Risks Associated With Natural Gas Pipeline Expansion in Appalachia

Proposed Atlantic Coast and Mountain Valley Pipelines Need Greater Scrutiny

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By Cathy Kunkel and Tom Sanzillo

EXECUTIVE SUMMARY

Major utilities, pipeline companies and natural gas producers are proposing construction of two new natural gas pipelines into Virginia and North Carolina from the Marcellus and Utica shale region of West Virginia.

Developers of the Atlantic Coast Pipeline and the Mountain Valley Pipeline, which would cost a total of nearly $9 billion to complete, have applied to the Federal Energy Regulatory Commission for approval.

The pipelines are proposed to go into service in 2018. They would be part of a larger expansion of natural gas pipeline infrastructure from the Marcellus and Utica shale region in Appalachia that has been described by Moody's Investors Services as an "once-in-a-lifetime build-out cycle" driven by the recent boom in natural gas production.

Some participants have openly acknowledged the likelihood of overbuilding, as when Kelcy Warren, CEO of Energy Transfer Partners, said in an earnings call last year that overbuilding is part-and-parcel of the industry ("The pipeline business will overbuild until the end of time," Warren said).

This report shows how the Atlantic Coast and Mountain Valley pipelines are emblematic of the risks that such expansion creates for ratepayers, investors and landowners.

Among its conclusions:

- Pipelines out of the Marcellus and Utica region are being overbuilt.
- Overbuilding puts ratepayers at risk of paying for excess capacity, landowners at risk of sacrificing property to unnecessary projects, and investors at risk of loss if shipping contracts are not renewed and pipelines are underused.
- The Federal Energy Regulatory Commission facilitates overbuilding. The high rates of return on equity that FERC grants to pipeline companies (allowable rates of up to 14%), along with the lack of a comprehensive planning process for natural gas infrastructure, attracts more capital into pipeline development than is necessary.
- FERC's approach to assessing the need for such projects is insufficient.
- Industry leaders recognize and acknowledge that current expansion plans will likely result in overbuilding.

- The arguments for the Atlantic Coast Pipeline have not been adequately scrutinized. While the pipeline developers have asserted that some of the gas supplied is needed by Dominion Resources for its new Brunswick and Greensville natural gas plants, Dominion has told the Virginia State Corporation Commission that it can supply those plants through the existing Transco pipeline.
- While ratepayers of the utilities (largely Duke Energy and Dominion Virginia Electric and Power) that have contracted to ship gas through the Atlantic Coast Pipeline would be burdened with the costs of building the pipeline (which would include a profit to the developers, largely Duke and Dominion), they will probably not realize the economic benefits promised by the developers.
- Communities along the Mountain Valley Pipeline face the risk that EQT Corporation (which owns the largest stake in that pipeline and has contracted for the largest volume of capacity on the pipeline) will continue to be harmed financially by weak natural gas prices and will not be a long-term, stable partner for these communities.

This report notes also that much of the $9 billion costs of the projects—aside from the costs embedded in the price of any natural gas that is exported—would ultimately be either added to the price consumers pay for natural gas or absorbed as a loss to project investors.

And it points out that regulators have not considered whether these pipelines are the best use of ratepayer dollars. None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas - energy efficiency, renewable energy or other forms of power generation - may be cheaper.

Given all of these circumstances, IEEFA recommends the following:

- That the applications for the Atlantic Coast and Mountain Valley pipelines be suspended until a regional planning process can be developed for pipeline infrastructure;
- That FERC lower the returns on equity granted to pipeline developers; and
- That an investigation be conducted into the relatively high failure rate of new pipelines.

INTRODUCTION

The Federal Energy Regulatory Commission is considering applications for construction of two major natural gas pipelines that would run from West Virginia into North Carolina and Virginia: the Atlantic Coast Pipeline and the Mountain Valley Pipeline.

These pipelines, which together would stretch for approximately 850 miles, are being contemplated during a time of major natural gas infrastructure expansion in the U.S.

In October 2014, Moody's Investors Service characterized the proposed pipeline build-out from the Marcellus and Utica shale region as "the start of a once-in-a-lifetime build-out cycle."[1]

This report examines the risks these projects pose to consumers, investors, and communities along the proposed routes.

Part 1 of the report describes the rapid buildout of Marcellus and Utica pipeline infrastructure in order to place the Atlantic Coast and Mountain Valley pipelines in the context of the larger expansion of pipeline infrastructure. Part 2 considers specific risks associated with the proposed Atlantic Coast and Mountain Valley pipelines.

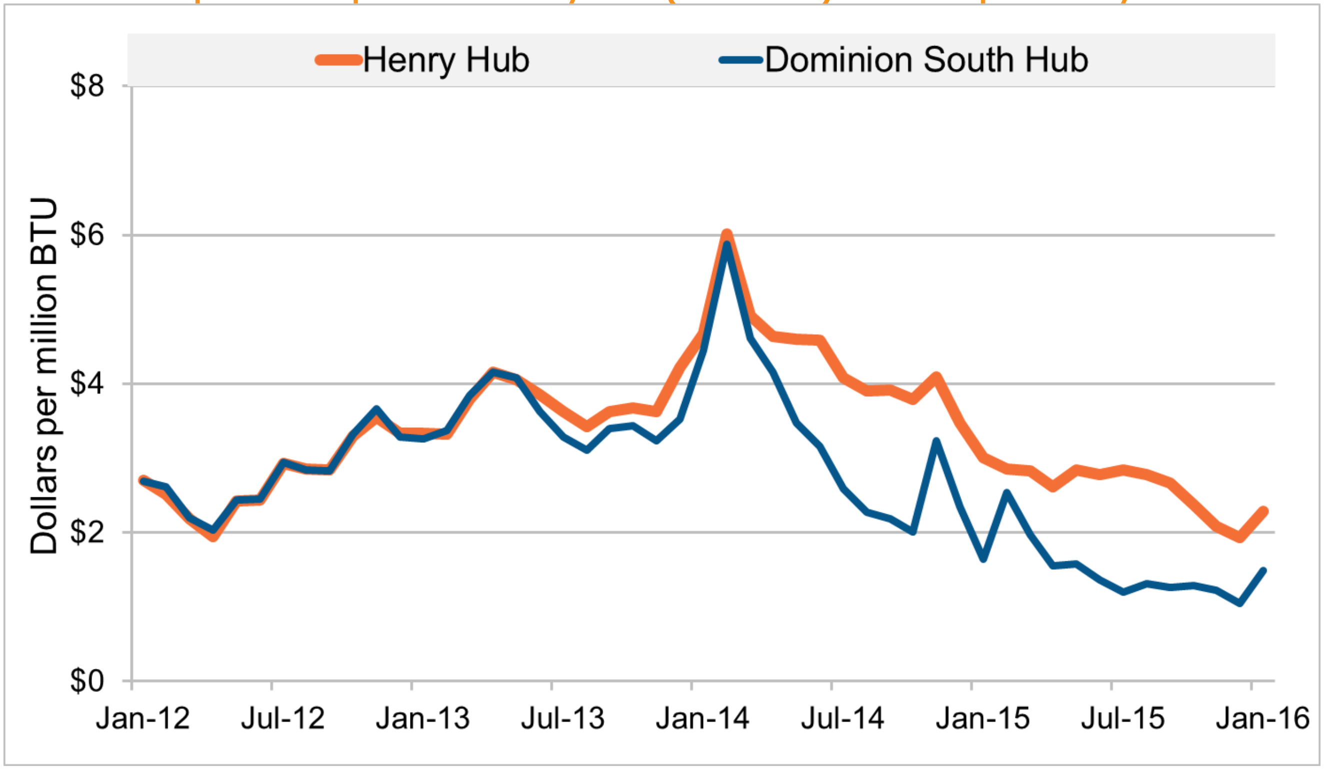
PART 1:
THE POTENTIAL FOR OVERBUILDING PIPELINES FROM THE MARCELLUS AND UTICA REGION

The boom in natural gas pipeline construction associated with the Marcellus and Utica shale region is driven fundamentally by the low price of shale gas and the desire on the part of developers to transport that gas to higher-priced markets, perhaps even to export markets. The following graph shows prices since January 2012 at the Dominion South Hub in southwestern Pennsylvania versus those at the Henry Hub in Louisiana. Henry Hub prices are often used as the benchmark for natural gas prices in the U.S. The Henry Hub has historically been where the largest volumes of gas have traded. In recent years, larger or comparable volumes have been

[1] "Shale-Fueled Inflection Point for Pipeline Operators; Offshore Rig Oversupply to Persist," Moody's Investors Service, October 15, 2014.

traded at the Dominion South Hub, reflecting the upsurge in natural gas production in the Marcellus and Utica regions.[2] The price of natural gas at the Dominion South Hub has recently been very low, averaging $1.50 per MMBTU in 2015 while Henry Hub prices averaged well over $2 per MMBTU. And 2015 was no anomaly. Over the past three years, prices at the Dominion South Hub have decoupled from Henry Hub prices, remaining consistently lower.

Figure 1. Natural gas prices at the Dominion South Hub (southwestern Pennsylvania) have decoupled from prices at Henry Hub (Louisiana) over the past few years.



Source: SNL Financial

The low price of Marcellus natural gas is partially a factor of limited takeaway capacity (the gas is less valuable if it cannot be tapped) for moving this natural gas to market. As a result, numerous proposals have been made to build new pipelines to move this natural gas out of West Virginia, western Pennsylvania and Ohio.

The financial dynamics of the natural gas industry encourage overbuilding of natural gas pipelines, i.e. the construction of excess capacity. A weak regulatory process and a lack of coordinated planning for natural gas infrastructure facilitate this process.

The next several sections here explore the causes and consequences of overbuilding pipeline capacity.

[2] In 2012 and 2013, the volume of gas traded at the Dominion South Hub exceeded the volume traded at the Henry Hub. In 2014, 84,000 MMBTU were traded at the Dominion South Hub versus 90,000 at the Henry Hub, and in 2015, 60,000 MMBTU were traded at the Dominion South Hub versus 61,000 at the Henry Hub. (Source: SNL Financial)

A. Industry Dynamics Encourage Overbuilding of Gas Pipelines

Various economic interests drive pipeline investment that tends toward building excess capacity. In the past, pipeline development in the U.S. has been done by a set of companies that specialize in the pipeline field, including Kinder Morgan, Columbia Pipeline Group and Williams Company. However, in recent years, electric and natural gas utilities, as well as natural gas producers, have begun to move into the natural gas pipeline business. All of these entities—traditional pipeline developers, utilities and producers—can have incentives to overbuild.

For example, current low natural gas prices in the Marcellus and Utica region are driving a race among natural gas pipeline companies that want to capitalize on low prices by building new pipeline capacity to higher-priced markets. An individual pipeline company acquires a competitive advantage if it can build a well-connected pipeline network that offers more flexibility and storage to customers; thus, pipeline companies competing to see who can build out the best networks the quickest.[3] This is likely to result in more pipelines being proposed than are actually needed to meet demand in those higher-priced markets.

"None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas — energy efficiency, renewable energy or other forms of power generation— may be cheaper."

Additionally, utilities—which have been attracted to the natural gas pipeline business because of its traditionally high returns and to further integrate their supply chains as electric power generation becomes increasingly reliant on natural gas—have an economic interest in building new lines. A regulated electric or gas utility that is purchasing natural gas for power generation or for use as a heating fuel passes the cost of its pipeline contracts, which include a FERC-approved profit for the pipeline developer, on to its customers.[4] If the regulated utility's parent company can build its own pipeline for use by its regulated subsidiary, it can capture this profit, giving a utility holding company an incentive to prioritize building its own pipeline rather than utilizing that of another company.[5] This structure also shifts some of the risk of

[3] Tyler Crowe, "5 Things Energy Transfer's Management Wants You to Know," The Motley Fool, September 10, 2015.

[4] Some utility holding companies are becoming involved in the natural gas pipeline business even though they do not own any power plants. In New England, regulated electric distribution utilities are proposing to enter into contracts for natural gas capacity on new pipelines in order to re-sell that capacity on the secondary market to natural gas power plants, with the goal of bringing down prices for natural gas generation. The costs or benefits of this transaction (the costs of long-term capacity contracts, net the revenues received from re-selling that capacity to generators) are to be passed on to the customers of the regulated distribution utilities. Some of the regulated utilities involved in these contracts are subsidiaries of holding companies, including National Grid and Eversource, that are investors in building the new pipelines. (Sources: M. Serreze, "National Grid seeks Massachusetts DPU approval of gas pipeline capacity contracts," MassLive, January 22, 2016; S. Sullivan, "Algonquin Gas introduces nearly 1-Bcf/d Access Northeast to FERC early review," SNL Financial, November 3, 2015;).

[5] State public utilities commissions often have a role in regulating contracts between regulated utilities and their affiliates (in this case, between the regulated utility and the affiliate that owns a share in the pipeline). State commissions also must ensure that the regulated utility acted prudently in sourcing its supply of natural gas. To our knowledge, no regulated utility has been denied cost recovery, in whole or in part, for a contract with an affiliated natural gas pipeline, but this is a potential risk to utilities in the future.

pipeline development from the developer and its shareholders to the regulated utility's ratepayers.

Some upstream producers of natural gas, such as EQT Corporation, have also moved into the pipeline construction business. For such companies, investment in pipelines promises a relatively stable revenue stream compared to the volatility of the natural gas drilling business. EQT, for example, has taken advantage of investors' willingness to fund pipeline development by creating an EQT-controlled master limited partnership (EQT Midstream), which has been able to raise equity through public offerings both for new pipeline projects and for buying gathering and processing infrastructure formerly owned by EQT, leaving EQT in a much better cash position than many other drillers. Such short-term balance sheet considerations for a company like EQT do not translate into rational planning of long-term infrastructure. These dynamics will be explored in more detail in Part 2, Section B below.

None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas— energy efficiency, renewable energy or other forms of power generation—may be cheaper. There is little discussion of how long-term natural gas demand will evolve over the lifetime of a proposed pipeline as alternatives become increasingly cost-effective and widespread.

B. Lack of Planning Process For Natural Gas Infrastructure Facilitates Building Excess Capacity

A coordinated planning process for natural gas infrastructure could serve as a check on the tendency of individual pipeline developers to overbuild.

But the U.S. has no overarching national or regional planning process for natural gas infrastructure development. This planning void contrasts sharply with established planning processes for electricity transmission lines, interstate highways and many other types of infrastructure. Electricity transmission in states with deregulated electricity markets, for instance, is overseen by Regional Transmission Organizations (regulated by the Federal Energy Regulatory Commission[6]) that have planning processes to determine whether proposed new transmission lines are needed and whether there are more cost-effective alternatives to building new lines. While electric transmission lines ultimately must be approved by FERC and by state public utilities commissions, the RTO-level transmission planning process has informed decision making and sometimes led to the cancellation of proposed new electric transmission lines that are shown to be unnecessary.[7]

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[6] The Federal Energy Regulatory Commission, FERC, regulates electric transmission under the Federal Power Act and natural gas pipeline infrastructure under the Natural Gas Act. The Federal Power Act, as amended by the Energy Policy Act of 2005, has explicit provisions for transmission planning (see Federal Power Act Section 217(b)(4)). FERC Orders 890 and 890-A relied on this authority in "mandating coordinated, open and transparent transmission planning on a local and regional level." These orders require transmission providers to incorporate nine principles into their planning process, including "coordination" with customers and neighboring transmission providers, "regional participation" (coordination with interconnected systems) and "economic planning studies." (*See*: Lawrence Greenfield, "An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States," Office of the General Counsel, Federal Energy Regulatory Commission, December 2010).

[7] For example, PJM's Regional Transmission Expansion Plan process allowed the Virginia State Corporation Commission to see that the PATH power line proposed through West Virginia, Virginia and Maryland was unnecessary because the reliability

No such planning process exists for the build-out of natural gas pipeline infrastructure. While FERC must approve the construction of new pipelines, it does not conduct any long-term assessment of regional natural gas demand in assessing the need for new pipelines.

Instead, FERC primarily relies on whether a pipeline developer has been able to recruit enough companies to contract for capacity on the line. If a pipeline is fully or near fully subscribed, FERC considers this strong evidence that the pipeline is necessary.

This approach by FERC is highly likely to result in excess capacity that will be underutilized. For example, in situations in which a pipeline developer contracts with an affiliate company to ship gas through a new pipeline, this is strong evidence that it is doing so because of the financial advantage to the parent company from building the pipeline, but not necessarily that there is a need for the pipeline. As described in the previous section, the private financial interests of individual pipeline developers do not necessarily align with the public interest.

C. Favorable Federal Regulatory Treatment Further Facilitates Overbuilding

Not only do the dynamics of the natural gas and pipeline industries tend to favor building excess capacity, but federal regulatory policy toward pipelines does too.

"…because there is no planning process for natural gas pipeline infrastructure, there is a high likelihood that more capital will be attracted into pipeline construction than is actually needed."

FERC is in charge of regulating the rates that pipeline companies charge to shippers (the entities that are contracted to ship gas through pipelines). Pipeline rates are required to be cost-based, meaning that they must reflect the cost to the pipeline company of providing the service. This cost includes a return on equity (profit) to the pipeline company for the capital that it has invested in building the line.[8] Pipelines are financed partially with debt and partially with equity.

In theory, without FERC regulation, a pipeline company could take advantage of a shipper by charging exorbitant rates, because the shipper may have no other option for delivering gas. In order to prevent this, FERC sets the "recourse rate," which is the rate that a shipper is allowed to demand and receive. This prevents the pipeline company from gouging a shipper. Both the Atlantic Coast Pipeline and the Mountain Valley Pipeline have applied for recourse rates that include a return on equity of 14%. This is a relatively common request, and one that has been granted on many recent greenfield pipelines, including the Constitution

problems that PATH would solve could be solved less expensively through rebuilding existing transmission lines. (Sources: Virginia State Corporation Commission, "Hearing Examiner's Ruling," Case No. PUE-2010-00115, January 19, 2011; PATH Allegheny Virginia Transmission Corporation, "Motion to Withdraw Application," Case No. PUE-2010-00115, February 28, 2011).

[8] It is worth noting that, at least in the case of the Atlantic Coast pipeline, this "capital" includes more than the actual construction costs of the pipeline. The Atlantic Coast Pipeline is seeking to earn a return on landowner outreach, community and government meetings regarding the route, and preparation of regulatory filings.(See: Atlantic Coast Pipeline, LLC & Dominion Transmission, Inc., FERC Docket Nos. CP15-554-000 & CP15-555-000, Response to Data Request, December 15, 2015.)

Pipeline[9] approved in 2014, the Sierrita Gas Pipeline in 2014,[10] the Ruby Pipeline in 2011,[11] the Bison Pipeline in 2010[12] and the ETC Tiger Pipeline in 2010.[13]

A 14% return on equity is high relative to returns that one could expect to receive by investing capital elsewhere in the utility business. In 2014, the average return on equity granted by state public utilities commissions to investor-owned electric utilities was 9.92%.[14] And FERC has recently lowered its allowed return on equity for electric transmission companies in New England to a maximum of 11.74% and is expected to lower returns for transmission companies in the Midwest as well this year. [15]

FERC has provided little justification to support recourse rates that include a 14% return on equity for new pipelines. In comments opposing a 14% return on equity for the Atlantic Coast Pipeline, the North Carolina Utilities Commission (NCUC) noted that FERC has never required pipeline companies to provide much evidence to support such requests. Indeed, the only support the developers of the Atlantic Coast Pipeline provided to justify its request were citations to previous FERC orders granting 14% returns on equity for new pipelines, but those FERC orders themselves did not provide any justification for granting 14% returns. The NCUC stated that "[w]hile the NCUC recognizes that in the past the Commission has merely accepted recourse rates based on cases citing previous cases, application of that policy would appear to conflict with the unambiguous statutory requirement that a filing entity demonstrate that its filing, including the recourse rates, comports with the public convenience and necessity."[16]

In practice, most major contracts between pipelines and shippers are not based on recourse rates, but on negotiated rates. Because a pipeline company needs to prove to FERC that it has attracted customers to ship gas on its pipeline in order to obtain FERC approval to build the line, it needs to negotiate long-term contracts with shippers in advance of proposing the pipeline to FERC. So-called "anchor" or "foundation" shippers who agree to enter into these long-term (15- to 20-year) contracts are typically granted preferential rate treatment, i.e. with negotiated rates that are lower than the recourse rates.

Negotiated rates do not have to be approved by FERC, but they must be filed with FERC between 30 and 60 days before the pipeline is placed into service.[17] This means that the negotiated rates for the Atlantic Coast and Mountain Valley pipelines are not currently publicly available, so there is no way of knowing what return on equity is embedded in these negotiated rates.

Even though the return on equity embedded in the recourse rate is not necessarily what the pipeline earns, because the negotiated rate may be based on a different return on equity, the recourse rate still provides an important benchmark. Interruptible rates for non-firm pipeline

[9] 149 FERC ¶ 61,199 (2014)
[10] 147 FERC ¶ 61,192 (2014)
[11] 136 FERC ¶ 61,054 (2011)
[12] 131 FERC ¶ 61,013 (2010)
[13] 131 FERC ¶ 61,010 (2010)
[14] Edison Electric Institute, "Industry Financial Performance," 2014, online at http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2014_02_IndustryFinPerf.pdf, accessed April 13, 2016.
[15] R. Walton"Breaking down FERC's recent, and pending, ROE decisions," Utility Dive, November 17, 2014; and J. O'Reilly, "RRA Focus on FERC – January 2016: Downward pressures on ROEs continues as FERC ALJ recommends significant reduction in MISO, new complaints filed against Duke in NC, SC," SNL Financial, January 15, 2016.
[16] FERC Docket No. CP15-554, "Comments in support of project and protest of proposed recourse rates of the North Carolina Utilities Commission," October 23, 2015.
[17] 133 FERC ¶ 61,220 (2010)

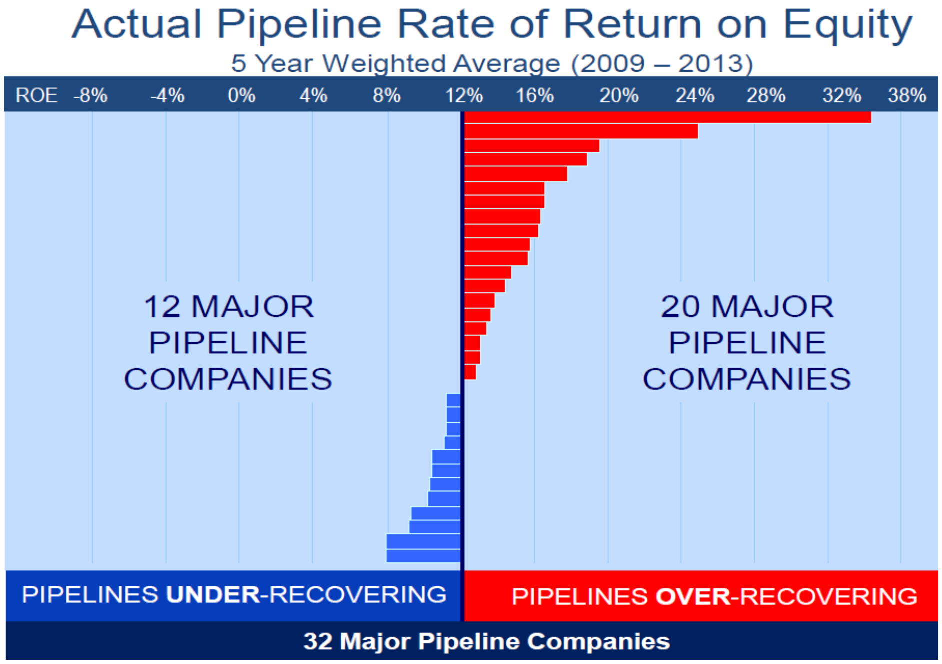
service are based on the recourse rates. And the rates of return embedded in the recourse rates define what is considered to be a reasonable return for pipeline companies, which is important for any entity seeking to file a complaint with FERC that a pipeline company is over-earning.

A pipeline's rates can be challenged by FERC Staff or by outside entities if the pipeline appears to be earning an excessive rate of return.[18] (Just because rates are set based on an expected return does not preclude the pipeline company from earning higher than that return, if it is able to reduce other costs). Such challenges are typically based on annual financial data that must be filed with FERC after a pipeline has been placed into service. While the FERC complaint process can result in new, lower rates being established, the excess earnings that the pipeline is found to have received in past years do not have to be refunded to customers.[19]

In practice, many pipelines appear to be earning higher returns than authorized in their recourse rates. A recent study from the National Gas Supply Association, an association of natural gas suppliers, producers and marketers, looked at the returns on equity from 2009-2013 of 32 major natural gas pipeline companies, comprising 75% of interstate natural gas market capacity. Fewer than 40% of the companies were earning returns on equity of 8-12%. The majority of companies earned returns on equity greater than 12%, with two of those companies earning returns on equity in excess of 24%.[20]

In short, the regulatory environment created by FERC encourages pipeline overbuild. The high returns on equity that pipelines are authorized to earn by FERC and the fact that, in practice, pipelines tend to earn even higher returns, mean that the pipeline business is an attractive place to invest capital. And because, as discussed previously, there is no planning process for natural gas pipeline infrastructure, there is a high likelihood that more capital will be attracted into pipeline construction than is actually needed.

Figure 2. The Majority of Major Pipeline Companies Earned Returns In Excess of 12% For 2009-2013.



Source: Natural Gas Supply Association

[18] For example, FERC opened an investigation into a Kinder Morgan pipeline in 2011 that FERC Staff estimated had earned a return on equity of 19.55% in 2010 and 18.51% in 2011. (Source: S. Sullivan, "WIC submits settlement to take care of FERC rate investigation," SNL Financial, June 25, 2013)

[19] American Public Gas Association, "Section 5," Online at http://www.apga.org/issues/issues-section-5, last accessed April 13, 2016.

[20] Pen Cankardes Ulrey, "Pipeline Cost Recovery Report: 32 Major Pipelines, 2009-2013," Natural Gas Supply Association (no date).

D. State Regulatory Processes Have Little Power to Prevent Overbuilding

State regulatory commissions play a very limited role in regulating interstate natural gas pipelines.

Although regulations vary from state to state, state public service commissions often regulate contracts and transactions between regulated utilities and their affiliates. Thus, if a regulated utility seeks to enter into a contract for pipeline capacity with a corporate affiliate that is developing the pipeline, it may require approval from the commission to enter into the contract. In the case of the Atlantic Coast Pipeline, the North Carolina Public Utilities Commission has granted approval for Duke Energy Progress, Duke Energy Carolinas and Piedmont Natural Gas to become shippers on the pipeline. Dominion Virginia Electric and Power has not yet sought similar approval from the Virginia State Corporation Commission.

State regulatory commissions also have a role in approving the pass-through of the costs of pipeline contracts to the rates of regulated utility customers. The cost of shipping natural gas on a pipeline, including the return on equity for the pipeline company, is an operating cost for the end-use utility and is therefore a cost that is passed through to utility customers, as long as the state commission agrees that this cost has been prudently incurred.[21] A commission could disallow all or part of the costs paid pursuant to a natural gas contract if the commission finds that such costs were not prudently incurred (for example, if the utility knowingly contracted for too much capacity or failed to secure a lower-priced contract). The commission would have to find that the utility's decision at the time of entering into the contract was imprudent, not that the contract turned out to be expensive for ratepayers in hindsight.

"The cost of shipping natural gas on a pipeline, including the return on equity for the pipeline company, is an operating cost for the end-use utility and is therefore a cost that is passed through to utility customers."

Such a potential disallowance would of course occur after the pipeline has been placed into service. In the absence of affiliate contracts, utilities have no incentive not to enter into prudent contracts with third-party suppliers. The transaction structure in which a regulated utility contracts to ship gas on a pipeline developed by an affiliate company is a relatively recent development that tends to shift risk from shareholders to ratepayers. It is not yet clear whether state public utilities commissions will scrutinize pipeline capacity procured under such contracts more closely in rate-making.

Additionally, if a state commission believes that a pipeline is earning excessive returns, it can challenge the pipeline's rates at FERC (as described above) but it does not have authority to alter recourse or negotiated rates.

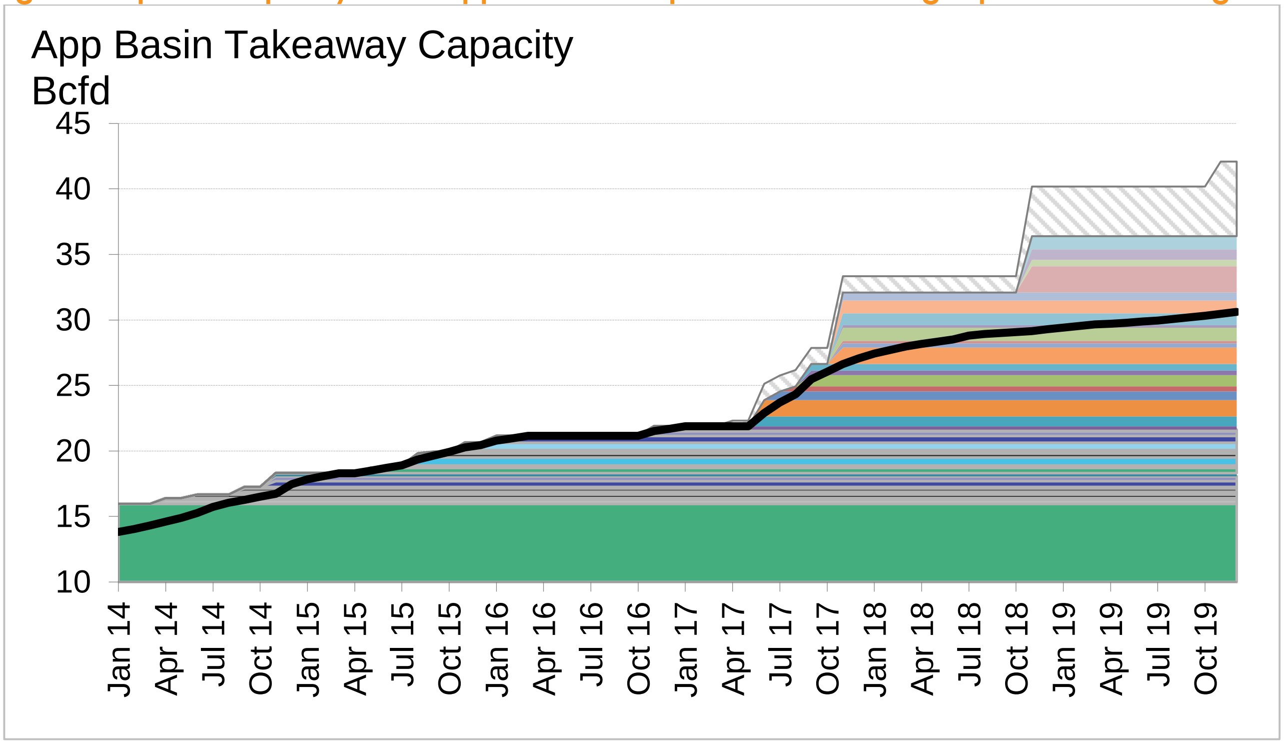
[21] For example, Dominion Virginia Electric and Power has entered into a contract for capacity on the Atlantic Coast Pipeline. That contract contains, embedded in it, a return on equity for the pipeline developer (in which Dominion Resources has an interest). The payments made pursuant to that contract are expenses that Dominion Virginia Electric and Power will be allowed to pass through to its ratepayers, as long as the Virginia State Corporation Commission agrees that those expenses were prudently incurred.

Thus, state regulatory commissions only play a role in approving the initial construction of a pipeline to extent that they are required to approve a regulated utility's decision to enter into a contract with an affiliate that is building the pipeline. The state regulatory commission's role in regulating the cost of natural gas contracts embedded in the rates of utility customers occurs after a pipeline has been constructed and therefore has little impact on the potential for overbuilding pipelines.

E. The Natural Gas Industry Expects Pipelines to Be Overbuilt

Industry financial dynamics, coupled with favorable federal regulatory treatment, will likely result in excess pipeline capacity being built out of the Marcellus and Utica shale region. **The pipeline capacity being proposed exceeds the amount of natural gas likely to be produced from the Marcellus and Utica formations over the lifetime of the pipelines.** An October 2014 analysis by Moody's Investors Service stated that pipelines in various stages of development will transport an additional 27 billion cubic feet per day from the Marcellus and Utica region. This number dwarfs current production from the Marcellus and Utica (approximately 18 billion cubic feet per day).[22] The following graph from Bloomberg New Energy Finance shows that pipeline capacity out of the Marcellus and Utica will exceed expected production by early 2017.[23]

Figure 3. Pipeline capacity out of Appalachia is expected to exceed gas production starting in 2017.



Source: Bloomberg New Energy Finance, 2016. The black line represents expected production and the bars represent planned capacity. Billion cubic feet per day (Bcfd).

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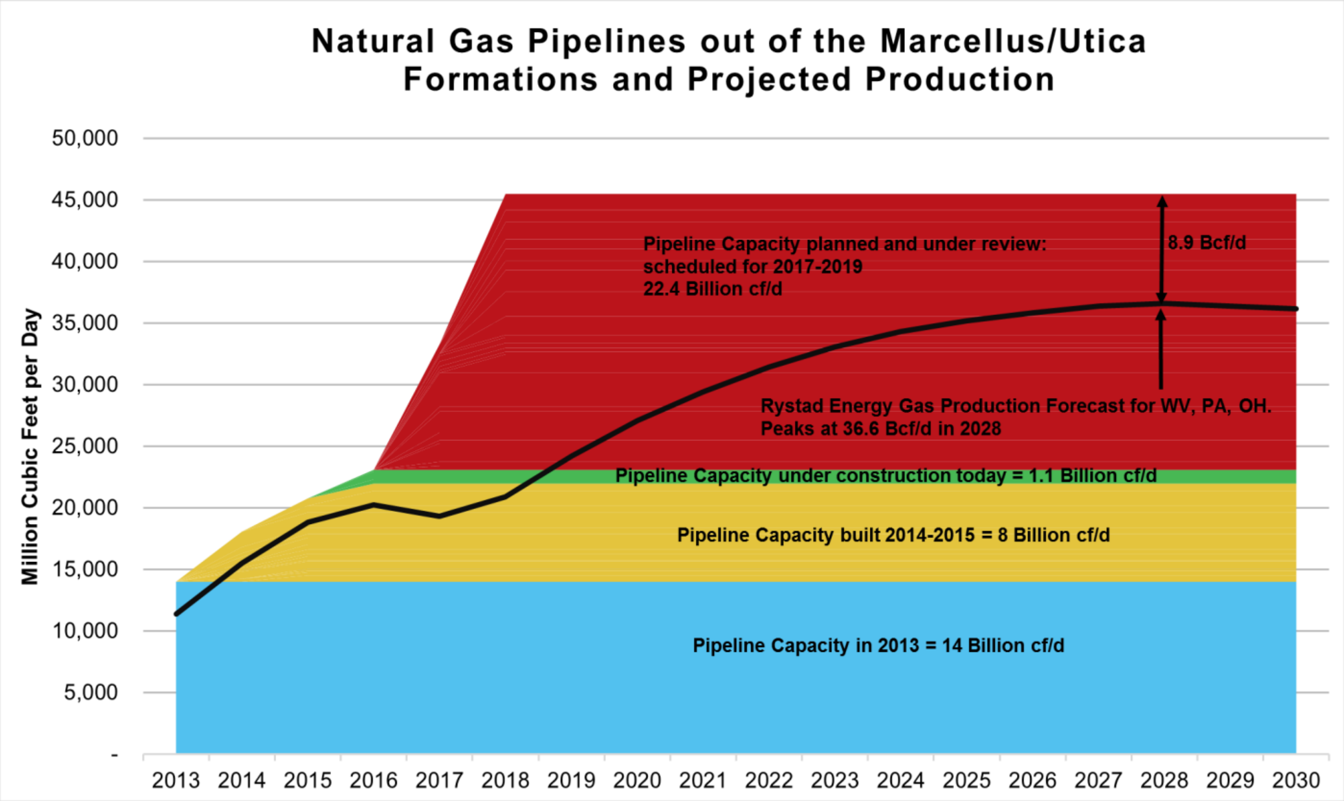
[22] U.S. Energy Information Administration, "Utica Region: Drilling Productivity Report," April 2016, and U.S. Energy Information Administration, "Marcellus Region: Drilling Productivity Report," April 2016.

[23] Joanna Wu, "US Gas Insight: Midstream Madness," Bloomberg New Energy Finance, March 8, 2016.

Over the long term, as shown in the following chart from a forthcoming paper by Oil Change International, pipeline capacity is expected to exceed Marcellus and Utica production through 2030, with production peaking around 2028.[24]

Figure 4. Natural gas pipeline capacity is expected to exceed production through 2030. Production forecast from Rystad.



Source: Oil Change International, 2016

Industry leaders are well aware that the dynamics of the pipeline industry lend themselves towards overbuilding.

'The pipeline business will overbuild until the end of time.'

Kelcy Warren, CEO of Energy Transfer Partners (ETP), said as much in comment last year on the company's second quarter 2015 earnings call: "The pipeline business will overbuild until the end of time. I mean that's what competitive people do."[25] In a subsequent earnings call, he provided the specific example of the Barnett shale in Texas: "There is no question there are certain areas that are overbuilt. For example, we overbuilt in Barnett shale. The production peaked and it's now down."[26] Energy Transfer Partners would know. It is the largest transporter of

[24] Discrepancies between the timing and extent of capacity additions shown in Figures 3 and 4 may be attributable to (a) the fluidity of projects in early stages of development in terms of proposed capacity; and/or (b) differences in attempting to distinguish between pipelines that are expected to add new takeaway capacity versus provide greater connectivity between pipeline networks.

[25] Energy Transfer Partners 2nd quarter 2015 earnings call, August 6, 2015.

[26] Energy Transfer Partners 3rd quarter 2015 earnings call, November 5, 2015.

natural gas out of the Barnett shale of northeast Texas; ETP's pipeline capacity alone now exceeds the total 2015 natural gas production in the Barnett shale, which is down 24% from its peak in 2012.[27,28]

Southwestern Energy, a driller in the Fayetteville shale of northwest Arkansas and in Appalachia, predicts overbuilt pipeline capacity by 2018.[29] And Elie Atme, vice president for Marketing and Midstream Operations for Range Resources, one of the largest Appalachian shale drillers, has stated that Range expects that "the Appalachian Basin's takeaway capacity will be largely overbuilt by the 2016-2017 timeframe."[30]

"Range expects that 'the Appalachian Basin's takeaway capacity will be largely overbuilt by the 2016-2017 timeframe.'"

In the meantime, existing natural gas pipeline capacity is going underutilized, even as companies propose new pipelines. A 2015 report by the Department of Energy found that from 1998 to 2013, existing pipelines in the U.S. had an average capacity utilization of 54%.[31,32]

As noted in a recent article in American Oil and Gas Reporter, new construction and potential overbuilding of pipelines may lead to existing pipelines losing shippers, "thus creating the irony of unused capacity at the same time new capacity is being constructed."[33]

F. Risks to Ratepayers, Investors and Communities of Overbuilding Natural Gas Pipelines

Overbuilding of natural gas pipeline infrastructure poses risks to ratepayers, investors and communities along pipeline routes.

Excluding natural gas destined for export, the rates charged for shipping gas on pipelines are ultimately passed through to the consumers of the gas, largely customers of electric and natural gas utilities. That leaves ratepayers at risk of paying for unnecessary new capacity.

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27 Energy Transfer Partners, "Press Release: Energy Transfer Adds Vital Capacity out of the Barnett Shale," January 8, 2009.
28 Texas Railroad Commission Production Data Query System, "Texas Barnett Shale Total Natural Gas Production 2000 through 2015," February 22, 2016. Online at: http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf
29 Southwestern Energy 2nd quarter 2015 earnings call, July 28, 2015.
30 Kallanish Energy Daily News & Analysis, "Marcellus-Utica could soon be 'overpiped,'" February 1, 2016.
31 U.S. Department of Energy, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," February 2015.
32 Existing pipelines in West Virginia, Virginia and North Carolina are even more underutilized. According to EIA data, average capacity utilization in 2014 for pipelines flowing out of West Virginia was 33%. Utilization of pipelines flowing into Virginia was 23% and, into North Carolina, 37%. (Source: U.S. Energy Information Administration, "International & Interstate Movements of Natural Gas By State," 2016 online at http://www.eia.gov/dnav/ng/ng_move_ist_a2dcu_nus_a.htm; U.S. Energy Information Administration, "U.S. State to State Capacity," online at http://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xls).
33 Tom Seng, "Resource Plays Spur Big Infrastructure Rebuild", American Oil and Gas Reporter, August 2013.

Overbuilding creates the risk for investors that a pipeline developer will be unable to renew its contract with shippers after the initial (typically 15- to 20-year) contracts expire. If a pipeline proves to be unnecessary, shippers may not want to renew their contracts. Because pipeline finances are structured so that the costs of the project are recovered over a period longer than the initial contract, investors lose out if the contracts cannot be renewed. This risk is greatly reduced if the shipper is a regulated utility affiliate of the developer.

"Landowners are at risk from having their land seized and potentially damaged for pipeline projects that are not needed."

Additionally, the boom in pipeline development is encouraging companies for whom pipeline development is not their core business to diversify into the sector. This poses its own risks for investors. Whether it is a supplier or utility-driven investment in natural gas pipelines, the companies involved are pursuing higher returns, based presumably on an assessment of their business models that point to a ceiling on the profitability of core business. For these companies, investing in a natural gas pipeline can look like an investment in an area with tightly drawn market adjacencies to their current core businesses, thus minimizing future risk. These investments outside the core can produce returns, but they can also produce pain.[34]

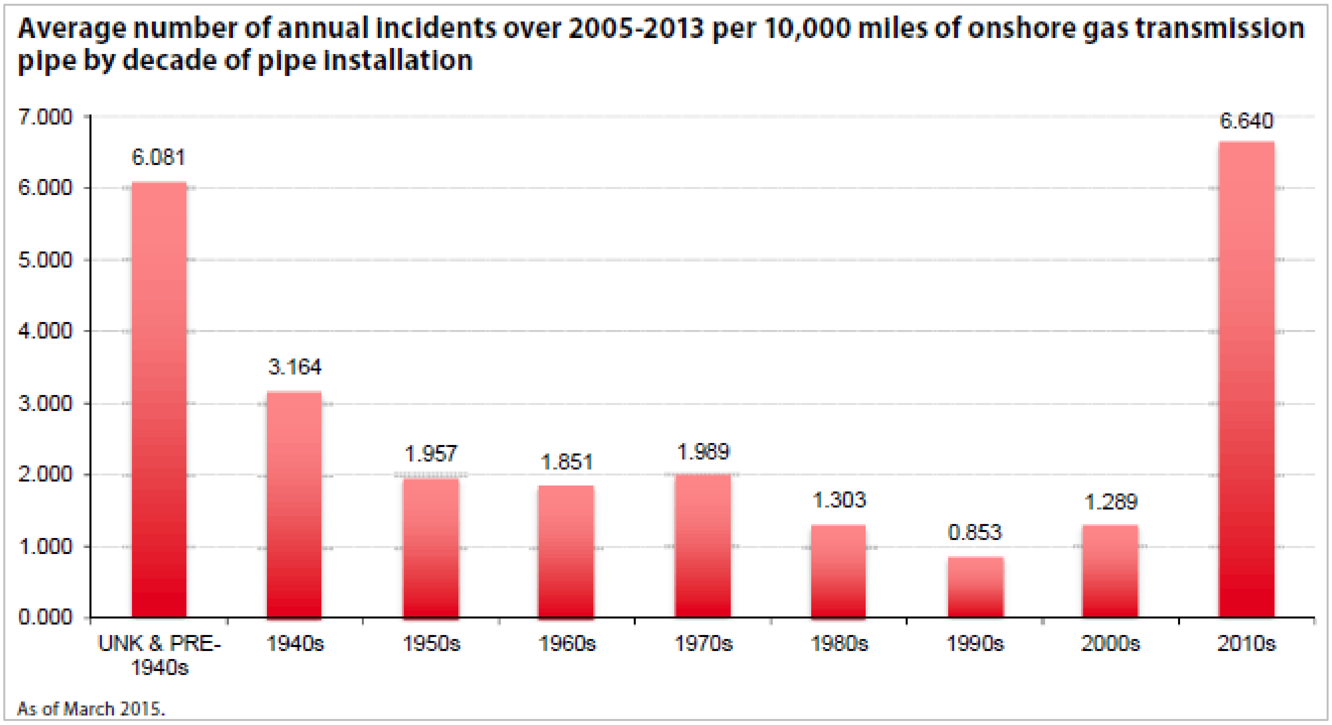
Landowners are at risk from having their land seized and potentially damaged for pipeline projects that are not needed. Additionally, landowners and communities along pipeline routes may be at risk of greater safety problems. As reported in SNL Financial, "the push to build new pipelines to transport abundant shale supplies appears to be having a materially adverse impact on pipeline safety." Data from the Pipeline Safety Trust shows that pipelines built in the 2010s are failing at a rate similar to the failure rate for pipelines constructed pre-1940 (see figure 5).[35] Though it is not clear the specific reasons for the high failure rate of the new pipelines, this data has led to speculation that the boom in construction of natural gas pipelines has led contractors to cut corners.[36]

[34] For example, FirstEnergy, an Ohio-based utility that owns many coal-fired power plants, bought into the Signal Peak coal mine in Montana in 2008, an investment related to, but outside of, FirstEnergy's core utility business. Signal Peak was seen as an attractive investment because it could feed FirstEnergy's own coal fleet and as could sell coal into a growing export market. The investment has since floundered as the coal mining business entered a downturn. FirstEnergy has recently incurred a significant asset impairment on this mine (Source: M. Brown, "Signal Peak Owner Says the Mine is Worth Nothing," Billings Gazette, February 24, 2016).

[35] S. Smith, "As U.S. rushes to build gas lines, failure rate of new pipes has spiked," SNL Financial, September 9, 2015.

[36] Ibid.

Figure 5. Pipeline incidents on newly installed pipelines are comparable to those installed pre-1940.



Source: U.S. Pipeline and Hazardous Materials Safety Administration, Pipeline Safety Trust

PART 2: THE ATLANTIC COAST AND MOUNTAIN VALLEY PIPELINES

One core similarity between the Atlantic Coast Pipeline and the Mountain Valley Pipeline is that they both have been proposed as affiliate transactions, meaning that the majority of the capacity on both of the lines has been reserved by companies that are affiliates of the same companies that are building the lines.

The projects are structured differently, however. Construction of the Atlantic Coast Pipeline is driven by natural gas utilities. Suppliers, not utilities, are driving construction of the Mountain Valley pipeline. This is a difference that raises ratepayer and investor risks that are unique to each project. In particular, IEEFA finds that the utility-driven Atlantic Coast Pipeline places most of the risk on ratepayers, whereas the Mountain Valley Pipeline poses greater risks for investors.

A. The Atlantic Coast Pipeline

Developers of the proposed 550-mile Atlantic Coast Pipeline propose bringing gas from the Marcellus region of northern West Virginia into Virginia and North Carolina.[37] The pipeline would carry up to 1.5 million dekatherms per day. The pipeline would be developed, owned and operated by a joint venture of Dominion Resources (which has a 45% interest in the venture), Duke Energy (40%), Piedmont Natural Gas Company (10%) and AGL Resources (5%).[38] AGL Resources is the target of a possible acquisition by the Southern Company, a deal which is expected to close in the second half of 2016.[39] Piedmont Natural Gas Company is the target of a pending acquisition by Duke Energy, also expected to close in the second half of 2016.[40] If both acquisitions go through, the ownership stake in the pipeline would be 48% Dominion, 47% Duke and 5% Southern.[41] The pipeline is expected to cost $5 billion, and developers anticipate putting the project into service in late 2018.[42]

Developers applied to FERC for a certificate of need in October 2015 with 96% of the capacity of the pipeline already subscribed. The contracts for the majority of this capacity are with utility - companies that are subsidiaries of the companies proposing the project. That is, developers of Atlantic Coast justify need for the line based on contracts negotiated with shippers who are affiliates of the same companies building the pipeline. The following table shows the six companies that have contracted to ship gas on the Atlantic Coast Pipeline.[43]

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[37] As originally proposed, the Atlantic Coast Pipeline route starts in Harrison County WV, traversing Lewis, Upshur, Randolph and Pocahontas counties in WV; Highland, Augusta, Nelson, Buckingham, Cumberland, Prince Edward, Nottoway, Dinwiddie, Brunswick and Greenville counties in VA; and Northampton, Halifax, Nash, Wilson, Johnston, Sampson, Cumberland and Robeson counties in North Carolina. In February 2016, the developers proposed a revised route for the pipeline after the National Forest Service objected to the original route because of impacts to endangered species. The new route adds Bath County, VA to the list of counties traversed by the pipeline. (Sources: Atlantic Coast Pipeline, “Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1, Exhibit F,” Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015; X. Mosqueda-Fernandez, “Forest Service staff rejects Atlantic Coast pipeline route,” SNL Financial, January 21, 2016; X. Mosqueda-Fernandez, “Atlantic Coast Pipeline forges alternative route with Forest Service,” SNL Financial, February 12, 2016).

[38] More specifically, each of these companies has set up subsidiaries to hold their interests in the project. The ownership interests therefore belong to Dominion Atlantic Coast Pipeline, LLC; Duke Energy ACP, LLC; Piedmont ACP Company, LLC; and Maple Enterprise Holdings, Inc., a subsidiary of AGL.

[39] “Southern Company acquires AGL Resources Inc.: Deal Profile,” SNL Financial, last accessed April 12, 2016.

[40] D. Sweeney, “In NC merger application, Duke Energy, Piedmont outline benefits of combined company,” SNL Financial, January 19, 2016.

[41] J. Dumoulin-Smith, M. Weinstein and P. Zimbardo, “Dominion Resources: A Plainer Dominion,” UBS Global Research, January 29, 2016.

[42] X. Mosqueda-Fernandez, “Atlantic Coast Pipeline forges alternative route with Forest Service,” SNL Financial, February 12, 2016.

[43] Atlantic Coast Pipeline, “Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description”, Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-11.

Table 1. Utilities contracted to ship gas on the Atlantic Coast Pipeline. All but Public Service Company of North Carolina are subsidiaries of companies involved in developing the pipeline.

Utility	Parent	Contracted capacity (dekatherms/day)
Virginia Power Services	Dominion	300,000
Duke Energy Progress	Duke	452,750
Duke Energy Carolinas	Duke	272,250
Piedmont	Piedmont Natural Gas	160,000
Public Service Company of North Carolina	SCANA Corporation	100,000
Virginia Natural Gas	AGL Resources	155,000

According to Atlantic Coast's application to FERC, a large portion of the gas (79%) that would be shipped through the pipeline would be destined for power generation in Virginia and North Carolina.[44] Of this amount, 86% would go to Duke and Dominion.[45]

The extent to which Dominion needs this new pipeline capacity to deliver natural gas to planned and proposed new natural gas plants in Virginia is questionable. The application to FERC cites the need for natural gas to supply Dominion's new Brunswick natural gas plant (currently under construction) and its planned Greensville natural gas plant. Both plants have received approval from the Virginia State Corporation Commission. In seeking approval for the Brunswick plant, Dominion represented that the plant would have a contract for firm natural gas supply from Transcontinental Gas Pipe Line Company ("Transco"), which was to construct nearly 100 miles of new pipeline to connect to the Brunswick Plant.[46] This pipeline was completed and placed into service in September 2015.[47] Similarly, for the Greensville plant, Dominion represented that the plant "will be fueled using 250,000 Dth per day of natural gas with reliable firm transportation provided by Transcontinental Gas Pipe Line Company, LLC" though it also noted that Greensville "will also have access to" Atlantic Coast.[48] The Transco pipeline is expected to be placed into service by December 2017.[49] Thus, in its applications to the Virginia State Corporation Commission, Dominion has represented that the Brunswick and Greensville plants will be supplied with natural gas from Transco. The Virginia State Corporation

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44 The remainder will be used for natural gas heating, industrial uses and commercial uses such as vehicle fuel. (Source: Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-5.)

45 Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-12.

46 State Corporation Commission of Virginia, Case No. PUE-2012-00128, "Application of Virginia Electric and Power Company for approval and certification of the proposed Brunswick County Power Station electric generation and related transmission facilities under §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider BW, under § 56-585.1 A 6 of the Code of Virginia," November 2, 2012.

47 Williams, "Press release: Williams' Transco Completes Virginia Southside Expansion," September 1, 2015, online at: http://investor.williams.com/press-release/williams/williams-transco-completes-virginia-southside-expansion.

48 State Corporation Commission of Virginia, Case No. PUE-2015-00075, "Application of Virginia Electric and Power Company for approval and certification of the proposed Greensville County Power Station and related transmission facilities pursuant to §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider GV, pursuant to § 56-585.1 A 6 of the Code of Virginia," July 1, 2015.

49 Williams, "Virginia Southside Expansion Project II," online at http://co.williams.com/expansionprojects/virginia-southside-expansion-project-ii/, last accessed April 13, 2016.

Commission has already approved construction of both gas plants without requiring any additional natural gas contracts.

The Atlantic Coast pipeline could be used as a back-up gas supply for Dominion's Brunswick and Greensville plants. Contracting for some amount of redundant natural gas supply may be prudent. But the Virginia State Corporation Commission approved the plants without any discussion of need for a redundant pipeline.[50] The question of how much redundant supply might be prudent is not likely to be addressed when FERC considers the need for the Atlantic Coast pipeline.

Moreover, Dominion's most recent integrated resource plan, which lays out its long-term plan for electricity supply, does not provide a clear vision for Dominion's natural gas expansion plans. The IRP describes four scenarios that are compliant with the Clean Power Plan; these scenarios vary substantially in the amount of new natural gas generation called for. The least gas-intensive scenario calls for building one additional 1,585 MW natural gas baseload combined cycle power plant in 2022 and two 457 MW natural gas peaking plants by 2030. The most gas-intensive scenario calls for building two 1,585 MW baseload plants, three 457 MW peaking plants and repowering several existing plants with natural gas. The IRP does not express a preference between these scenarios.[51]

While Duke and Dominion are required to file integrated resource plans showing their detailed natural gas capacity expansion plans with state regulators in Virginia and North Carolina, these plans have not been filed with FERC. Thus, FERC will not be able to scrutinize these plans in assessing the need for the Atlantic Coast Pipeline.

Risks to Ratepayers

Ratepayers—specifically the customers of Dominion Virginia Power, Piedmont, Virginia Natural Gas, Public Service Company of North Carolina, Duke Energy Progress and Duke Energy Carolinas—are on the hook for 96% of the project's costs through the rates that they are charged to ship gas on the pipeline.

These ratepayers will bear the following risks.

One is that the Atlantic Coast pipeline would go underutilized. As described above, it is not clear that the utilities that have contracted to ship gas on the pipeline actually need all of the gas that they are contracted to purchase. The utilities have the option to sell the capacity that they're not using on the secondary market and crediting this money back to ratepayers. If the excess capacity cannot be sold, ratepayers will pay for the capacity that their utilities are under contract to purchase. If the excess capacity can be sold, ratepayers still bear the risk that the price received for this capacity is less than what they are paying for it.

[50] State Corporation Commission of Virginia, "Final Order," Case No. PUE-2012-00128, August 2, 2013.

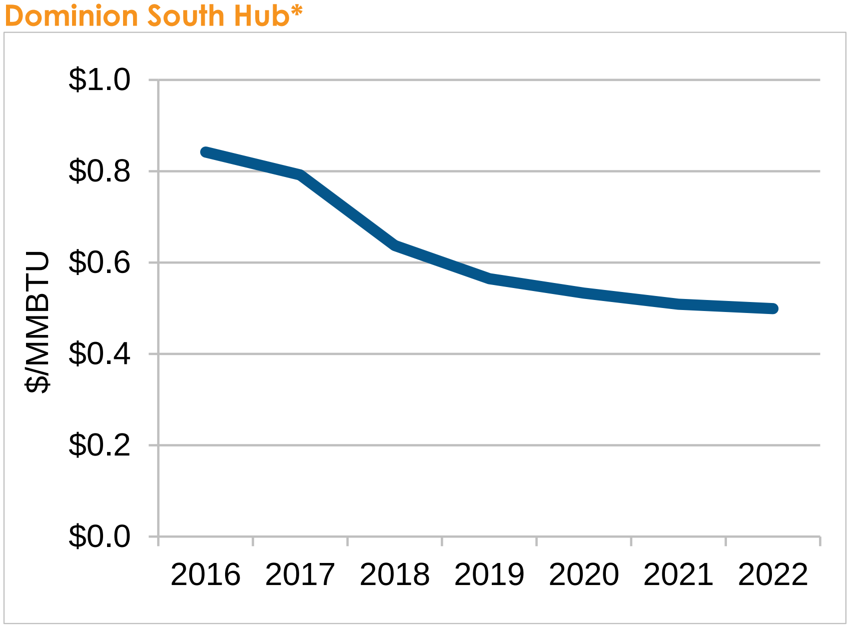
[51] Dominion, Integrated Resource Plan, as filed with the Virginia State Corporation Commission and the North Carolina Utilities Commission, July 1, 2015, pp. 5-8.

Ratepayers are also at risk that natural gas prices from the Marcellus and Utica region will not continue to be significantly cheaper than Henry Hub prices. Part of the supposed rationale for building the Atlantic Coast Pipeline is that ratepayers will benefit from a cheap supply of natural gas from the Marcellus and Utica region. But ratepayers would benefit only if the cost advantage of sourcing gas from the Marcellus/Utica outweighs the cost to ratepayers of building the pipeline. While a study conducted on behalf of the developers by ICF International to justify the economic benefits of the pipeline does not provide a forecast of future natural gas prices from the Marcellus region, it does assert that Marcellus/Utica natural gas will continue to be $1-$1.75/MMBTU cheaper than natural gas from the Henry Hub through 2035, which would mean that the Atlantic Coast pipeline would generate savings for ratepayers over the lifetime of the pipeline. However, ICF's projection of a widening spread between Henry Hub and Marcellus/Utica gas (at the Dominion South Hub) contradicts current market expectations. ICF projects the price difference between the Dominion South Hub and the Henry Hub narrowing to about $0.50/MMBTU by 2018 but then steadily increasing to about $1/MMBTU by 2022 and $2/MMBTU by 2028.[52] By contrast, current market expectations, as revealed by futures prices, project the spread between the two hubs steadily narrowing to $0.50/MMBTU by 2022.

"Ratepayers—specifically the customers of Dominion Virginia Power, Piedmont, Virginia Natural Gas, Public Service Company of North Carolina, Duke Energy Progress and Duke Energy Carolinas—are on the hook for 96% of the project's costs"

As more pipelines are built out of the Marcellus and Utica region, the excess pipeline capacity will further narrow the price differential between the hubs. That is, as natural gas pipeline capacity increases to meet or exceed the glut of natural gas supply, natural gas prices in the Marcellus should rise. A January 2016 article in Midstream Business noted that "new Marcellus Shale regional pipelines are beginning to pressure Henry Hub prices, *sapping differentials in gas value* as more of the area's production escapes regional lockdown" (emphasis added).[53]

Figure 6. Projected price difference between Henry Hub and Dominion South Hub*



*based on OTC Global Holding futures prices retrieved 2/26/16

[52] ICF International, "The Economic Impacts of the Atlantic Coast Pipeline," February 9, 2015

[53] Darren Barbee, "Contents Under Pressure: New Pipelines Ease Marcellus Takeaway Troubles," Midstream Business, January 12, 2016.

It is clear that the current low natural gas prices in the Marcellus and Utica are not sustainable for drillers, a factor that will likely drive Marcellus and Utica gas prices higher over the long term, likely reducing the price differential with the Henry Hub and affecting ratepayers who are on the hook for shipping contracts for the next 20 years. Many of the companies with the greatest production in Appalachia operated at a loss in 2015. Of the top 10 Appalachian drilling companies, only two (EQT and Antero) posted positive net income in 2015.[54] Chesapeake Energy, the largest Appalachian driller, is widely expected to go bankrupt (though the company is currently denying that it will file for bankruptcy).

In response to continued low prices, drillers have cut back on capital expenditures. Capital expenditures by the top eight Appalachian shale drillers in the fourth quarter of 2015 were 54% lower than in the fourth quarter of 2014. And capital expenditures for the first quarter of 2016 are expected to be 49% lower than in the first quarter of 2015.[55] This reduction in capital expenditures is reflected in production volumes; according to the most recent figures from the Energy Information Administration, production growth has slowed over the past several months and a decline is projected from February to April 2016.[56]

Low oil prices since late 2014 have also hurt many Appalachian drillers who had previously been able to use profitable wet gas drilling operations to prop us less profitable dry gas drilling. Low oil prices have driven down prices for natural gas liquids, making wet gas drilling less profitable.[57]

In spring 2016, banks will be re-determining the revolving credit lines for many shale gas drillers. They are widely expected to cut back on lending.[58]

It is all but certain that the instability and financial problems brought about by current low natural gas prices will drive some of the shale gas drilling companies into bankruptcies. According to JP Morgan there have been 48 bankruptcies in the oil and gas exploration and production sector since 2014,[59] and further bankruptcies are expected in 2016.

Production will be scaled back and prices will stabilize at a higher level. It is not clear over what timeframe this will occur, though natural gas prices are generally expected to remain low at least through 2016. According to Standard & Poor's, "commodity prices will remain low in 2016, impeding cash flows and increasing the risk for negative rating and outlook actions as leverage measures and liquidity continue deteriorating."[60]

While most analysts are not projecting a near-term rise in gas prices (and futures prices show Dominion South Hub prices remaining below $2.50 per MMBTU through 2022), shale drillers cannot continue to produce below cost indefinitely. In the longer term (10-15 years), it is likely that Marcellus and Utica gas prices will stabilize at a somewhat higher level. These longer-term prices will have a significant impact on the long-term economics of the Atlantic Coast Pipeline, which is designed as a 40-year project.

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[54] List of top 10 Appalachian drillers from B. Holland, "Appalachian drillers vow to slow down after brutal Q3," SNL Financial, November 12, 2015. Net incomes obtained from individual company 2015 Form 10-K Securities and Exchange Commission filings.

[55] B. Holland, "Billions evaporate from gas industry as Northeast drillers gut spending," SNL Financial, January 8, 2016.

[56] Energy Information Administration, "Drilling Productivity Report: Report Data," March 7, 2016. https://www.eia.gov/petroleum/drilling/xls/dpr-data.xlsx

[57] X. Mosqueda-Fernandez, "NGL projects could struggle under low crude price future," SNL Financial, June 17, 2015.

[58] B. Holland, "JP Morgan clamping down on oil, gas clients, expects more bankruptcies," SNL Financial, February 24, 2016.

[59] Ibid.

[60] B. Holland, "Lack of oil, gas hedging could lead drillers to spring defaults, S&P warns," SNL Financial, December 21, 2015.

Thus, ratepayers run the risk of paying higher than expected natural gas prices for gas delivered on the Atlantic Coast pipeline as the difference between Marcellus and Henry Hub natural gas prices narrows.

Ratepayers also bear risks associated with delays in project construction. It is not clear how much of the risk of project delay would be borne by ratepayers versus investors in the project. According to Atlantic Coast's application to FERC, "in an agreed-upon risk sharing agreement, the negotiated rates would be decreased by specified amounts for certain delays in the Project in-service date."[61] The developers offer no further detail on how the risk of delay would be shared among project investors and ratepayers. Given that the negotiated rates were negotiated between affiliated companies, it seems likely that the burden of the risk would be placed on ratepayers, not project investors.

Ratepayers may also bear some risk of construction cost overruns. Dominion has noted that the terrain that the Atlantic Coast pipeline will traverse accentuates the risk of construction cost overruns and delays: "The large diameter of the pipeline and difficult terrain of certain portions of the proposed pipeline route aggravate the typical construction risks with which DTI [Dominion Transmission Inc] is familiar. In-service delays could lead to cost overruns and potential customer termination rights."[62]

Atlantic Coast pipeline's application to FERC provides no additional detail on these "potential customer termination rights." It is not clear whether customers would be able to terminate their contracts and walk away with the project without any losses, or whether they would still end up paying for a portion of the project if their contract is terminated.

Finally, ratepayers face the risk of future regulation of greenhouse gas emissions. The Atlantic Coast Pipeline is designed to recover its construction costs from ratepayers over a 40-year period, i.e. through 2058. It is reasonable to expect significant policies requiring reductions in greenhouse gas emissions by then, changes that will constrain the use of natural gas.

Risks to Investors

Generally speaking, the Atlantic Coast pipeline does not appear to be particularly risky to investors. The pipeline will be paid for through shipping rates paid by financially stable, regulated utilities with captive customers.

Nevertheless, there are still investor risks.

First is that a state utilities commission (either the North Carolina Utilities Commission or the Virginia State Corporation Commission) will disallow some of the costs of the pipeline from being passed through to ratepayers based on a decision that the costs were imprudently incurred. Such a decision would likely be predicated on a conclusion that the utility had contracted for more capacity than it needs, based on what was known about future natural gas demand at the time the contract was entered into.

Investors also face the risk of delays or construction cost overruns that cause shippers to back out of the project or to receive lower rates. As described in the previous section, delays and

[61] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 32.
[62] Dominion Resources, 2014 Form 10K, p. 26.

cost overruns could trigger shippers to pull out of the project, though it is not clear what level of delay or cost overrun would be required to allow a shipper to terminate its contract. Furthermore, developers of the Atlantic Coast project have apparently agreed to lower negotiated rates if the project is delayed by a certain amount though, again, there are no details on these agreements. Given that these contracts are largely between affiliated entities, it seems reasonable to assume that the risks of delay and cost overruns will be borne more by ratepayers than by investors.

Investors are also at risk that the pipeline owners would not be able to renew shipping contracts after 20 years. The contracts that Atlantic Coast has signed with shippers are all 20-year contracts. Yet the rates charged in these contracts are designed to recover the costs of the constructing the pipeline over a 40-year period.[63] Thus, Atlantic Coast is banking on its ability to renew shipping contracts in order to fully recover the costs of building the pipeline. The risk of not being able to renew these contracts is, in theory, borne by the project's investors. However, given that almost all of Atlantic Coast's shipping contracts are with affiliates, there will be strong pressure on the regulated utilities to renew the contracts. IEEFA therefore views this as a minimal risk to investors.

B. Mountain Valley Pipeline

The Mountain Valley Pipeline is a proposed 300-mile pipeline that originates in West Virginia and terminates in Virginia.[64] The Mountain Valley Pipeline would carry up to 2 million dekatherms per day. It is a joint venture of EQT Midstream (45.5% ownership interest), NextEra Energy (31%), Con Edison (12.5%), WGL Holdings (7%), Vega Energy Partners (3%) and RGC Resources (1%) and will be operated by a subsidiary of EQT.[65] The pipeline is expected to cost $3.7 billion and to go into service in the fourth quarter of 2018.[66]

All of the capacity on the Mountain Valley Pipeline has been reserved by shippers. The companies that have entered into shipper contracts are EQT (64.5%), Consolidated Edison (12.5%), USG Properties Marcellus Holdings, a subsidiary of NextEra (12.5%), WGL Midstream (10%) and Roanoke Gas (0.5%). EQT and USG Properties Marcellus Holdings, which together have contracted for 77% of the capacity of the pipeline, are natural gas supply companies.

The Mountain Valley Pipeline is very different from the Atlantic Coast Pipeline in that is a supplier-driven pipeline, rather than a customer-driven pipeline. That is, the entities that have entered into long-term contracts for the majority of the capacity on the Mountain Valley Pipeline are producers of natural gas.

As shown in the following table, the entities that have entered into contracts for capacity on the Mountain Valley Pipeline are all affiliates of the companies that are partners in the joint

[63] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1, Exhibit P," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015

[64] The proposed route starts in Wetzel County and traverses Harrison, Doddridge, Lewis, Braxton, Webster, Nicholas, Greenbrier, Summers and Monroe counties in WV; and Giles, Craig, Montgomery, Roanoke, Franklin and Pittsylvania counties in VA. The pipeline route terminates at an intersection with the Transco line, a pipeline owned by Williams Corporation that is a backbone of the East Coast natural gas transmission system, connecting the Gulf Coast to New York. (Source: Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit F," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015.)

[65] Mountain Valley Pipeline, "Frequently Asked Questions," http://mountainvalleypipeline.info/faqs/, last accessed April 12, 2016.

[66] S. Sullivan, "Mountain Valley applies to FERC for 2-Bcf/d gas pipeline," SNL Financial, October 23, 2015.

venture. The pipeline is fully subscribed. EQT is, by far, the largest shipper, as well as being the dominant partner in the joint venture to build the pipeline.

Table 2. All of the shippers on the Mountain Valley Pipeline are affiliates of companies involved in developing the project.

Pipeline owner	Ownership interest	Shipper	Capacity contracted (dekatherms/day	Capacity contracted (%)
EQT Midstream Partners, LP	45.5%	EQT Energy, LLC	1,290,000	64.5%
NextEra Energy US Gas Assets, LLC	31%	USG Properties Marcellus Holdings, LLC	250,000	12.5%
Con Edison Gas Midstream, LLC	12.5%	Consolidated Edison Company of New York	250,000	12.5%
WGL Midstream, Inc.	7%	WGL Midstream, Inc.	200,000	10%
Vega Midstream MVP LLC	3%			
RGC Midstream LLC	1%	Roanoke Gas Company	10,000	0.5%

Investors in the Mountain Valley Pipeline are at greater risk of being harmed by financial problems with the shippers than investors in the Atlantic Coast Pipeline are because natural gas producers are much less financially stable than regulated utilities. According to Moody's Investor Services, the long-term credit rating of EQT is Baa3 (the lowest investment-grade credit rating), whereas the largest shippers on the Atlantic Coast pipeline have credit ratings of A1 (Duke Energy Carolinas) and A2 (Duke Energy Progress and Dominion Virginia Electric and Power Company).

In recent months, investors have grown increasingly aware of the risks of supplier-driven pipelines, like the Mountain Valley Pipeline, because of the weak financial position of many shale drilling companies. As described by SNL Financial:

> "Firm transportation contracts with counterparties that have credit ratings below investment grade, such as Chesapeake Energy Corp., have the potential to disrupt operators if the shippers cannot keep up with reservation payments for the duration of the contracts.
>
> As oil and gas prices remain depressed, exploration and production companies have continued to watch their valuations fall. These upstream problems may work their way down the value chain, putting previously stable revenue for midstream companies at risk as their contract counterparties look to renegotiate pricing, or in some instances, file for bankruptcy. Pipelines with higher proportions of volume contracted with these companies are more exposed to these effects."[67]

Two pending bankruptcy proceedings are raising the issue of whether drillers' contracts with pipelines are likely to be honored if the drillers go bankrupt. In its pending bankruptcy

[67] M. Bearden, "Exploring interstate pipeline exposure to lower-rated E&Ps," SNL Financial, February 18, 2016.

proceeding, Sabine Oil & Gas successfully terminated its contracts with natural gas pipeline companies for gathering and processing natural gas.[68] Quicksilver Resources, also in bankruptcy, is following suit, seeking to terminate its contracts for gathering and processing.[69] Similarly, while Chesapeake Energy – the largest company drilling in the Marcellus shale—has denied plans to file for bankruptcy,[70] it is experiencing serious financial troubles and a bankruptcy would potentially jeopardize its payments to pipeline companies with which it is contracted to ship gas.

In the case of the Mountain Valley Pipeline, the financial health of EQT is critical to how the project moves forward. EQT is a major shale gas drilling company whose operations are concentrated in the Marcellus and Utica shale region (78% of its proved reserves are in the Marcellus).[71] As described in the previous section, the shale drilling sector in general is in turmoil because of prolonged low natural gas prices. While EQT is positioned better than many other major Appalachian shale drillers (it was one of only two of the top ten Appalachian drillers to post positive net income in 2015, for example), it is still not immune to the effects of low prices. EQT's stock price has fallen 26% since January 2014, a period in which the Dow Jones Industrial Average has increased 8%.[72] Its long-term credit ratings from S&P, Moody's and Fitch are all one notch above junk status.[73] Additionally, as of December 2015, EQT had only 37% of its production hedged for 2016, lower than Antero, Range and several other major Appalachian drillers.[74]

"Two pending bankruptcy proceedings are raising the issue of whether drillers' contracts with pipelines are likely to be honored if the drillers go bankrupt."

EQT has had negative free cash flow for the past nine years, meaning that the cash generated from drilling operations is not sufficient to finance the ongoing capital expenditures of the company. While it is standard industry practice to rely upon equity and debt cash infusions during a period of growth, this is done with the expectation that project returns will occur over a longer period and cash flow will flip from negative to positive as projects start generating returns. EQT's long period of negative free cash flow reflects a decision to continue investing in the drilling business despite the poor short-term future outlook. In a time when many companies are facing distressed financial scenarios, a nine-year negative free cash flow raises the company's risk profile. EQT's situation appears to be worsening, with free cash flow declining from -$450 million in 2013 to -$1,217 million in 2015.

EQT's business outlook remains focused on growth and, so far, investors have been willing to continue investing in EQT. Despite low prices, EQT's natural gas production volume increased 27% in 2015 over 2014.[75] Part of EQT's growth strategy has been to grow its pipeline business, a less risky line of business than natural gas drilling. EQT launched the master limited partnership EQT Midstream in 2012. EQT has sold pipeline assets to EQT Midstream to raise cash, and EQT Midstream has raised money through public offerings. In 2015, for example, EQT raised $1.1

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[68] B. Holland, "E&P bankruptcy ruling brings clouds for midstream and a 'kind of' silver lining," SNL Financial, March 9, 2016.
[69] N. Amarnath, "More trouble for midstream MLPs as struggling producers seek to ditch contracts," SNL Financial, February 9, 2016.
[70] M. Passwaters, "Chesapeake says it is not seeking bankruptcy as shares plummet," SNL Financial, February 8, 2016.
[71] EQT, 2015 Form 10-K, page 10.
[72] SNL Financial, "EQT Corporate Profile," retrieved April 17, 2016.
[73] Baa3 from Moody's, BBB from S&P and BBB- from Fitch. (Source: SNL Financial)
[74] B. Holland, "Lack of oil, gas hedging could lead drillers to spring defaults, S&P warns," SNL Financial, December 21, 2015.
[75] EQT, 4Q 2015 earnings call transcript, February 4, 2016.

billion from sales of assets to EQT Midstream, and EQT Midstream was able to raise $1.2 billion through public offerings.[76] The Mountain Valley Pipeline represents a major area of growth for EQT Midstream.

In part because of its infusions of cash from EQT Midstream, EQT would be in a strong position to be able to buy up the assets of other natural gas drillers who are in financial distress due to low natural gas prices. EQT's basic business strategy is to continue growing and hope that it will be well-positioned to take advantage of higher natural gas prices in the future.

The key question, of course, is how long natural gas prices will stay low. The longer they do, the riskier EQT's business strategy becomes. Natural gas prices at the Dominion South Hub averaged $1.50/MMBTU in 2015 and futures prices project prices falling further to $1.22/MMBTU in 2016, before rising to $1.70 in 2017 and $1.93 in 2018. Fitch has estimated that the average cost of production in the Marcellus shale is $2.50, implying that futures prices for the next few years are expected to be below the average cost of gas production.[77] As noted in a recent article in SNL Financial, "Most independent gas drillers have finally resigned themselves to low prices indefinitely (the highest price on the NYMEX gas futures strip is $4.611/MMBtu all the way at the end, December 2028) and are now in a race to wrangle their expenses inside their cash flow before they default."[78]

Even if EQT is better positioned to withstand continued low natural gas prices than other Appalachian drillers, it would be adversely affected by the bankruptcies that are widely expected in the sector, which will likely drive capital out of the entire drilling sector.

Risks to Investors

In addition to the fundamental risk posed by EQT's weak financial condition, other risks to investors include the risk that the pipeline owners will be unable to renew shipping contracts after 20 years. As with the Atlantic Coast pipeline, the rates for the Mountain Valley Pipeline are designed to recover the costs of the pipeline over 40 years, which is longer than the length of the initial shipping contracts.[79] Pipeline investors bear the risk that Mountain Valley will not be able to renew its shipping contracts after 20 years or that it will not be able to renew them with as favorable terms.

This risk is compounded by the risk that greenhouse gas regulations imposed over the next 20 years will restrict the use of natural gas.

Investors also may be vulnerable to cost-overrun risks. Mountain Valley's shipping contracts includes a provision for adjusting the negotiated rates if the actual construction cost differs from the estimated cost, but the nature of this adjustment is not publicly available.[80]

[76] EQT Form 10-K, February 11, 2016, pp. 78-79.
[77] B. Holland, "Fitch warns Marcellus prices fail to cover costs as Pa. cash hubs drop below $1," SNL Financial, November 2, 2015.
[78] B. Holland, "Gas world faces reckoning of drillers' 'growth at the expense of profit'," SNL Financial, December 28, 2015.
[79] Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 38.
[80] Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit I," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 160.

Risks to Communities

Communities and landowners along the pipeline route also bear risks that stem from EQT's financial weakness. EQT does not appear to be a stable, long-term partner for these communities.

EQT's weakened financial position suggests it will adopt only a limited commitment to communities or perhaps be forced to sell its ownership interests to a new company that is not part of current deliberations. Natural gas pipelines are not just long-term investments between companies and investors, they are long-term partnerships between the companies and their host communities. Company culture matters.

Another risk to communities directly affected by the proposed project: Pipeline safety problems are on the rise, as documented in Figure 5, and how a company perceives such risk, monitors for it, seeks to prevent it, and communicates about it to affected communities is paramount. Closely related to this risk are those that stem from a company's land management and reclamation activities. Companies involved in positive corporate citizenship buy locally to stimulate local businesses, hire locally, and invest locally in new businesses and community projects.

Risks to Ratepayers

The clearest risks to ratepayers from the Mountain Valley Pipeline are the risks to the customers of the regulated utilities that have contracted as shippers on the pipeline. These are Consolidated Edison and Roanoke Gas.

The risks to ratepayers on the Mountain Valley Pipeline are similar to those posed by the Atlantic Coast Pipeline.

These include the risk of project delay. According to the contracts that have been signed by shippers on the Mountain Valley pipeline, a shipper many terminate its contract if the pipeline has not been placed into service by June 1, 2020, but it is still required to pay its share of the expenses incurred to that date, plus fifteen percent unless the developer can re-sell the shipper's capacity to a third party. In other words, ratepayers may be on the hook for a share of construction costs even if the utilities ultimately pull out of the project.[81]

Ratepayers are at risk that natural gas prices from the Marcellus shale will not turn out to be substantially lower than Henry Hub prices over the long term. Customers of the regulated utilities that have contracted to ship gas on the Mountain Valley Pipeline will pay for their share of the construction cost of the pipeline through their rates. If the expense of the pipeline outweighs the savings from access to a lower-cost supply of natural gas, then this cost will be borne by ratepayers.

Finally, the potential for greenhouse gas regulations poses a ratepayer risk. As with the Atlantic Coast pipeline, it is likely that ratepayers will bear the cost of their utilities' share of the stranded capacity on the Mountain Valley pipeline if and when greenhouse gas emissions regulations restrict the use of natural gas.

[81] Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit I," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 166.

RECOMMENDATIONS

To limit the potential for overbuild pipeline capacity out of the Marcellus and Utica region, IEEFA recommends:

- The establishment of a comprehensive planning process for natural gas pipeline development. FERC's current practice of considering the need for projects on an individual basis is insufficient.
- Lower returns on pipeline development. The returns on equity embedded in recourse rates for new interstate natural gas pipelines exceed authorized returns for state-regulated electric utilities and federally regulated electric transmission lines. This is especially egregious given that the growing trend of transactions between regulated utilities and affiliated pipeline developers tends to shift risk from utility shareholders to ratepayers. FERC should lower the returns it allows on equity for pipeline development.
- An investigation into the safety of new pipelines with a focus on the relatively high failure rate of newly installed pipelines.

Additionally, with regard to the Atlantic Coast Pipeline, IEEFA recommends that:

- The Virginia State Corporation Commission closely examine the prudence of contracts signed by regulated utilities to ship gas on a pipeline owned by affiliated companies.
- FERC consider information presented to state regulators by Duke and Dominion in integrated resource plans and in certificate applications regarding their planned buildout of regional natural gas power generation.

Finally, IEEFA recommends that:

- FERC acknowledge that it lacks sufficient evidence to evaluate the need for the Atlantic Coast and Mountain Valley Pipelines and that applications for those project be suspended until such time than an appropriate regional planning process is developed.
- FERC should recognize that pipelines are being proposed with different corporate structures that involve very different risk profiles. In assessing supplier-driven pipelines, FERC should assess industry trends and the short and long term financial condition of companies along the chain (with careful attention paid to leverage and free cash flow). FERC could also consider a range of recourse rates that would reflect different risks.

CONCLUSION

Natural gas pipeline infrastructure out of the Marcellus and Utica region of Appalachia will probably become overbuilt within the next several years, an outcome recognized by many in the industry itself. The economic and financial factors that incentivize companies to invest in the development of new natural gas pipelines—from drilling companies that seek to diversify into a sector with more stable income to traditional pipeline companies angling to build larger and better-connected networks—will not produce a socially rational outcome. Without a coordinated approach to natural gas pipeline planning, as exists for many other types of infrastructure, the Federal Energy Regulatory Commission cannot make an honest determination of the need for these pipelines. Ratepayers and communities will shoulder much of the costs and risks of the Atlantic Coast and Mountain Valley pipelines, investments of nearly $9 billion that are poised for approval without adequate scrutiny.

About the Authors

Cathy Kunkel, Energy Analyst, is an independent West Virginia-based consultant focusing on energy efficiency and utility regulation. She has testified on multiple occasions before the West Virginia Public Service Commission for the nonprofit coalition Energy Efficient West Virginia. She has done graduate work for the Energy and Resources Group at the University of California-Berkeley and is a former senior research associate at Lawrence Berkeley National Laboratory. Kunkel has an undergraduate degree in physics from Princeton University and graduate degree in physics from Cambridge University.

Tom Sanzillo, director of finance for IEEFA, is the author of several studies on coal plants, rate impacts, credit analyses, and public and private financial structures for the coal industry. He has testified as an expert witness, taught energy-industry finance training sessions, and is quoted frequently by the media. Sanzillo has 17 years of experience with the City and the State of New York in various senior financial and policy management positions. He is a former first deputy comptroller for the State of New York, where he oversaw the finances of 1,300 units of local government, the annual management of 44,000 government contracts, and where he had oversight of over $200 billion in state and local municipal bond programs and a $156 billion pension fund. Sanzillo recently contributed a chapter to the Oxford Handbook of New York State Government and Politics on the New York State Comptroller's Office.

APPENDIX: QUESTIONS ABOUT THE RISKS OF THE ATLANTIC COAST AND MOUNTAIN VALLEY PIPELINES

Many details about the Atlantic Coast and Mountain Valley pipelines have not yet come to light in the FERC application process. These details may never come to light through that process because they are not necessarily issues that FERC prioritizes in deciding on the "need" for a pipeline. Nevertheless these are questions that need to be answered if there is to be appropriate public scrutiny over whether these pipelines are worth the risks.

A. Questions regarding the Atlantic Coast Pipeline:

- Why are ratepayers being asked to pay for redundant natural gas supply for Dominion Virginia Electric and Power's Brunswick and Greensville natural gas plants?
- Which specific proposed natural gas plants do Duke and Dominion plan to supply with gas from that Atlantic Coast pipeline? When are these plants expected to be constructed?
- Why have there recently been so many safety problems with new pipelines?
- Dominion's 2014 10-K states, "certain portions of the proposed pipeline route aggravate … typical construction risks." Which portions of the route? What is Dominion doing to minimize these risks?
- Who will be the construction contractor for the Atlantic Coast pipeline? What is this contractor's recent safety track record?
- Who will be liable for damages from pipeline explosions?
- Who will pay for construction cost overruns, shippers or the pipeline developer?
- If a shipper terminates their contract due to project cost overruns or delays, to what extent is that shipper still liable for construction costs of the pipeline?
- What are the rates that have been negotiated between Atlantic Coast and its shippers? What return on equity is embedded in these rates?
- How much do negotiated rates decrease if there are delays in putting the pipeline into service?

B. Questions regarding the Mountain Valley Pipeline:

- Who will be the construction contractor for the Mountain Valley pipeline? What is this contractor's recent safety track record?
- Who will be liable for damages from pipeline explosions?
- Who will pay for construction cost overruns, shippers or the pipeline developer?
- What are the rates that have been negotiated between Mountain Valley and its shippers? What return on equity is embedded in these rates?
- How much do negotiated rates decrease if there are delays in putting the pipeline into service?
- If a shipper goes bankrupt, how likely is it that the shipper's contract with Mountain Valley pipeline will be terminated?