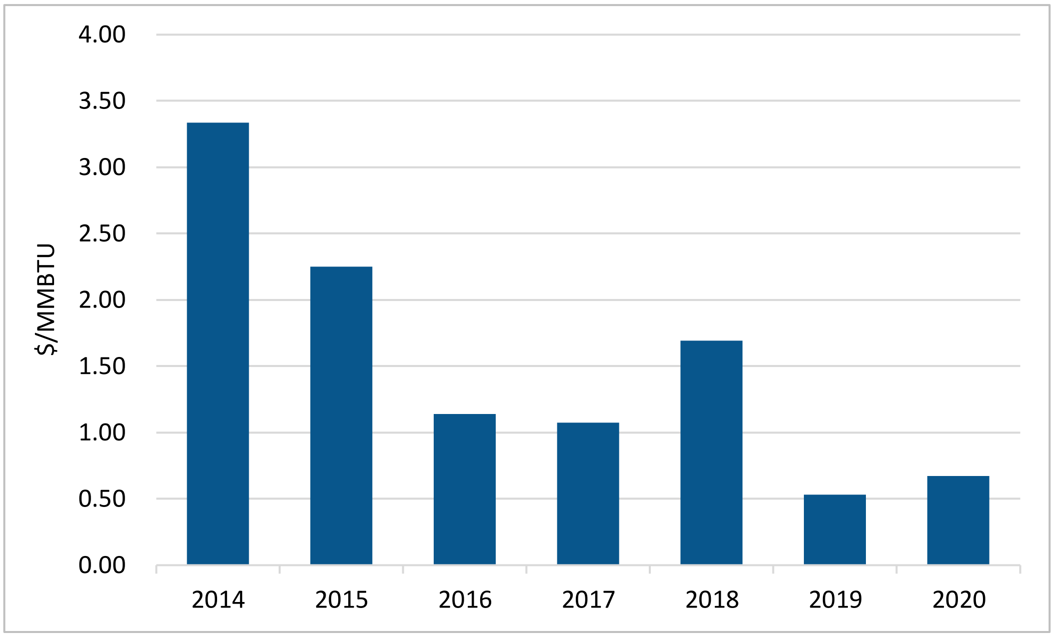
In the seven years since the Mountain Valley Pipeline was first proposed, natural gas markets in the region to be served by the pipeline have evolved. Significant pipeline capacity has been added to take gas out of the Appalachian Basin, even as the outlook for domestic natural gas demand and exports has grown more uncertain. In the next section, we review the regulatory process for determining whether a pipeline is needed. Subsequent sections address (1) the weakening economic justification for the project; (2) changes in natural gas demand since the project was proposed; and (3) the near-term and mid-term outlook for natural gas demand from the Appalachian Basin.

The Economic Case for Shipping Gas on the Mountain Valley Pipeline Has Eroded Since the Project Was First Proposed

The Mountain Valley Pipeline would terminate at an interconnection with the Transco Pipeline at Station 165 in Transco Zone 5 (the portion of the Transco pipeline spanning Virginia and the Carolinas). Downstream utility customers Con Ed and WGL then have to ship gas from this point to their facilities—as far away as New York City, in the case of Con Ed. From the perspective of these utility customers, the rationale for signing up for capacity on the Mountain Valley Pipeline was the access to cheaper sources of natural gas. For these utilities, the pipeline would make economic sense as long as the cost of purchasing natural gas in northern West Virginia (at the Dominion South hub) is less than the cost of purchasing the gas directly elsewhere in Transco Zone 5, where Mountain Valley ends. Increasingly, these utilities run the risk that this will not be the case, largely due to the fact that increasing pipeline takeaway capacity out of the Appalachian basis has been leveling the cost differential between the Dominion South and Transco Zone 5 hubs. (See Figure 2.)

[9] Mountain Valley Pipeline. Application for Certificate of Public Convenience and Necessity and Related Authorizations, FERC Docket No. CP16-10. October 23, 2015, p. 159.
[10] Associated Press. Mountain Valley Pipeline to cost more, take longer to build. November 5, 2020.

Figure 2: Average Annual Spot Price Differential Between Transco Zone 5 and Dominion South Hubs



Source: SNL Financial.

The only publicly available negotiated rate for shipping gas on MVP is EQT's rate of $0.77/MMBtu.[11] Since EQT is the largest shipper on MVP, it is reasonable to assume that other shippers' negotiated rates are comparable or higher. Figure 2 shows that the pricing differential between the Dominion South and Transco Zone 5 hubs was substantially higher than the cost of shipping on MVP when the pipeline was first proposed back in 2014. This difference has eroded over time, and for the last two years has been less than $0.77/MMBtu. Thus, the risk is increasing that downstream utility shippers have signed up for capacity that will not provide access to cheaper gas and that the excess cost will be passed on to ratepayers.[12]

The erosion of the pricing differential between the Transco Zone 5 hub and the Dominion South hub is also a problem for the natural gas producers who have contracted to ship natural gas on the pipeline. These companies have entered into contracts under the assumption that they will be able to sell the natural gas that they have transported to Transco Zone 5 at a better price (including the transportation cost) than they would have been able to realize from selling the gas at the Dominion South hub where it is produced. This is an increasingly risky proposition, and is likely one of the driving factors behind EQT's desire to sell off its rights to capacity on the Mountain Valley Pipeline.

---

[11] EQT Corporation. Q2 2020 earnings call transcript. July 27, 2020.

[12] This argument was advanced by the Environmental Defense Fund in a Con Ed rate case. (See: Direct Testimony of Gregory Lander. New York Department of Public Service Case 19-G-0066 and 19-E-0065. May 24, 2019.)

Additionally, the Mountain Valley Pipeline has already experienced significant cost overruns and may experience more. The original project sponsors estimated that the Mountain Valley Pipeline would cost $3.7 billion,[13] but after numerous delays, the expected cost had ballooned to roughly $6 billion by late 2020.[14] The cost impacts of the project sponsors' recent decision to begin a new regulatory application process to obtain an individual water permit and state approvals is not yet known.

The risk is even greater that shippers will be stuck with uneconomic capacity.

The extent to which these cost overruns on the project will drive up shipping rates is not clear. Negotiated rates for the pipeline were based on the project's original estimated construction cost, which has since risen by 60% and may increase further. The shipping contracts contain a provision for adjusting rates if actual project costs deviate from estimated costs, but the details of this adjustment formula are not public information. To the extent that EQT and other shippers are ultimately paying rates in excess of $0.77/MMBtu, the risk is even greater that shippers will be stuck with uneconomic capacity.

The Outlook for Natural Gas Demand in the Southeast and Mid-Atlantic Has Weakened Since MVP Was First Proposed

In its original application to FERC, Mountain Valley Pipeline made the broad statement that the pipeline, by terminating at an interconnection with the Transco pipeline system, would serve growing natural gas demand in the mid-Atlantic and Southeast markets.[15] The application did not provide any region-specific projections of natural gas demand or of coal-to-gas switching in the electric power sector. Mountain Valley Pipeline subsequently supplemented its application to FERC by filing a January 2016 Wood Mackenzie study, "*Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project*," commissioned by the Mountain Valley Pipeline joint venture. The study focuses on the Southeast (Virginia, North Carolina, South Carolina, Georgia, Alabama, Tennessee and Florida) as "one of the destination markets for the MVP project."[16] The report includes the following projections about growth of natural gas demand in these southeastern states from 2015 to 2030:

---

[13] Mountain Valley Pipeline. Application for Certificate of Public Convenience and Necessity and Related Authorizations, FERC Docket No. CP16-10. October 23, 2015, p. 274.
[14] Equitrans Midstream. News Release: Equitrans Midstream Announces Third Quarter 2020 Results. November 3, 2020.
[15] Mountain Valley Pipeline. Application for Certificate of Public Convenience and Necessity and Related Authorizations, FERC Docket No. CP16-10. October 23, 2015. p. 10.
[16] Wood Mackenzie. Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project. January 2016, p. 3

- Gas demand would grow 2.4 bcf/d by 2020 and 4.2 bcf/d by 2030.[17]
- Power generation would be the fastest-growing sector of natural gas demand, with new natural gas capacity growing by almost 50 GW by 2030.[18]

As discussed below, these trends are not materializing nearly to the extent forecast by the 2016 Wood Mackenzie report and are not projected to do so through 2030. Thus, Mountain Valley Pipeline's shippers face an increasing risk of underutilized capacity, calling the need for the pipeline into question.

Declining Natural Gas Consumption

According to the EIA, actual natural gas consumption in the seven southeastern states studied increased by 1.9 bcf/d from 2015 through 2019. For the U.S. as a whole, natural gas consumption was expected to decrease slightly (by 1.7%) in 2020, due mainly to the impact of the COVID-19 pandemic.[19] Assuming 2020 consumption in the Southeast to be approximately the same as 2019 consumption, demand grew by 20% less than the Wood Mackenzie 2015-20 forecast.

Government forecasts of regional natural gas consumption now show declines through 2030, in contrast to the continued increase projected by Wood Mackenzie. The EIA's Annual Energy Outlook, released in February 2021, forecasted a net decline in natural gas consumption in its South Atlantic, South East Central and Mid-Atlantic regions[20]—regions that encompass the broad range of geography that the MVP's application stated that it aimed to serve. Specifically, in the South Atlantic region,[21] natural gas consumption is projected to decline 7%, or 0.82 bcf/d, from 2019 to 2030. In the South East Central region,[22] natural gas consumption is projected to decline 8%, or 0.41 bcf/d. Only in the Mid-Atlantic region does EIA forecast a small increase of 0.3%, or 0.03 bcf/d.[23] This is in contrast to EIA's 2015 Annual Energy Outlook, which had projected growing natural gas consumption across all three regions totaling 0.74 bcf/d from 2019 through 2030.[24]

Wall Street and industry analysts now forecast trends similar to EIA's predictions. A September 2020 Standard & Poor's report predicted a decline in overall U.S. natural gas consumption of about 2 bcf/d from 2020 to 2030.[25] In February 2020 (pre-pandemic), IHS Markit predicted a short-term decline in total U.S. natural gas

---

[17] *Ibid.*, p. 6.
[18] *Ibid.*, pp. 14-15.
[19] S&P Global Market Intelligence. US EIA bumps up gas production, consumption estimates for early 2021. November 10, 2020.
[20] U.S. Energy Information Administration. Annual Energy Outlook 2021. February 2021, Tables 2.2, 2.5 and 2.6.
[21] EIA defines this region to include West Virginia, Maryland, Delaware, Virginia, North Carolina, South Carolina, Georgia and Florida.
[22] EIA defines this region to include Kentucky, Tennessee, Alabama and Mississippi.
[23] EIA defines this region to include Pennsylvania, New Jersey and New York.
[24] U.S. Energy Information Administration. Annual Energy Outlook 2015. April 2015, Tables 2.2, 2.5 and 2.6.
[25] S&P Global Ratings. The Energy Transition: COVID-19 Undermines the Role of Gas as a Bridge Fuel. September 24, 2020, Chart 4.

consumption of 1.8 bcf/d by 2023, citing a decline in power sector gas consumption due to "higher prices and greater renewables penetration."[26]

Lower Forecasts of Gas Plant Construction

Natural gas plant construction is not anticipated to materialize at the level anticipated by the Wood Mackenzie study. According to data compiled by S&P Global, almost 18 gigawatts (GW) of new natural gas capacity in the seven southern states was constructed from 2015 through 2020. Over the next decade, however, growth in natural gas plant generation in the entire Southeast Electric Reliability Council region (a region that includes Louisiana, Mississippi and parts of Missouri, Arkansas and Kentucky) is only expected to amount to 10 GW.[27] New natural gas plant capacity from 2015 to 2030 is likely to be closer to half of the 50 GW projected by Wood Mackenzie, even before factoring in any long-term impacts on economic growth from the COVID-19 pandemic.

The decline in utility forecasts for new generation is illustrated by the situation of Duke and Dominion, the lead backers of the Atlantic Coast Pipeline. When the Atlantic Coast Pipeline was cancelled in the summer of 2020, it was reported that Mountain Valley Pipeline was trying to interest Duke and Dominion's regulated utility subsidiaries in Virginia and North Carolina in purchasing capacity from Mountain Valley.[28] To date, no such sale has transpired. In January 2019, IEEFA and Oil Change International published a report noting that Duke and Dominion's plans for expanding natural gas capacity in the region had been reduced and delayed substantially since the Atlantic Coast Pipeline was first proposed.[29]

The number of uncertainties make it more likely that the recovery will be slower than the most optimistic projections.

Uncertain Pandemic Recovery

The impact of the pandemic on economic growth and energy is unclear. The speed of economic recovery will depend on a number of factors, including the duration of the COVID-19 pandemic, potential resurgences of the virus in the population after pandemic measures have abated, the resilience and response of the business community, the rising level of debt burden on both businesses and individual consumers, and the extent and effectiveness of government efforts to spur recovery.

---

[26] IHS Markit. North American Natural Gas Short-Term Outlook. February 2020.
[27] North American Electric Reliability Corporation. 2019 Long-Term Reliability Assessment. December 19, 2019, pp. 79-85.
[28] S&P Global Market Intelligence. EQT lures Dominion, Duke shippers with "desirable" Mountain Valley pipe capacity. July 27, 2020.
[29] IEEFA and Oil Change International. The Vanishing Need for the Atlantic Coast Pipeline. January 2019.

The number of uncertainties make it more likely that the recovery will be slower than the most optimistic projections.

Southgate Cancellation

Finally, the potential cancellation of the Southgate Extension weakens the case that the Mountain Valley Pipeline is needed. Public Service Company of North Carolina has contracted for 12.5% of Mountain Valley's capacity so it can bring natural gas from northern West Virginia to its North Carolina facilities via the Southgate Extension. In 2020, the state of North Carolina denied a Clean Water Act § 401 certification for the Southgate Extension. If the Fourth Circuit Court of Appeals upholds the state's decision, the Southgate Extension cannot be built, and Public Service Company of North Carolina's justification for contracting for Mountain Valley Pipeline capacity evaporates.

Near-Term and Mid-Term Outlooks for Appalachian Gas Production and LNG Exports Have Weakened

The Mountain Valley Pipeline was proposed at a time when the Appalachian Basin was constrained by takeaway capacity. This is no longer the case. EQT CEO Toby Rice noted during a second-quarter earnings call that the Appalachian Basin's current production of 32 bcf/d is less than the current pipeline takeaway capacity of 35 bcf/d. Takeaway capacity would expand to 37 bcf/d with the addition of the Mountain Valley Pipeline. At least in the near-term, due to declines in rig counts and drilling activity, Rice anticipated that production would decline and "widen the gap in takeaway." He predicted that "just sustaining 32 Bcf a day … [is] going to be a headwind for the basin to keep up."[30]

It is generally expected that Appalachian gas production will remain flat or slightly decline in 2021. Major Appalachian drillers are keeping capital expenditures roughly constant in 2021, and also plan to keep production roughly constant.[31]

These actions follow a decade in which Appalachian drillers have been largely unable to produce positive free cash flow; their operations have produced less cash from selling natural gas than needed to cover their capital expenditures. The glut of natural gas has produced prices unable to sustain drilling operations, resulting in bankruptcies, consolidations, and threats from investors to pull back on the sector.

Given that U.S. natural gas demand is expected to be flat to declining through 2030, Appalachian drillers seeking new markets for their natural gas in this decade will likely need to break into existing markets at the expense of production in other U.S. gas basins, or find reliable new export markets, most likely as overseas shipments of liquefied natural gas (LNG).

---

[30] EQT Corporation. Q2 2020 earnings call transcript. July 27, 2020.

[31] See, for example, Q3 2020 earnings call transcripts of Southwestern Energy, Cabot Oil & Gas, and National Fuel Gas. See also Moody's Investor Service. Credit Opinion: Antero Resources Corporation. January 13, 2021.

Range Resources, a major Appalachian driller, is optimistic that LNG exports can drive increased Appalachian natural gas production. From 2019 to 2025, Range predicts a growth of 11 bcf/d from Appalachia, as part of meeting an overall increase in natural gas demand of 17 bcf/d. Of that 17 bcf/d, more than 13 bcf/d is attributed to growing LNG exports (~11 bcf/d) and pipeline exports to Mexico. IHS Markit projects a comparable level LNG export growth of 6.1 bcf/d by 2023. This represents a rapid increase over the 5 bcf/d exported in 2019.

Other estimates of U.S. LNG export growth are less bullish. In its 2021 Annual Energy Outlook, the EIA projects LNG export growth of only 6.6 bcf/d from 2019 to 2025. And the International Energy Agency forecasts U.S. LNG export growth of just under 7 bcf/d.[32] Yet U.S. LNG exports may not materialize even at the lower range of these estimates. The growth of U.S. LNG exports, particularly from Appalachian gas, faces four major risks:

1. Asian LNG demand growth remains uncertain.

   Global growth in LNG demand is expected to be driven by Asia-Pacific LNG consumption, particularly China and southeast Asia. Morgan Stanley, for example, forecasts that 75% of incremental LNG demand over the next five years will come from the Asia Pacific region. The International Energy Agency similarly forecasts Asian demand accounting for the majority of LNG growth, with China and India alone accounting for 60% of incremental demand.

   IEEFA has previously analyzed U.S. LNG exports to China, finding that Chinese natural gas utilities need LNG prices to remain at about $7/MMBtu to avoid losing money. Yet that price leaves little profit margin for U.S. exporters.[33] Higher Asian LNG prices would likely encourage Chinese utilities to rely more on pipelines for gas imports, rather than importing more LNG.

   Exports to southeast Asia are also price-sensitive. Morgan Stanley, for example, recently suggested that Indian and southeast Asian LNG demand could flatten if prices exceed $6.25/MMBtu, a level that typically leaves U.S. exports in the red.[34] At the same time, robust southeast Asian LNG demand hinges on a rapid gas buildout of a complete gas infrastructure— from import terminals to pipelines to storage facilities to local transmission lines, industrial facilities, and power plants—that are often completely absent at present.[35] The sheer scale of new infrastructure required suggests that southeast Asian LNG import growth will likely proceed more slowly than the industry hopes.

---

[32] International Energy Agency. Gas 2020. June 2020.
[33] Morgan Stanley. Global Gas & LNG: The Start of a New Cycle. January 25, 2021. p. 6 and 10.
[34] Morgan Stanley. Global Gas & LNG: The Start of a New Cycle. January 25, 2021. p. 7.
[35] For a discussion of the example of Vietnam, see: IEEFA. Beyond the Noise: Setting the Right Expectations for Vietnam's LNG Project Pipeline. January 2021.

IEEFA has also commented on the price volatility of the Asian LNG market, which has recently led to project cancellations.[36] Both developing LNG consumers and their potential suppliers face risks associated with this price volatility. Some developing LNG importers, including Vietnam, have shown reluctance to take on traditional guaranteed offtake agreements with firm volume and price commitments. This reluctance could force their suppliers to take on more price and market risk. Yet at the same time, utilities in developing countries also face political and financial risks from tying electric generation and rates to price-volatile imported commodities.

2. Lower-cost LNG-exporting nations may undermine U.S. export ambitions.

Even if global LNG demand grows over the coming years, much of this growth will likely be supplied by low-cost suppliers outside the U.S. Qatar, the world's highest-volume, lowest-cost LNG exporter, plans to expand its LNG export capacity by 40 percent in the next five years, rising from 77 million tons per year today to 110 million tons in 2026, an increase of 4.4 bcf/d.[37] Qatari LNG supplies reportedly boast breakeven prices of just over $4/MMBtu, a cost that U.S. producers will be unable to match. Qatari LNG producers also benefit from lower transportation costs, particularly to Pakistan, India, and southeast Asia, giving Qatari LNG an additional economic edge over U.S. exports in key potential growth markets. And Qatari gas is just the beginning: The U.S. LNG industry will also face competition from plants that are currently sanctioned or under construction in Canada, Mozambique, Russia, Indonesia, Malaysia, Mauritania and Nigeria.[38]

Even if global LNG demand grows over the coming years, much of this growth will likely be supplied by low-cost suppliers outside the U.S.

Independent analysts find that the growth in low-cost supplies in nations such as Qatar will likely erode U.S. market share in the coming years. Morgan Stanley has identified 11.6 bcf/d in new capacity "likely" and "very likely" LNG export facilities to come online by 2026 (including Qatar), only 1.9 bcf/d of which would come from the U.S.[39] Similarly, Moody's concluded that less than a quarter of planned LNG capacity to come online between

---

[36] IEEFA. Gas and LNG Price Volatility to Increase in 2021. January 2021.
[37] Reuters. Qatar Petroleum signs deal for mega-LNG expansion. February 8, 2021.
[38] International Gas Union. 2020 World LNG Report. 2020.
[39] Morgan Stanley. Global Gas & LNG: The Start of a New Cycle. January 25, 2021, p. 18.

2021 and 2024 would be in the United States.[40] U.S. drillers and developers face a substantial risk that even if Asian LNG demand does materialize, much of that demand will be met by lower-cost competitors rather than the U.S. LNG industry.

3. New U.S. LNG export terminals may face challenges in securing financing.

   The initial buildout of U.S. LNG export terminals came at a time when the U.S. was a low-cost supplier into the global LNG market. From 2011-2014, LNG spot prices in Asia (as measured by the JKM index) were in the USD$15/MMBtu range. At such prices, exporting U.S. natural gas at $9-$10/MMBtu to Asia would be profitable.[41] Long-term contracts with U.S. LNG export terminals put the risk of falling LNG prices on buyers, not on the terminal developers (which mainly operate through either take-or-pay or tolling arrangements).[42]

   Financing a second wave of U.S. LNG export terminals is likely to be a more challenging proposition when Asian spot market prices are low. Indeed, some proposals for new terminals in the U.S. involve new strategies, such as indexing gas contracts to non-Henry Hub pricing points (such as Asian or European gas spot market prices, rather than U.S. prices), or developing gas production and pipeline facilities to directly supply terminals, both of which are inherently riskier for terminal developers.[43]

4. New U.S. LNG terminals may be supplied by gas suppliers outside Appalachia.

   Appalachian natural gas suppliers may face growing competition from suppliers in other basins. Some analysts, for example, project substantial increases in gas production in the Permian Basin in Texas and New Mexico.[44] More than 4 Bcf/day of pipeline capacity is expected to come online in the Permian in the coming year, and many Permian operators plan to use the pipelines to market gas that they are currently venting or flaring—particularly as those practices have attracted growing scrutiny from regulators.[45]

---

[40] Moody's Investors Service. LNG competition intensifies amid reduced demand expectations. October 15, 2020, p. 3.
[41] At Henry Hub prices during those years of $3-$4/MMBtu and assuming a $3.50/MMBtu liquefaction fee.
[42] In a take-or-pay contract, the buyer pays a fixed liquefaction fee for capacity they have contracted, regardless of whether they use that capacity. They also buy natural gas from the terminal operator, priced at a benchmark price plus a 15% markup. A tolling arrangement similarly requires buyers to pay a fixed liquefaction fee, but the buyer sources their own gas.
[43] King & Spalding. The Emerging Price Offerings from Second Wave U.S. LNG Projects: Perspectives from Sellers and Buyers. pp. 8-9.
[44] RBN Energy. Some Beach – 4 bcf/d Permian gas capacity headed to the beach – What happens to flows and basis? October 5, 2020.
[45] Bloomberg. Texas Oil Regulator Signals Flaring Crackdown After Backlash. February 9, 2021.

> Other gas-producing basins may be poised to capture market share from Appalachia as well. The oilfield services company Baker Hughes reports that gas drilling activity in Appalachia's Marcellus Basin fell by more than half over the past two years, and has barely recovered since COVID sent oil and gas prices crashing last spring. At the same time, drilling activity in the Haynesville Basin, a gas-producing region straddling Texas and Louisiana, is at its highest level in more than a year, having fully recovered from the COVID price crash.[46] Other basins with easy access to Gulf Coast LNG terminals are poised to boost market share as well. As one example, EOG Resources, one of the most financially healthy independent oil and gas producers in the U.S., announced last fall that it had identified major new gas resources in both the Austin Chalk and Eagle Ford basins, promising breakeven prices lower than in the Marcellus.[47,48] The low costs of such new discoveries, coupled with their proximity to new Gulf Coast LNG terminals, could limit the competitiveness of Appalachian gas in supplying new LNG terminals.

IEEFA sees significant downside risks to forecasts for rapid growth in U.S. LNG exports. Given flat or declining domestic natural gas demand, IEEFA sees a substantial risk that demand for Appalachian gas will not be as strong as industry forecasts. FERC should take a broader look at all of the proposed takeaway capacity out of the Appalachian Basin and the market demand for this gas when considering the need for a particular pipeline.

This analysis raises the additional question of whether the "need" for a pipeline whose likely use is to provide a path for natural gas to reach export markets should be treated the same way as a pipeline that is more obviously needed to satisfy domestic natural gas demand. FERC's policy on pipeline need was developed in 1999, when the United States exported negligible quantities of natural gas and almost two decades before it became the world's third-largest exporter of gas. Today's changed circumstances should spur a new policy assessment.

IEEFA sees significant downside risks to forecasts for rapid growth in U.S. LNG exports.

Thus far, however, FERC has treated these needs as equal. In an order on the NEXUS pipeline in September 2020, FERC's majority opinion stated, "[T]he fact that a precedent agreement may be with a foreign shipper for ultimate delivery to foreign customers does not diminish the probative value of such agreements in supporting a

[46] Baker Hughes. North America Rig Count. February 2020.
[47] EOG Resources. EOG Resources Reports Third Quarter 2020 Results; Adds Premium Natural Gas Play in South Texas; Provides Three-Year Outlook. November 5, 2020.
[48] Hart Energy. EOG Adds 21 Tcf Resource Potential with Austin Chalk, Eagle Ford Gas Play. November 5, 2020.

finding of public convenience and necessity."[49] The case is on appeal to the U.S. Court of Appeals District of Columbia Circuit.

FERC's failure to assess natural gas pipelines for export differently from pipelines to serve domestic demand also means that FERC has not analyzed the risks that increasing gas exports to volatile international markets may pose for U.S. consumers. IEEFA and others have previously warned that the volatility in international gas markets will increase price volatility in domestic gas markets.[50] Given the instability of international gas demand and the potential effects of gas exports on domestic prices, FERC's failure to analyze international export precedent contracts is even more unreasonable and egregious than its failure to analyze U.S.-based precedent contracts.

Conclusion

The natural gas markets have changed substantially since the Mountain Valley Pipeline was proposed in 2014. Domestic natural gas demand is expected to be flat to declining through the end of the decade in the region that Mountain Valley Pipeline is intended to serve. One of the shippers on Mountain Valley faces a high risk that its rationale for purchasing capacity on the pipeline will be completely undermined by the likely cancellation of the Southgate Extension.

Pipeline capacity out of the Appalachian Basin exceeds production. Growth in Appalachian natural gas production is increasingly dependent on a growing export market for Appalachian gas, a prospect that faces significant risks. Thus, Mountain Valley Pipeline faces a significant risk that its capacity will be underutilized.

---

[49] NEXUS Gas Transmission, LLC, 172 FERC ¶61,199 (September 3, 2020) (Order on Remand), p. 5.

[50] IEEFA. Risks Outweigh Rewards for Investors Considering PJM Natural Gas Projects. October 2020, pp. 27-34. Also see: Commodity Futures Trading Commission. Liquefied Natural Gas Developments and Market Impacts. May 2018, p. 15 ("Given the magnitude of U.S. exports, there is also the potential that domestic natural gas markets could become subject to global supply-demand dynamics with the potential for increased volatility").

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

About the Authors

Cathy Kunkel

Cathy Kunkel has written reports and given expert testimony on the finances of Appalachian natural gas pipelines and drilling; electric utility mergers, rates and resource planning; energy efficiency; and Puerto Rico's electrical system. She has degrees in physics from Princeton and Cambridge.

Clark Williams-Derry

Clark Williams-Derry served as director of energy finance and research director for the Sightline Institute, a multi-issue sustainability think-tank based in Seattle for 18 years, where his research focused on U.S. and global energy markets. He was also a senior analyst for Environmental Working Group.

Suzanne Mattei

Suzanne Mattei, an attorney (Yale Law School) and consultant with Lookout Hill Public Policy Associates, has over 30 years' experience in environmental policy. As Regional Director for the NYS Department of Environmental Conservation for four years, she led permitting and enforcement in New York City. Her widely cited recent report on a proposed fracked gas pipeline in New York found flaws in proponents' arguments. As NYC Executive for the Sierra Club, her research exposed federal mismanagement of the 9/11 response; her testimony to Congress helped lead to passage of the James Zadroga Act, providing healthcare to Ground Zero workers.