UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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Mountain Valley Pipeline, LLC	)	**Docket No. CP16-10-000**
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MOTION TO ANSWER AND ANSWER OF MOUNTAIN VALLEY PIPELINE, LLC TO COMMENTS ON THE DRAFT ENVIRONMENTAL IMPACT STATEMENT

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure,[1] Mountain Valley Pipeline, LLC ("Mountain Valley") hereby moves to answer and answers certain comments filed regarding the Commission's Draft Environmental Impact Statement ("DEIS") prepared for the Mountain Valley Pipeline Project ("MVP Project" or "Project").[2] On September 16, 2016, the Commission issued a Notice of Availability of the DEIS for the MVP Project, requiring comments on the DEIS be submitted by December 22, 2016.[3] The DEIS concludes that while the MVP Project may result in some adverse environmental impacts, the majority of impacts "would be reduced to less-than-significant levels"

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[1] 18 C.F.R. §§ 385.212& 385.213 (2016).

[2] *Mountain Valley Pipeline, LLC*, Draft Environmental Impact Statement for the Mountain Valley Project and Equitrans Expansion Project, Docket Nos. CP16-10-000, CP16-13-000 (Sept. 16, 2016) ("DEIS"). Equitrans, LP has requested authorization to construct and operate natural gas facilities in Pennsylvania and West Virginia that will interconnect with other interstate systems, including the MVP Project. Because the proposed projects are interrelated and connected actions, FERC is preparing a single comprehensive EIS addressing both projects.

[3] Notice of Availability of the Draft Environmental Impact Statement for the Proposed Mountain Valley and Equitrans Expansion Project, Docket Nos. CP16-10-000, CP16-13-000 (Sept. 16, 2016). On January 13, 2017, the Commission issued a supplemental notice extending the comment period to February 21, 2017 with respect to certain route changes filed by MVP in October 2016. *See* Letter Discussing Route Modifications to Mountain Valley Pipeline LLC's Mountain Valley Pipeline Project (Jan. 13, 2017).

through the implementation of various mitigation measures.[4] In this Answer, Mountain Valley responds to a number of comments on the Project filed by environmental organizations, landowners, local governments, and concerned citizens.

The MVP Project is a new greenfield pipeline system designed to transport up to 2.0 million dekatherms ("MMDth") per day of natural gas to growing markets in the Appalachian, Mid-Atlantic, and Southeast United States ("U.S.") regions. The Project includes approximately 303 miles of 42-inch diameter pipeline, three compressor stations, interconnection facilities, metering and regulation facilities, and other associated ancillary facilities located in West Virginia and Virginia. Mountain Valley is a joint venture between EQT Midstream Partners, LP; NextEra Energy US Gas Assets, LLC; Con Edison Gas Midstream, LLC;[5] WGL Midstream, Inc.; and RGC Midstream, LLC. Mountain Valley hereby submits the following answer to comments on the DEIS.

I.
EXECUTIVE SUMMARY

Mountain Valley has fully demonstrated the need for the MVP Project. Mountain Valley conducted its open season process consistent with Commission requirements and has signed precedent agreements with five shippers for the full 2.0 MMDth per day of capacity for the Project. The Project is designed to and will support demand in the Appalachian, Southeast, and Mid-Atlantic U.S. markets. Moreover, the construction and

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[4] DEIS at ES-14; 5-1.

[5] On January 27, 2016, Mountain Valley filed a supplement to the Application noting that Con Edison Gas Midstream, LLC has become a party to the Mountain Valley joint venture and Consolidated Edison Company of New York, Inc. has become a Project shipper. *See Mountain Valley Pipeline, LLC*, Supplemental Information of Mountain Valley Pipeline Regarding New Shipper (Jan. 27, 2016).

operation of the Project will produce economic benefits for the states in which it is located. Mountain Valley has submitted detailed reports developed by Wood Mackenzie, Inc. ("Wood Mackenzie") analyzing the long-term natural gas supply and demand in the Southeast and Mid-Atlantic Markets. The Wood Mackenzie reports conclude that demand for natural gas in these markets is expected to grow through 2030, and demonstrate that there is more than enough demand for pipeline transportation capacity in the Mid-Atlantic and Southeast regions to support the MVP Project and other planned expansions designed to serve those markets. The September 2016 report prepared by Synapse Energy Economics, Inc. ("Synapse") does not undermine the demonstrated need for the MVP Project, as the report is based on unreliable analysis that contains numerous flaws, inaccuracies, and methodological deficiencies.

Despite assertions otherwise, the National Environmental Policy Act ("NEPA") does not require the Commission to prepare a revised or supplemental DEIS for the Project. A revised DEIS is required only where the draft "is so inadequate as to preclude meaningful analysis," and a supplemental DEIS is required if the Commission makes "substantial changes" in the proposed action that are relevant to environmental concerns, or there are "significant new circumstances or information" relevant to environmental concerns.[6] No such circumstance is present here. The DEIS, while not a final document, is thorough, comprehensive, and certainly does not warrant the preparation of a revised or supplemental draft, as it adequately addresses the purpose and need for the MVP Project and contains more than sufficient information to provide the public an opportunity for

[6] 40 C.F.R. §§ 1502.9(a) &1502.9(c)(1)(i)-(ii).

meaningful analysis. As evidenced by the volume and variety of comments on the DEIS, the DEIS allows for meaningful analysis by participants in the proceeding.

NEPA also does not require the Commission to prepare a broad programmatic environmental impact statement ("EIS") for the Project and other projects in the region. The Commission must consider the environmental impacts of the MVP Project as required by NEPA just as it must consider such impacts of any other new pipeline project seeking authorization. As such, there is no basis to assert that the Commission will not completely fulfil its mandate under NEPA. An extended programmatic EIS, however, covering multiple unrelated projects that happen to be planned in the same general region is unnecessary to facilitate the Commission's review of the MVP Project. Rather, the Commission's long-standing policy of conducting a project-specific environmental review is appropriate here. To be sure, the Commission's process looks at all the direct, indirect and cumulative impacts of, and reasonable alternatives to, the Project. This is fully consistent with the Commission's NEPA responsibilities, and a programmatic EIS is not necessary.

Additionally, there is no NEPA requirement that the Commission consider impacts from upstream natural gas production allegedly induced by the MVP Project. The individual states, and not the Commission, regulate upstream activities associated with the exploration and production of natural gas. Further, NEPA does not require an analysis of upstream natural gas development because the impacts of such activities are neither causally connected to the MVP Project nor are they reasonably foreseeable. The

DEIS thus properly concluded that impacts from upstream natural gas production are outside the scope of issues to be considered in the DEIS.

The DEIS also correctly observes that the MVP Project is not contemplated for export of liquefied natural gas overseas. As Mountain Valley clearly stated in its Application, the Project facilities were not designed to transport natural gas to an export terminal, and Mountain Valley has no intention of seeking authorization to export natural gas.

With respect to environmental issues raised by commenters, Mountain Valley has taken a variety of safety measures and conducted field verifications to better understand the potential sensitive hydrology in the Project area and how to best avoid impacting features that may be present in karst terrain. Mountain Valley has conducted thorough assessments of karst features in the Project area, and has developed and submitted to the Commission karst-specific reports and plans to avoid, reduce, and minimize impacts when crossing karst terrain. In addition, Mountain Valley has researched and incorporated route variations and deviations, including the Mount Tabor Variation, in order to minimize impacts to sensitive karst features. Moreover, Mountain Valley has demonstrated that Hybrid Alternative 1A would pose significant constructability issues and not offer a significant environmental advantage over the proposed route.[7]

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[7] On January 26, 2017, Commission staff issued a Post-DEIS Environmental Information Request to Mountain Valley that, among other things, requested information about the so-called Hybrid Alternative 1A. In addition to the information supplied in this Answer, Mountain Valley will submit the requested information to Commission staff in its response to the data request. See Post-DEIS Environmental Information Request, Docket No. CP16-10-000 (Jan. 26, 2017).

The Commission has also properly consulted with Native American tribes consistent with the National Historic Preservation Act ("NHPA") by actively reaching out to tribes to initiate consultation. Mountain Valley has also reached out to the relevant tribes and has conducted extensive cultural resource surveys to identify, and avoid or mitigate, impacts to important historic properties. The DEIS also adequately addresses the potential greenhouse gas emissions attributable to the construction and operation of the MVP Project, including cumulative impacts, and concludes that construction and operation-related emissions are not expected to have a significant impact on local or regional air quality.[8] In sum, the Commission's DEIS is consistent with the requirement that the Commission take a "hard look" at the environmental impacts of its actions.[9]

II.
MOTION TO ANSWER

Although answers to comments are not prohibited under the Commission's Rules of Practice and Procedure, out of an abundance of caution Mountain Valley requests leave to answer comments filed on the DEIS.[10] This Answer will help ensure a complete record upon which the Commission can base its decision on the merits of Mountain Valley's Application and will aid the Commission in its disposition of issues raised in this proceeding.[11] For these reasons, Mountain Valley submits this Answer and

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[8] Mountain Valley is continuing to evaluate comments from other government agencies and will file responses to those agencies separately.

[9] *Mo. Coal. for the Env't v. FERC*, 544 F.3d 955, 958 (8th Cir. 2008) (quoting *Mayo Found. v. Surface Transp. Bd.*, 472 F.3d 545, 549 (8th Cir. 2006)); *see also Balt. Gas & Elec. Co. v. Nat. Res. Def. Council, Inc.*, 462 U.S. 87, 97 (1983).

[10] 18 C.F.R. § 385.213(a).

[11] *See Millennium Pipeline Co.*, 157 FERC ¶ 61,096, at P 8, n.11 (2016) (allowing answer and noting that "Rule 213(a)(3) permits answers to any pleadings not specifically prohibited under paragraph (a)(2)."). *See*

respectfully requests that the Commission permit Mountain Valley to respond to certain comments filed with respect to the DEIS to aid the Commission in its decision-making process.

III.
ANSWER

A. Mountain Valley has Fully Demonstrated the Need and Demand for the Project.

Mountain Valley explained in its Application and other filings that the MVP Project is needed to provide up to 2.0 MMDth per day of new pipeline capacity necessary to meet the firm transportation service requirements for the growing demand for natural gas by local distribution companies ("LDCs"), industrial users, and power generation facilities in the Mid-Atlantic and Southeast U.S. markets, as well as markets in the Appalachian region.[12] The MVP Project would supply natural gas to the Mid-Atlantic and Southeast markets through its interconnection with Transcontinental Gas Pipe Line LLC's ("Transco") Zone 5 compressor Station 165 in Pittsylvania County, Virginia. The entire capacity created by the MVP Project is fully subscribed by five Project shippers—EQT Energy, LLC ("EQT Energy"); Roanoke Gas Company, LLC ("Roanoke Gas"); USG Properties Marcellus Holdings, LLC ("USG"); WGL Midstream, Inc. ("WGL"); and Consolidated Edison Company of New York, Inc. ("Con Edison")—each of which

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also Columbia Gas Transmission, LLC, 157 FERC ¶ 61,247, at P 5, n.4 (2016) (allowing answer to comments because it would "not delay the proceeding, and it would assist the Commission in understanding the issues raised and ensure a complete record"); *Algonquin Gas Transmission, LLC*, 157 FERC ¶ 61,164, at P 10 (2016) (allowing answer to comments that provides information that would assist Commission is decision-making process).

[12] Application for Certificate of Public Convenience and Necessity and Related Authorizations of Mountain Valley Pipeline, LLC at 2, 5 (Oct. 23, 2015) ("Application").

signed binding long-term, 20-year agreements supporting the Project.[13] The Commission considers precedent agreements such as these to be "significant evidence of need or demand for a project."[14]

In addition to precedent agreements, the Commission's Certificate Policy Statement permits the applicant to demonstrate need using a variety of relevant factors, including market studies with demand projections.[15] Mountain Valley has included detailed market reports to further demonstrate the need for the MVP Project. As discussed in more detail below, Mountain Valley previously submitted a detailed report, developed by Wood Mackenzie, analyzing the long-term natural gas supply and demand markets in the Southeast U.S. ("Southeast Report").[16] The Southeast Report concludes that demand in the Southeast United States for natural gas produced in the Appalachian Basin is projected to grow robustly in the near and long term, further supporting the need for the Project. In addition, Mountain Valley is now submitting a second report prepared by Wood Mackenzie analyzing the natural gas supply and demand markets in the Mid-Atlantic U.S. ("Mid-Atlantic Report").[17] The Mid-Atlantic Report concludes that the MVP Project will help satisfy a large and growing demand for capacity and gas supply in

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[13] As noted in the January 27, 2016 supplemental filing, USG Properties Marcellus Holdings, LLC, an MVP Project Shipper, has agreed to reduce its firm transportation capacity commitment by 250,000 Dth per day in order to accommodate the precedent agreement with Con Edison. No new or modified facilities will be necessary to accommodate the Con Edison capacity.

[14] *Arlington Storage Co., LLC*, 128 FERC ¶ 61,261, at P 8 (2009) ("*Arlington Storage*"); *see also Algonquin Gas Transmission, LLC*, 150 FERC ¶ 61,163, at P 23 (2015) (long-term commitments for capacity "constitute strong evidence that there is market demand for the project.").

[15] *See Arlington Storage* at P 8 (citing *Certificate Policy Statement*, 88 FERC ¶ 61,227 at 61,749).

[16] Wood Mackenzie, Inc., Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project (Jan. 2016). The Wood Mackenzie Southeast Report was previously filed with Mountain Valley's January 27, 2016 Answer, and is attached hereto as Exhibit A.

[17] Wood Mackenzie, Inc., Mid-Atlantic Natural Gas Demand in Support of the Mountain Valley Pipeline Project (Jan. 2017). The Wood Mackenzie Mid-Atlantic Report is attached hereto as Exhibit B.

the Mid-Atlantic region over the near and long terms. As these reports demonstrate, there is enough demand for transportation capacity in the region to support the MVP Project and other planned expansions in the region.

In addition, a number of commenters reference a September 2016 report prepared by Synapse on behalf of the Southern Environmental Law Center and Appalachian Mountain Advocates ("AMA") entitled "Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary?" ("Synapse Report") as allegedly undermining the need for the Project.[18] As explained herein, the Synapse Report contains significant methodological deficiencies that render its analysis inaccurate and unreliable, that when corrected, further demonstrate a need for the Project. Therefore, as explained below, Mountain Valley has fully supported the need for the Project.

1. The Southeast Market alone has more than enough natural gas demand to support the MVP Project's full capacity.

Wood Mackenzie, a highly-regarded energy consulting and market research firm, was requested by Mountain Valley to provide a detailed independent analysis of the long-term natural gas supply and demand markets in the Southeast U.S.[19] Wood Mackenzie evaluated recent historical trends and long-term projections of daily natural gas demand, peak demand, pipeline capacity utilization, and supply shifts in the Southeast market. The average daily demand for natural gas in the Southeast is expected to grow by 4.2

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[18] Synapse Energy Economics, Inc., Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity into Virginia and Carolinas (Sept. 12, 2016) (submitted by Kimberly Kirkbride (Dec. 21, 2016) and Russell Chisholm (Dec. 22, 2016)).

[19] The Southeast refers to "the states of Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama and Florida. West Virginia is also included in states served by MVP." *See* Southeast Report at 3, n.1.

billion cubic feet ("Bcf") per day through 2030.[20] This substantial demand growth is driven in large part by coal-fired electric generation plant retirements. "The Southeast leads all regions in total projected migration from coal- to gas-fired power generation."[21] Specifically, 16.5 gigawatts ("GW") of coal-fired plants have closed since 2010, with an additional 8 GW expected to be retired between 2015 and 2030.[22] Gas-fired power plants are expected to supply the largest share of generation replacing coal. The Southeast Report projects that gas-fired generation will comprise nearly 50 percent of the region's total capacity by 2030, making the MVP Project a critically necessary addition to the reliability of the region. In addition, the Southeast Report finds that, by 2020, approximately 3.3 Bcf per day of current gas flows to the Southeast will be displaced in favor of new, lower-priced Appalachian Basin sources.[23] The Southeast Report explains that Southeast buyers' shift from traditional Gulf Coast and Mid-continent sources to Appalachian Basin supplies is driven by the relative economics of the regional supply choices.[24]

Ultimately, the Southeast Report concludes that by 2030, the MVP Project will be needed to help serve as much as 8.3 Bcf per day of new demand for pipeline capacity in the Southeast and existing pipeline capacity demand that is currently flowing gas production from Gulf Coast and Mid-continent producing basins to the Southeast.[25] The chart below depicts the total projected Southeast gas demand and the supply regions that

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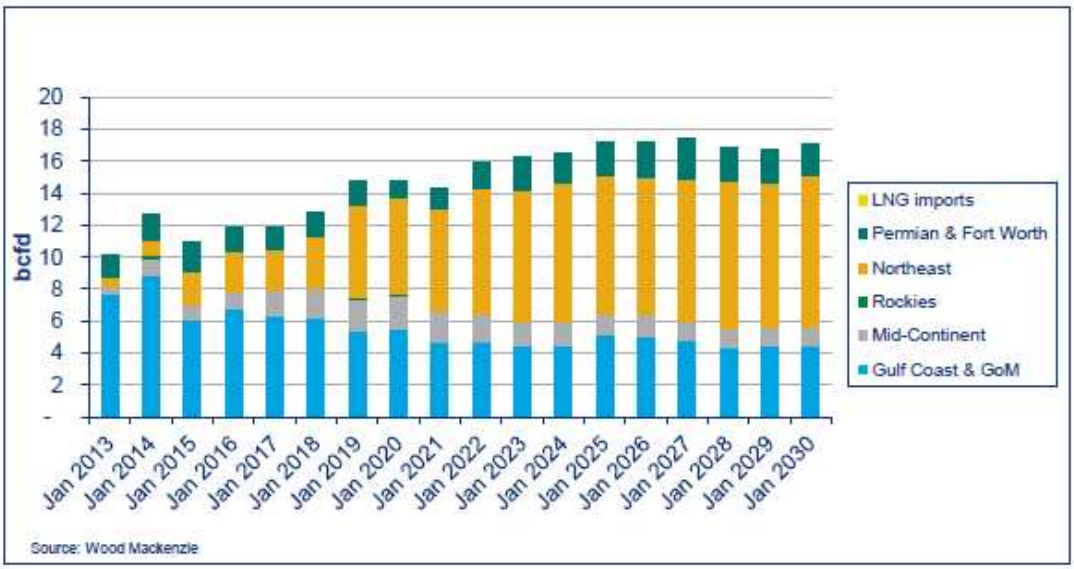
[20] *Id*. at 14.
[21] *Id*.
[22] *Id.* at 15.
[23] *Id*. at 20.
[24] *Id*.
[25] *Id*. at 5, 21.

will meet that demand during the peak winter month of January. As shown, the share of Appalachian Basin supplies, which are labeled "Northeast" in the chart, increases from approximately 1.0 Bcf per day in 2014 to nearly 10.0 Bcf per day by 2030 to meet the growing demand:[26]



This increased demand for natural gas supplies in the Southeast U.S., and in particular from the lower-priced Appalachian Basin supplies, clearly demonstrates the absolute need for the Project to meet current and future demand for natural gas transportation service to Southeast U.S. markets. The Project will further enable Southeast buyers to realize economic benefits by shifting approximately 3.3 Bcf per day of supplies from traditionally more expensive Gulf Coast and Mid-continent sources to Appalachian supplies.[27] The Southeast Report makes clear that the Southeast market

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[26] *Id*. at 19, 20 (Chart 14).
[27] *Id.* at 21.

alone has more than enough natural gas demand to support the MVP Project's 2.0 MMDth per day of capacity even though the Southeast is only one of Mountain Valley's target markets.

2. Demand for natural gas in the Mid-Atlantic market also exceeds the Project's capacity.

Mountain Valley also requested Wood Mackenzie perform a similar analysis of the long-term natural gas supply and demand in the Mid-Atlantic region of the United States.[28] The Mid-Atlantic represents a significant demand region for gas supplies. According to Wood Mackenzie, over 15 percent of the U.S. population resides in the Mid-Atlantic region, making it among the largest regional gas markets.[29] Annual gas consumption in the region has grown from 2.9 trillion cubic feet ("Tcf") in 2010 to over 3.5 Tcf in 2015.[30] The average daily demand for natural gas in the Mid-Atlantic region is expected to grow by 3.9 Bcf per day through 2035, driven in large part by the increased consumption of electricity fueled by natural gas.[31]

Historically, demand for gas in the Mid-Atlantic region depended primarily on seasonal variations, where heating and cooling-degree days drove demand in the winter and summer months.[32] In the future, the Mid-Atlantic Report projects that "both winter and summer gas demand will become more sensitive to electricity consumption and the

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[28] The Mid-Atlantic region refers to the states of Delaware, Maryland, New Jersey, New York, Pennsylvania, and the District of Columbia. *See* Mid-Atlantic Report at 3 n.2.
[29] *Id.* at 4-5.
[30] *Id.* at 5, Figure 2.
[31] *Id.* at 3-4.
[32] *Id.* at 5.

need to fuel gas-fired generation plants."[33] The Mid-Atlantic region is transitioning to increased use of gas-fired generation at a steady rate, as evidenced by the retirement of coal and nuclear power plants, and the phase-out of oil-fired peak shaving.[34] Although the use of renewable energy sources is increasing, natural gas is projected to be the predominant source for power generation.[35] The Mid-Atlantic Report projects that electricity consumption will increase from 480 million megawatt hours ("MWh") in 2016, to 538 MWh in 2035—an increase of 12 percent—with natural gas expected to supply more than approximately 54 percent of this total electricity consumption.[36]

Pipeline capacity construction in the Mid-Atlantic is typically based on satisfying winter demand expectations.[37] Overall demand for gas during peak winter months is forecast to increase by 3.9 Bcf by 2035.[38] With the transition to increased gas-fired generation during the winter, winter-season daily demand in the power sector is projected to grow by 2.0 Bcf between 2015 and 2035.[39] Average winter peak-month daily demand is also expected to increase by approximately 1.9 Bcf per day between 2015 and 2035 across all other sectors, including industrial, residential, and commercial.[40] With coal and nuclear having historically provided the largest percentage of winter baseload power, the

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[33] *Id.*
[34] *Id.* at 5-6, 13.
[35] *Id.* at 6.
[36] *Id.* at 12, Figure 8.
[37] *Id.* at 13.
[38] *Id.* at 13-14, Figure 10.
[39] *Id.* at 14, Figure 11.
[40] *Id.* at 14-15, Figure 12.

switch to winter season gas-fired generation will shift a significant portion of demand to natural gas.[41]

According to the Mid-Atlantic Report, one implication of increased winter demand and gas-fired generation is a "need for gas supply certainty during times of peak demand."[42] Mid-Atlantic power generators traditionally relied on secondary market supplies from traditional supply sources to satisfy peak demand, resulting in supply constraints and price volatility.[43] Increased winter demand and gas-fired generation has the potential to exacerbate these issues. In addition, rising demand in the Gulf Coast region has the potential to raise gas prices, making it more expensive to acquire supplies for peak demand.[44] The MVP Project offers the opportunity to mitigate these issues by providing new pipeline capacity for the delivery of lower-priced, Appalachian Basin supplies.

The Mid-Atlantic Report concludes that by 2035, pipelines like the MVP Project will be necessary to serve as much as 6.1 Bcf per day of new demand for pipeline capacity in the Mid-Atlantic.[45] Further, immediately upon entering service, the MVP Project will help serve current market demand of 2.2 Bcf per day, which by itself exceeds

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[41] *Id.* at 15.
[42] *Id.* The Commission recently approved PJM's proposal to incentivize natural gas generators to encourage fuel supply assurances. *See Centralized Capacity Markets in Reg'l Transmission Orgs. & Indep. Sys. Operators*, 149 FERC ¶ 61,145 (2014) (*Fuel Assurance Guidance Order*) and *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, *order granting reh'g in part*, 152 FERC ¶ 61,064 (2015), *order on reh'g*, 155 FERC ¶ 61,157 (2016), *appeal docketed sub nom. Advanced Energy Mgmt. All. v. FERC*, No. 16-1234 (D.C. Cir. filed July 8, 2016).
[43] *Id.*
[44] *Id.* at 15-16.
[45] *Id.* at 17.

the MVP Project's capacity.[46] The current demand, coupled with the increased demand over the next twenty years, demonstrates the strong need for the MVP Project in the Mid-Atlantic region.

3. The Synapse Report contains numerous flaws and does not properly estimate demand for natural gas pipeline capacity.

Some commenters reference a paper prepared by Synapse as undermining the need for the Project.[47] However, the Synapse Report includes a number of critical flaws in estimating capacity and demand, such as (1) artificially limiting the region in which the Project will satisfy demand, (2) failing to include industry-standard pipeline facility planning tools or concepts and publically-available contract data in determining available firm pipeline capacity, (3) ignoring key commercial and operational realities, and (4) relying on incorrect or questionable assumptions and calculations. These inaccuracies render the report unreliable and ill-suited for assessing the need for critical energy infrastructure and demand for crucial natural gas transportation capacity.

The Synapse Report improperly limits the demand region to Virginia and the Carolinas. Contrary to the assertion in the Synapse Report, Mountain Valley has never stated that one of its primary purposes is to meet growing demand in Virginia and North Carolina. Rather, Mountain Valley has stated repeatedly in public filings that the Project is intended to meet existing and growing demand in the Southeast and Mid-Atlantic

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[46] *Id.* at 16.

[47] *See, e.g.,* Comments on the Draft Environmental Impact Statement for the Proposed Mountain Valley Pipeline and Equitrans Expansion Project of Appalachian Mountain Advocate at 24 (Dec. 23, 2016) ("Comments of AMA"); Comments of Jessica Alley (Dec. 22, 2016); Comments of Pamela Humphrey (Dec. 21, 2016); Comments of Kimberly Kirkbride (Dec. 21, 2016). *See also* Synapse Energy Economics, Inc., Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? (Sept. 12, 2016).

markets, which is broader than Virginia and North Carolina.[48] To transport natural gas to these target markets, Mountain Valley designed the Project to connect with Transco at Transco's Compressor Station 165. By connecting with Transco at that location, Transco shippers can source natural gas from Mountain Valley and move that gas north or south to meet existing and growing demand up and down the eastern seaboard. In addition, Transco shippers and natural gas buyers in the Southeast and Mid-Atlantic markets will shift from traditional Gulf Coast and Mid-continent sources to new, lower-priced Appalachian Basin supplies. This is driven by the relative economics of the regional supply choices, which ultimately benefits consumers in the form of lower prices and higher source reliability and, therefore, is consistent with least cost gas procurement objectives required of regulated utilities.

In any event, even if the Project's demand region is limited to Virginia and the Carolinas, any consideration of new pipeline capacity cannot include the WB Xpress Project and a very large portion of the Atlantic Sunrise Project. As demonstrated by the table attached as Exhibit C to this Answer, such projects are not designed to bring new gas volumes to Virginia and the Carolinas and certainly will not double the region's pipeline capacity to meet regional demand given their stated purposes.

The Synapse Report does not include industry-standard pipeline facility planning tools or concepts in the determination of available firm pipeline capacity in the market. In contrast, the Synapse Report relies on an overly simplistic spreadsheet approach that uses state border capacities and various subjective adjustments as its primary inputs. As

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[48] *See* Application at 2, 5, 10-15, 23-24.

discussed more fully above, the Synapse Report applies this methodology inconsistently to a narrowly-defined geographic market, which hides additional deficiencies that would become apparent if the report reviewed the entirety of Mountain Valley's target markets. Two such deficiencies are: (1) the role of pipeline delivery pressures under peak conditions; and (2) that pipeline capacity is often location-specific and not fungible across a given study region. Neither of these issues is discussed in the Synapse Report.

The Synapse Report also does not consider the publicly-available contract data in the pipelines' Index of Customers, which provides a more reasoned basis for estimating firm pipeline transportation and storage contract quantities in the regional pipeline grid because of at least two considerations. First, interstate natural gas pipelines are required to make all unsubscribed firm capacity available to shippers. Pipelines do not maintain a reserve or withhold capacity from the market. Second, because demand in the Project's target markets has grown consistently over recent decades, at most times, all firm capacity serving the Project's markets has remained fully subscribed by utilities and wholesale energy marketers. There is no unsubscribed capacity that is waiting for a peak day buyer. In contrast to the Synapse Report, the supply and demand studies prepared by Wood Mackenzie, discussed above, appropriately utilize contract information.

Further, the Synapse Report ignores several important commercial and operational realities. For example, the Synapse Report contains no discussion about the rapidly growing Gulf Coast market and the competition market buyers may face. The Synapse Report assumes that gas production and sellers in traditional Gulf Coast supply basins will be adequate at all times, even on peak days, and be able to flow on legacy

south-to-north pipeline capacity. However, as set forth in the Wood Mackenzie reports, rising demand in the Gulf Coast region has the potential to raise gas prices, making it more expensive to acquire supplies for peak demand.[49] In addition, the Synapse Report does not address the illiquidity that often exists in the hourly/mid-day gas markets, particularly during peak conditions. No allowances are made to account for any hourly capacity sources that would be supply constrained at such times. Similarly, the Synapse Report gives no consideration to gas market volatility and the implications for consumers. It is well documented that spot gas prices can move sharply at times when regional capacity utilization is well below 100 percent, and that rising spot gas prices are communicated quickly across power market prices.

In addition to its fundamentally-flawed capacity planning methodology, the Synapse Report relies on numerous incorrect or questionable assumptions and calculations. In the table attached as Exhibit C to this Answer, Mountain Valley provides additional, specific comments regarding incorrect assertions in the Synapse Report. Mountain Valley's non-exhaustive responses to the Synapse Report are intended to highlight discrepancies in the report's analysis and should not be interpreted as Mountain Valley's agreement, support, or endorsement of Synapse's faulty methodology, assumptions, estimates, or conclusions.

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[49] *See* Southeast Report at 14; Mid-Atlantic Report at 15-16, Figure 13.

4. Mountain Valley properly conducted its open season process consistent with Commission requirements.

One commenter argues the Commission's DEIS fails to address the legitimacy of the Mountain Valley's open season process for the Project.[50] AMA notes that the DEIS includes a summary of Mountain Valley's open seasons and argues that some of the precedent agreements were not "connected" to the open season process and that, as a result, the process was not proper.[51] This is simply not so. Mountain Valley properly conducted its open season process garnering shipper support for the full capacity of the Project. AMA does not—and cannot—allege that Mountain Valley discriminated against any potential shipper. Notably, no market participant has made any such allegations. AMA is neither a shipper of natural gas nor a participant in the natural gas transportation market in any way; therefore, its arguments with respect to the open season are specious, at best.

AMA's assertion that the signed precedent agreements were not "connected" to the open season relies on a mischaracterization of the Commission's open season process. The Commission's "open season policies, developed through its orders and opinions, require that new interstate pipeline construction be preceded by a fair open season process through which potential shippers may seek and obtain firm capacity rights."[52]

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[50] *See* Comments of AMA at 8 (Dec. 23, 2016). Although this issue was raised in comments on the DEIS, to the extent Mountain Valley's open season process is addressed by the Commission, the appropriate place to address these arguments is not during the environmental review process, but in the certificate order.
[51] Comments of AMA at 8.
[52] *Pine Prairie Ctr.*, 135 FERC ¶ 61,168, at P 30, *order on reh'g*, 137 FERC ¶ 61,060 (2011). The Commission does not have regulations addressing the need for any open season for pipeline project, except for the Alaska Natural Gas Transportation Projects, which the Commission was required to promulgate under Section 103 of the Alaska Natural Gas Pipeline Act. *Regulations Governing the Conduct of Open*

The Commission has not promulgated any regulations on precisely what an open season must contain, but allows a pipeline to tailor an open season to fit the needs of its project, so long as the pipeline adheres to the Commission's policy and precedent. Open seasons—which may be binding or nonbinding—are designed to provide important information to the market about the project sponsor's proposals and determining whether there is a need for the service the project is proposed to provide. In this way, "[a]n open season is intended to provide transparency to the market concerning potential new capacity and to ensure that new capacity is allocated in a not unduly discriminatory manner. An open season will also provide a project sponsor with valuable information regarding market interest that it can utilize to properly size the project."[53] Therefore, an open season is required to assess market demands and properly size a project, but not all contracts are required to be completed during the short open season window. The Commission allows pipelines to enter into precedent agreements both before and after the open season windows.[54]

As explained in the Application, "Mountain Valley conducted a non-binding open season for firm transportation capacity from June 12, 2014 through July 10, 2014,

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Season for Alaska Natural Gas Transp. Projects, Order No. 2005, FERC Stats. & Regs., Regs. Preambles ¶ 31,174, at P 9, *order on reh'g*, Order No. 2005-A, FERC Stats. & Regs., Regs. Preambles ¶ 31,187 (2005), *amended*, Order No. 2005-B, FERC Stats. & Regs., Regs. Preambles ¶ 31,304 (2010), *reh'g denied*, 132 FERC ¶ 61,175 (2010).

[53] *Pine Prairie Energy*, 135 FERC ¶ 61,168 at P 30.

[54] *See Fla. Gas Transmission Co., LLC*, 154 FERC ¶ 61,256, at P 5 (2016) (Commission approved project with prearranged agreement); *Tex. Gas Transmission, LLC*, 152 FERC ¶ 61,160, at P 9 (2015), *reh'g denied*, 155 FERC ¶ 61,099, at n.4 (2016) (noting additional capacity was subscribed after the open season); *Paiute Pipeline Co*., 151 FERC ¶ 61,132, at P 10 (2015) (noting one shipper was awarded capacity in the open season and another shipper after the open season).

followed by a binding open season from September 2, 2014 through October 21, 2014."[55] These open season notices "provided all market participants, including producers, marketers, LDCs, and power generators, the opportunity to identify transmission capacity needs at diverse receipt locations in the Appalachian Basin to the new interconnect with Transco at its Zone 5 Compressor Station 165 in Pittsylvania County, Virginia as well as additional delivery points between those points."[56] Notably, in its September 2 binding open season notice, Mountain Valley "reserve[d] the right to continue to market the MVP to other shippers beyond the close of the Binding Open Season to the extent capacity remains available or can be developed on commercial and economic terms acceptable to [Mountain Valley],"[57] clearly signaling to the market that Mountain Valley would continue marketing the capacity beyond the short open season windows.

As Mountain Valley clearly explained in its Application, following the open seasons, Mountain Valley continued to market its Project to prospective shippers.[58] Initially, Mountain Valley signed precedent agreements with two foundation shippers, EQT Energy and USG, for the full 2.0 MMDth per day of capacity created by the Project. In the meantime, negotiations with prospective shippers continued and eventually, additional shippers, Roanoke Gas, WGL, and Con Edison signed long-term, 20-year agreements supporting the Project. Despite AMA's erroneous assertions to the contrary, the fact that additional shippers signed up Project capacity, after the initiation of pre-

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[55] Application at 15. Copies of the open season notices are included in Exhibit Z-4 to the Application.
[56] Application at 15.
[57] Application, Exhibit Z-4, Mountain Valley Pipeline, LLC, Binding Open Season Notice at 4.
[58] Application at 15.

filing or after the filing for the Application, is neither improper nor uncommon; indeed it is quite the opposite as it demonstrates the strong market need and demand for the Project.

AMA misapplies and misinterprets Commission precedent to argue the Commission has viewed "with skepticism, precedent agreements that are not connected to the open season process."[59] In *Independence Pipeline*, the Commission held:

> [W]here an affiliated shipper was created virtually overnight to subscribe to the project because the Director of [Office of Pipeline Regulations, predecessor to Office of Energy Projects] threatened to dismiss the application because the precedent agreements predicted by Independence did not materialize, we find that the [precedent] agreement does not constitute compliance with the contract requirement under our policy.[60]

But this certainly is not the case here, where Mountain Valley conducted an orderly open season process in full compliance with Commission policy. The Project was fully subscribed at the commencement of the pre-filing process (Docket No. PF15-3-000) as well as the certificate proceeding (Docket No. CP16-10-000). This is the opposite of the circumstances in *Independence Pipeline*, where an *ex post facto* shipper was established solely for the purpose of showing market need, rather than the other way around. The Project shippers represent genuine and strong market need for the Project. It is fatuous to suggest otherwise.

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[59] Comments of AMA at 11 (citing *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277 at p. 62,141 (2002)).
[60] *Independence Pipeline Co.*, 89 FERC ¶ 61,283, at p. 61,840 (1999).

5. Agreements with the Project shippers are an appropriate demonstration of Project need.

One commenter argues that the DEIS should have discussed the fact that precedent agreements for capacity on the MVP Project are with shippers affiliated with the owners of Mountain Valley.[61] AMA argues that "the presumption of sufficient market need is undercut by the fact that [Project] shippers also decided to take an ownership interest in the project at the same time, and the inherent conflicting signals (i.e., self-interest) implied therefrom."[62] However, AMA fails to acknowledge that the precedent agreements, whether with affiliates or not, represent real and strong actual need and demand for the Project.

As explained, the entire capacity created by the MVP Project is fully subscribed by five project shippers each of which signed binding long-term, 20-year agreements supporting the Project. The Commission considers precedent agreements such as these to be "significant evidence of demand for a project."[63] The Commission has explained that its "concern with precedent agreements is whether they are long-term in nature and whether they are binding," not whether the agreement is with an affiliate.[64] "The fact that the marketers are affiliated with the project sponsor does not lessen the marketers' need

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[61] Comments of AMA at 11.
[62] Comments of AMA at 10.
[63] *Certification of New Interstate Natural Gas Pipeline Facilities*, Statement of Policy, 88 FERC ¶ 61,227, at p. 61,747 (1999); *order clarifying statement of policy*, 90 FERC ¶ 61,128; *order further clarifying statement of policy*, 92 FERC ¶ 61,094 (2000) ("Certificate Policy Statement"). *See also Arlington Storage Co., LLC*, 128 FERC ¶ 61,261, at P 8 (2009) ("*Arlington Storage*"); *Algonquin Gas Transmission, LLC*, 150 FERC ¶ 61,163, at P 23 (2015) (long-term commitments for capacity "constitute strong evidence that there is market demand for the project.").
[64] *Transcon.. Gas Pipe Line Corp*., 81 FERC ¶ 61,104, at p. 61,382 (1997), *reh'g denied*, 82 FERC ¶ 61,084 (1998) (citing *Portland Nat. Gas Transmission Sys.*, 76 FERC ¶ 61,123 (1996)).

for the new capacity or their obligation to pay for it under the terms of their contracts."[65] The on-the-ground reality of pipeline investment and construction bear this out. It is axiomatic that investors in major pipeline projects will not spend large amounts of capital for projects that lack a genuine market. The investors in the MVP Project are no different. The Commission should therefore, consistent with its policy and precedent, find that the precedent agreements supporting the Project are strong evidence of the Project's need.

B. The Commission is not Required to Prepare a Revised or Supplemental Draft EIS for the MVP Project.

A few commenters incorrectly assert that the Commission is required to prepare a revised or supplemental DEIS for the MVP Project.[66] The Allegheny Defense Project ("ADP") asserts, without support, that because the DEIS allegedly "lacks sufficient information about the MVP Project and its potential environmental impacts," "[o]nly the issuance of a revised or supplemental DEIS that thoroughly analyzes this missing information will satisfy NEPA's public comment procedures."[67] Specifically, ADP argues the DEIS lacks sufficient information about the MVP Project and fails to address the need for the Project.[68] Additionally, ADP argues the DEIS lacks sufficient information relating to potential environmental impacts because it calls for certain information to be submitted "either by the end of the DEIS comment period or before

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[65] *Greenbrier Pipeline Co., LLC*, 103 FERC ¶ 61024, at P 17 (2003).
[66] *See, e.g.*, Comments of Allegheny Defense Project et al. at 3 (Oct. 19, 2016) ("Comments of ADP"); Comments of AMA at 3 (Dec. 23, 2016); Comments of Appalachian Trail Conservancy at 3 (Dec. 14, 2016); Comments of Indian Creek Watershed Ass'n at 3 (Dec. 22, 2016); Comments of Montgomery County, Virginia at 9 (Dec. 22, 2016).
[67] Comments of ADP at 4.
[68] Comments of ADP at 4.

construction begins," depriving the public of the "opportunity to meaningfully review and comment on [such] information before the final EIS is issued."[69]

Several commenters, however, misunderstand the purpose of a DEIS, and overstate the requirements under NEPA to prepare a revised or supplemental DEIS. In fact, the Commission's DEIS adequately addresses the purpose and need of the MVP Project and contains more than sufficient information for the public to understand the impacts for the Project and comment meaningfully thereupon.

1. The DEIS adequately addresses the purpose and need for the MVP Project in accordance with NEPA.

ADP argues that the DEIS fails to assess the need for the MVP Project, which "undermines the development of reasonable alternatives to the proposed project" and "frustrates the public's opportunity to provide meaningful comments."[70] However, ADP erroneously conflates the concept of "purpose and need" under NEPA with the Commission's analysis of "need" for the Project under the Natural Gas Act. The Council on Environmental Quality's ("CEQ") NEPA regulations require the Commission to "briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed action."[71] While the need for the Project is manifest, as explained above, it is not the intent of the DEIS to "reach a conclusion on whether there is a need for a proposed project."[72] Rather, "[t]he function

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[69] Comments of ADP at 4.
[70] Comments of ADP at 3-4.
[71] 40 C.F.R. § 1502.13. *See also Kern River Gas Transmission Co.*, 138 FERC ¶ 61,037, at P 27 (2012) ("The Council on Environmental Quality (CEQ) regulations implementing NEPA requires only that an EA include a brief discussion of the need for the proposal.") (citing 40 C.F.R. § 1508.9 (2011) .
[72] *Kern River Gas Transmission*, 138 FERC ¶ 61,037 at P 27.

of a statement of purpose and need . . . is to define the objectives of the proposed action such that the agency can identify and consider legitimate alternatives."[73] The Commission, therefore, is not required to consider "alternatives that are not consistent with the purpose and need of the proposed project."[74]

Contrary to ADP's assertion, the DEIS includes an appropriate statement describing the MVP Project's purpose and need, in compliance with NEPA. The DEIS states that the purpose of the MVP Project is to alleviate transportation constraints by providing necessary pipeline infrastructure to transport lower-priced natural gas produced in the Appalachian Basin to industrial users, power generators, and local distribution companies in the Northeast, Mid-Atlantic, and Southeast.[75] The DEIS also notes that the MVP Project is fully subscribed by five separate Project shippers.[76] Likewise, the DEIS sufficiently addresses all reasonable alternatives to the MVP Project, including the "No Action Alternative," alternative modes of natural gas transportation, system alternatives, route alternatives and variations, and aboveground facility alternatives.[77] Thus, it is clear that the DEIS adequately addresses the purpose and need of the Project in compliance with NEPA, and that the Commission has not "undermine[d] the

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[73] *Kern River Gas Transmission*, 138 FERC ¶ 61,037 at P 27 (citing *Colo. Envtl. Coal. v. Dombeck*, 185 F.3d 1162, 1175 (10th Cir. 1999)).
[74] *Dominion Transmission, Inc.*, 155 FERC ¶ 61,106, at P 113 (2016) (citing *Pacific Coast Fed'n of Fishermen's Ass's v. Blank*, 693 F.3d 1084, 1100 (9th Cir. 2012)).
[75] DEIS at 1-7, 1-8.
[76] DEIS at 1-9.
[77] DEIS at 3-3 to 3-90.

development of reasonable alternatives."[78] To suggest otherwise, as ADP does, would ignore the plain content of the DEIS.

2. The DEIS contains sufficient information to provide the public an opportunity for meaningful analysis and neither a revised or supplemental DEIS is warranted.

The Council on Environmental Quality ("CEQ") regulations implementing NEPA provide that an agency shall prepare a revised DEIS if the "draft statement is so inadequate as to preclude meaningful analysis[.]"[79] The CEQ regulations further provide that an agency shall prepare a supplemental DEIS if: "(i) The agency makes substantial changes in the proposed action that are relevant to environmental concerns; or (ii) There are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impacts."[80] Neither of these conditions is present in this case. There is no basis to warrant a revised or supplemental DEIS.

As the United States Court of Appeals for the District of Columbia has held, "[b]y its very name, the DEIS is a draft of the agency's proposed [final] EIS, and as such the purpose of a DEIS 'is to elicit suggestions for change[,]'" and to provide a "springboard for public comment."[81] In the same vein, the Commission has explained that the DEIS "put[s] interested parties on notice of the types of activities contemplated and of their

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[78] Comments of ADP at 3.
[79] 40 C.F.R. § 1502.9(a).
[80] 40 C.F.R. § 1502.9(c)(1)(i)-(ii).
[81] *Nat'l Comm. for the New River v. FERC*, 373 F.3d 1323, 1329 (D.C. Cir. 2004) (quoting *City of Grapevine, Tex. v. Dep't of Transp.*, 17 F.3d 1502, 1507 (D.C. Cir. 1994); *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989)) ("*New River*"). *See also Se. Supply Header, LLC*, 120 FERC ¶ 61,257, at P 27 (2007) (denying request to issue revised DEIS where DEIS called for submission information before the end of the comment period or prior to construction).

impacts."[82] Commenters must show that any alleged omissions in the DEIS "left the public unable to make known its environmental concerns about the project's impact."[83] It is not sufficient that the public was not able to "analyze each aspect of the project, such as specific rather than generalized statements of proposed sitings."[84] Courts have recognized that due to "the practical realities of large projects," such as the MVP Project, "if every aspect of the project were required to be finalized before any part of the project could move forward, it would be difficult, if not impossible, to construct the project."[85]

These practical realities are evidenced by the Commission's "longstanding practice to issue environmental documents along with recommended mitigation measures that request specific documentation of agency consultation, construction plans, and detailed information to supplement baseline data."[86] It is thus reasonable—and consistent with Commission practice—for the DEIS to contemplate that certain information will be provided subsequent to issuance of the DEIS. The mere fact that additional information will be submitted after issuance of the DEIS does not, as commenters erroneously suggest, in and of itself require the Commission to prepare a revised DEIS. "NEPA does not require agencies to constantly revise their issued analyses as new information

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[82] *Constitution Pipeline Co.*, 154 FERC ¶ 61,046, at P 31 (2016).
[83] *New River*, 373 F.3d at 1329. The volume of comments received in response to the DEIS indicates the opposite—that commenters were more than able to make environmental concerns known to the Commission. *See New River*, 373 F.3d at 1329-30.
[84] *New River*, 373 F.3d at 1329.
[85] *New River*, 373 F.3d at 1329 (quoting *E. Tenn. Nat. Gas Co.*, 102 FERC ¶ 61,225, at P 25 (2003)); *see also Robertson*, 490 U.S. at 352 (NEPA does not require all plans to be finalized and complete in draft or even final EIS).
[86] *Algonquin Gas Transmission, LLC*, 150 FERC ¶ 61,163, at P 56 (2015) , *reh'g denied*, 154 FERC ¶ 61,048 (2016).

becomes available."[87] The "fact that many of the permits, approvals, consultations, and variances required for the . . . project have been or will be filed after the formal public notice and comment periods does not mean that the public is excluded from meaningful participation."[88] On the contrary, information filed after the comment period continues to be "accessible to the public in the Commission's electronic database."[89]

Likewise, the Commission is not required to prepare a supplemental DEIS because the practical realities of the MVP Project necessitate additional filings after issuance of the DEIS. The Supreme Court has soundly rejected the notion that an agency is required to prepare a supplemental DEIS each time new information becomes available. According to the Court, requiring otherwise "would render agency decisionmaking intractable, always awaiting updated information only to find the new information outdated by the time a decision is made."[90] Whether to prepare a supplemental DEIS is subject to the Commission's discretion.[91] The Commission's decision on whether to prepare a supplemental DEIS is subject to a rule of reason: "[i]f there remains major 'Federal action' to occur, and if the new information is sufficient to show that the remaining action will 'affect the quality of the human environment' in a significant manner or to a significant extent not already considered, a supplemental EIS

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[87] *Dominion Cove Point LNG, LP*, 151 FERC ¶ 61,095, at P 52 (2015).
[88] *Constitution Pipeline*, 154 FERC ¶ 61,046 at P 31.
[89] *Constitution Pipeline*, 154 FERC ¶ 61,046 at P 31.
[90] *Marsh v. Or. Nat. Res. Council*, 490 U.S. 360, 373 (1989). *See also Altamont Gas Transmission Co.*, 75 FERC ¶ 61,348 (1996) (denying request for supplemental EIS).
[91] *Wisconsin v. Weinberger*, 745 F.2d 412, 417 (7th Cir. 1984).

must be prepared."[92] The significance of the new information depends on whether it "provides a *seriously* different picture of the environmental landscape."[93]

In this case, the information to be filed subsequent to issuance of the DEIS does not contemplate fundamental changes to the environmental impacts of the Project and will not result in a seriously different picture of the environmental impacts of the Project. The DEIS contains seven recommendations with respect to information Mountain Valley is requested to file prior to the end of the comment period.[94] Specifically, the DEIS requested that Mountain Valley file information relating to coordination with stakeholders regarding the crossing of the Appalachian National Scenic Trail; the Mount Tabor Variation and other minor route variations; proximity to waterbodies; avoidance of permanent impacts to and justification of certain rights-of-way within wetlands; and minimization of impacts to migratory birds. The subsequent filings are intended to supplement baseline data in a manner that takes the practical realities of the MVP Project into account and provides the Commission with information necessary to prepare the final EIS. Not only has Mountain Valley fully complied with the conditions recommended in the DEIS and submitted the required information before the end of the DEIS comment period, Mountain Valley has also gone above and beyond what was required and completed a number of additional mitigation measures not required until

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[92] *Marsh*, 490 U.S. at 373-74.
[93] *City of Olmsted Falls, OH v. FAA*, 292 F.3d 261, 274 (D.C. Cir. 2002) (quoting *Wisconsin*, 745 F.2d at 418).
[94] DEIS at 5-20 – 5-21, Recommendations 14-20.

after issuance of a certificate order.[95] In addition, the proposed reroutes filed with the Commission in October 2016 ("October 2016 Proposed Route"),[96] addressed in further detail below, does not require a supplemental EIS. All major reroutes in the October 2016 Proposed Route were addressed already in the DEIS and the remaining variations and adjustments are only minor in nature. None of the reroutes represent "substantial changes in the proposed action" or "significant new circumstances or information relevant to environmental concerns" requiring a supplement.[97] Further, the Commission has allowed newly identified potentially affected landowners to submit comments, thus affording any landowners potentially affected by the October 2016 Proposed Route the opportunity to participate in the Commission's environmental review process.[98]

C. The Commission is not Required to Prepare a Programmatic EIS for the MVP Project.

Some commenters incorrectly assert that the Commission is required to prepare a programmatic EIS encompassing the entire region including impacts of several different projects.[99] The Roanoke Appalachian Trail Club ("RATC") argues, as it did previously

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[95] In addition to the environmental mitigation conditions recommended in the DEIS that required a response from Mountain Valley before the end of the DEIS comment period, Mountain Valley also complied with recommended conditions 12 (adopting the Mayapple School Route Alternative), 13 (adopting the Sunshine Valley School Route Alternative), 24 (Landslide Mitigation Plan), 25 (filing fracture trace/lineament analysis results), 28 (filing Pigg River and Blackwater River HDD studies), and 35 (adopting the October 2016 Proposed Route does not impact the Mill Creek Springs Natural Area Preserve).

[96] *Mountain Valley Pipeline, LLC*, Supplemental Materials – Oct. 2016 Proposed Route, Attachment A, Analyses for Minor Route Variations Incorporated into the October 2016 Proposed Route and Variation 35 (Oct. 14, 2016) ("October 2016 Proposed Route Analyses").

[97] 40 C.F.R. § 1502.9(c)(1)(i)-(ii).

[98] Letter Discussing Route Modifications to Mountain Valley Pipeline LLC's Mountain Valley Pipeline Project (Jan. 13, 2017) (providing for a comment deadline of February 21, 2017).

[99] *See, e.g.*, Comments of Roanoke Appalachian Trail Club ("Comments of RATC") at 2 (dated June 11, 2015, filed Oct. 17, 2016); Comments of AMA at 4 (Dec. 23, 2016); Comments of Appalachian Trail

in this proceeding, that NEPA requires the Commission to prepare a programmatic EIS that includes the Mountain Valley Pipeline, Atlantic Coast Pipeline, the Appalachian Connector Pipeline, and the WB XPress Project.[100] There is no basis for the assertion that the Commission must prepare a region-wide EIS for pipeline projects proposed in the central Appalachian region.[101] The Commission has repeatedly and appropriately rejected arguments identical to those of RATC and other commenters requesting a programmatic EIS.[102] The Commission's long-standing, existing practice of performing a fulsome environmental review of an individual project that includes a review of the direct, indirect, and cumulative impacts of the project and all reasonably foreseeable alternatives in individualized NEPA review documents fully satisfies the requirement that the Commission take a "hard look" at the environmental impacts of its actions.[103] Simply put, the Commission is not required to prepare a programmatic EIS under NEPA. Indeed, the Commission has determined that it would not be appropriate to prepare a programmatic environmental impact statement for the Atlantic Coast and Mountain

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Conservancy at 5 (Dec. 8, 2016); Comments of Sierra Club-Virginia Chapter at 9 (Dec. 21, 2016). The Appalachian Connector Project is purely speculative as no application to move it forward has ever been filed at FERC.

[100] Comments of RATC at 2. *See also Mountain Valley Pipeline LLC*, Motion to Answer and Answer of Mountain Valley Pipeline, Docket No. CP16-00 (Jan. 27, 2016) (addressing assertions that FERC is required to prepare a programmatic EIS).

[101] Comments of RATC at 2.

[102] *See, e.g., Dominion Transmission, Inc.*, 152 FERC ¶ 61,138, *order on reh'g*, 153 FERC ¶ 61,284 (2015); *Tex. Gas Transmission, LLC*, 152 FERC ¶ 61,160, at P 53 (2015); *Tenn. Gas Pipeline Co., L.L.C.*, 150 FERC ¶ 61,160 (2015). *See also* Response to U.S. Representative Bob Goodlatte's Correspondence Forwarding Letter Regarding the Mountain Valley Pipeline Project, Docket No. CP16-10 (Nov. 25, 2015) (Letter from Chairman Norman Bay stating that Commission determined it was not appropriate to prepare a programmatic EIS for the MVP Project).

[103] *Mo. Coal. for the Env't v. FERC*, 544 F.3d 955, 958 (8th Cir. 2008) (quoting *Mayo Found. v. Surface Transp. Bd.*, 472 F.3d 545, 549 (8th Cir. 2006)); *see also Balt. Gas & Elec. Co. v. Nat. Res. Def. Council, Inc.*, 462 U.S. 87, 97 (1983).

Valley Pipeline projects.[104] Further, the DEIS fully addresses, and rejects, RATC's and other commenters' requests that the Commission prepare a region-wide EIS that includes planned and proposed pipeline projects in the same geographic area as the MVP Project.[105]

The decision regarding "whether to prepare a programmatic EIS at all [is] initially committed to [the Commission's] discretion."[106] Courts have explained that "[u]nder CEQ regulations a programmatic EIS *should* be prepared if actions are 'connected,' 'cumulative,' or sufficiently 'similar' that a programmatic EIS is 'the best way' to identify the environmental effects."[107] The United States Court of Appeals for the District of Columbia Circuit has noted that two considerations are helpful in reviewing the decision whether or not to prepare a programmatic EIS: "(a) Could the programmatic EIS be sufficiently forward looking to contribute to the decisionmakers' basic planning of the overall program? and, (b) Does the decisionmaker purport to 'segment' the overall program, thereby unreasonably constricting the scope of primordial environmental evaluation?"[108]

The Commission does not "direct the development of the gas industry's infrastructure," nor does it "engage in regional planning."[109] Rather, the Commission "acts on individual applications filed by entities proposing to construct interstate natural

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[104] *See* Letter of Chairman Norman Bay to Congressman Bob Goodlatte, Docket Nos. CP16-10-000, CP15-554-000 (Jan. 27, 2016).
[105] DEIS at 1-21.
[106] *Nat'l Wildlife Fed'n v. Appalachian Reg'l Comm'n*, 677 F.2d 883, 888 (D.C. Cir. 1981) (citing *Kleppe v. Sierra Club*, 427 U.S. 390, 412 (1976)).
[107] *Found. on Econ. Trends v. Heckler*, 756 F.2d 143, 159 (D.C. Cir. 1985) (citing 40 C.F.R. § 1508.25).
[108] *Nat'l Wildlife Fed'n*, 677 F.2d at 889.
[109] DEIS at 1-22 (quoting *Tex. E. Transmission, LP*, 141 FERC ¶ 61,043, at P 25 (2012).

gas pipelines."[110] The Commission's environmental reviews are highly fact specific, which supports the Commission's project-specific analyses. Consistent with NEPA, the Commission conducts a "thorough examination of the potential impacts of specific projects," however; a programmatic EIS is not required.[111] The Commission has explained where there is no showing of an "interrelationship or connectedness between the various [proposed] pipeline projects . . . beyond the fact that they might share a general regional proximity" the Commission is not required to prepare a programmatic EIS.[112]

As explained in the DEIS, "there is no Commission plan, policy, or program for the development of natural gas infrastructure," and the Commission's "review and approval of individual projects under the NGA does not constitute a coordinated federal program."[113] Without an "overall program" to be reviewed in a programmatic EIS, none of the projects identified in the RATC's comments are "connected," "cumulative," or sufficiently "similar" that a programmatic EIS is "the best way" to identify the environmental effects. The MVP Project is a stand-alone project with its own customers and specific project purpose, independent from the other three projects, and will have limited environmental impacts that are separate and distinct from the other referenced

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[110] DEIS at 1-22. *See also Dominion Transmission*, 152 FERC at P 30 (noting that "[t]he Commission will issue a certificate to authorize a proposed pipeline project if it finds in accordance with section 7(e) of the NGA that the construction and operation of the proposed facilities 'is or will be required by the present or future public convenience and necessity.'") (quoting 15 U.S.C. § 717f(e)) .

[111] DEIS at 1-22.

[112] *Tenn. Gas Pipeline*, 150 FERC ¶ 61,160 at P 55.

[113] DEIS at 1-21-22 (citing *Tex. E. Transmission, LP*, 149 FERC ¶ 61,259, at PP 38-47 (2014); *Columbia Gas Transmission, LLC*, 149 FERC ¶ 61,255 (2014)). *See also See Dominion Transmission*, 153 FERC at P 62; *Algonquin Gas Transmission*, 154 FERC ¶ 61,048 at P 97 ("We have explained that there is no Commission plan, policy, or program for the development of natural gas infrastructure.").

projects. A programmatic EIS would not be "sufficiently forward looking" to assist the Commission's review because none of the four projects mentioned by the commenters are part of the Commission's "basic planning of [an] overall program." The Commission also does not "purport to 'segment' the overall program," but is providing, and will continue to provide, the necessary environmental review for all proposed projects, as required by NEPA.

Further, a programmatic EIS is unnecessary because the DEIS already considers the cumulative impacts of other projects within the geographic scope of analysis for the MVP Project, including the WB Xpress Project, the Supply Header Project, the Atlantic Coast Pipeline Project, the Rover Pipeline Project, the Columbia Smithfield III Expansion Project, and the Virginia Southside Expansion Project.[114] The DEIS concluded that in consideration of best management practices, design features and mitigation measures, as well as federal and state laws and regulations protecting resources, that the MVP Project would not have significant adverse cumulative impacts when added to other reasonably foreseeable future actions within the geographic scope.[115]

Where actions are actually "connected" such that a programmatic EIS is the best way to evaluate impacts, the Commission does not hesitate to combine environmental

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[114] DEIS at 4-494 to 4-496.

[115] DEIS at 4-517. As noted by the Chairman, "[t]he Commission does not direct the development of the gas industry's infrastructure, either on a broad regional basis or in the design of specific projects, and does not engage in regional planning exercises that would result in the selection of one project over another if both are supported by market needs. As a result, Commission staff has determined that it would not be appropriate to prepare a programmatic environmental impact statement for the Atlantic Coast and Mountain Valley Pipeline projects."

reviews into specific document.[116] The DEIS itself is one such example, as the Commission combined its review of the MVP Project and Equitrans Expansion Project into a single document. Therefore, the Commission is willing and able to combine multiple projects into a single environmental review where doing so is appropriate.

Neither RATC nor any other commenter has made any showing that the MVP Project is "functionally or financially dependent upon any other project" or that the MVP Project is "dependent upon the timing of another project's approval or service date" that may require the combination of the projects into a single NEPA review.[117] As the DEIS concludes, the Commission is, therefore, not required to prepare a programmatic EIS that includes the MVP Project.

D. Impacts From Upstream Natural Gas Production are Neither Causally Connected to the MVP Project nor Reasonably Foreseeable.

Commenters have asserted that the Commission should conduct additional analysis to consider impacts from upstream natural gas production, including those caused by hydraulic fracturing or "fracking," allegedly induced by the MVP Project.[118] However, the "FERC does not regulate activities associated with the exploration and production of natural gas, including fracking."[119] The DEIS recognized that individual

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[116] *See Fla. Se. Connection, LLC*, Final Environmental Impact Statement, Docket Nos. CP14-544, CP15-16, CP15-17 (Dec. 18, 2015) (combining the Florida Southeast Connection, Hillabee Expansion, and Sabal Trail Projects into a one environmental impact statement). *Tenn. Gas Pipeline Co., LLC*, Final Environmental Assessment, Docket Nos. CP14-88, CP14-100 (July 16, 2014) (combining Tennessee's Niagara Expansion Project with National Fuel Gas Supply Corporation's Northern Access 2015 Project).
[117] *Tenn. Gas Pipeline, L.L.C.*, 150 FERC ¶ 61,160, at P 55 (2015).
[118] *See, e.g.*, Comments of AMA at 91, 96; Comments of Blue Ridge Environmental Defense League at 2 (Dec. 22, 2016); Comments of Chesapeake Climate Action Network at 1 (Dec. 22, 2016).
[119] DEIS at 1-22. *See, e.g., Constitution Pipeline Co., LLC*, 154 FERC ¶ 61,046, at P 137 (2016) ("The Commission does not have jurisdiction over natural gas production."); *Dominion Transmission, Inc.*, 156

states, and not FERC, regulate the exploration and production of natural gas.[120] Further, a review of upstream natural gas development is not required under NEPA because the impacts of such drilling are not causally connected to the MVP Project or reasonably foreseeable. The DEIS thus properly concluded that impacts from upstream natural gas production are outside the scope of issues to be considered in the EIS.[121]

As the Commission recently explained, "the environmental effects resulting from natural gas production are generally neither caused by a proposed pipeline (or other natural gas infrastructure) project nor are they reasonably foreseeable consequences of our approval of an infrastructure project, as contemplated by the CEQ regulations."[122] According to the DEIS, although FERC is generally aware that natural gas will be produced in the Appalachian Basin, "there is no reasonable way to determine the exact wells providing gas transported in the MVP . . . pipeline[], nor is there a reasonable way to identify the well-specific exploration and production methods used to obtain those gas supplies."[123] The Commission staff's approach in the DEIS is consistent with Commission and court precedent.

Federal appellate courts have consistently upheld the Commission's orders declining to consider so-called "induced" shale gas production as when conducting its

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FERC ¶ 61,140, at P 44 (2016) (same); *Tenn. Gas Pipeline Co., LLC,* 156 FERC ¶ 61,156, at P 83 (2016) (same).

[120] DEIS at 1-22.

[121] DEIS at 1-23.

[122] *Dominion Transmission*, 153 FERC at P 13(internal citation omitted); DEIS at 1-22.

[123] DEIS at 1-22.

NEPA review.[124] The Commission has found that rather than pipeline projects causing natural gas drilling "the opposite causal relationship is more likely, *i.e.*, once production begins in an area, shippers or end users will support the development of a pipeline to move the produced gas."[125]

The Commission has further explained that the impacts from the development of upstream natural gas resources "are not reasonably foreseeable."[126] In *Central New York*, the Commission found that:

> To require the Commission to guess whether or when permitted wells may be drilled, when additional wells may be permitted, and where additional infrastructure such as compressor and gas processing stations, gathering lines, *etc*. will be placed, would at best amount to speculation as to future events and would be of little use as input in deciding whether to approve the [project].[127]

On review, the United States Court of Appeals for the Second Circuit upheld the Commission's determination regarding "induced" natural gas production, holding that "FERC reasonably concluded that the impacts of that development are not sufficiently

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[124] *See e.g.*, *Cent. N.Y. Oil & Gas Co., LLC*, 137 FERC ¶ 61,121 (2011), *order on reh'g*, 138 FERC ¶ 61,104 (2012), upheld by the Second Circuit in *Coal. for Responsible Growth & Res. Conservation v. FERC*, 485 Fed. Appx. 472, 474 (2nd Cir. 2012) ("*Central N.Y. Oil and Gas Co.*"); *Sierra Club v. FERC*, 827 F.3d 59, 69 (D.C. Cir. 2016).

[125] *Nw. Pipeline, LLC*, 157 FERC ¶ 61,093, at P 32 (2016) (noting that "[t]o date, the Commission has not been presented with a proposed project that the record shows will cause the predictable development of gas reserves," and that "the opposite causal relationship is more likely"); *Dominion Transmission*, 153 FERC at P 24; DEIS at 1-22.

[126] *Central N.Y. Oil and Gas Co.*, 137 FERC at P 95.

[127] *Central N.Y. Oil and Gas Co.*, 137 FERC at P 100. *See also Nw. Pipeline*, 157 FERC at P 33 (observing that the Commission "generally does not have sufficient information to determine the origin of the gas that will be transported," and that a "meaningful analysis of production impacts would require more detailed information." "Accordingly, the impacts of natural gas production are not reasonably foreseeable because they are 'so nebulous' that [the Commission] cannot forecast their likely effects.") (citing *Habitat Educ. Ctr. v. U.S. Forest Serv.*, 609 F.3d 897, 902 (7th Cir. 2010) (impacts that cannot be described with sufficient specificity for meaningful consideration need not be included in environmental analysis)).

causally-related to the project to warrant a more in-depth analysis."[128] Consistent with this opinion and the Commission's precedent, the Commission is not required to look at the impacts of upstream natural gas drilling in its review of the MVP Project. The DEIS thus properly declined to consider impacts from upstream natural gas production.

E. The MVP Project is not Contemplated for LNG Exports.

Commenters continue to assert that the ultimate purpose of the MVP Project is to export natural gas overseas as liquefied natural gas ("LNG").[129] The DEIS correctly observes that this is incorrect.[130] As noted in the DEIS, Mountain Valley "clearly stated in its application that it did not design its facilities to transport natural gas to an LNG export terminal."[131] Mountain Valley explained that the MVP Project "is not designed to provide natural gas to any LNG export terminal and has no intention of seeking authorization under Section 3 of the NGA to export natural gas."[132] The MVP Project will terminate at Transco Station 165, which is located inland more than 150 miles from the nearest coastal port in Virginia, and farther still from the nearest LNG export facility.[133] Although the DEIS notes that the Dominion Cove Point LNG terminal is the nearest LNG export facility at 190 miles away,[134] the "MVP Project has no direct connection to Cove Point and is [at least] two pipelines removed from the export

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[128] *Coal. for Responsible Growth & Res. Conservation*, 485 Fed. Appx. at 474.
[129] *See, e.g.*, Comments of Blue Ridge Environmental Defense League at 22-26 (Dec. 22, 2016); Comments of David Arthur (Dec. 14, 2016); Comments of Katie Bennett (Dec. 13, 2016); Comments of David Werner (Dec. 7, 2016).
[130] DEIS at 1-7 – 1-8.
[131] DEIS at 1-7 – 1-8.
[132] Application, Resource Report 1, General Project Description at 1-2(Oct. 23, 2015).
[133] Application, Resource Report 1 at 1-2.
[134] DEIS at 1-8.

facility."[135] Accordingly, the MVP Project "does not have the physical ability to export natural gas," and the DEIS correctly concluded that the MVP Project is not contemplated for LNG exports.[136]

F. The DEIS Properly Considers Environmental Issues.

1. The Kastning Report contains numerous deficiencies.

Several commenters have asserted that the DEIS fails to consider the karst issues included in the July 2016 report entitled "*An Expert Report on Geologic Hazards in the Karst Regions of Virginia and West Virginia*," by Ernst H. Kastning ("Kastning Report").[137] However, the Commission's DEIS cites to and considers the Kastning Report.[138] In addition, as detailed below, Mountain Valley prepared and submitted information that demonstrates the deeply flawed nature of the Kastning Report.

During the early environmental review process for this Project, Mountain Valley submitted extensive data regarding karst regions in Virginia and West Virginia. This formulated data was reported in Mountain Valley's Karst Hazards Assessment, which was first submitted to the Commission in October 2015 and subsequently updated in April 2016 and again in October 2016.[139] The Karst Hazards Assessment provided a comprehensive summary of karst features identified within a secondary karst buffer (0.25-mile of the alignment) and the 150-foot right-of-way. The Karst Hazards

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[135] Application, Resource Report 1 at 1-2, DEIS at 1-8.
[136] Application, Resource Report 1 at 1-2.
[137] Comments of the Virginia Chapter of the Sierra Club on Hazards Associated with Karst Topography in the Area of the Mountain Valley Pipeline (July 13, 2016) (submitted by AMA).
[138] DEIS at 4-72.
[139] Application at Resource Report 6, Appendix D.2; Mountain Valley Pipeline, LLC, Responses to Data Requests issued March 31, 2016, Attachment DR2 RR2-12 (Apr. 21, 2016); Mountain Valley Pipeline, LLC, Supplemental Materials – October 2016 Proposed Route, Attachment H, (Oct. 14, 2016).

Assessment utilized extensive site specific investigations, field mapping and desktop studies that include aerial photographs, geologic mapping and review of published and unpublished karst resources. Karst features were catalogued and risk ranked relative to size, location, drainage patterns, and other features pertinent to the Project alignment. Further, Mountain Valley took several additional steps to mitigate the impacts of the Project in karst formations. Mountain Valley prepared and submitted to the Commission a Karst Mitigation Plan and a Karst-specific Erosion and Sediment Control Plan to reduce impacts that could arise when crossing karst terrain.[140]

Months after Mountain Valley submitted its updated Karst Hazards Assessment, but prior to the issuance of the DEIS on September 16, 2016, the Kastning Report was submitted to the Commission.[141] Therefore, while drafting the DEIS, the Commission had the karst information and reports submitted by Mountain Valley, as well as the Kastning Report, before it. The DEIS cites to Mountain Valley's Karst Hazards Assessment Report, Karst Mitigation Plan, and Karst-specific Erosion and Sediment Control Plan numerous times.[142] Specifically, Appendix L of the DEIS identifies all the karst features within 0.25 mile of the MVP Project and recommends special construction techniques and measures for Mountain Valley to implement in order to reduce and mitigate impacts from karst. In addition, the DEIS cited to the Kastning Report in the

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[140] Application at Resource Report 6, Appendix 6-D (Karst Mitigation Plan); Mountain Valley Pipeline LLC Responses to Data Requests issued December 24, 2015, Attachment General 1a-1 (Erosion and Sediment Control Plan (West Virginia)) and Attachment General 1b, (Karst-Specific Erosion and Sediment Control Plan-Virginia) (Feb. 26, 2016).

[141] *See* Comments of the Virginia Chapter of the Sierra Club on Hazards Associated with Karst Topography in the Area of the Mountain Valley Pipeline (July 13, 2016) (submitted by AMA).

[142] *See e.g.*, DEIS at 2-34 (listing the plans and reports applicable to the MVP Project), 4-35, 4-49, 4-78, 4-110, 4-112, 4-116.

discussion of karst,[143] and includes the Kastning Report in the References section.[144] In finding that impacts would be reduced to less-than-significant levels, the DEIS cited to "resource-specific mitigation plans filed with [Mountain Valley's] application to the FERC, or included in various supplemental filings, including its *Karst Mitigation Plan* and *Karst-specific Erosion and Sediment Control Plan* to reduce impacts when crossing karst terrain[.]"[145] A review of the karst analysis in the DEIS makes it clear that Commission Staff specifically and properly considered karst issues and the relevant reports and assessments filed by Mountain Valley and others, including the Kastning Report.

Following the issuance of the DEIS, Mountain Valley submitted to the Commission an analysis of the Kastning Report prepared by its karst experts ("Rebuttal to Kastning").[146] Mountain Valley's Rebuttal to Kastning concluded that the Kastning Report is deeply flawed and "reaches an erroneous conclusion on the risk presented by the [MVP] Project and does not account for the true nature of the karst hydrogeological systems in question."[147] The Rebuttal to Kastning identifies various inaccurate and fundamentally flawed claims and assumptions in the Kastning Report, including assertions that karst, and especially Appalachian karst, is a "no-build" zone, which is obviously false considering there are existing natural gas pipelines that traverse karst terrain, including the Appalachian Mountains of Virginia and West Virginia. In addition

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[143] DEIS at 4-72.
[144] DEIS at Appendix V.
[145] DEIS at ES-14.
[146] *Mountain Valley Pipeline, LLC*, Supplemental Materials, Attachment E, Analysis of the July 2016 Report by Ernst H. Kastning (Dec. 22, 2016).
[147] *Id.* at 1.

to pipelines, the Kastning Report also ignored the other numerous current uses of the karst landscapes in West Virginia and Virginia, including the wide use of domestic wells and septic systems, the farms and pastures that have uncontrolled runoff, and the roads, homes and other structures that are constantly being constructed on karst.

In conclusion, the Kastning Report does not: (1) present any new information that Mountain Valley has not addressed in filings with the Commission; (2) reflect the reality of construction practices in karst terrain; (3) consider the volumes of technical information that Mountain Valley has provided to the Commissions that properly characterizes karst features and the risks; or (4) consider Mountain Valley's prior actions or future plans to avoid, assess, and mitigate these risks. The DEIS, therefore, properly concludes that, "[w]ith the implementation of the [Mountain Valley's] [best management practices], as well as [Commission staff's] additional recommendations regarding karst topography and mines, . . . impacts on geological resources would be adequately minimized."[148]

2. Mountain Valley will reduce impacts of construction and operation in karst areas.

In addition to the Kastning Report, other commenters have raised concerns regarding karst. Mountain Valley has implemented a variety of safety measures and conducted field verifications to better understand the potential sensitive hydrology in the Project area and how to best avoid impacting features that may be present in karst terrain. Mountain Valley has thoroughly assessed karst features and understands the sensitive

[148] DEIS at 5-2.

details of these formations and how best to operate in an environmentally responsible manner. Mountain Valley has developed karst-specific reports and plans, as well as researched and incorporated route variations and deviations to avoid sensitive karst features and areas of concern. Based on scientific surveying and a detailed evaluation, Mountain Valley does not anticipate any significant risk associated with karst that cannot be addressed through minor route adjustment or the Karst Mitigation Plan.

As previously mentioned, to further minimize potential risks, Mountain Valley developed a Karst Mitigation Plan and a Karst-specific Erosion and Sediment Control Plan to reduce impacts when crossing karst terrain.[149] The Karst Mitigation Plan provides for construction inspections, procedures for unanticipated karst discoveries and mitigation options when minor karst features are encountered. The Karst Mitigation Plan also includes protocols for agency coordination and notification if and when appropriate. While construction entails a relatively shallow 10-foot excavation, Mountain Valley also will implement enhanced erosion and sediment control measures during all phases of construction to contain and manage construction run-off in order to limit the potential for impacts to the local karst hydrogeology. Additionally, no water used during hydrostatic testing will be discharged in karst locations in order to prevent potential impacts. Moreover, Mountain Valley's Spill Prevention, Control, and Countermeasures Plan not only addresses the steps Mountain Valley will take to prevent potential spills of

[149] DEIS at ES-4.

construction-related liquids, but also prohibits certain activities such as fueling and maintenance in those areas that are identified as sensitive, such as karst features.[150]

In addition to the steps set forth in its Karst Mitigation Plan, Mountain Valley has committed to deploying a Karst Specialist Team during all phases of pipeline construction to ensure that disturbance to karst features is avoided or mitigated. Specialist Team members will be in addition to project engineers, managers, inspectors and construction monitors who implement construction activities on a normal basis. The Karst Specialist Team will be comprised of individuals with karst-related expertise in southern West Virginia and southwestern Virginia.[151] The Karst Specialist Team will survey previously identified karst features within the construction limit of disturbance and vicinity, and evaluate through a two-tiered detailed inspection program any subsequently discovered karst features. If sensitive karst features are discovered, the Karst Mitigation Team will provide recommendations for avoidance and mitigation, and act accordingly in order to safeguard sensitive areas.

The combination of the Karst Mitigation Plan and the deployment of the Karst Specialist Team for inspection during all phases of construction will provide strong protection to karst features; it will not only manage erosion and sediment controls to

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[150] Mountain Valley Pipeline, LLC, Responses to Data Requests issued December 24, 2015, Spill Prevention, Control, and Countermeasures Plan, Attachment General 1d-1(West Virginia) and Attachment 1d-2 (Virginia), (Feb. 26, 2016)

[151] Karst Specialist Team members must: be geologists registered in the state of Virginia and demonstrate sufficient professional knowledge of West Virginia (as no state licensure exists); have field experience in karst mitigation techniques; be familiar with karst hydrogeology and associated karst features of the project area; be familiar with state karst protection, general karst assessment and mitigation guidelines; and be familiar with local and state erosion and sediment control, and stormwater management guidelines, ordinances and regulations.

protect karst resources, but will also identify and mitigate particularly vulnerable scenarios that could threaten the local karst hydrogeology. For example, this program will safeguard the karst system during a major precipitation event while construction is on-going in the vicinity of a drainage feature, ensure environmental integrity is maintained, and mitigate any potential impact factors that may arise.

Mountain Valley has studied the local karst hydrogeology and will implement environmental safeguards to prevent potential impacts during construction. Thus, the Commission properly concludes in the DEIS that in considering the "protective measures proposed by [Mountain Valley], we have not identified any cumulative impacts on karst terrain that would result from construction and operation of the [MVP Project]," and that "impacts on geological resources would be adequately minimized."[152] As such, Mountain Valley does not anticipate any significant risk associated with karst that cannot be addressed through minor route adjustment or the Karst Mitigation Plan.

3. Mountain Valley has adopted the Mount Tabor Variation to avoid sensitive karst features.

Commenters have raised issues with regard to the Mount Tabor Variation. As discussed below, the Mount Tabor Variation, which Mountain Valley incorporated into its October 2016 Proposed Route, is clearly preferable to the original route.

Mountain Valley identified a concentration of sinkholes and sensitive karst features in the vicinity of what is informally termed the Mount Tabor sinkhole plain. This

[152] DEIS at 4-501; 5-2.

area is located along the original proposed alignment in Montgomery County, Virginia.[153] The Commission requested that Mountain Valley explore the feasibility of alternative routes to minimize the effects to the Mount Tabor sinkhole plain. In accordance with that request, Mountain Valley developed the Mount Tabor Variation and filed an assessment of the alternative in April 2016.[154]

In developing the Mount Tabor Variation, the Karst Specialist Team completed a karst hazards assessment on the proposed Mount Tabor Variation route that included desktop review and field reconnaissance, and resulted in an updated Karst Hazards Assessment.[155] The updated Karst Hazards Assessment better defined the location of the Pulaski thrust fault,[156] provided a better understanding of the potential areas of concern, and revealed that the Mount Tabor Variation would avoid a denser distribution of mapped and field-observed sinkholes and sensitive karst features that were present in the initially proposed route. The Mount Tabor Variation would also avoid the Virginia Department of Conservation and Recreation's ("DCR") Blake preserve and a Virginia Outdoors Foundation easement.

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[153] DEIS at 3-52.
[154] Mountain Valley Pipeline LLC, Responses to FERC Environmental Information Request Dated March 31, 2016, Response to Data Request Resource Report 10(2)(b) at 183 & Attachment DR2 RR10-2b (Apr. 21, 2016).
[155] Mountain Valley Pipeline, LLC, Supplemental Materials – Oct. 2016 Proposed Route, Attachment H at 34, Karst Hazards Assessment (Oct. 14, 2016).
[156] An ancient inactive reverse-motion fault crossed by the Mount Tabor Variation route at approximately Milepost 221.7 (of the current October 2016 Propose Route), north of which non-karst forming bedrock is present.

Mountain Valley updated its Karst Hazards Assessment to reflect its better understanding of potential sensitive hydrology.[157] In its initial evaluation of the pipeline route through karst areas, Mountain Valley used a Light Detection and Ranging (LiDAR) method, which is a valuable resource for desktop evaluation of karst topography. "However, field evaluation by direct observation and geophysical methods, such as [electrical resistivity ("ER")], provides a more comprehensive understanding of the sub-surface geology."[158] Mountain Valley addressed specific concerns with regard to the Mount Tabor Variation by conducting a subsurface geophysical survey of the physically-accessible areas of the Mount Tabor Variation for karst features using ER survey data.[159] The ER analysis indicated a stable sub-surface within the design depth of the pipeline excavation and through a depth where the pipeline could affect, or be affected by, any karst features.[160] Any karst encountered during construction can be addressed through the processes detailed in the Karst Mitigation Plan, including minor route adjustments. Based upon this analysis, coupled with the Karst Hazards Assessment desktop analysis and field reconnaissance, Mountain Valley does not anticipate any significant risk associated with karst terrain between mileposts 221.78 and 227.20 of the October 2016 Proposed Route. As such, Mountain Valley confirmed that the referenced portion of the

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[157] Mountain Valley Pipeline, LLC, Supplemental Materials – October 2016 Proposed Route, Attachment H at 34, Karst Hazards Assessment (Oct. 14, 2016).

[158] Mountain Valley Pipeline, Supplemental Materials, Attachment A, Supplemental Responses to FERC Staff's Recommended Mitigation in DEIS, Recommendation No. 15 (Dec. 22, 2016).

[159] An ER survey is a technique for geophysical analysis of sub-surface conditions using measurements made at the surface using electrodes that measure changes in an induced electrical current passing through the subsurface geology.

[160] Mountain Valley Pipeline, Supplemental Materials, Attachment A, Supplemental Responses to FERC Staff's Recommended Mitigation in DEIS, Recommendation No. 15 (Dec. 22, 2016).

October 2016 Proposed Route (the Mount Tabor Variation route) was preferable to the originally proposed alignment in the vicinity of the Mount Tabor sinkhole plain.

In addition, as discussed more in the section above, Mountain Valley has committed to implementing enhanced erosion and sediment control measures, as well as enhanced monitoring during construction, in karst terrain, including in the area of the Mount Tabor sinkhole plain. The Karst Specialist Team will also be present to conduct inspections during all phases of construction in the Mount Tabor area, to not only manage erosion and sediment control, but also to identify and mitigate potential issues that could threaten local karst hydrogeology. Thus, the October 2016 Proposed Route is preferable to the original proposed route with respect to the Mount Tabor sinkhole plain.

Finally, in conjunction with the Mount Tabor Variation, Mountain Valley expects to propose in an upcoming response to the Commission's January 26, 2017 data request a new minor route variation (Variation 250) to address a concern raised by the Virginia DCR regarding stream crossings within the Slussers Chapel Conservation Site. If the Commission were to adopt Variation 250, the route would move approximately 1,000 feet to the northeast and avoid stream crossings at two locations, avoid construction parallel to an intermittent segment of a stream near milepost 221.9, and minimize potential impacts at the karst boundary.

These minor route adjustments and variations demonstrate that Mountain Valley has seriously considered and evaluated concerns that were raised regarding karst terrains. Mountain Valley has taken decisive actions, through route variations and karst avoidance, to reasonably avoid and mitigate environmental concerns regarding karst features.

4. Hybrid Alternative 1A would not offer a significant environmental advantage.

A number of commenters assert that the Commission should have analyzed and adopted "Hybrid Alternative 1A," a modified version of Alternative 1, as the route for the Project in the DEIS.[161] Alternative 1 was analyzed and considered by the Commission in the DEIS.[162] Hybrid Alternative 1A (as well as another modified version of Alternative 1 known as Hybrid Alternative 1B) is a minor variation of Alternative 1 which was evaluated by Mountain Valley at the request of the Commission in a data request. As Mountain Valley demonstrated in its alternatives analysis for Hybrid Alternative 1A submitted April 21, 2016, Hybrid Alternative 1A is not preferable to the proposed route. Based on the record before the Commission, Mountain Valley has demonstrated that Hybrid Alternative 1A would pose significant constructability issues, and not offer a significant environmental advantage, and thus was an unreasonable alternative.

Courts and the Commission have properly explained that NEPA requires the Commission to identify and analyze reasonable alternatives during its review of a proposed action.[163] Moreover, CEQ's regulations on the alternatives analysis require the Commission to "[r]igorously explore and objectively evaluate all *reasonable* alternatives,

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[161] The Commission has recently requested that Mountain Valley provide an updated analysis of the October 2016 Proposed Route, as compared to Hybrid Alternatives 1A and 1B. *See* Post-DEIS Environmental Information Request at 27 (Jan. 26, 2017). Mountain Valley is currently in the process of compiling the analysis, including a table comparing impacts on specific environmental resources, as requested by the Commission. *See* Mountain Valley Pipeline LLC Responses to FERC Environmental Information Request Dated March 31, 2016, Attachments DR2 RR10-3a, DR2 RR10-3b (Apr. 21, 2016).

[162] DEIS at 3-22-3-24.

[163] *Minisink Residents for Envtl. Pres. & Safety v. FERC*, 762 F.3d 97, 102 (D.C. Cir. 2014); *Millennium Pipeline Co., L.L.C.*, 157 FERC ¶ 61,096, at P 112 (2016) (citing 42 U.S.C. §4332(2)(C) (2012) and 40 C.F.R. §§ 1502.1, 1502.14, and 1502.16 (2016)).

and for alternatives which were eliminated from detailed study, briefly discuss the reasons for their having been eliminated."[164] While NEPA does not define what constitutes a "reasonable alternative," CEQ guidance clarifies that alternatives are not reasonable if they are not feasible.[165] CEQ guidance further provides that "reasonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense."[166] In this regard, the Commission has found that "[a]n agency's specification of the range of reasonable alternatives is entitled to deference."[167]

When evaluating whether an alternative is preferable to a proposed action, the Commission considers three evaluation criteria.[168] These criteria are: (1) whether "the alternative meets the stated purpose of the project;" (2) whether the alternative "is technically and economically feasible and practical; and" (3) whether the alternative "offers a significant environmental advantage over a proposed action."[169] In accordance with NEPA and Commission policy, the DEIS evaluated Alternative 1 to determine whether it would be technically feasible and offer significant environmental advantage to the proposed project while meeting the Project's stated objective.

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[164] 40 C.F.R. § 1502.14 (emphasis added)
[165] *Enable Gas Transmission*, LLC, 153 FERC ¶ 61,055 at P 25 (2015) (citing Guidance Regarding NEPA Regulations, 48 Fed. Reg. 34,263 (July 28, 1983).
[166] *See* Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations, 46 Fed. Reg. 18,026, 18027 (Mar. 23, 1981).
[167] *Transcontinental Gas Pipe Line Co.*, 154 FERC ¶ 61,166, P 48 (2016).
[168] DEIS at 3-1.
[169] *Id.*

Alternative 1 was an alternative considered by Mountain Valley to allow for more colocation of the Project than the proposed route.[170] Alternative 1 proposed to collocate approximately 101 miles, or about 31 percent of its total length, as compared to the proposed route which is collocated for 22 miles, or about 7 percent of its total length.[171] Alternative 1 also affected fewer Historic Districts, less Forest Service land, including old growth forest, roadless areas, and semi-primitive areas, and less interior forest in comparison to the proposed route.[172]

Alternative 1, however, also disturbed 336 more acres of land and was 23 miles longer than the proposed route. Additionally, Alternative 1 affected more water resources than the proposed route, including "approximately 2,226 feet more of wetlands and 36 more perennial waterbodies compared to the proposed route," as well as crossing the New River twice and crossing the Radford University Conservancy property, resources that are avoided in the proposed route.[173]

Finally, Alternative 1 crossed approximately "51 more miles of steep slope and 42 more miles of severe side slope" than the proposed route.[174] These additional miles of steep and severe side slopes created significant construction challenges including the need for extra workspaces to achieve a level working area and an increased the risk of future slope instability following restoration.[175] After review of all of these factors, the

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[170] DEIS at 3-22.
[171] *Id.*
[172] *Id.*
[173] *Id*
[174] *Id.*
[175] *Id.*

Commission concluded that Alternative 1 did not offer a significant environmental advantage when compared to the corresponding proposed route.[176]

During the course of the Commission's data collection, Commission staff requested information from Mountain Valley regarding two alternatives; Hybrid Alternative 1A and Hybrid Alternative 1B.[177] The Hybrid Alternative 1A was a minor variation of Alternative 1 that incorporated the northern half of the proposed route and the southern half of Alternative 1. The Hybrid Alternative 1B was another minor variation of Alternative 1 that incorporated the northern half of Alternative 1 and the southern half of the proposed route. In response, Mountain Valley provided a description of the two minor variations, identified both environmental and constructability issues with those variations and prepared a table comparing data for the two minor alternatives and the proposed route.[178]

In providing data to the Commission on Hybrid Alternative 1A,[179] Mountain Valley identified the same concerns as the Commission identified with Alternative 1, namely significant constructability issues due to large amounts of side slope and miles of severe side slope along the route, and increased water resources along the alternative as compared to the proposed route.[180] Mountain Valley thus concluded, as the Commission

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[176] *Id.*
[177] *See* Environmental Information Request (Dec. 24, 2015); Post-Application Environmental Information Request No. 2 (Mar. 31, 2016).
[178] *See* Mountain Valley Responses to FERC Environmental Information Request Dated March 31, 2016, Attachments DR2 RR10-3a, DR2 RR10-3b (Apr. 21, 2016).
[179] A specific discussion of Hybrid Alternative 1B is beyond the scope of this response to comments related to Hybrid Alternative 1A, although the same analysis would apply.
[180] *See* Mountain Valley Responses to FERC Environmental Information Request Dated March 31, 2016 (Apr. 21, 2016), pg. 185

concluded on Alternative 1, that Hybrid Alternative 1A would not offer a significant environmental advantage over the proposed route.

Hybrid Alternative 1A is not discussed explicitly in the DEIS, however, this is not a fatal flaw in the DEIS or the Commission's alternative analysis. CEQ guidance recognizes there may be situations where there is "an alternative which is a minor variation of one of the alternatives discussed in the draft EIS, but this variation was not given any consideration by the agency."[181] When such an alternative "is qualitatively within the spectrum of alternatives that were discussed in the draft, a supplemental draft will not be needed."[182] Instead, "the agency should develop and evaluate the new alternative, if it is reasonable, in the final EIS,"[183] which is appropriate in this case.

Hybrid Alternative 1A is a minor variation of Alternative 1, which is analyzed in the DEIS. The DEIS properly analyzed Alternative 1 and concluded that it would not offer a significant environmental advantage.[184] Hybrid Alternative 1A is within the spectrum of alternatives because it is a part of Alternative 1. The same environmental and construction concerns the Commission raised in evaluating and dismissing Alternative 1 would also apply for Hybrid Alternative 1A. Should the Commission address Hybrid Alternative 1A in the final EIS, based on the analysis previously submitted by Mountain Valley, the Commission should reasonably conclude that Hybrid Alternative 1A is a not reasonable alternative because it would not offer a significant

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[181] Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations46 Fed. Reg. 18,026, 18,035 (Mar. 23, 1981).
[182] *Id*.
[183] *Id*.
[184] DEIS at 5-15.

environmental advantages over the proposed route and would present constructability issues.

5. The DEIS shows the Commission is appropriately conducting tribal consultation.

Some commenters question whether the Commission has properly consulted with Native American Tribes as part of its review of the MVP Project. As explained in the DEIS, the Commission has taken an appropriate approach to tribal consultation under Section 106 of the NHPA.[185]

Section 106 of the National Historic Preservation Act ("NHPA") requires "[t]he head of any Federal agency having direct or indirect jurisdiction over a proposed Federal . . . undertaking . . . shall . . . prior to the issuance of any license . . . take into account the effect of the undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register."[186] Here, the "undertaking" is the Commission's review and issuance of a certificate authorizing the MVP Project.[187] The NHPA is strictly *procedural* and not outcome determinative. Courts have explained that Section 106 does not impose substantive requirements; rather, it only seeks to ensure that agency decision makers "stop, look, and listen," by identifying affected historic sites and engaging in a limited and timely consultation process prior to the initiation of a Federal undertaking.[188] As a result, each Section 106 process is unique, and by establishing

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[185] DEIS at 4-334 - 4-339.
[186] 54 U.S.C. § 306108.
[187] "Undertaking" in the NHPA is defined as including actions "requiring a Federal permit, license, or approval." 36 C.F.R. § 800.16(y).
[188] *Narragansett Indian Tribe v. Warwick Sewer Auth.*, 334 F.3d 161, 166 (1st Cir. 2003) (citing *Muckleshoot Indian Tribe v. U.S. Forest Serv*., 177 F.3d 800, 805 (9th Cir. 1999) (*per curiam*); *see Nat'l*

certain procedural parameters, the Federal agency is allowed to reasonably determine its own best practices, as well as the requisite level of consultation.[189] In this case, the Commission is appropriately complying with the requirements of Section 106.

Mountain Valley reached out to the various tribes as early as December 2, 2014, sending letters to 34 tribes informing them of the Project and requesting comments. "Mountain Valley received responses from the Delaware Nation of Oklahoma, Peoria Tribe of Oklahoma, Stockbridge-Munsee Band of the Mohican Nation, and the United Keetoowah Band of Cherokee Indians in Oklahoma[,]" who all indicated that the Project would "not adversely impact sites of cultural or religious importance."[190]

The Commission "identified Indian tribes that historically used or occupied the project areas" for the purpose of initiating consultation with the interested tribes.[191] As explained in the DEIS, the Commission sent copies of the April 17, 2015 Notice of Intent to Prepare an Environmental Impact Statement for the Project to 30 tribes.[192] Furthermore, the Commission initiated government-to-government consultation with tribes on July 21, 2015 by sending individual letters to tribal leaders informing them about the Project and requesting comments or information about resources important to the tribes.[193] The Commission noted in the DEIS that it received one response from an

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Mining Ass'n v. Fowler, 324 F.3d 752, 755 (D.C. Cir. 2003) (requirements imposed by section 106 are procedural, not substantive)).

[189] *See Narragansett Indian Tribe*, 334 F.3d at 166 (citing *Chevron U.S.A., Inc. v. Nat. Res. Def. Council*, 467 U.S. 837, 842-44 (1984) ("Of course, we defer to an authorized administrative agencies reasonable elaboration of an ambiguous statutory term such as 'consultation.'").

[190] DEIS at 4-338 - 4-339.

[191] DEIS at 4-335.

[192] DEIS at 4-335; 4-336 – 4-338, Table 4.10.4-1.

[193] DEIS at 4-335; 4-336 – 4-338, Table 4.10.4-1.

Indian tribe to its April 17, 2015 and July 21, 2015 letters.[194] The Stockbridge-Munsee Band of the Mohican Nation indicated that the Project was not within its area of interest.[195]

One commenter suggests certain local tribes that should have been contacted, were not.[196] However, with the exception of the Monacan Nation (which Mountain Valley did contact, as detailed below) those tribes are not recognized by the federal government or the state governments in Virginia and West Virginia.[197] In April 2015, the Commission requested that Mountain Valley contact certain non-federally-recognized tribes as a courtesy in addition to reaching out to federally-recognized tribes. The Commission provided Mountain Valley with a list of non-federally-recognized tribes, which included the Monacan Nation. Accordingly, Mountain Valley sent a letter to the Monacan Nation on May 5, 2015, but did not receive a response. The Commission's list of non-federally-recognized tribes did not include the Occaneechi, Tutelo, or Saponi tribes.[198]

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[194] DEIS at 4-338, Table 4.10.4-1 (noting response from Stockbridge-Munsee Band of the Mohican Nation).
[195] DEIS at 4-338.
[196] Transcript of November 1, 2016 Meeting in Chatham, Virginia, Testimony of Mark Joyner at 4:16 – 5:2 (asserting that Mountain Valley failed to contact for consultation the "Saponi, Tutelo, Pocono, [O]chenochee and Monacan Tribes."
[197] *See* National Conference of State Legislatures, Federal and State Recognized Tribes, (updated Oct. 2016) http://www.ncsl.org/research/state-tribal-institute/list-of-federal-and-state-recognized-tribes.aspx.
[198] According to the National Conference of State Legislatures, Federal and State Recognized Tribes, the Occaneechi, Tutelo, and Saponi tribes appear not to be recognized by the Commonwealth of Virginia. The Occaneechi are however recognized by the state of North Carolina. *See* http://www.ncsl.org/research/state-tribal-institute/list-of-federal-and-state-recognized-tribes.aspx

In addition, in December 2016, Mountain Valley's Tribal Relations team sent comprehensive project update letters to 44 tribes.[199] The letters were intended to give an overall project update, provide consolidated information on cultural resource surveys, and offer the opportunity for in-person meetings and additional coordination to address any concerns identified by the tribes in their review of the project. As of January 2017, Mountain Valley's Tribal Relations team successfully contacted 10 of the 44 tribes as a follow-up to the December 2016 letter. A majority of the tribes that the Project has contacted have little to no interest in the Project area. Mountain Valley will continue to reach out to the tribes to proactively ensure that their concerns, if any, are addressed and well-coordinated.

To date, Mountain Valley has conducted extensive cultural resource surveys on all but approximately 36 miles of the Project's route. These surveys identified a number of important historic properties within the Project study corridor. As explained in the DEIS, the majority of these resources will be avoided or mitigated, while a number require additional study.[200] Based on this work and consultation with interested tribes, the DEIS appropriately concludes that the Project "would have no effect on sites of traditional, cultural, or religious importance to Indian tribes," and therefore, the

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[199] On January 26, 2017, Commission staff issued a Post-DEIS Environmental Information Request to Mountain Valley that, among other things, requested that Mountain Valley "[r]efresh outreach with Indian tribes by documenting recent communications between Mountain Valley and tribes listed on table 4.10.4-2 in the draft EIS and recording their responses to the project." Mountain Valley will submit the requested information to Commission staff in its response to the data request. *See* Post-DEIS Environmental Information Request (Jan. 26, 2017).

[200] DEIS at 4-374 – 4-382, Table 4.10.9-1.

Commission "completed compliance with Section 101(d)(6) of the NHPA."[201] Noting that the entire process of compliance with Section 106 of the NHPA has not yet been completed for the MVP Project, the DEIS recommends a mitigation condition that requires the completion of consultation under Section 106 before Mountain Valley can start construction. In that way, the Commission will ensure that any adverse effects on historic properties are resolved before construction activities start.

6. The DEIS adequately addresses greenhouse gas emissions.

Commenters assert that the DEIS fails to adequately assess the potential greenhouse gas ("GHG") emissions and the effects of such emissions on climate change.[202] However, the DEIS adequately analyzes the GHG emissions attributable to the construction and operation of the Project and includes an analysis of these emissions and their sources. Consistent with Commission precedent, the DEIS also addresses cumulative impacts of GHG emissions from the Project and concludes that "GHG emissions from the construction and operation of the MVP [Project] would be negligible compared to the global GHG emission inventory."[203]

On August 1, 2016, the CEQ published its Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews ("CEQ GHG

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[201] DEIS at 4-384.
[202] *See, e.g.*, Comments of AMA at 86 (Dec. 23, 2016); Comments of Montgomery County, Virginia at 41 (Dec. 22, 2016); Comments of Oil Change International at 1 (Dec. 22, 2016); Comments of Sierra Club-Virginia Chapter at 6 (Dec. 22, 2016).
[203] DEIS at 4-516.

Guidance").[204] The non-binding guidance is intended to assist federal agencies in considering greenhouse gas emissions during the evaluation of proposed federal actions under NEPA and the CEQ Regulations. The DEIS incorporates recommendations from the CEQ GHG Guidance, to the extent practicable, by presenting "the direct and indirect GHG emissions associated with construction and operation of the projects and the potential impacts of GHG emissions in relation to climate change."[205]

The DEIS estimates the GHG emissions associated with construction and operation of the MVP Project, evaluates the potential impacts of such emissions, and presents the mitigation proposed by Mountain Valley to minimize impacts. No further analysis is necessary to inform the Commission's decision making under NEPA.[206] The DEIS states that construction of the MVP Project "would result in intermittent and short-term increases in emissions," including GHG emissions.[207] Construction-related emissions, however, "would be temporary and localized, and would dissipate with time and distance from areas of active construction."[208] Operational GHG emissions will mainly be attributable to the installation and operation of the Bradshaw, Harris, and Stallworth compressor stations.[209] The DEIS notes that Mountain Valley has committed to implement mitigation measures to reduce construction and operational emissions,

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[204] Council on Environmental Quality, Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews (Aug. 1, 2016).
[205] DEIS at 4-516.
[206] *See Dominion Transmission, Inc., order denying reh'g*, 158 FERC ¶ 61,029, at P 5 (Jan. 17, 2017) (finding that the Commission's consideration of greenhouse gas emissions was sufficient under NEPA).
[207] DEIS at 4-403. *See id* at 4-404, Table 4.11.1-5 (estimating construction emissions for MVP Project).
[208] DEIS at 4-408.
[209] DEIS at 4-408. Mountain Valley received air permits for the Bradshaw, Harris, and Stallworth compressor stations on March 15, 2016, March 23, 2016, and April 11, 2016, respectively.

including by adhering to all applicable federal, state, and local regulations to minimize emissions.[210] The DEIS concludes that the MVP Project's "construction-related impacts are not expected to result in a significant impact on local or regional air quality."[211] Further, "[e]missions generated during operation of the MVP [Project] would be minimal," and "any emissions resulting from operation of the compressor facilities would not be expected to have significant impacts on local or regional air quality."[212]

With respect to cumulative impacts, the DEIS, "to the extent practicable . . . present[s] the direct and indirect GHG emissions associated with construction and operation of the [MVP Project] and the potential impacts of GHG emissions in relation to climate change."[213] The DEIS characterizes GHG emissions from the MVP Project as "negligible compared to the global GHG emission inventory."[214] It also notes that because coal is widely used in the Appalachian region in which the MVP Project is located, "it is anticipated that the [MVP Project] would result in the displacement of some coal use, thereby potentially offsetting some regional GHG emissions."[215] However, with respect to climate change, alleged impacts from the Project must be "caused by" the proposed project and be "reasonably foreseeable" to be part of a NEPA analysis.[216] Because there is "no standard methodology to determine how the [MVP

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[210] DEIS at 4-407, 4-4-412.
[211] DEIS at 4-417.
[212] DEIS at 4-418.
[213] DEIS at 4-516.
[214] DEIS at 4-516.
[215] DEIS at 4-516.
[216] 40 C.F.R. §§ 1508.8(a) & 1508.8(b) ("Indirect effects . . . are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable"). *See also Columbia Gas Transmission, LLC*, 158 FERC ¶ 61,046, at P 104 (2017) (noting that reasonably foreseeable indirect

Project's] relatively small incremental contribution to GHGs would translate into physical effects of the global environment," the DEIS is unable to determine whether the Project's "contribution to cumulative impacts on climate change would be significant."[217] Therefore, the DEIS reasonably concluded that GHG emissions from the construction and operation of the Project would be minimal in compliance with the applicable regulations and guidance.

IV.
CONCLUSION

As demonstrated in the Application and in this Answer, the need for the MVP Project is firmly established. As explained above, neither a supplemental DEIS or programmatic EIS is necessary for the Commission's review of the Project, because the DEIS adequately addresses the purpose and need for the MVP Project while providing the public an opportunity for meaningful analysis, and it is consistent with the Commission's long-standing policy of conducting a project-specific environmental review. Furthermore, commenters' arguments that the Commission is required to consider upstream impacts of drilling activities are unfounded because the impacts of such activities are neither causally connected to the MVP Project nor are they reasonably foreseeable. The DEIS also correctly observes that the MVP Project is not designed or

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effects are those that are "sufficiently likely to occur [such that] a person of ordinary prudence would take it into account in reaching a decision").

[217] DEIS at 4-516; *Columbia Gas Transmission, LLC*, 158 FERC ¶ 61,046, at P 104 (An agency is "not required to engage in speculative analysis or to do the impractical, if not enough information is available to permit meaningful consideration").

intended to transport natural gas to an export terminal. Furthermore, the DEIS properly considers the environmental issues raised by commenters during the comment period.

Mountain Valley's proposed construction techniques and mitigation measures will reduce the environmental and safety impacts of the Project to the greatest extent possible. The Commission staff's in-depth DEIS provides a thorough analysis of the environmental impacts of the Project and properly considered all potential impacts of the project. The DEIS, therefore, properly concludes that with the exception of impacts to forested lands, the construction and operation of the MVP Project would result in limited adverse environmental impacts, and recommended mitigation measures to be attached as conditions to any authorization issued by the Commission.[218]

[218] DEIS at 5-1.

WHEREFORE, Mountain Valley requests the Commission (1) grant this Motion to Answer and (2) accept this Answer to protests and comments filed in this proceeding.

Respectfully submitted,

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Dated: February 3, 2017

Exhibit A

Wood Mackenzie
A Verisk Analytics Business

January 2016

Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project

Table of Contents

Table of Exhibits

Introduction

The developers of the Mountain Valley Pipeline ("MVP") project retained Wood Mackenzie to analyse the long term natural gas market in the Southeast United States (the "Southeast"), one of the destination markets for the MVP project.[1] Wood Mackenzie is an industry leading energy consulting firm and provider of energy market research, data and insights. This report presents the findings of our independent analysis. Wood Mackenzie is advised that the MVP project sponsors may include all or parts of this report in certificate application filings before the Federal Energy Regulatory Commission (FERC).

As designed, the proposed Mountain Valley Pipeline project will traverse from its origin at receipt points in Wetzel County, West Virginia, to a terminus interconnection with the Williams Partners L.P.'s gas pipeline – Transco ("Transco") system at its compressor station 165 in Pittsylvania County, Virginia. When placed into service MVP will provide consumers across a broad region of the Southeast United States and other markets with firm gas transportation access to the prolific and relatively low cost gas reserves of the Marcellus and Utica shales in West Virginia, Pennsylvania, and Ohio.[2]

The Southeast is a large natural gas market, and among the fastest growing consuming regions in North America. New pipeline capacity will be required to satisfy the projected demand requirements. In addition to Southeast demand growth, MVP will also support the region's and other region's migration away from their traditional Gulf Coast and Mid-continent gas supplies as gas market conditions make Marcellus and Utica production more economic for consumers. These capacity demand drivers and other relevant factors impacting the Southeast gas market and the need for MVP are addressed in this report, which is organized as follows:

- Executive Summary - presents the primary findings of our analysis.
- Section 1 – explains our approach to the report and describes the intellectual property and analytical methods used in producing it.
- Section 2 – provides a sectoral analysis of historical Southeast gas market consumption for the 5-year period 2010 to 2014.
- Section 3 – identifies the sources of gas supply used to satisfy regional demand based on reported gas pipeline flows into the region.
- Section 4 – presents Wood Mackenzie's long term Southeast gas demand forecast through 2030. These projections help define MVP's role in serving both current and growing gas demand requirements.
- Section 5 – provides concluding comments and summary capacity requirement estimates.

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[1] For this report, the "Southeast" gas market includes the states of Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama and Florida. West Virginia is also included in states served by MVP.

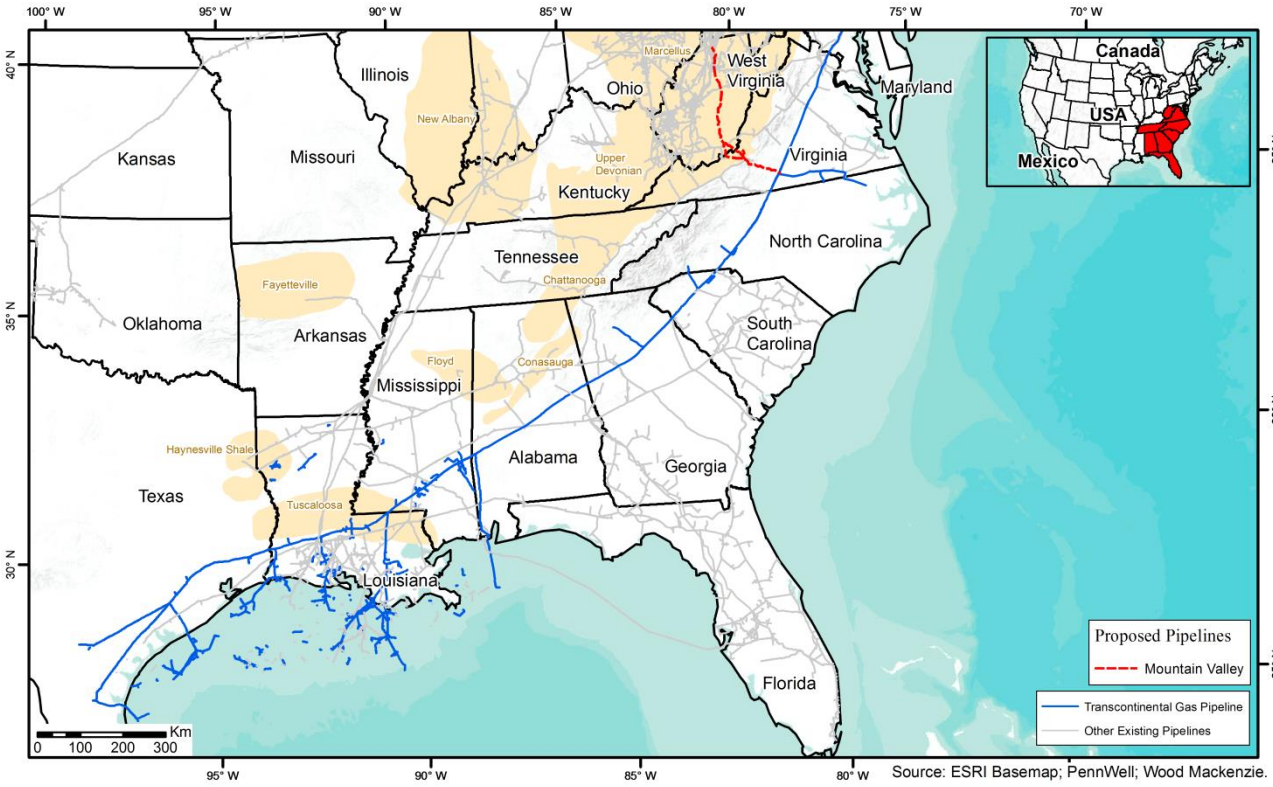
[2] Marcellus and Utica shale natural gas are variously referred to as "Appalachian" and "Northeast" gas supply in this report.

- The Appendix includes supporting tables and other relevant exhibits based on our research.

Executive Summary

MVP will serve markets in the Southeast that historically have been supplied by gas production from the Gulf Coast and Mid-continent producing regions.[3] MVP's nexus to the Southeast market is seen in the map below.

Figure 1 Mountain Valley Pipeline project and the Southeast market



As summarized below and discussed in detail in this report, the demand for natural gas and firm transportation in the Southeast are expected to grow, in particular as a fuel for natural gas-fired generation to maintain pace with the region's growing demand for electricity and carbon emissions goals. Wood Mackenzie research indicates that by 2030, MVP will be needed to serve as much as 8.3 bcfd of new demand for pipeline capacity in the Southeast and existing pipeline capacity demand that is currently flowing gas production from Gulf Coast and Mid-continent producing basins.

Unlike most other regions on the interstate pipeline grid, the Southeast generally lacks the geology for in-ground natural gas storage. This means that peak demand periods must largely be satisfied by pipeline capacity or LNG peak-shaving facilities and as a result, the gas pipeline system must be designed to not only serve annual average demand, but peak requirements as well.

As detailed in this report, Wood Mackenzie analysis finds that:

[3] The Gulf Coast producing region primarily includes onshore gas plays in Texas, Louisiana, and Mississippi. The Gulf Coast reference can also include the offshore blocks of the Gulf of Mexico ("GOM"). Mid-continent production broadly includes gas supplies from Oklahoma, Kansas and Arkansas.

Historical Demand and Supply (2010-2015)

- Southeast average daily consumption grew at a compound annual growth rate ("CAGR") of 3.7% from 2010 to 2014. This is equivalent to a 15.5% average daily increase of 1.5 bcfd (9.7 to 11.2 bcfd). Estimates for 2015 indicate demand will grow another 0.4 bcfd.

- Gas use in power generation grew at a 4.8% CAGR, equivalent to 1.0 bcfd between 2010 and 2014, as an estimated 16.5 gigawatts of coal-fired plants were replaced by more than 18.0 gigawatts of gas-fired units between 2010 and 2014.

- Core[4] and other market sector demand have grown, accounting for approximately 15 to 20 percent of total regional demand.

- The Southeast has growing demand during the winter months, as evidenced by average daily demand in January 2014, which was 3.5 bcfd higher (32%) than the 2014 annual average. January 2014 average daily demand was 2.5 bcfd higher than January 2013.

- Southeast gas buyers procured approximately 53% of the regions gas supplies from Gulf Coast producing basins in 2014. This reflects a 5% market share decrease from 2013.

Forecast Demand and Supply (2015-2030)

- In total, growing Southeast gas demand could require as much as 8.3 bcfd of new pipeline capacity by 2030,

- Southeast average daily demand is projected to grow by 4.2 bcfd through 2030 when compared to 2015 estimates. Interim demand grows 2.4 bcfd by 2020, and 3.6 bcfd by 2025.

- New pipeline capacity from the Appalachian Basin will enable Southeast buyers to ultimately shift as much as 3.3 bcfd of current Gulf Coast and Mid-continent supply purchases to Marcellus and Utica sources.

- Peak hour gas demand for electric generation, stated in terms of rateable daily demand, required approximately 4.5 bcfd of capacity in 2015. New power load through 2030 projects to increase pipeline capacity requirements by an estimated .8 bcfd to manage hourly demand swings. Note that there is no stated allowance for current hourly swings.

- Power generation is the largest consuming (~60%) and fastest growing Southeast demand sector, with winter and summer average daily demand increasing by approximately 2.1 and 3.7 bcfd, respectively, by 2030.

- Core and other market sectors are projected to expand at a 1.6% CAGR over the 2015-2030 period, with demand growth being highest in the winter season.

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[4] "Core" market demand in the natural gas industry is comprised of the residential, commercial and industrial sectors, each of which experiences heavy demand during the winter season.

This demand growth, past and projected, will require new sources of gas supply and transportation capacity. Wood Mackenzie forecasts the need for new gas pipeline capacity from Appalachia to the Southeast – the corridor and one of the markets to be served by MVP.

Section 1 – Analytical Approach

Wood Mackenzie develops gas market forecasts based on a deep analysis of market fundamentals: supply, demand and the infrastructure linking sources to uses. Each of these elements is the subject of continuous research such that market outlooks reflect the most recent trends and impacts of key variables affecting the market. The analysis is further supported by proprietary models that forecast gas prices and flows under equilibrium conditions.

Figure 2 Wood Mackenzie's integrated global and cross commodity approach

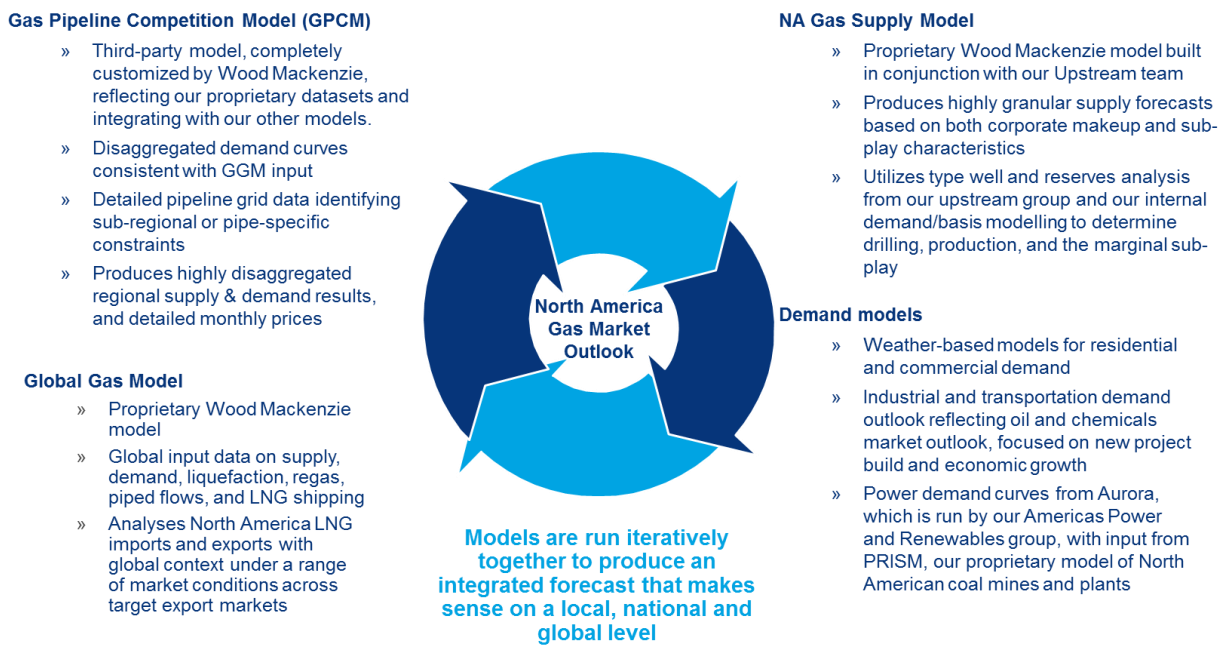
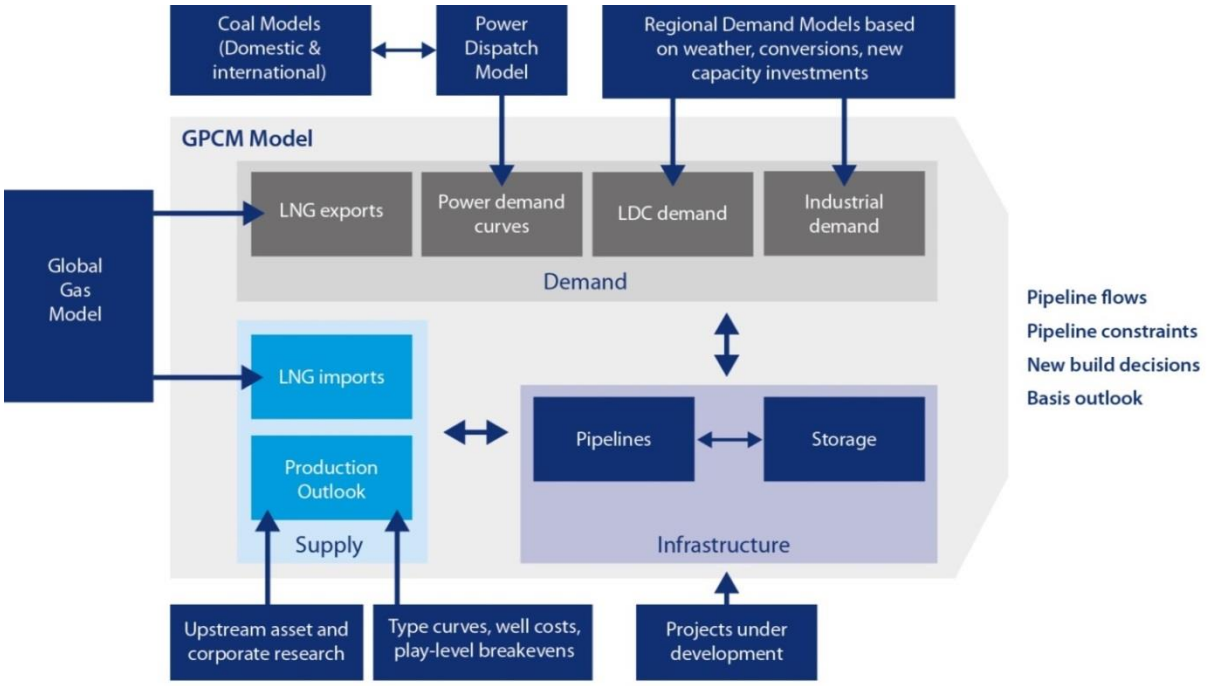


Figure 3 Wood Mackenzie's North America gas modelling



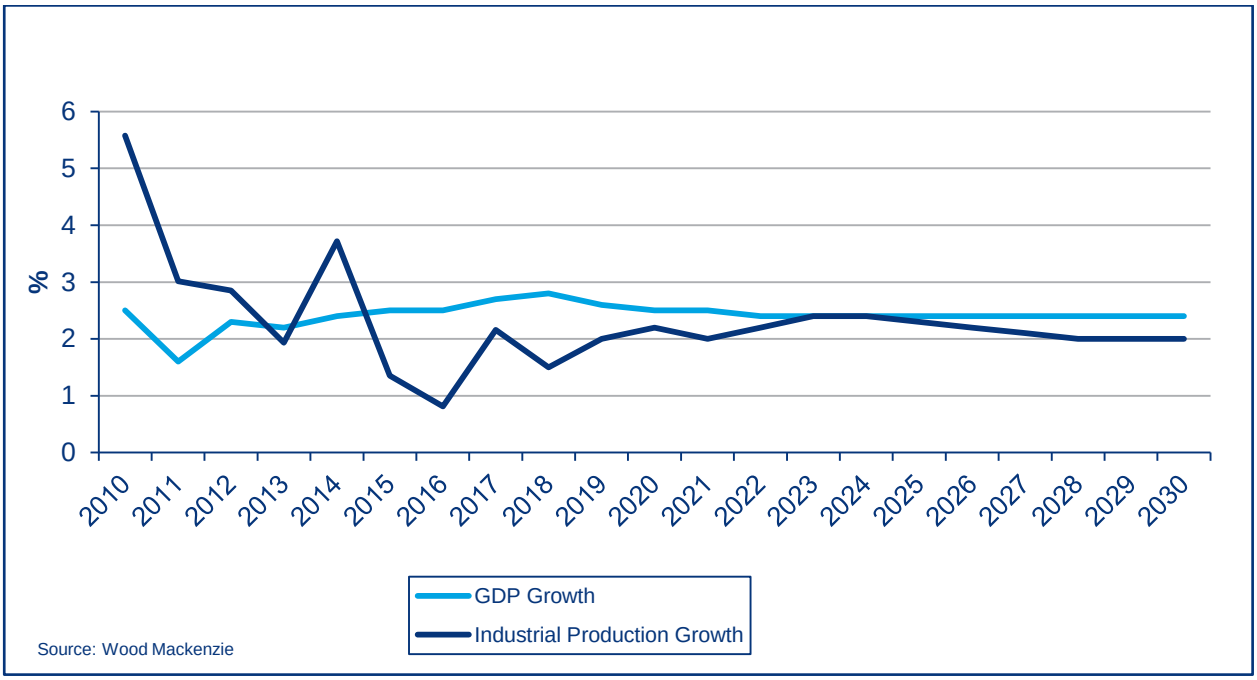
Source: Wood Mackenzie

A distinguishing characteristic of Wood Mackenzie gas market forecasts is the extent to which views on the natural gas market reflect the integrated nature of energy markets. When producing its forecasts Wood Mackenzie analysts ensure internal consistency of assumptions and outputs across all fuels and power markets. These processes yield robust results and insights into the interaction among fuel markets. In particular for this report, Wood Mackenzie has undertaken extensive research on the expected migration of regional power markets from coal- to gas-fired generation.

Energy market forecasts require extensive and important assumptions. Wood Mackenzie's analysts conduct extensive detailed research into their respective focus areas, relying on public and proprietary sources. Assumptions that are most relevant to this study and report are summarized here and discussed more in the Appendix.

- Wood Mackenzie assumes U.S. GDP growth to peak at 2.8% in 2018 before stabilizing at 2.4% in the long-term. We assume inflation to remain at 2.0% per year
- We expect industrial production to oscillate between 1 and 2.5% before stabilizing at 2% at the end of the study period
- Population growth is based on the United Nations, World Population Prospects

Chart 1 U.S. GDP growth and industrial production projection



Our data is subject to a rigorous integrity checking and quality control process carried out across several teams. In Wood Mackenzie, we strive to publish a single integrated market outlook across the entire globe and energy value chain. Hence, there is natural check in place as the analysis and the data behind the analysis feeds into the analysis of other parts of the Wood Mackenzie analytical network.

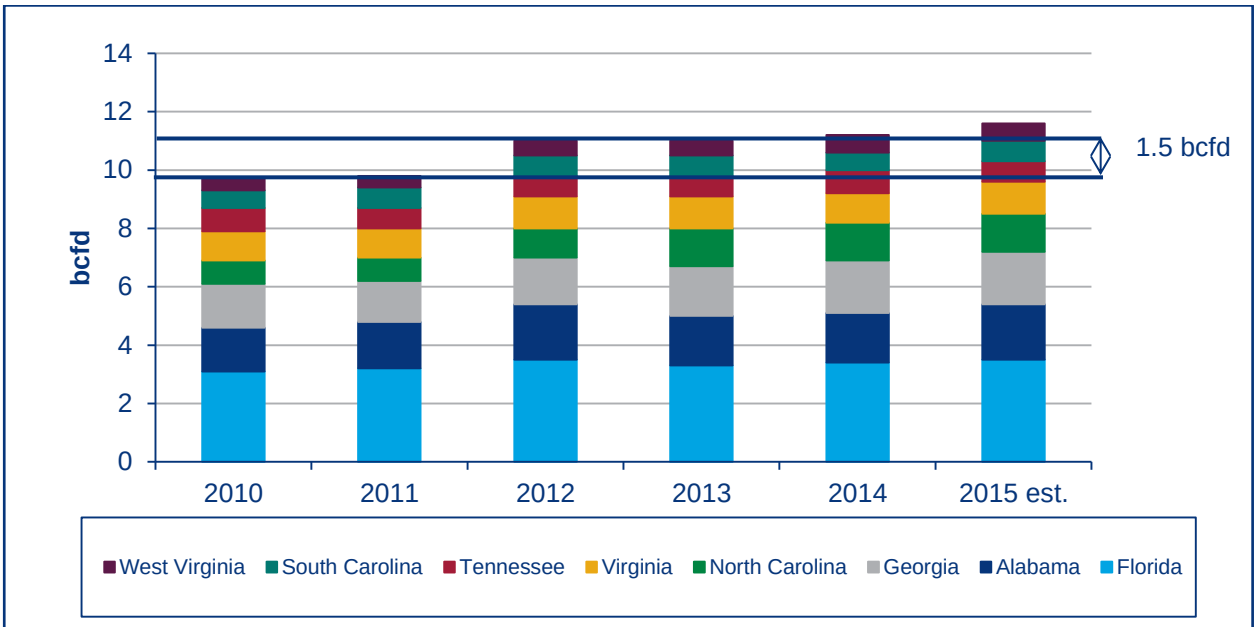
Inter-team discussions and data reviews are a core part of the data validation process. In this way, we have in place a comprehensive set of checks, which are carried out during every update cycle at zone, country, regional and global level. This includes, but is not limited to, iteration between models where the output from one model is an input into another, team discussions, peer review, and knowledge sharing. In addition, Wood Mackenzie client feedback and regular interaction with key regional market players contributes to data validation and enhancement.

Section 2 – Historical Southeast Gas Consumption (2010 – 2015e)

Natural gas consumption in the Southeast has grown at an annual rate of 3.7% from 2010 to 2014. This equates to a 15.5% average daily volume increase of 1.5 bcfd from 9.7 to 11.2 bcfd over the period.

The fastest absolute growth occurred in the most populous states, with Florida accounting for the largest increases. Chart 2 below illustrates that the increases in regional gas consumption have been comparatively broad-based across all states. Georgia, Alabama and North Carolina, in particular, have shown the fastest increases in gas use with a combined 1.0 bcfd growth over the period.

Chart 2 Growing daily gas consumption in the Southeast U.S. (2010 – 2015e)

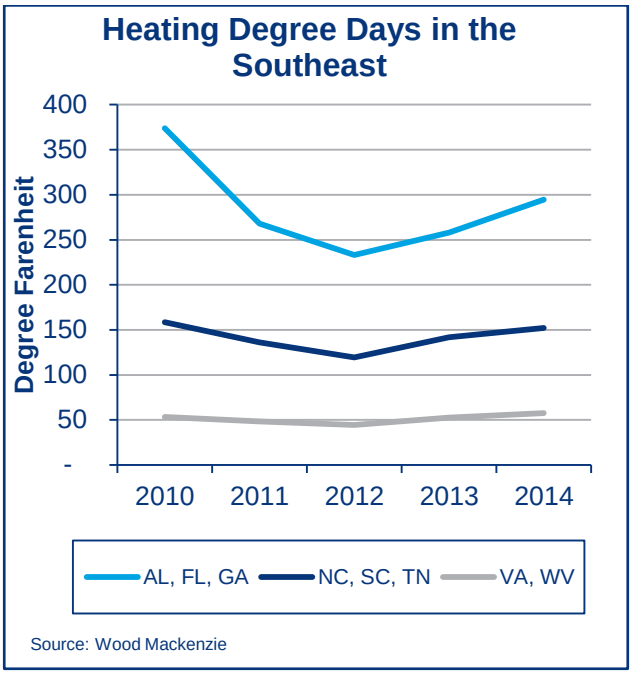


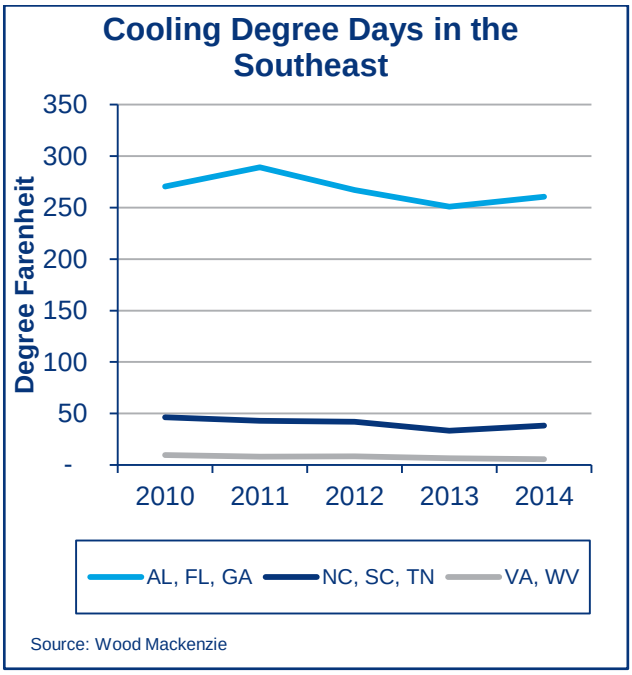
Source: Wood Mackenzie

The primary driver for increased gas consumption has been the expanded role of gas-fired power generation, which grew at an annual rate of 5.8%, owing in part to the Mercury and Air Toxics Standards (MATS) regulations that accelerated the retirements of coal plants. Between 2010 and 2015, generators retired an estimated 16.5 gigawatts (GW) of coal-fired plants and placed more than 18.0 GW of gas-fired plants into service, effectively shifting more of the regional electric dispatch to natural gas plants.

Southeast demand growth over 2010-2014 appears not to have been disproportionally affected, either to the negative or positive, by non-normal weather conditions when viewed over an entire winter or summer season. Wood Mackenzie's review of heating and cooling degree-days, as illustrated in Chart 3 below, shows that seasonal and average temperatures have not exerted major upward or downward impacts on consumption.

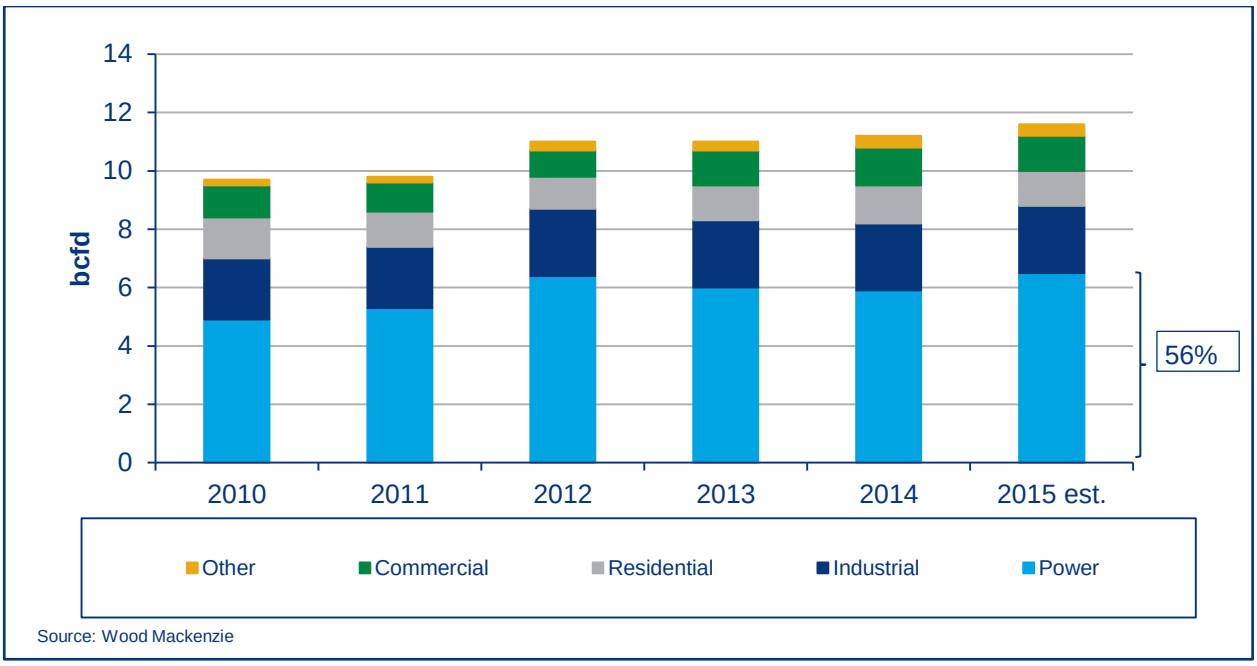
Chart 3 Southeast Heating Degree Days and Cooling Degree Days (2010-2014)





As discussed above and illustrated below in Chart 4, natural gas-fired power generation has increased by nearly 2 bcfd and accounts for the largest share of regional gas consumption growth. Chart 4 also shows that other market sectors have grown, accounting for approximately 15 to 20 percent of the aggregate average annual day growth. Since these other sectors include core winter season customers, the peak-day percentage demand growth rates can be higher and comprise a larger percentage of total daily capacity requirements than observed with annual average-day data.

Chart 4 Southeast average daily gas demand, by sector

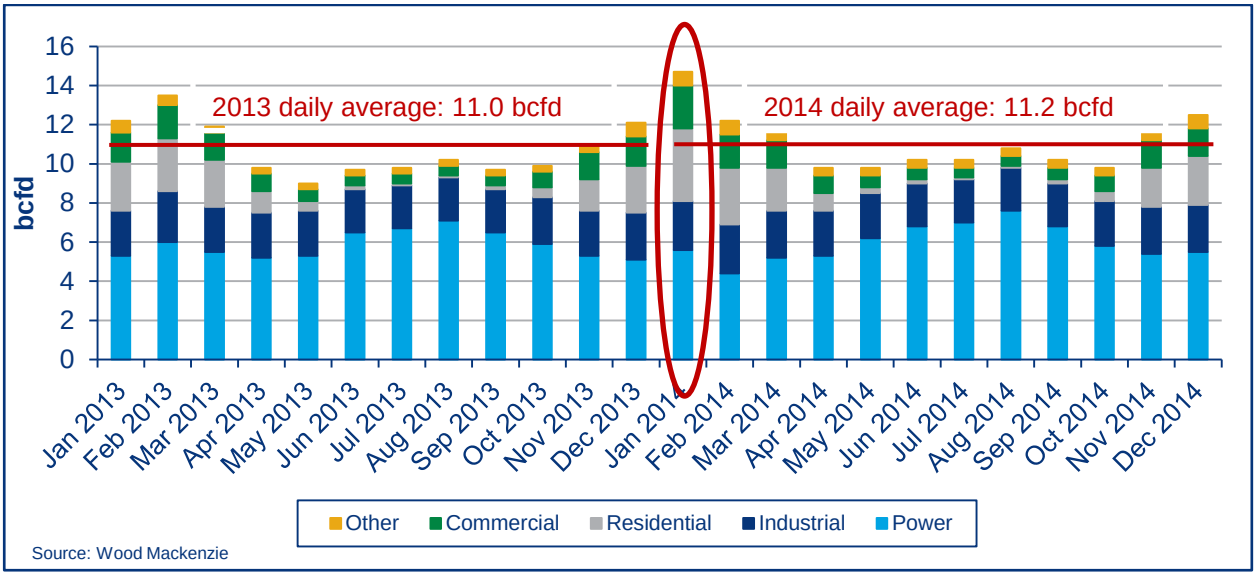


Seasonal Demand

The average annual daily demand figures discussed above are an important benchmark for measuring growth. The Southeast, however, remains a highly seasonal market with gas demand being highest in the winter months due to space heating requirements. Assessments of regional pipeline capacity adequacy should consider the higher daily demand that occurs during the peak winter months. There is also a strong summer peak as power generation use increases to meet air conditioning requirements.

Chart 5 below shows average daily demand across the Southeast, *by month*. Note that during January 2014, spurred in part by the Polar Vortex[5] cold weather episodes that occurred that season, average daily demand was more than 3.5 bcfd higher than the annual average day for that year. In all, daily demand in the coldest 2013 and 2014 months was 26 and 32 percent, respectively, higher than the average annual daily consumption.

Chart 5 Average daily gas demand by Southeast U.S. sector (2013-2014)



Peak Demand

The monthly average daily demand graphed above does not reflect higher peak/design day[6] demand that often occurs during extreme weather conditions. Peak- day, design-day and average annual daily consumption can grow at different rates, such that peak-day and design-day supply capacity may be inadequate, even though installed capacity is sufficient for serving annual average demand. Individual utilities, among other consumers, take peak

[5] Gas demand in parts of the Southeast market spiked materially during the "Polar Vortex" cold fronts that swept across much of the eastern United States and Canada in the winter of 2013/2014.

[6] References vary, but in this report "peak-day" refers to the highest consumption, heating-degree day or cooling degree day figures occurring in a given year. "Design-day" references an analytical peak over an extended year period (e.g.10-100+ years) used in capacity planning. Both figures will be greater than average annual day figures.

and design demand conditions into account when planning their gas pipeline capacity portfolios.

Peak/design considerations are becoming increasingly relevant as winter-season gas-fired generation expands in the Southeast and shares resources with other regional markets, such as the Mid-Atlantic and Northeast U.S. Electric reliability, going forward, will depend more on incremental gas capacity that can satisfy energy needs and provide operating flexibility during the course of an operating day.

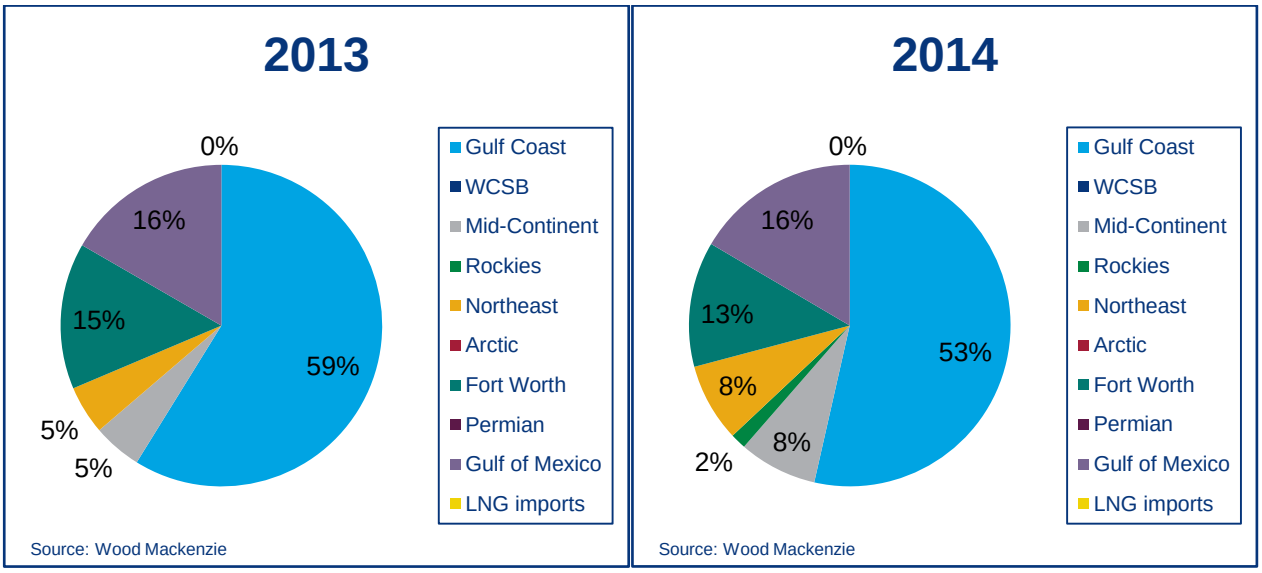
Section 3 – Southeast Gas Supply and Pipeline Utilization (2014)

The Southeast region states have historically been served by gas supply originating from the Gulf Coast and Mid-continent production regions. This gas flows eastward into the Southeast consuming markets, with additional gas then flowing up to the Mid-Atlantic and New England.

Historically, the majority of gas supplies delivered into the market have been sourced from producing fields and pipeline interconnections in the Gulf Coast. During 2014, the Southeast states, south of West Virginia and Virginia, sourced nearly three-quarters of their gas supplies from the onshore Gulf Coast and offshore Gulf of Mexico fields.

In response to strong Southeast market demand growth and declining Gulf Coast production, pipeline operators first expanded transportation linkages to Mid-continent fields in Oklahoma and Arkansas via new pipelines to Alabama, where downstream pipelines take receipt for final transportation delivery. Chart 6 below provides a comparison of Southeast source volumes from 2013 to 2014.

Chart 6 Natural gas supply sources for the Southeast



At the same time, Chart 6 also shows a shift from Gulf Coast region (which includes onshore Gulf Coast states and offshore Gulf of Mexico in the chart above) to Northeast (Appalachian Basin) gas supply, which is a more recent trend. This change has been relatively modest so far in the Southeast, due to the lack of pipeline capacity from the Northeast. Appendix Charts 16, 17 and 18 show this migration to new supplies by Southeast sub-region.

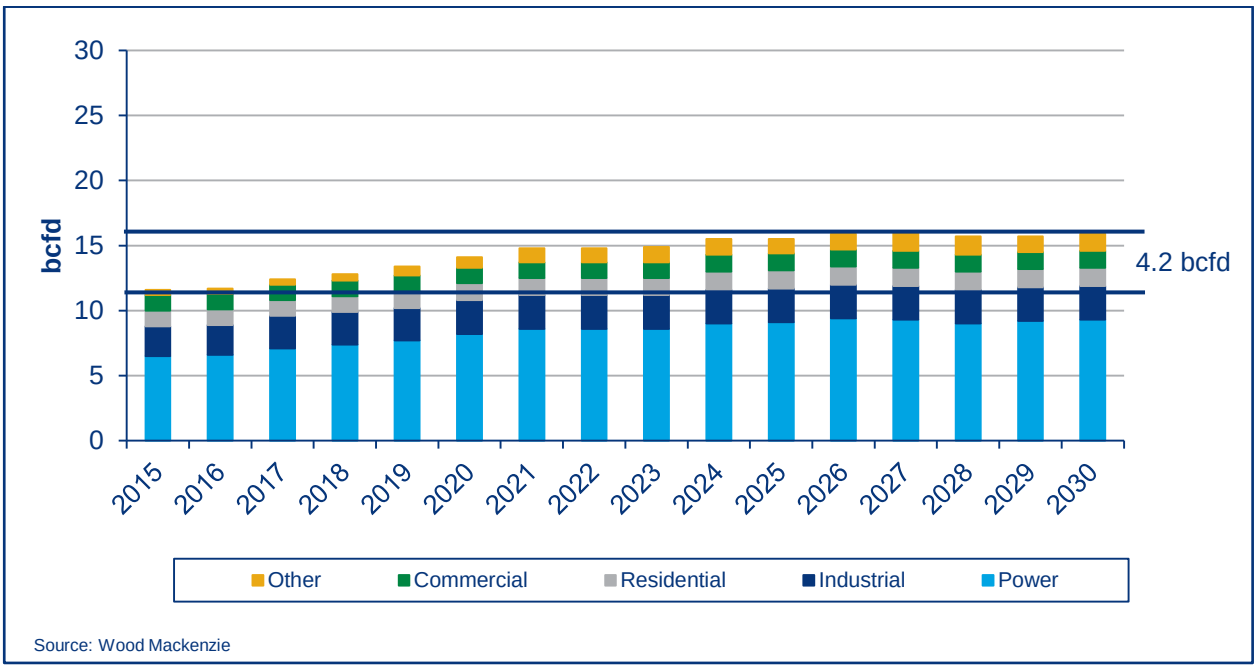
Wood Mackenzie believes that the Marcellus and Utica will become the principal source of gas supply growth in the Southeast U.S. and that this gas supply will be key in serving both existing demand and demand growth in the Southeast. As discussed below, growing Gulf Coast market growth will increasingly compete for supplies that have historically flowed into the Southeast, highlighting the need for new supply sources and pipeline capacity.

Section 4 – Long-Term Southeast Demand Outlook (2015-2030)

Planning standards for developing new pipeline capacity can vary, but most often benchmark regional capacity against average annual, seasonal and daily measures of market demand growth. This section reviews Wood Mackenzie's long term outlook for the Southeast.

The Southeast is very large and one of the fastest growing gas consuming regions in North America. As seen in the graph below, through 2030, average annual daily demand is projected to increase by 4.2 bcfd at a 2.1% CAGR, which equates to 3.5 bcfd by 2030 in the winter months, and up to 2.3% annually in the summer months.

Chart 7 Projected sectoral Southeast gas demand - Annual daily average



Source: Wood Mackenzie

As noted, average annual demand projections are one measure of a region's pipeline capacity requirements. Taken alone, however, average annual demand estimates provide an incomplete assessment of capacity needs, and for that reason should be considered in tandem with corresponding peak seasonal and daily demand projections which are often higher. These are discussed in more detail below in the review of Southeast pipeline capacity drivers.

Three main factors underscore the need for new gas pipeline capacity and supply in the Southeast.

1. Power generation. The Southeast leads all regions in total projected migration from coal- to gas-fired power generation.

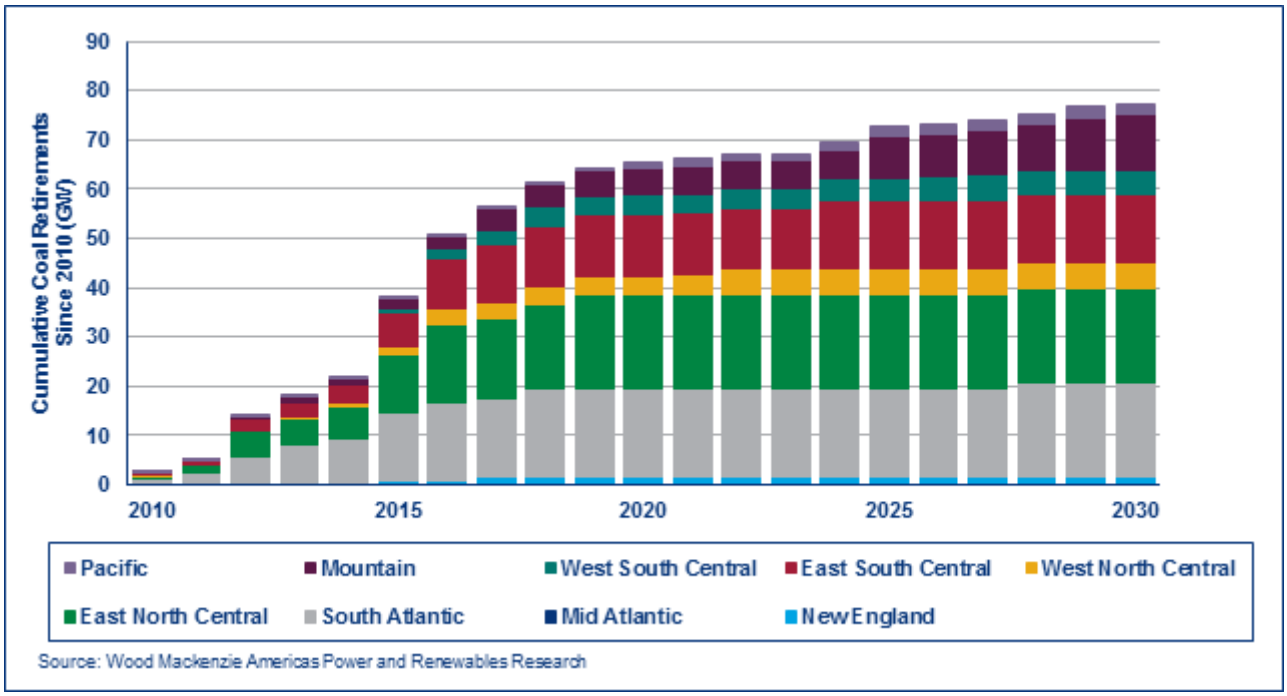
2. Peak period demand growth. In addition to seasonal peak demand spikes in core market sectors, significant pipeline capacity will be required to meet the peak hour dispatch rates in gas-fired power generation.

3. Economic supply displacement. Buyers reduce purchases of current Gulf Coast gas supply sources in favor of more economic Marcellus and Utica production.

Power Generation – Coal retirements drive Southeast growth in gas-fired generation

As discussed in Section 2 above, 16.5 GW of Southeast coal-fired plants have been shuttered since 2010. As shown in Chart 8, another 8 GW are expected to retire between 2015 and 2030. Chart 12 below shows how the Southeast power market (measured by the South Atlantic census region, in gray) has been one of the most aggressive regions in shifting away from coal-fired power generation.

Chart 8 Southeast coal retirements approach 25 GW (2010-2030)

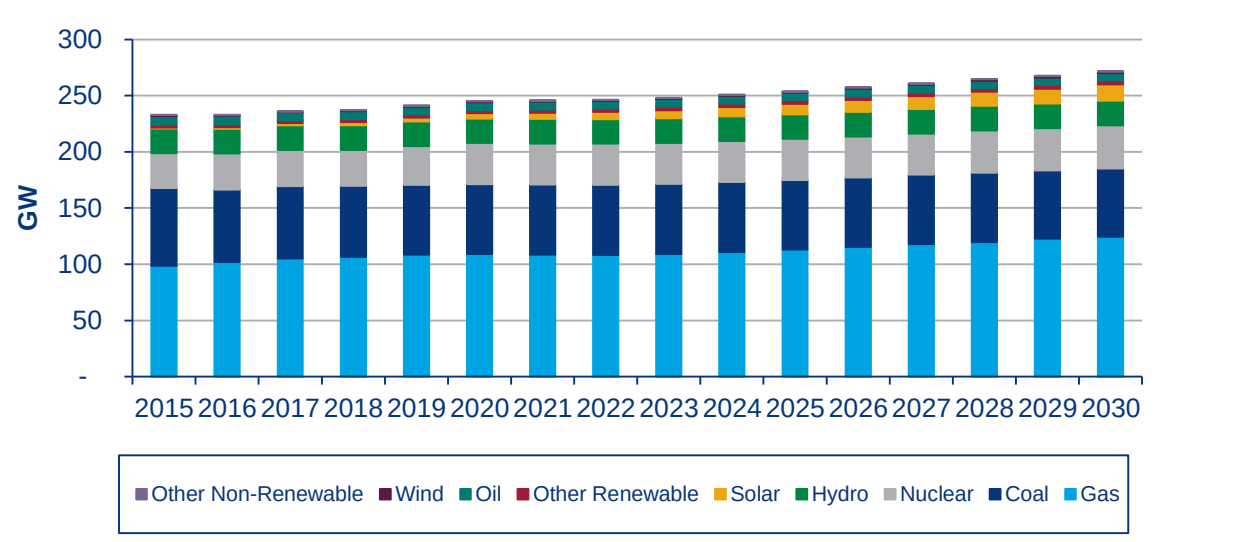


Note: The Southeast region as defined in this graph is comprised of the South Atlantic and part of the East South Central regions.

Going forward, Southeast gas-fired power plants are expected to take the largest share of generation abandoned by coal. As shown in Chart 9, Wood Mackenzie projects that total new gas-fired generation capacity rises nearly 50 GW to almost 125 GW over the period. In total, gas-fired generation is projected to comprise nearly 50% of the region's total capacity by 2030.

Solar energy and other renewables also experience a significant increase, but renewable energy's absolute share of the regional energy portfolio remains limited at 7.0% by 2030. The aggregate composition of the Southeast region's power fleet is shown below in Chart 9.

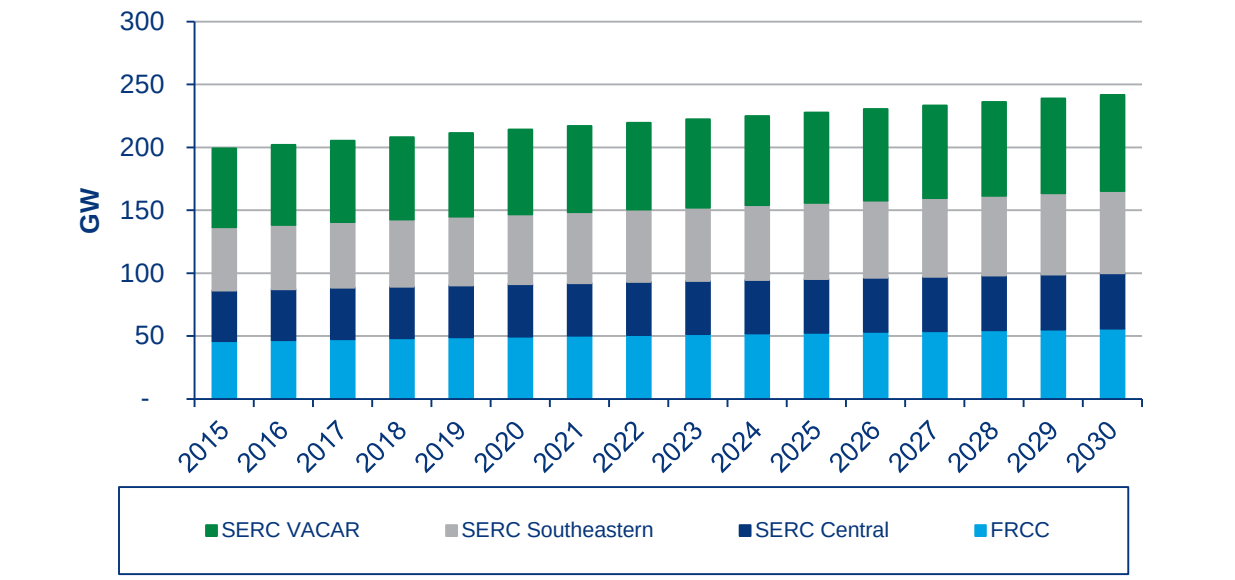
Chart 9 Forecast of installed generation capacity in the Southeast (2015 – 2030)



Source: Wood Mackenzie

It is important to note that electric generation capacity and energy production are dispersed broadly across the Southeast market, and not concentrated in any single geographic area. The chart below illustrates how Southeast generators in the Southeast North American Electric Reliability ("NERC") regions will benefit from a supply project such as MVP that can affect deliveries to all states in the region.

Chart 10 Growing electricity peak demand in Southeast NERC regions



Source: Wood Mackenzie

Note: FRCC is the Florida Reliability Coordinating Council; SERC is the Southern Electric Reliability Corporation, it is divided in sub-regions; The VACAR sub-region comprises North Carolina, South Carolina and Virginia, the Central region comprises Tennessee, Kentucky and parts of Georgia, Alabama and Mississippi; the Southeastern region comprises Alabama, Georgia and part of Florida and Mississippi.

Peak Period Demand Growth – Winter season core market and power generation demand

Between 2015 and 2030, power sector gas consumption projections increase at a 1.9% CAGR in winter and 2.6% in summer. By 2030, power generation load represents almost 60% of the Southeast's total demand for natural gas.

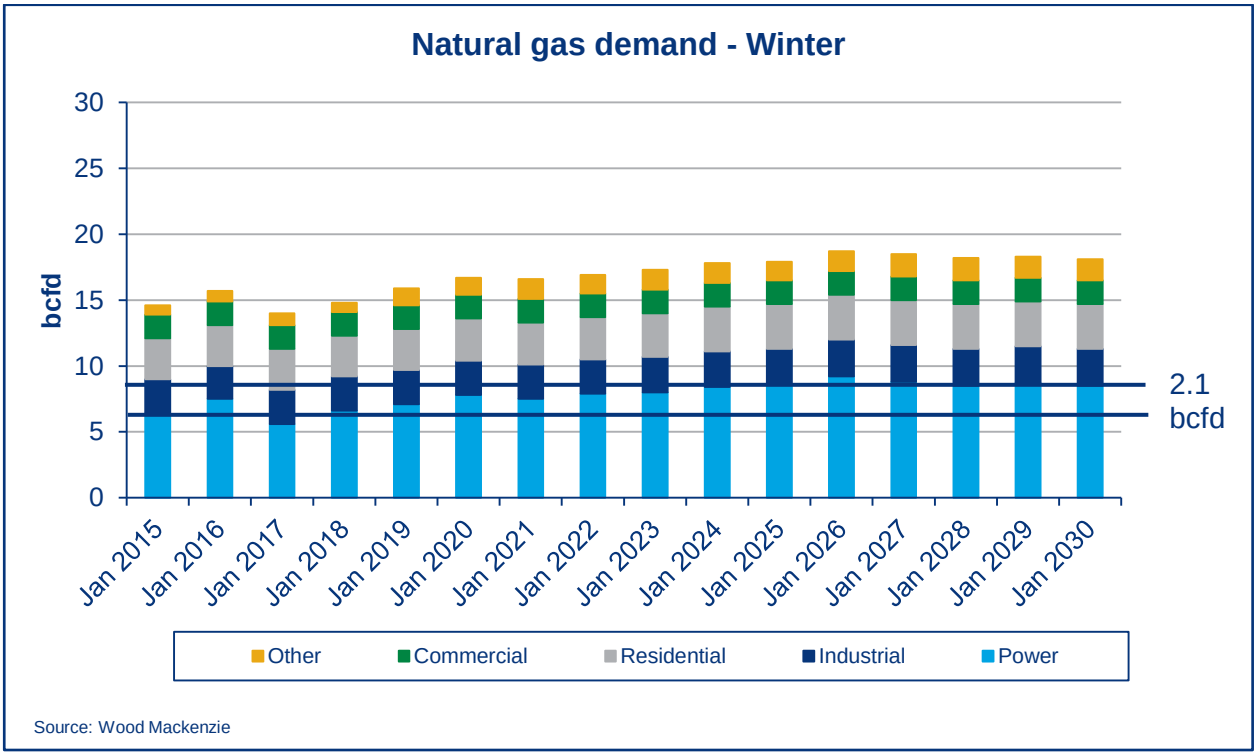
Power generation remains the largest Southeast growth sector, with summer average daily demand increasing by more than 3.7 bcfd (approximately 30% from 8.0 to 11.7 bcfd). Winter season power generation grows by approximately 2.1 bcfd through 2030.

During the same time period, core sector consumption is projected to grow at a 1.6% CAGR.

The proliferation of gas-fired generation portends a potential change for capacity planners in the relationship between winter and summer peak month. As gas plants increasingly dispatch during the winter, when firm core markets also require supply, gas-fired generators may require that a greater percentage of their portfolio be sourced under firm transportation arrangements.

Charts 11 & 12 provide forecasts of power generation and core sector gas demand during the peak winter and summer season months of January and August, respectively. As seen, power generation demand is the largest growth sector, growing by 2.1 bcfd in winter and 3.7 bcfd in the summer.

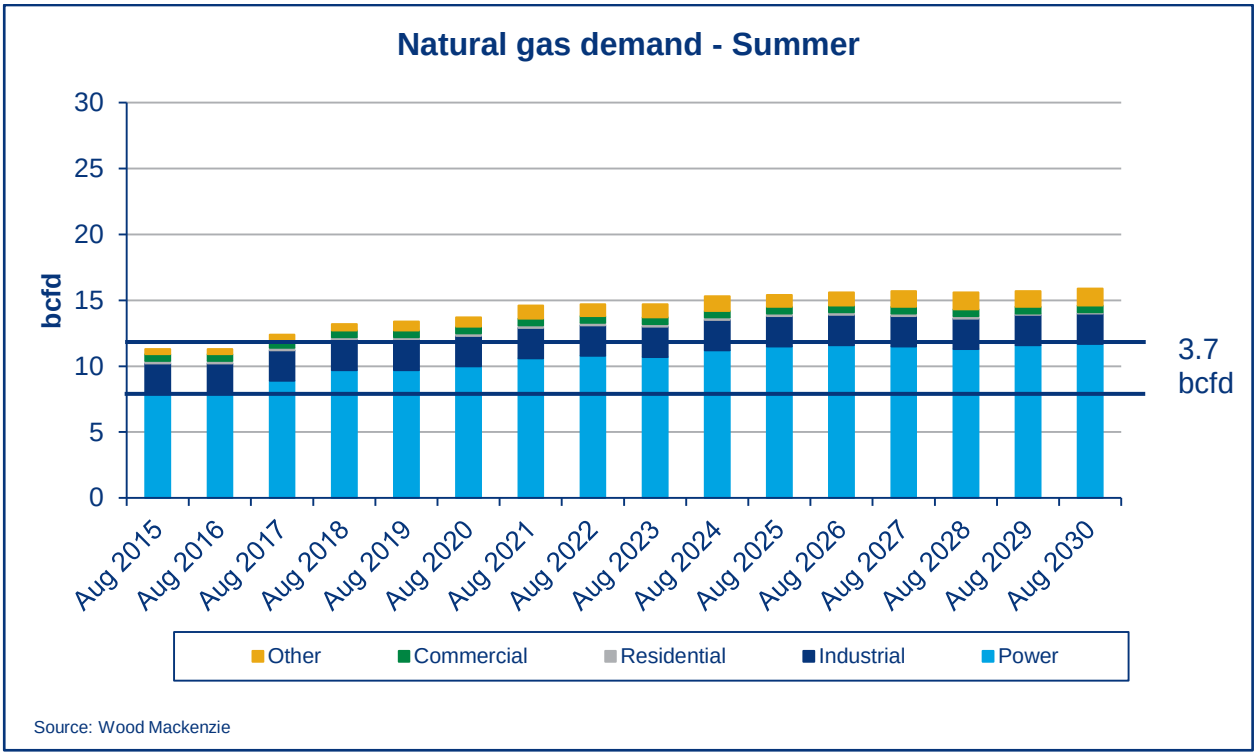
Chart 11 Projected Southeast power generation gas demand – Winter Peak Month



Comparing demand in the charts above and below shows that although summer demand grows more rapidly than winter demand, the winter demand growth will occur at times

when the pipeline grid is much more heavily utilized and gas non-firm gas deliverability is vulnerable to interruption.

Chart 12 Projected Southeast power generation gas demand – Summer Peak Month



Peak Period Demand Growth – Pipelines capacity to manage power generation hourly demand swings

For numerous reasons power markets in the Southeast are unlikely to dispatch gas-plants on a "baseload" basis for a 24-hour day or for continuous hourly blocks.[7] Instead, many gas plant load profiles will vary widely on an hourly (or shorter) basis in the course of a day. These hourly demand "swings" can result in "rateable" daily pipeline capacity requirements that are materially higher than actual daily gas consumption.[8] Since there is little gas storage in the Southeast, pipelines must be prepared to manage this hourly swing, which they do typically by drawing on latent capacity and linepack.[9]

Wood Mackenzie analysis and estimates indicate that the difference in rateable peak-hour versus average daily gas demand can equate to as much as a 50% difference between rateable daily requirement and actual consumption. The comparisons in Chart 13 below

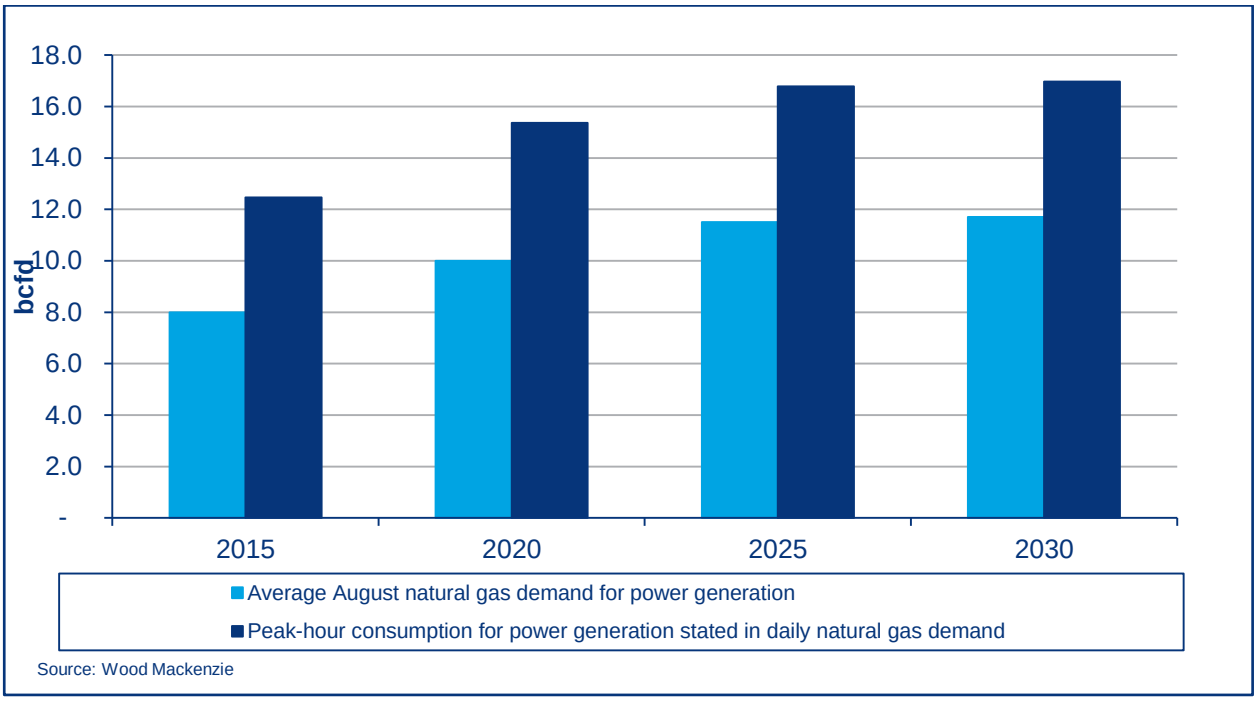
[7] "Baseload" demand equals continuous operation throughout a day or periods of a day which often correspond to 16-hour on-peak and 8-hour off-peak blocks in the course of a day.

[8] Power markets design and dispatch facilities on 15 minute intervals, while pipelines contract capacity on a 24-hour daily interval. "Rateable" daily gas demand by a power generator is calculated as a facility's hourly gas use x 24 hours. Pipelines must be designed and operated to be able to deliver gas supplies at the peak hour rate, which on rateable basis is typically greater than the actual daily demand,

[9] "Linepack" is pipeline gas that is at pressure and which can be drawn upon to maintain service during short duration peak periods, typically measured in hours.

illustrate how hourly power generation swings can require as much as 5.3 bcfd of additional capacity over average daily volumes by 2030. This reflects an additional .8 bcfd of new swing capacity needs between 2015 and 2030. Note that capacity planners historically make no express allowances for hourly swing in their pipeline capacity planning.

Chart 13 Average daily vs rateable peak-hour demand in Southeast plants



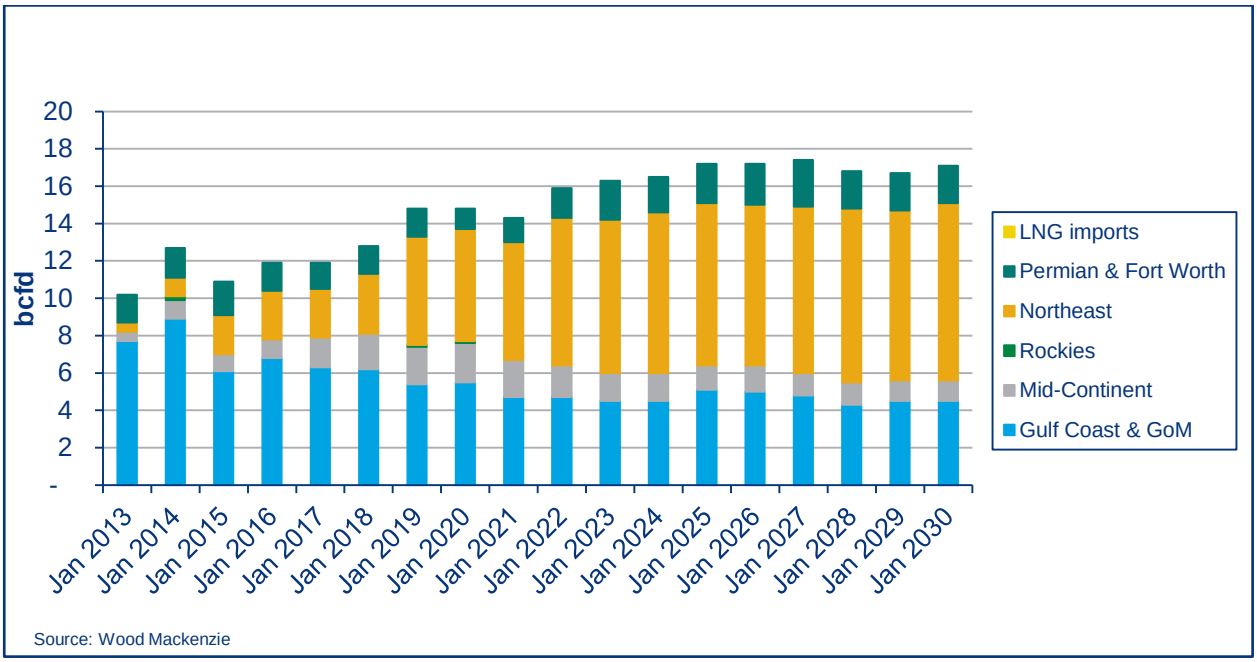
Source: Wood Mackenzie

Economic Displacement – Southeast shift to Marcellus and Utica gas supplies

The Southeast's rapid growth is a major driver for new pipeline capacity connections to the Appalachian Basin and its Marcellus and Utica shale production. But demand growth is not the only impetus for new pipeline construction into the Southeast. The North American gas market is highly integrated and changes in the price of gas in the Gulf Coast and Appalachia will affect how the Southeast procures supply. Of particular relevance is the upward pressure that growing Gulf Coast demand may have on the prices of gas in the region, and the downward pressure that new gas production has on Appalachian production. These pricing trends clearly show that Southeast consumers stand to realize economic benefits from increased access to Marcellus and Utica gas supplies.

The chart below depicts total projected Southeast gas consumption and the composition of gas producing basins that will supply the region during the peak winter month of January. The role that Marcellus and Utica supplies (labelled "Northeast" in the graph legend) play in meeting growing demand is evident, growing from approximately 1.0 bcfd in 2014 to nearly 10.0 bcfd by 2030.

Chart 14 Southeast natural gas demand and supply sources (through 2030)



Source: Wood Mackenzie

As seen above, the growing share of Northeast gas supply in the Southeast is greater than the total growth in Southeast demand. This implies a shift in gas flows that reflects not only the utilization of new pipeline capacity originating in the Northeast, but also the Southeast's displacement of other sources of gas, in particular the Gulf Coast and Mid-continent. In our analysis, by 2020, approximately 3.3 bcfd of current gas supplies are displaced in favor of new Marcellus and Utica shale sources.

The projections of displaced Gulf Coast and Mid-continent production are a function of the economic algorithms used in Wood Mackenzie forecast modelling. These algorithms are designed to mimic rational economic behaviors between gas market buyers and sellers. In the analysis of MVP and the Southeast market, the shift by Southeast buyers away from traditional Gulf Coast and Mid-continent sources to Northeast (Appalachian Marcellus and Utica shale) supplies is driven by the relative economics of the regional supply choices. The variables and interactions of the North American market as modelled that underlie the shifting Southeast resource patterns are numerous and complex, but can be summarized as result of growing economic supplies in Appalachia that become less costly than gas supplies procured in the demand Gulf Coast and Mid-continent markets. When presented with pipeline transportation alternatives such as MVP that access a lower cost supply, Wood Mackenzie models reflect that buyers will shift their purchases to the lower cost basins.

Section 5 – Conclusion

The Southeast U.S. is a large and growing natural gas market that will require new sources of gas supply to satisfy future demand. Given the evolution of North American natural gas production, the Marcellus and Utica shale plays of the Appalachian Basin will become a critical component of the Southeast supply portfolio.

Connecting the growing Southeast markets to Appalachian production will require new pipeline capacity. Wood Mackenzie analysis indicates that the MVP capacity will be an essential source in reliably meeting Southeast regional demand, particularly during peak period conditions.

Wood Mackenzie projects that Southeast average daily gas demand, driven by new gas-fired power generation, will increase by 4.2 bcfd through 2030, with much of that growth occurring early in the next decade. This growth projection assumes normal weather conditions.

It is important to note that pipeline capacity must be designed to supply gas during colder-than-normal peak periods, as witnessed during the 2013 and 2014 winter Polar Vortex episodes, when January actual demand was 26% and 32%, respectively above the average for that month. Average peak winter-month (January) daily demand grows by a slightly lower 3.5 bcfd, this growth occurs when pipeline capacity is typically more scarce. Designing for colder-than-normal winter month peaks could increase winter capacity pipeline requirements by approximately 1.0 bcfd.

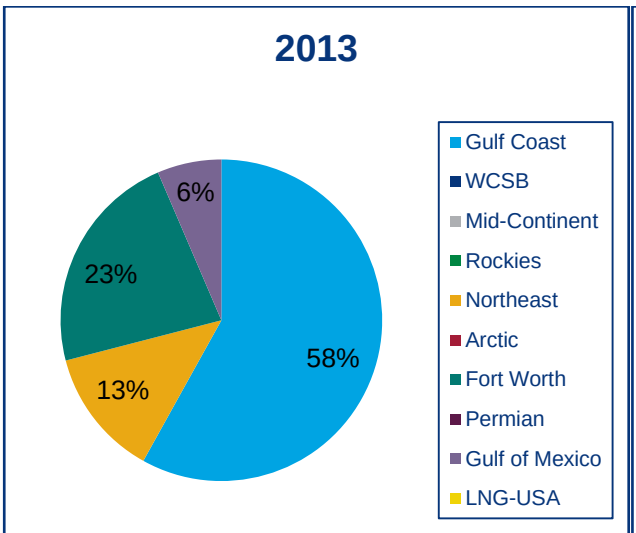
The addition of significant new gas-fired generation in the Southeast will require pipeline capacity that is able to match the hourly dispatch cycles of gas plants in the region. Analysis of historical dispatch rates indicates that power generation could require the daily equivalent of an additional 5.3 bcfd of capacity during peak hours, an increase of .8 bcfd through 2030. Although pipelines have typically worked with generators to manage these swings using existing capacity, new capacity may ultimately be required as loads grow, particularly as generators dispatch in winter months when capacity conditions can be tight.

Finally, the evolution of North American markets and supplies is changing the buyer procurement practices. Our analysis indicates that Southeast buyers will realize economic benefits by shifting approximately 3.3 bcfd of supplies from traditional Gulf Coast and Mid-continent sources to Appalachian supplies, assuming new pipeline capacity is available.

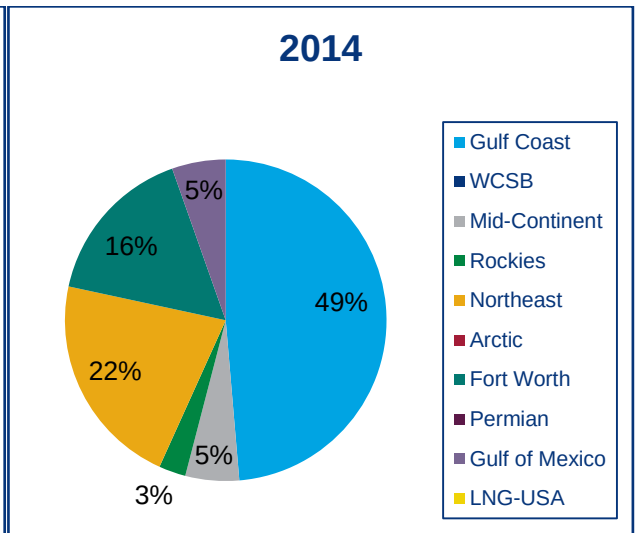
In all, total daily Southeast demand for pipeline capacity is poised to grow by as much as 8.3 bcfd between 2015 and 2030. This will require new pipeline construction such as MVP from reliable and economic supply basins.

Appendix

Chart 15 Southeast gas supply sources (WV, VA, NC and SC)

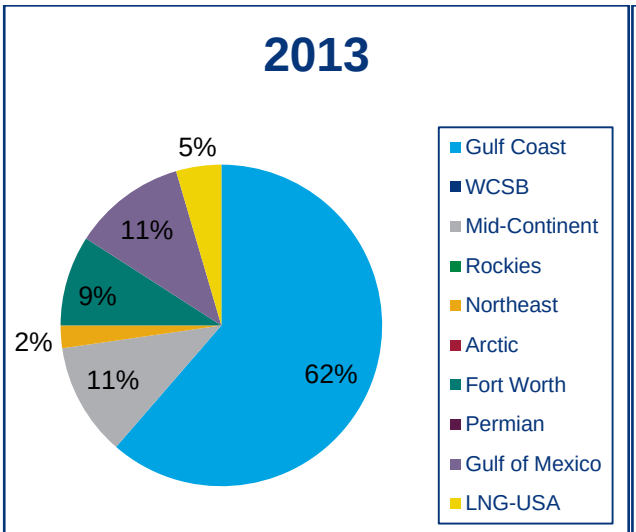


Source: Wood Mackenzie

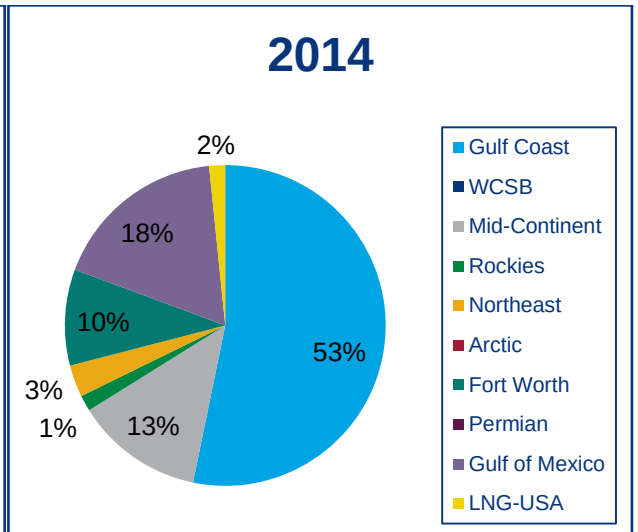


Source: Wood Mackenzie

Chart 16 Southeast gas supply sources (AL, GA and TN)

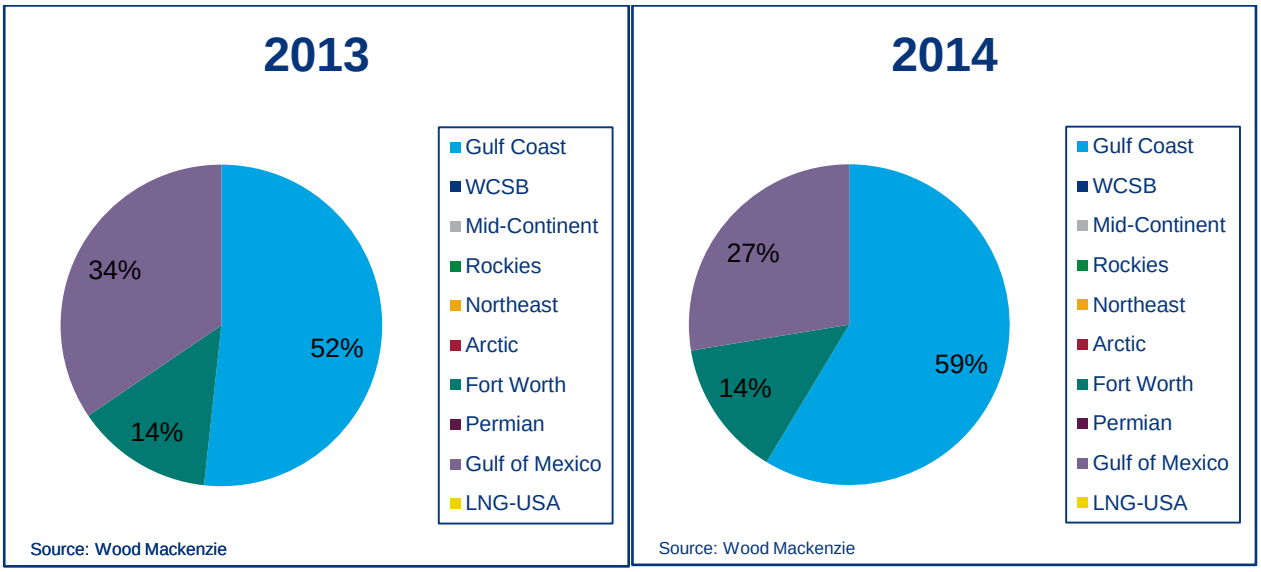


Source: Wood Mackenzie



Source: Wood Mackenzie

Chart 17 Florida gas supply sources



Analytical Approach and Key Assumptions

Wood Mackenzie analysis and forecasts are developed through the integration of specialist teams:

Table 1 Internal data sources

Data item	Wood Mackenzie Team
GDP and exchange rates	Macroeconomics team
Global coal prices	Coal market team
Gas supply and long run marginal cost of gas fields	Upstream team
Liquids prices, demand, and infrastructure	NGLs team
Industrial demand	Chemicals team
Yet-to-Find gas reserves	Exploration team
Crude oil demand and prices	Macro oils team
Diesel and oil product prices	Downstream team
Overall energy balance and market structure issues	Energy markets team

Source: Wood Mackenzie

GDP forecasting

GDP is the monetary value of all finished goods and services produced within the borders of a country over a given time period. Wood Mackenzie reports GDP in constant 2000 US

dollars. This is a measure of real GDP (taking inflation into account) and uses market exchange rates to convert local currency GDP into US dollar GDP. The date stamp of the market exchange rate used to make the conversion is determined by the World Bank. GDPs can only be compared across countries when measured in the same units.

Short-term GDP is forecast using a combination of lead indicators (which help economists set the very short-term) and an assessment of key economic variables within and across key economies over the current business cycle. An assessment of the key sectors within economies is made once per quarter using industry data and lead indicators to provide guidance on turning points and growth momentum within these sectors. Purchasing Managers Indices (PMI), and retail and business surveys are used to inform sector growth forecasts; household confidence, income measures, and unemployment rates are used to inform household consumer spending forecasts. Wood Mackenzie also pays close attention to key policy drivers including monetary and fiscal policy, assessing the impact of any change to both domestic and external sectors of the economy.

In line with standard growth accounting theory, the long-term growth potential of an economy (beyond five years) is estimated using three key growth drivers: (i) the labor force in an economy; (ii) growth in capital stock; and (iii) growth in productivity. These structural supply-side drivers tend to be driven by relatively stable trends through time, providing a robust basis for estimating long-run GDP growth potential of an economy. It is useful to note that the long-term GDP model estimates potential or trend growth that reflects the smoothed growth path of an economy, rather than cyclical fluctuations (as in the short-term).

Wood Mackenzie does not measure real GDP using Purchasing Power Parity (PPP). While the PPP measure of GDP is a useful relative measure of a country's output at any given time, it is not a reliable (or informative) measure of GDP when forecasting beyond five years. PPP GDP is highly sensitive to PPP exchange rates which are only estimated once every five years (by the International Comparison Program) and are not possible to forecast. Assumptions can be made, but long-term PPP forecasts are subject to large error bands and could generate misleading inferences in Wood Mackenzie's commodity analysis.

Key steps - industrial production forecasting

IP is a measure of output of the industrial sector of an economy. In the short-term, specific industry sector data and lead indicators such as the Purchasing Managers Indices (PMI) are used to inform Wood Mackenzie's Macroeconomics team of the direction and momentum of change in a country's industrial sector.

Over the long-term, the industrial trends of an economy are assessed using several approaches. Wood Mackenzie pays attention to the influence of energy and other commodity prices on the competitive and comparative advantage of an economy's industry, which informs the view of industrial migration over the 20-year time horizon. When a relationship exists, GDP growth can also be used to inform the view on industrial output growth. Wood Mackenzie also forecasts auto production (primarily used in metal demand modelling) and the construction outlook for core economies. These sectors also inform the industrial production outlook.

Key steps - inflation forecasting

Inflation is a measure of the increase in price of a standard basket of goods and services in an economy over a specific time horizon (usually one year). There are many inflation rates (in all countries), each measuring different baskets of goods, services and/ or inputs into the production process. Wood Mackenzie forecasts headline inflation, typically Consumer Price Inflation (CPI).

Wood Mackenzie's economists forecast headline inflation by assessing two main sources of inflation: demand pull and cost push in any given economy. Assessing the level of demand pull inflation is best done through the output gap, which is the difference between actual and potential output of an economy. Output gaps can be positive or negative, a positive gap occurs when actual output is less than potential, and this tends to put downward pressure on prices. When actual output is greater than potential output, the output gap is negative, and upward pressure is put on prices in the general economy as too much money chases too few goods. Cost push inflation arises when input costs rise, or the cost of imported goods rise. This is most common when commodity prices rise and/or when import prices rise due to currency depreciation.

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Exhibit B

Wood Mackenzie
A Verisk Analytics Business

January 2017

Mid-Atlantic Natural Gas Demand in Support of the Mountain Valley Pipeline Project

Table of Contents

Table of Exhibits

Introduction

Nextera Energy, on behalf of Mountain Valley Pipeline[1] ("MVP"), retained Wood Mackenzie to provide an analysis and report on the future demand for gas in the Mid-Atlantic market of the United States.[2] Wood Mackenzie is an industry leading energy consulting firm and provider of energy market research, data and insights. This report presents the findings of our independent analysis. Wood Mackenzie is advised that MVP may include all or parts of this report in certificate application filings before the Federal Energy Regulatory Commission ("FERC").

Executive Summary

MVP will provide transportation for up to 2 billion cubic feet per day ("Bcf/d") extending from the Equitrans transmission system in Wetzel County, West Virginia, to Transcontinental Gas Pipe Line's ("Transco") Zone 5 compressor Station 165 in Pittsylvania County, Virginia. From Station 165 gas can flow on Transco to target markets in the Mid- and South-Atlantic/Southeast regions of the U.S.

In its prior January 2016 report, Wood Mackenzie analyzed the demand for new gas pipeline capacity and supply in South Atlantic and Southeast U.S. states.[3] That report presented analysis supporting a significant need for new pipeline capacity in the region. Wood Mackenzie developed this report on the Mid-Atlantic market to complement its prior report. This Mid-Atlantic report presents evidence of a large and growing need for the capacity and gas supplies that MVP will help satisfy throughout the 20-year study horizon, beginning in 2016.

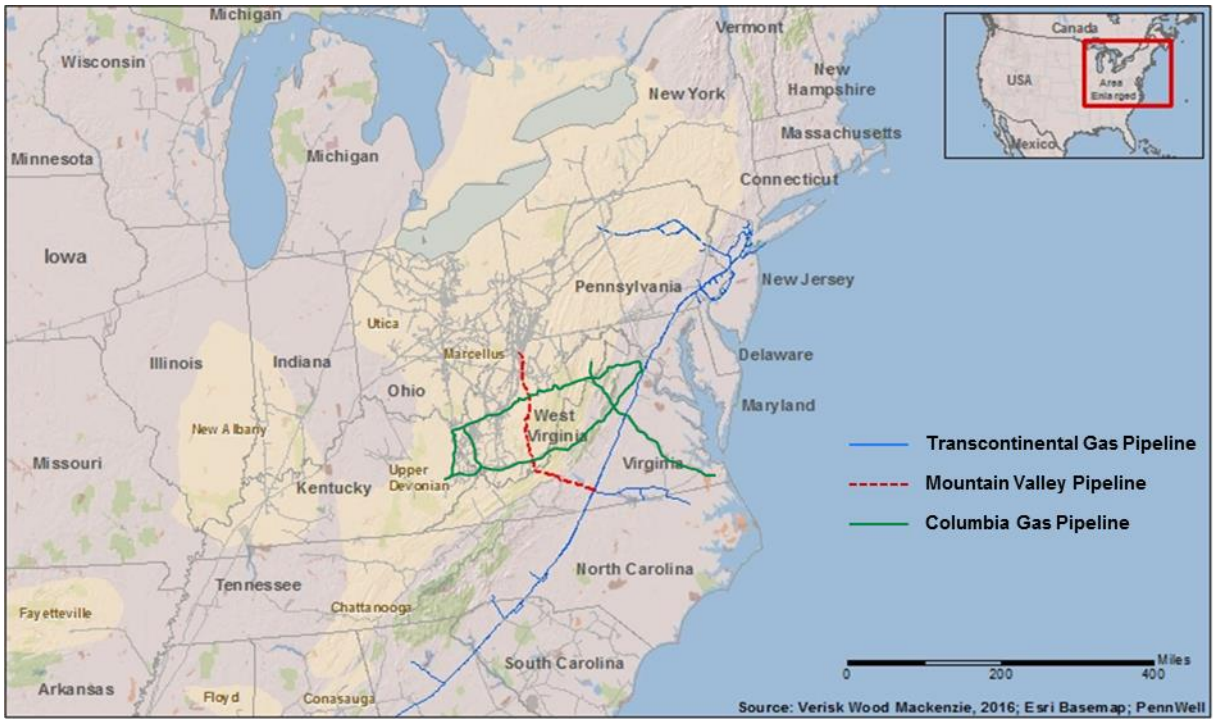
The Mid-Atlantic is a large and diverse U.S. market for gas demand, and it is expected to grow in large part based on the increased consumption of electricity fueled by natural gas.

[1] MVP is a joint venture between EQT Midstream Partners, LP; NextEra US Gas Assets, LLC; Con Edison Gas Midstream, LLC; WGL Midstream; and RGC Midstream, LLC.

[2] Gas markets can be considered by area; for this report, areas are defined by US states located in a defined, integrated distribution area referred to as the "Mid-Atlantic" gas market, which includes the states of Delaware, Maryland, New Jersey, New York, Pennsylvania, and the District of Columbia.

[3] For the January 2016 report, "South Atlantic and Southeast" includes the states of Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama and Florida. West Virginia is also included in states served by MVP.

Figure 1 Mountain Valley Pipeline and the Mid-Atlantic



Our analysis of the Mid-Atlantic demand for MVP recognizes the pipeline's ability to integrate with the interstate grid and immediately serve a share of current regional market demand, as well as its potential to be an economically competitive source of supply for projected future demand growth. As detailed in this report and summarized below, we estimate the long term Mid-Atlantic market demand that can be served by MVP to be 6.1 Bcf/d by 2035, or roughly 3x MVP's proposed capacity. As important, the current market demand of 2.2 Bcf/d is also greater than its proposed capacity. Taken together, both our near and long term outlooks suggest a robust Mid-Atlantic market for the capacity and new supply offered by MVP. Further the proximity of MVP's large market and its access to low cost gas production through MVP suggests that it will enjoy high utilization rates.

MVP Mid-Atlantic Gas Market	Bcf/d
Current Market	2.2
Growth Market	3.9
Total Market	**6.1**

The sections that follow successively describe the Mid-Atlantic market, review MVP's pipeline linkages to that market, and then quantify the demand for MVP capacity and the gas supply it can deliver.

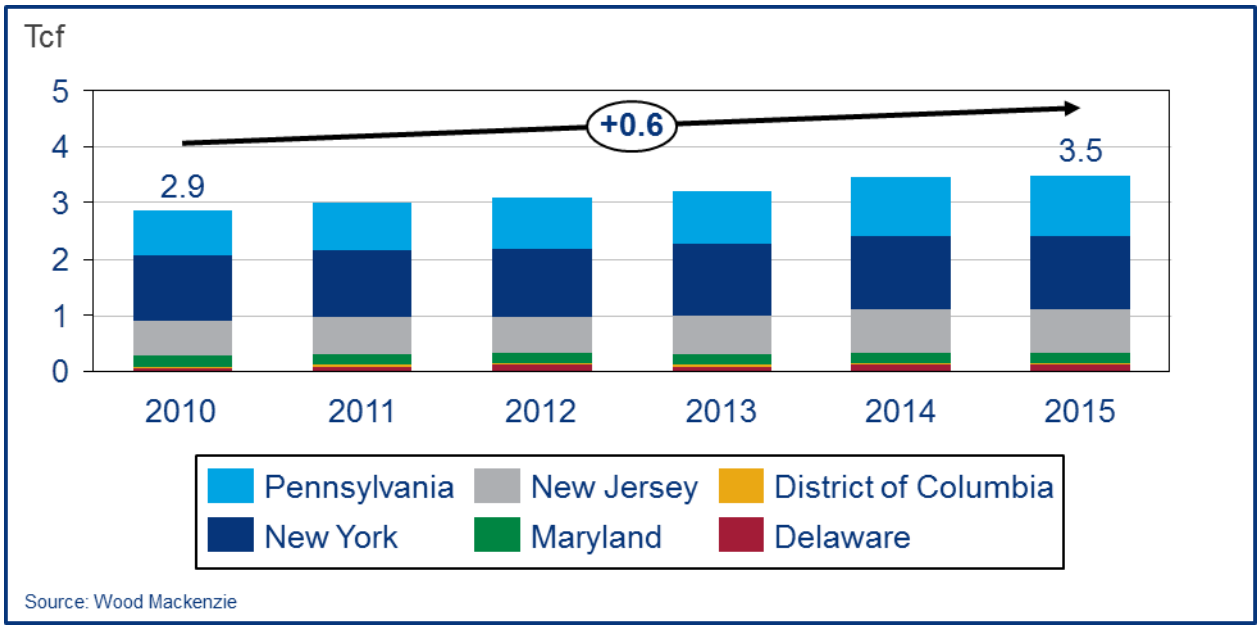
The U.S. Mid-Atlantic Gas Market

Summary Overview

The Mountain Valley Pipeline Mid-Atlantic gas market includes the states of New York, New Jersey, Pennsylvania, Maryland, Delaware, and the District of Columbia. The Mid-Atlantic is home to over fifteen percent of total U.S. population and is among the largest

regional gas markets in the country. Total annual volumes consumed in the region since 2010 have grown from less than 2.9 trillion cubic feet ("Tcf") to over 3.5 Tcf in 2015, corresponding with growth in state gross domestic product (GDP).

Figure 2 Mid-Atlantic Historical Annual Gas Consumption (2010 to 2015)



Mid-Atlantic gas buyers in these states will have access to MVP shipper supplies principally through downstream transportation on the Transco pipeline system. Through its large network of mainlines, laterals, interconnections and delivery points, Transco is able to provide physical gas delivery to most Mid-Atlantic geographic sub-markets. Through interconnections and various commercial arrangements, shippers also should be able to extend the reach of MVP supplies beyond the Transco system and effect deliveries to customers on other pipeline systems.

Evolving Mid-Atlantic Gas Supply and Demand Profile

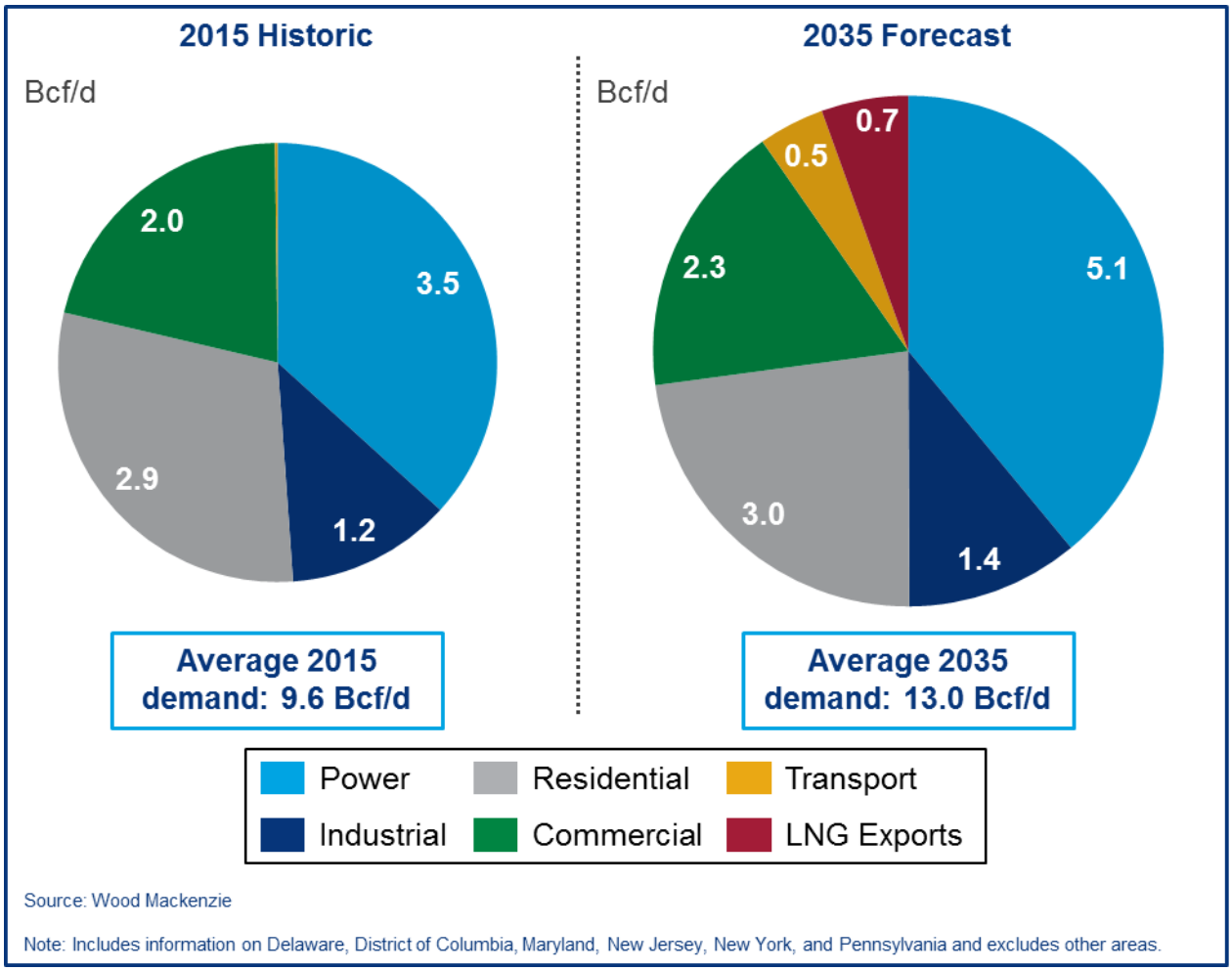
Historically, Mid-Atlantic gas supplies have been produced principally from conventional sources in the Appalachian Basin, the U.S. Gulf Coast, and Western Canada. Each Mid-Atlantic state market is uniquely connected to these producing basins by an extensive network of pipeline and storage facilities, through which gas flowed to regional delivery points, as well as further downstream into New England. With the rapid proliferation of gas production in the Marcellus and Utica shales, Mid-Atlantic buyers are increasingly realigning their portfolios to changing sources of supply and infrastructure is needed to transport this significant new gas supply to Mid-Atlantic markets.

The nature of Mid-Atlantic gas demand is also changing. Heretofore, seasonal and daily demand profiles have varied in the winter based largely on heating degree-days, while summer demand was driven by cooling degree-days and industrial and power generation sector fuel switching. Going forward, Mid-Atlantic market trends indicate that both winter and summer gas demand will become more sensitive to electricity consumption and the need to fuel gas-fired generation plants.

The Mid-Atlantic transition to increased gas use for power demand is forecast to grow at a steady rate, accelerated in key market areas by the retirement of coal and nuclear power

plants. Renewable energy sources are also increasing as a share of installed capacity, but gas is forecast to be the predominant fuel source for power generation. Figure 3 below illustrates the impact of increased power generation load on gas demand.

Figure 3 Mid-Atlantic Forecast Annual Average Daily Gas Demand (2015 to 2035)



MVP provides a highly valuable source of supply to Mid-Atlantic consumers by providing the necessary pipeline infrastructure to supply a prolific, cost-competitive and new gas source to the existing and growing market at the MVP-Transco interconnection. This creates value by allowing gas buyers along the Transco system to acquire Marcellus/Utica supplies and arrange firm delivery using their existing (or new) Transco firm transportation portfolio. MVP deliveries at Station 165 also enhance Transco capacity optimization opportunities by unloading capacity upstream of Station 165.

MVP Linkage with Mid-Atlantic Gas Users

Upon in-service, MVP shipper gas supplies will be positioned to serve current and future Mid-Atlantic demand via the Transco pipeline system. The primary pipeline path to both current and future markets will originate at the interconnection with the Transco mainline at Station 165 in Virginia and terminate at Transco delivery points throughout the region and on connecting pipelines to downstream markets. While this study focuses on MVP's interconnection with Transco, MVP will also interconnect with Columbia Gas Transmission's ("Columbia") WB pipeline and provide MVP shippers the ability to deliver

up to 1.0 Bcf/d of natural gas into Columbia's system in order for certain markets served off of that system to source gas from MVP.

In this study the "current" market for MVP supplies is defined by the aggregate daily Rate Schedule FT rights held by Transco Mid-Atlantic shippers, which can be supplied through receipts at Station 165. It envisions that existing gas buyers will be incentivized to switch from current sources on Transco to a more economic MVP supply if available. As summarized above and detailed below, the current market is approximately 2.2 Bcf/d.[4]

The "growth" market for MVP gas supplies in this study refers to projected increases in Mid-Atlantic daily demand, particularly during peak months. A large share of this growing firm demand will likely come from gas-fired power generation plants that will be essential to regional power grid reliability. Increased firm gas service to serve this growth will require new gas sources such as the Marcellus and Utica supplies that MVP will provide.

This section reviews three primary transportation contracting choices by which Mid-Atlantic gas market consumers can integrate MVP shipper supplies into their gas supply portfolios and serve current or future markets. As discussed, these choices include a mix of existing and potential incremental transportation services, both firm and non-firm.

Rate Schedule FT Market

Mid-Atlantic gas consumers holding certain Transco Rate Schedule FT transportation contracts on its mainline will have immediate access to MVP shipper supplies. Transco's FERC Gas Tariff allows Rate Schedule FT customers[5] to nominate and receive up to 100 percent of their Maximum Daily Quantity ("MDQ") volumes at receipt points downstream of Station 65 at the Louisiana/Mississippi state line. Because the new Station 165 interconnect is downstream of Station 65[6] and lies "in the path" of their firm receipt and delivery point rights, it is operationally (and economically[7]) feasible that these Rate Schedule FT shippers could absorb the entire volume of gas transported by MVP. Sales by MVP shippers to this Mid-Atlantic market would not require new certificate capacity on Transco or other pipelines; they are able to trade on day 1 of the MVP in-service.

It is important to note that Mid-Atlantic displacement of Gulf Coast supplies by MVP supplies would not create a surplus of pipeline capacity or gas supply in the market. More

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[4] Since it is larger than MVP's proposed capacity, this estimate of the current market for MVP conservatively excludes the potential to pair MVP supplies with Transco expansions and serve existing demand on other Mid-Atlantic pipeline systems.

[5] Transco provides firm transportation services under various Rate Schedule designations. Rate Schedule FT services are the largest class of service by MDQ and by geographic expanse. Sometimes referred to as "legacy" services because firm rights are designed to allow gas flows from Texas/Louisiana to eastern market gas utility city gates, they allow Mid-Atlantic shippers wide flexibility to acquire MVP supplies using "in the path" receipt rights.

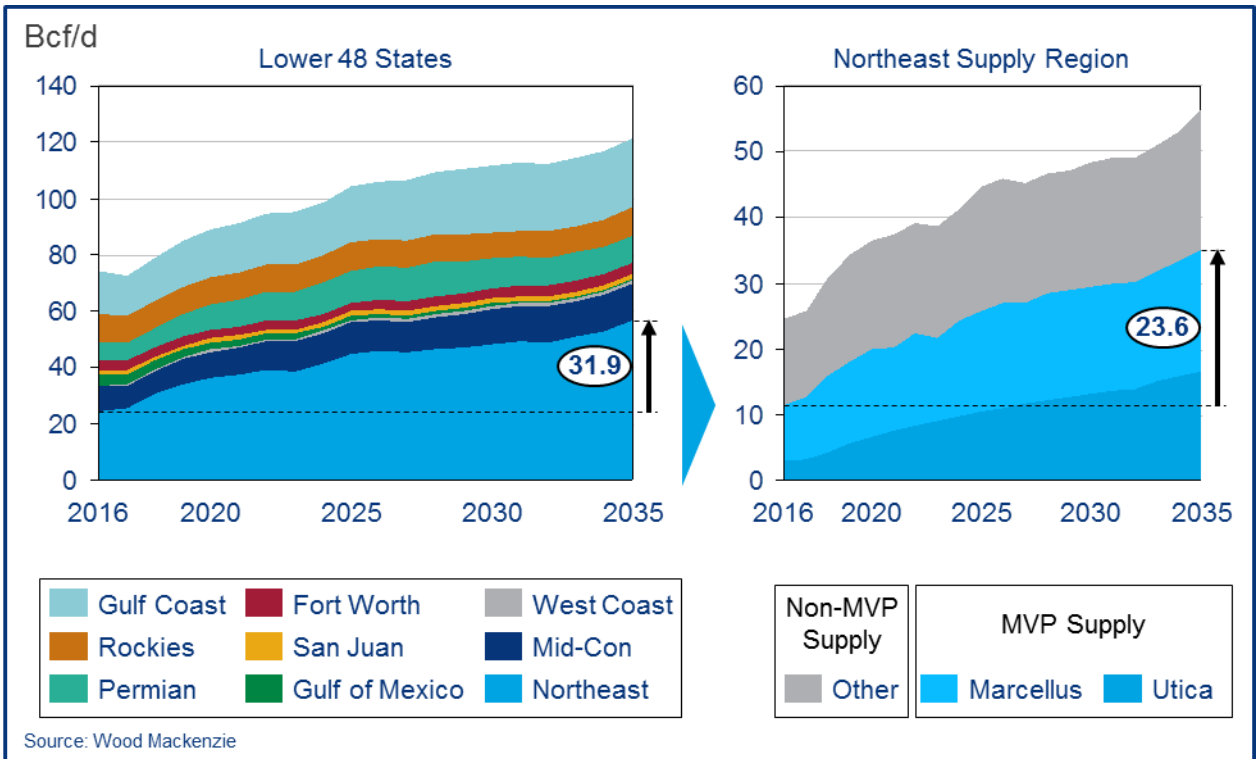
[6] Transco Station 65 is located at the Louisiana/Mississippi border. It represents the location downstream of which long-haul Rate Schedule FT shippers have rights to procure 100 percent of the MDQ entitlements.

[7] Gas market economics have evolved such that Mid-Atlantic Rate Schedule FT shippers are tied to Gulf Coast supplies that trade at some of the highest prices in North America.

likely, any such displacement would divert the most cost-effective gas supplies to other markets across the interstate pipeline grid and lower overall market costs to consumers by removing the highest marginal cost supply.

The Wood Mackenzie Lower 48 supply curve shown in Figure 4 below illustrates the anticipated growth in gas supply forecast from the lower 48 states. Growth forecast through 2035 is driven by the northeast region, which includes both the Marcellus and Utica. This growth is enabled by additional infrastructure buildout, such as MVP, to alleviate constraints in the supply region. Without MVP, northeast supply could not grow as quickly, despite being some of the lowest cost gas in the country. MVP's location positions it to serve the fastest-growing sub-plays in the SW Marcellus and Utica – giving it access to an additional 23.6 Bcf/d by 2035.

Figure 4 Lower-48 and Northeast Region Gas Supply (2016-2035)

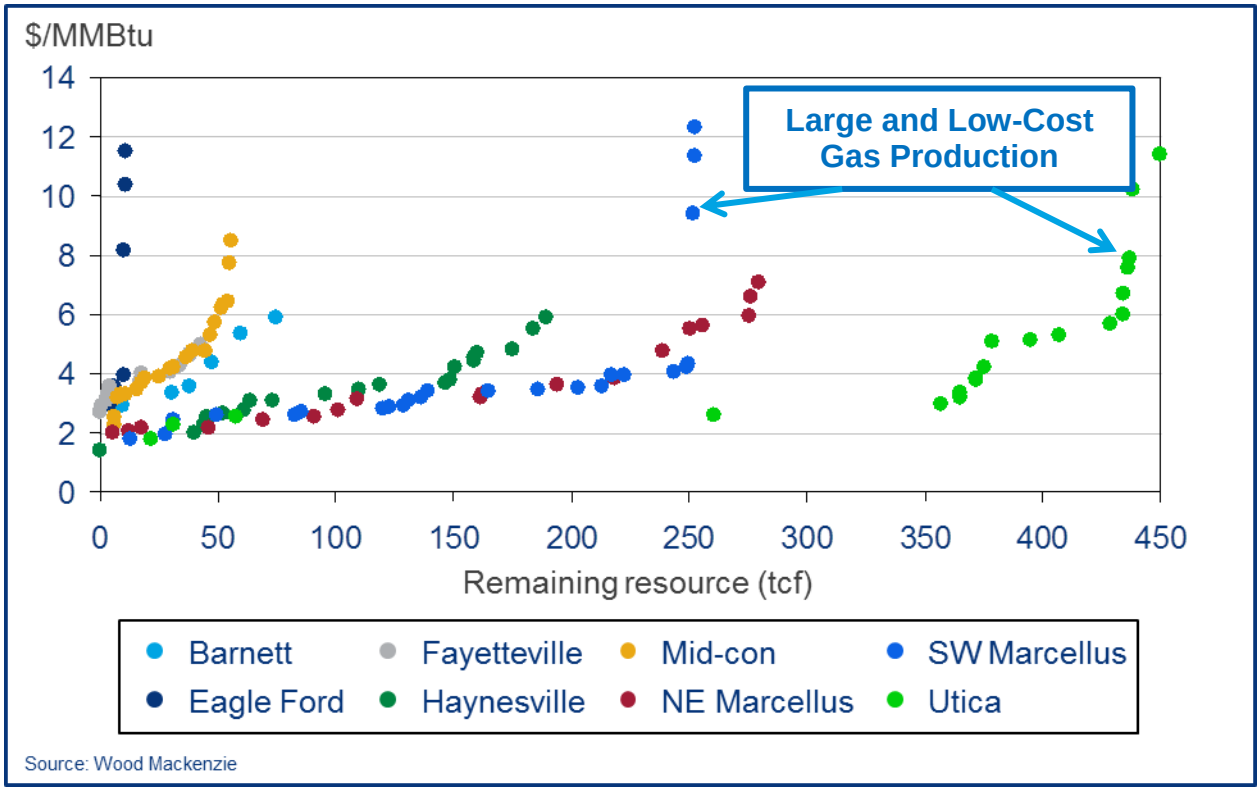


Source: Wood Mackenzie

Note: Excludes marginal imported gas supply from Canada (piped) and LNG. "Northeast" is defined as Marcellus, Utica, and historic vertical wells. "Utica" regions in the "MVP Supply" category include Utica regions in West Virginia and Central/Southwestern Pennsylvania. "Other NE" gas supply includes production from Appalachian, Michigan, and Illinois vertical wells and enhanced oil recovery efforts on preexisting vertical wells.

These plays comprise the largest and are among the lowest-cost production in the US Lower 48 supply stack, as seen below in Figure 5. Together, the Marcellus and Utica have 587 tcf of resource that breaks even at less than $3/mmbtu, and because of its strategic location MVP is proximate to 462 tcf of this resource. The low cost of this gas and its proximity to a large market enhances the likelihood this gas will flow on a consistent basis.

Figure 5 Local Market Breakeven and Remaining Resource for Gas Plays in the Lower-48 States



Source: Wood Mackenzie

Interstate Secondary Market

Another linkage between Mid-Atlantic gas consumers and MVP supplies is the secondary market, which includes capacity release and interruptible transportation ("IT").

Capacity release transactions may be structured in several ways to connect the Mid-Atlantic and MVP, but a primary option involves Transco Rate Schedule FT releases by Mid-Atlantic shippers. Depending on the primary capacity holder rights and the release terms, MVP supplies may flow on a firm basis to Transco delivery points across the Mid-Atlantic. MVP enhances the value of these release transactions for asset optimizers because deliveries at Station 165 create segmentation opportunities to both the north and south of the interconnect.

Transco IT service, northward into the Mid-Atlantic from MVP, is also a viable option for many days, even during peak winter months. As operator, Transco will ultimately determine the daily availability of IT capacity on its system, but the development of MVP coincides with prospective operating conditions that may increase the availability of IT capacity between MVP and Mid-Atlantic delivery points.

Incremental Firm Transportation Market

Continuing a long-term trend, the Mid-Atlantic is growing and expected to require new gas capacity and supplies to support increasing energy consumption. In recent decades regional gas buyers have relied on various west-to-east pipeline expansions across New York and Pennsylvania that delivered gas produced in Alberta, the U.S. Rockies, and the Appalachian Basin. Going forward, MVP creates a new and valuable alternative path for incremental supplies to flow northward from Station 165 into the Mid-Atlantic.

Consumers benefit when gas buyers obtain the lowest cost supplies and the cost of delivering new firm gas supplies into the Mid-Atlantic will depend in part on the cost of pipeline transportation. In some situations, depending on supply source and the demand location, providing new firm services in the Mid-Atlantic will require incremental pipeline transportation capacity. MVP supplies are unique because the relatively close proximity of Station 165 to Mid-Atlantic delivery points and the potential to add incremental capacity along an existing Transco system creates a linkage that is likely to be more economic than other potential sources.

Mid-Atlantic Demand for MVP

The MVP and Mid-Atlantic pipeline linkages discussed above provide a framework for estimating both the current and growth market demand for MVP supplies.

Current Market Demand

Transco Rate Schedule FT shippers holding primary receipt rights in the Gulf Coast (Transco Zones 1-3) and delivery rights in the Mid-Atlantic comprise a large and immediate market for MVP gas supplies. These shippers are primarily natural gas utilities. These utilities and their asset managers utilize these contracts to serve winter season and year-round markets, as well as for summer season storage injections off Transco's Leidy Line in Pennsylvania. Market, operational and commercial factors have resulted in Rate Schedule FT contracts historically flowing at very high load factors.

An estimate of the current Mid-Atlantic firm market size can be derived from the maximum daily quantity ("MDQ") delivery rights listed in Transco's Index of Customers. Based on Transco's FERC Gas Tariff and historical operating practice, each Mid-Atlantic Rate Schedule FT shipper will hold the right to buy up to 100 percent of their MDQ off the MVP system at Station 165. As summarized in Figure 6 below, these shipper MDQs total to approximately 2.15 Bcf/d.[8]

[8] FT shipper MDQs in Virginia add an additional ~.4 Bcf/d of current Southeast market that can be delivered north of Station 165 using Rate Schedule FT rights.

Figure 6 Current MVP Mid-Atlantic Market – Transco Rate Schedule FT Shippers[9,10]

Shipper	MMBtu/d*
PSEG Energy Resources & Trade LLC	445,618
Consolidated Edison Co of New York Inc	348,107
Brooklyn Union Gas Co	262,856
Washington Gas Light Co	172,288
Philadelphia Gas Works	167,179
PECO Energy Co	158,832
KeySpan Gas East Corp	157,961
South Jersey Gas Co	133,917
UGI Energy Services Inc	61,000
Delmarva Power & Light Co	56,718
South Jersey Resources Group LLC	41,400
National Fuel Gas Distribution	38,121
Baltimore Gas & Electric Co	35,000
UGI Central Penn Gas	20,180
UGI Penn Natural Gas Inc	15,695
Chesapeake Utilities Corp Delaware Division	11,423
UGI Utilities Inc	8,499
NJR Energy Services Co	8,075
Chesapeake Utilities Corp Maryland Division	6,128
New Jersey Natural Gas Co	3,931
Corning Natural Gas Corp	898
Total	2,153,826

Source: Velocity

* MMBtu = Million British thermal units

Incremental Market Demand

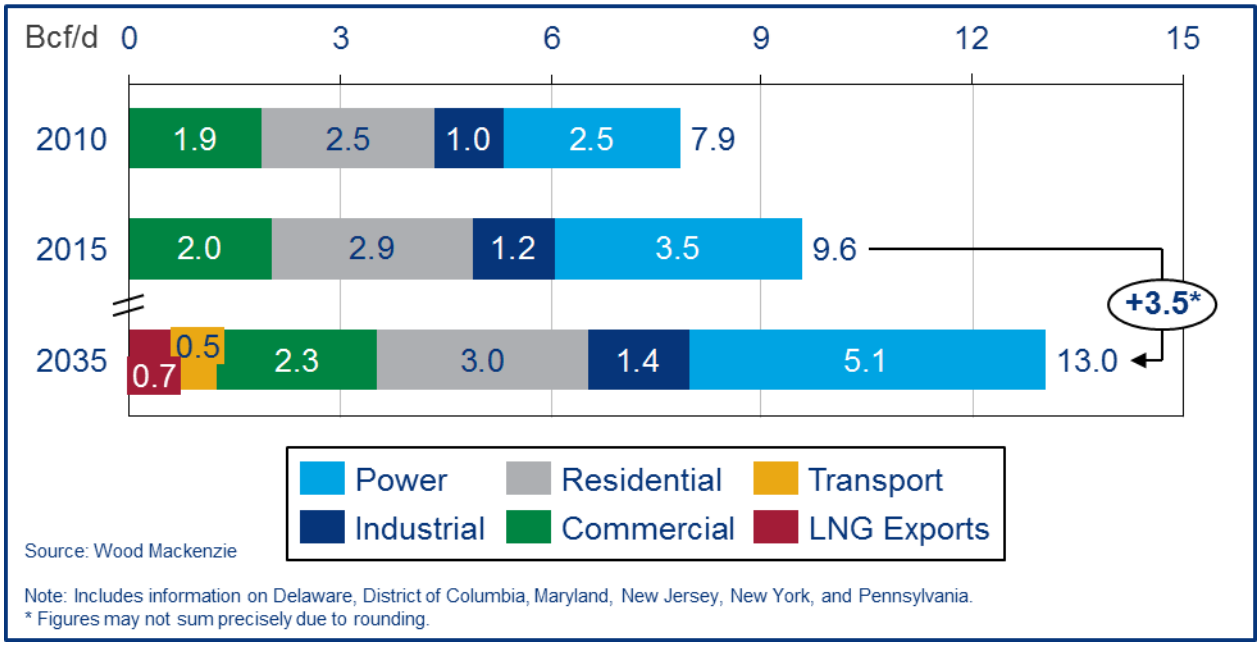
Gas demand in the Mid-Atlantic States is expected to grow, with the primary drivers being a rising GDP, larger population, and the increased use of gas in power generation. Because rising demand in the Mid-Atlantic often requires new firm transportation supplies to satisfy reliability goals, buyers in the region may consider firm transportation northward from Station 165 and MVP as a potential solution.

As depicted in the Figure 7 below, Wood Mackenzie projects 2035 average annual daily consumption will increase by approximately 3.5 Bcf/d over 2015 actual consumption. Note that growth occurs across all sectors.

[9] Conversions from British thermal unit ("Btu", an energy measure) to cubic feet (a capacity measure) consider a Transco system heat rate that ranges between 980-1070 Btu per Mcf.

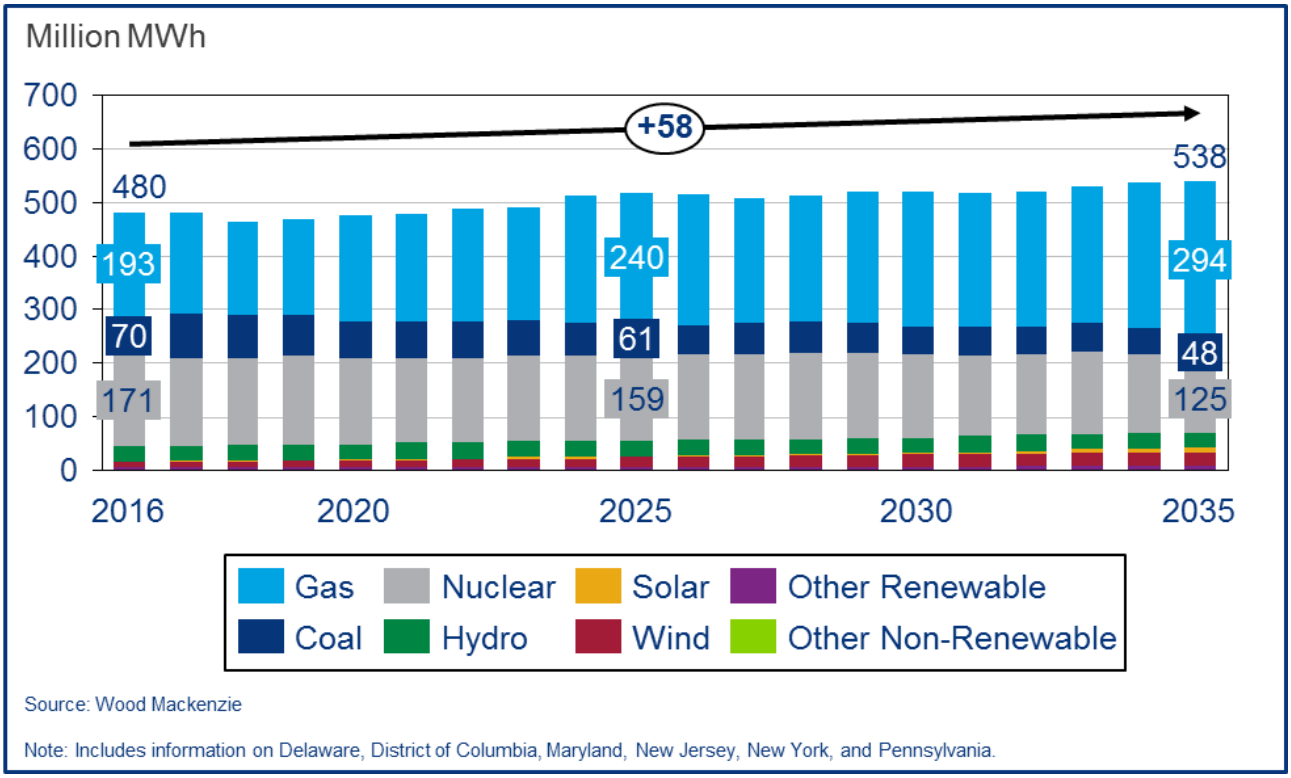
[10] One of the largest Mid-Atlantic mainline shippers on Transco is also a sizeable shipper on MVP, which demonstrates the market benefit of this cost competitive, prolific, and new supply source for this market.

Figure 7 Mid-Atlantic Annual Average Daily Gas Demand



Mid-Atlantic demand growth will be most affected by changes occurring in the power generation sector. One major change in power markets is rising electricity consumption. As shown in Figure 8 below, after several years of efficiency gains offsetting rising demand, electricity use is expected to resume an upward trend by the end of this decade. Wood Mackenzie projects a 12 percent increase in total Mid-Atlantic electricity consumption through 2035, rising to 538 million megawatt hours ("MWh").

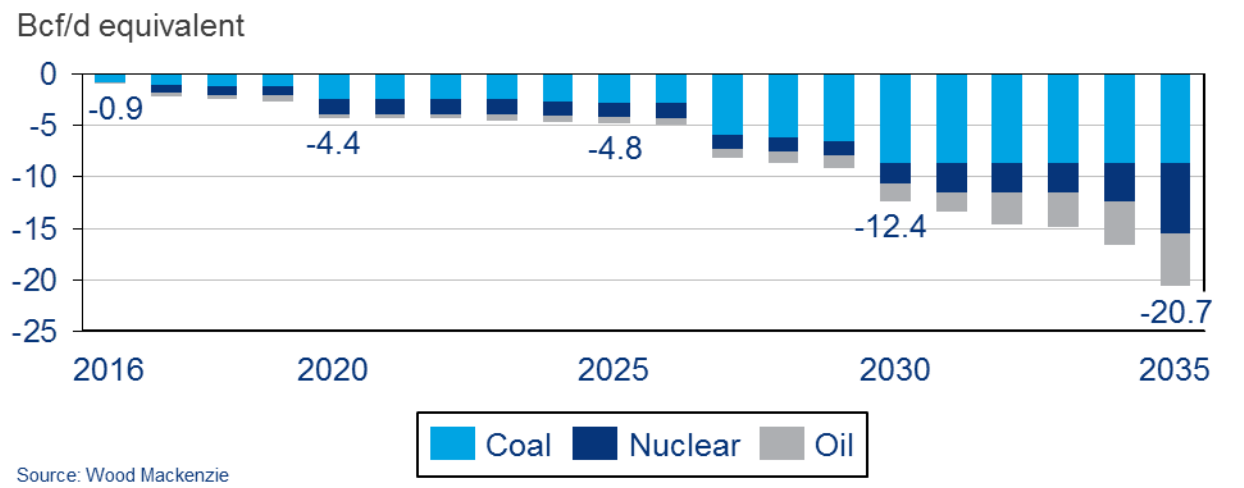
Figure 8 Forecast Annual Mid-Atlantic Power Generation



Another impetus for rising power market gas demand is the projection for continued migration away from other power generation fuels and sources to natural gas and

renewable energy. Figure 9 below depicts Wood Mackenzie expectations for progressive Mid-Atlantic coal plant closures, followed by nuclear retirements and a phase-out of oil-fired peak-shaving. Note that near term gas demand growth is not solely dependent on coal plant closures. Wood Mackenzie estimates the daily gas demand equivalent attributable to retirements and fuel conversions will escalate from approximately 4.4 Bcf/d in 2020 to 20.7 Bcf/d by 2035.

Figure 9 Forecast Mid-Atlantic Coal, Nuclear, and Oil-fired Generating Capacity Retirements (cumulative)



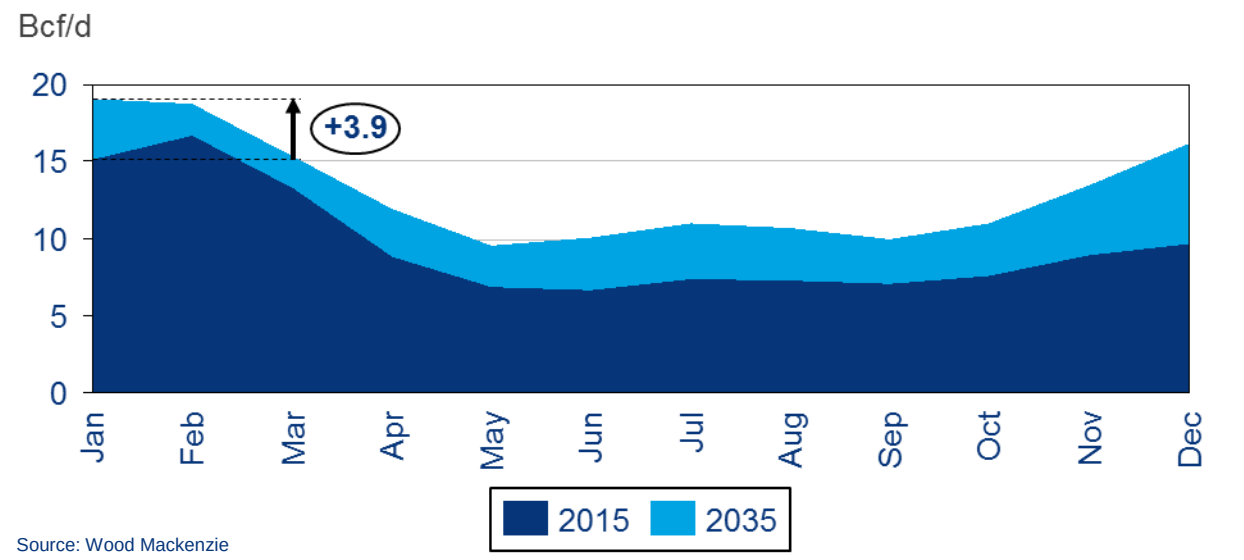
Source: Wood Mackenzie

Notes:
1. Includes information on Delaware, District of Columbia, Maryland, New Jersey, New York, and Pennsylvania.
2. Bcf/d equivalents calculated utilizing full load heat rates from individual facilities.
3. Assumed Clean Power Plan compliance date of 2022.

Implications of Increased Winter Season Demand

While the average annual daily gas demand projections discussed above illustrate a growing market, pipeline capacity construction into the Mid-Atlantic is typically based on expectations for winter season demand. As can be seen by in Figure 10 below, peak gas demand occurs during the winter months and is forecast to grow by 3.9 Bcf/d by 2035.

Figure 10 Mid-Atlantic Average Daily Gas Demand (2015 Actual vs. 2035 Forecast)

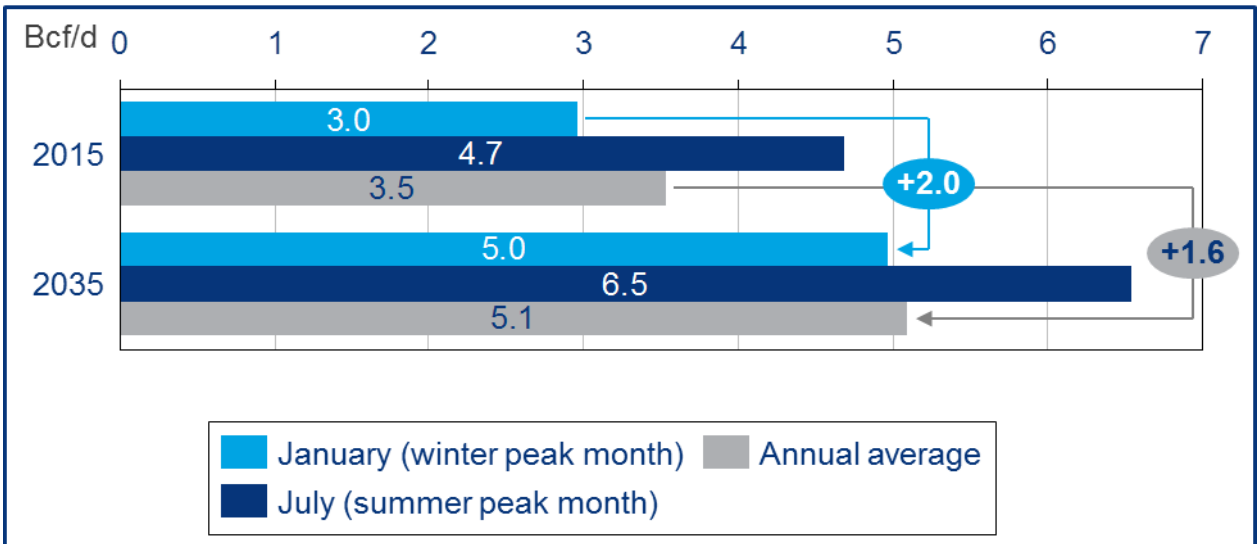


Source: Wood Mackenzie

Notes: Change forecast is conservative because 2015 base year is colder than normal year, providing an elevated base due to higher than normal count of heating degree days in January 2015. Figure includes information on Delaware, District of Columbia, Maryland, New Jersey, New York, and Pennsylvania.

The transition to increased winter season gas-fired dispatch can be seen in Figure 11 below. As shown, average annual daily demand is projected to grow between 2015 and 2035 by 1.6 Bcf/d, while winter season demand (represented by average January daily demand) increases faster at 2.0 Bcf/d.

Figure 11 Mid-Atlantic Average and Peak-Month Daily Gas Demand (Power Sector)

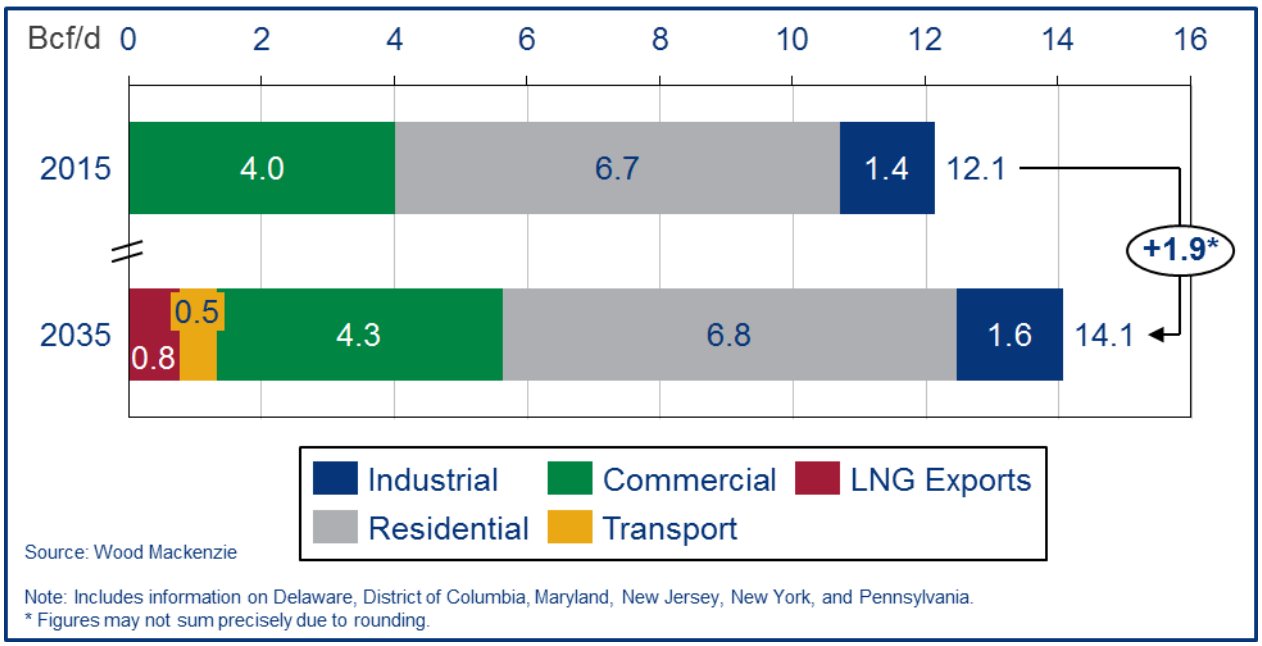


Source: Wood Mackenzie

Note: Includes information on Delaware, District of Columbia, Maryland, New Jersey, New York, and Pennsylvania.

Figure 12 below shows that average winter peak-month daily demand from all other sectors is also projected to grow by approximately 1.9 Bcf/d between 2015 and 2035.

Figure 12 Mid-Atlantic Forecast Average January Daily Gas Demand (by Sector, excluding Power)



As previously shown in Figure 10 above, MVP shippers' potential total incremental Mid-Atlantic winter peak month markets approach 3.9 Bcf/d. In that regard, an important aspect of new Mid-Atlantic gas-fired generation capacity and non-gas power plant retirements is the increased dispatch of gas-fired generation during the winter season. Coal and nuclear generation have historically provided the largest percentage of winter baseload power, but natural gas and renewable generation will be expected to shoulder materially increased shares of winter electricity demand going forward.

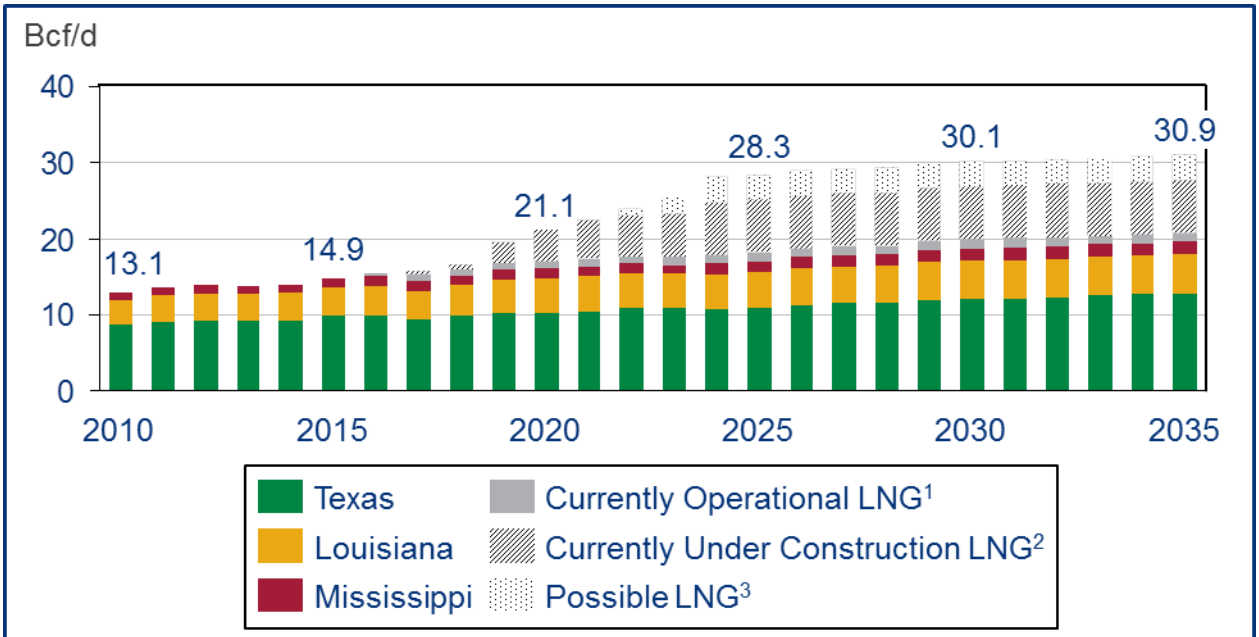
For Mid-Atlantic consumers and MVP shippers, one implication of increased winter gas demand in general and gas-fired generation in particular is a growing need for gas supply certainty during times of peak demand. In this regard, merchant power generators serving the Mid-Atlantic have not universally contracted for firm transportation in their fuel supply portfolios, instead often relying on secondary market supplies to operate plants. This practice has at times resulted in supply constraints and price volatility when regional pipeline capacity was essential for serving residential, commercial and industrial firm customers. The addition of new gas-fired plants, coupled with other sectoral growth, has the strong potential to exacerbate constraints and volatility if matched against fixed capacity sources. MVP offers the potential to mitigate the risk and impacts of such supply constraints.

Shifting Supply Diversity

As discussed above Transco's FERC Gas Tariff allows Rate Schedule FT shippers to source up to 100 percent of their supply from MVP shippers. The potential to acquire supply outside of the U.S. Gulf Coast is a valuable right for Mid-Atlantic consumers as a hedge against higher gas costs. Rising demand in the U.S. Gulf Coast, driven in particular by LNG exports, has the potential to raise gas prices across the breadth of Transco's traditional supply area receipt points, from Texas to Station 85 in Alabama.

Figure 13 below illustrates Wood Mackenzie's outlook for rising gas demand in Texas, Louisiana, and Mississippi domestic markets, as well as international demand for Liquefied Natural Gas ("LNG"). Because of its magnitude, LNG is distinguished from other demand sectors. As shown, the rate of long term gas demand growth in the Gulf Coast will be among the highest in North America.

Figure 13 Historic and Forecast Gulf Coast Gas Demand



Source: Wood Mackenzie

Notes:
1. Terms "Operational" and "Under Construction" are as of date of this report, not during indicated year.
2. Gas demand from projects which have taken the Final Investment Decision (FID) and/or are under construction.
3. Gas demand from proposed supply projects that are named and which are reasonably well defined in terms of participation, structure and underlying gas resources, but which are not expected to take the FID within the next 12 months and have no major issues or challenges preventing the project from making substantial progress.

This rapidly growing Gulf Coast demand will force increased competition between Gulf Coast and traditional Mid-Atlantic gas buyers for available supplies, with the potential to bid up gas prices over time. As such, relative regional basis price movements will encourage Mid-Atlantic gas buyers to shift purchases to MVP and away from Gulf Coast supplies.

Summary

The analysis presented in this report supports our finding that the MVP project offers significant value to a large and growing Mid-Atlantic market. The MVP project integrates well with the existing configuration of the Transco system, one of the largest gas systems serving the East Coast. Upon in service, MVP will be positioned to immediately serve a 2.2 Bcf/d market, which exceeds the capacity of the MVP project. Moreover, economic incentives exist that will encourage current Transco shippers to purchase supplies off MVP. In so doing, gas buyers stand to realize lower gas costs, and will enjoy new opportunities to optimize their existing gas supply portfolios, all to the benefit of end users.

Over the longer term, MVP introduces a large and valuable source of new gas supply that can support the Mid-Atlantic region's growing demand for gas. Wood Mackenzie projects

market demand for daily pipeline capacity and supply for all sectors will grow by 3.9 Bcf/d, nearly twice the capacity MVP offers the market. MVP conveys the additional benefit of opening a new path for southwest Marcellus and Utica supply source to reach the Mid-Atlantic. In addition, the location of MVP close to Mid-Atlantic markets could mitigate the cost to expand downstream pipeline systems after MVP goes in service to provide additional future firm deliveries to Mid-Atlantic markets.

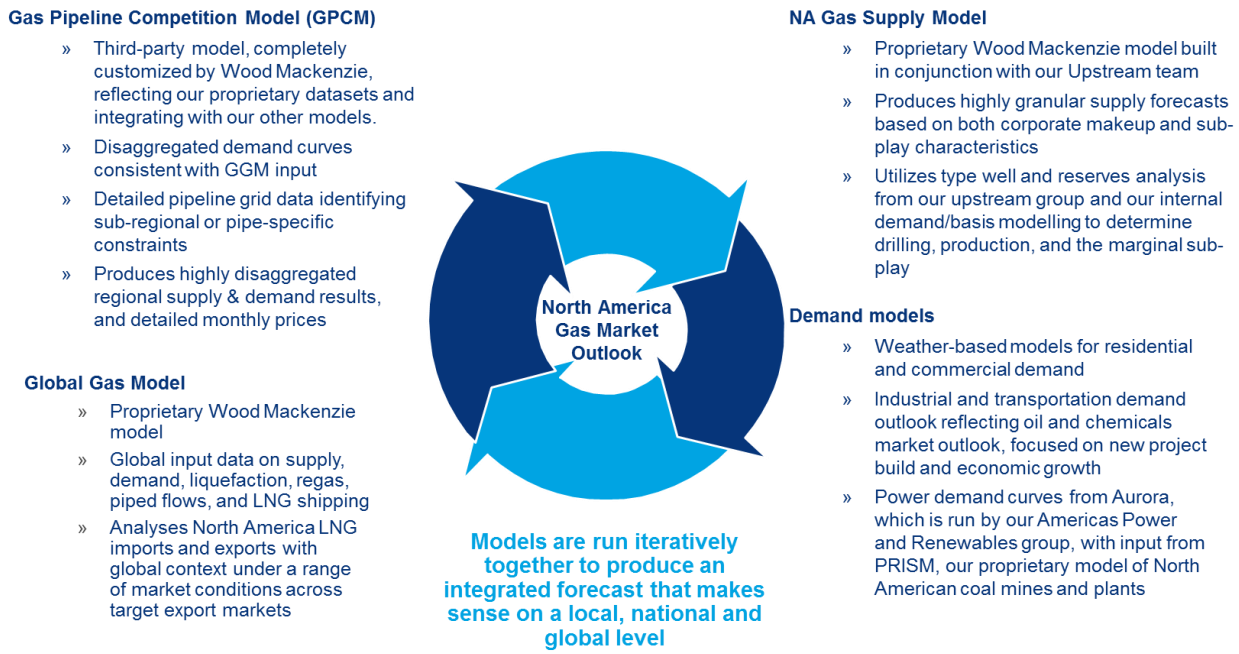
In all, MVP offers 2.0 Bcf/d to a market that Wood Mackenzie projects will grow steadily to more than 6.1 Bcf/d across a diverse sector portfolio. The cost of supplies it accesses and the integration with the existing grid creates economic and infrastructure reliability across the regional Mid-Atlantic grid for a wide range of gas consumers.

Appendix

Analytical Approach

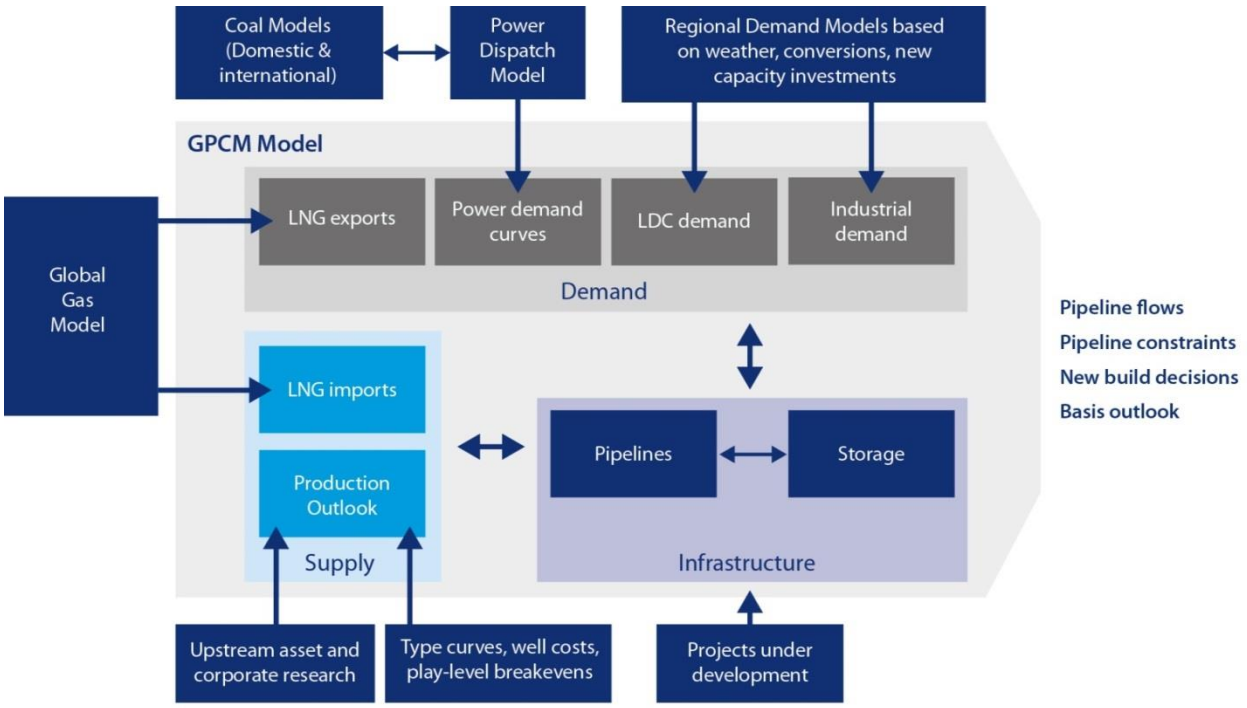
Wood Mackenzie develops gas market forecasts based on a deep analysis of market fundamentals: supply, demand and the infrastructure linking sources to uses. Each of these elements is the subject of continuous research such that market outlooks reflect the most recent trends and impacts of key variables affecting the market. The analysis is further supported by proprietary models that forecast gas prices and flows under equilibrium conditions.

Figure 14 Wood Mackenzie's integrated global and cross commodity approach



A distinguishing characteristic of Wood Mackenzie gas market forecasts is the extent to which views on the natural gas market reflect the integrated nature of energy markets. When producing its forecasts, Wood Mackenzie analysts ensure internal consistency of assumptions and outputs across all fuels and power markets. These processes yield robust results and insights into the interaction among fuel markets. In particular for this report, Wood Mackenzie has undertaken extensive research on the expected migration of regional power markets from coal- to gas-fired generation.

Figure 15 Wood Mackenzie's North America gas modelling



Source: Wood Mackenzie

Energy market forecasts require extensive and important assumptions. Wood Mackenzie's analysts conduct extensive detailed research into their respective focus areas, relying on public and proprietary sources. Assumptions that are most relevant to this study and report are summarized here and discussed more in the Appendix.

- Wood Mackenzie assumes U.S. GDP growth of 2.0% in the long-term, revised down from 2.4% in the H2 2015 forecast. We assume inflation to remain at 2.0% per year
- We expect industrial production to oscillate between -0.8 and 2.1% before stabilizing at 1.7% at the end of the study period
- Population growth is based on the United Nations, World Population Prospects

Our data is subject to a rigorous integrity checking and quality control process carried out across several teams. In Wood Mackenzie, we strive to publish a single integrated market outlook across the entire globe and energy value chain. Hence, there is natural check in place as the analysis and the data behind the analysis feeds into the analysis of other parts of the Wood Mackenzie analytical network.

Inter-team discussions and data reviews are a core part of the data validation process. In this way, we have in place a comprehensive set of checks, which are carried out during every update cycle at zone, country, regional and global level. This includes, but is not limited to, iteration between models where the output from one model is an input into another, team discussions, peer review, and knowledge sharing. In addition, Wood Mackenzie client feedback and regular interaction with key regional market players contributes to data validation and enhancement.

Key Assumptions

To develop our gas market analysis, we use the following data developed by other specialist teams within Wood Mackenzie:

Figure 16 Internal data sources

Data item	Wood Mackenzie Team
GDP and exchange rates	Macroeconomics team
Global coal prices	Coal market team
Gas supply (contracted and technical reserves) & long run marginal cost of gas fields	Upstream team
Liquids prices, demand, and infrastructure	NGLs team
Industrial demand	Chemicals team
Yet-to-Find gas reserves	Exploration team
Crude oil demand and prices	Macro oils team
Diesel and oil product prices	Downstream team
Overall energy balance and market structure issues	Energy markets team

Source: Wood Mackenzie

GDP forecasting

GDP is the monetary value of all finished goods and services produced within the borders of a country over a given time period. Wood Mackenzie reports GDP in constant 2000 US dollars. This is a measure of real GDP (taking inflation into account) and uses market exchange rates to convert local currency GDP into US dollar GDP. The date stamp of the market exchange rate used to make the conversion is determined by the World Bank. GDPs can only be compared across countries when measured in the same units.

Short-term GDP is forecast using a combination of lead indicators (which help economists set the very short-term) and an assessment of key economic variables within and across key economies over the current business cycle. An assessment of the key sectors within economies is made once per quarter using industry data and lead indicators to provide guidance on turning points and growth momentum within these sectors. Purchasing Managers Indices (PMI), and retail and business surveys are used to inform sector growth forecasts; household confidence, income measures, and unemployment rates are used to inform household consumer spending forecasts. Wood Mackenzie also pays close attention to key policy drivers including monetary and fiscal policy, assessing the impact of any change to both domestic and external sectors of the economy.

In line with standard growth accounting theory, the long-term growth potential of an economy (beyond five years) is estimated using three key growth drivers: (i) the labor force in an economy; (ii) growth in capital stock; and (iii) growth in productivity. These structural supply-side drivers tend to be driven by relatively stable trends through time,

providing a robust basis for estimating long-run GDP growth potential of an economy. It is useful to note that the long-term GDP model estimates potential or trend growth that reflects the smoothed growth path of an economy, rather than cyclical fluctuations (as in the short-term).

Wood Mackenzie does not measure real GDP using Purchasing Power Parity (PPP). While the PPP measure of GDP is a useful relative measure of a country's output at any given time, it is not a reliable (or informative) measure of GDP when forecasting beyond five years. PPP GDP is highly sensitive to PPP exchange rates which are only estimated once every five years (by the International Comparison Program) and are not possible to forecast. Assumptions can be made, but long-term PPP forecasts are subject to large error bands and could generate misleading inferences in Wood Mackenzie's commodity analysis.

Key steps - industrial production forecasting

IP is a measure of output of the industrial sector of an economy. In the short-term, specific industry sector data and lead indicators such as the Purchasing Managers Indices (PMI) are used to inform Wood Mackenzie's Macroeconomics team of the direction and momentum of change in a country's industrial sector.

Over the long-term, the industrial trends of an economy are assessed using several approaches. Wood Mackenzie pays attention to the influence of energy and other commodity prices on the competitive and comparative advantage of an economy's industry, which informs the view of industrial migration over the 20-year time horizon. When a relationship exists, GDP growth can also be used to inform the view on industrial output growth. Wood Mackenzie also forecasts auto production (primarily used in metal demand modelling) and the construction outlook for core economies. These sectors also inform the industrial production outlook.

Figure 17 U.S. GDP growth and industrial production projection

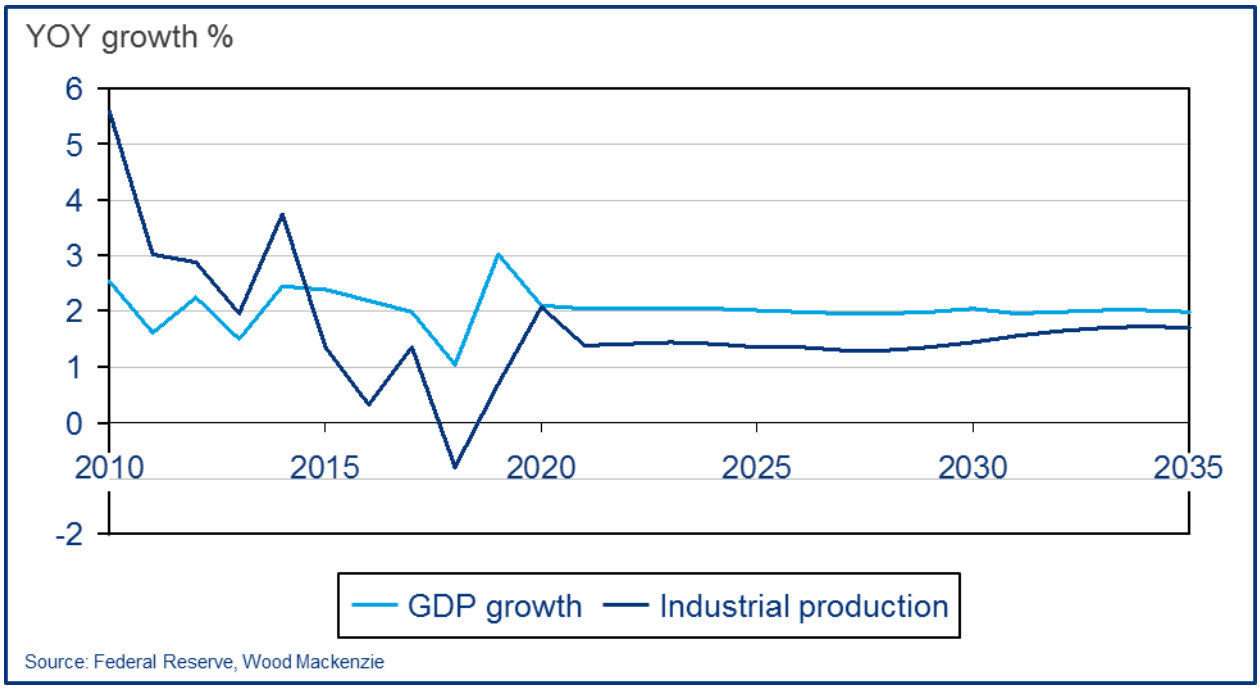
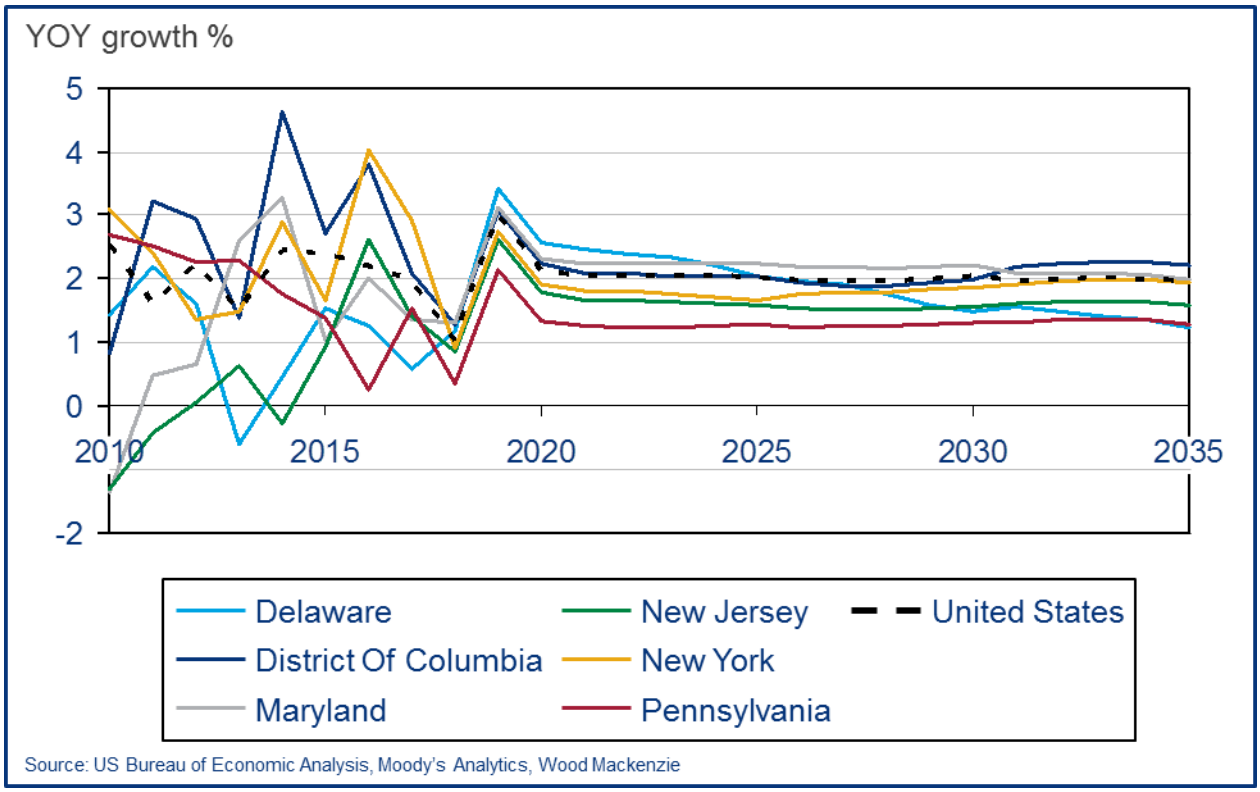


Figure 18 Annual GDP growth Mid-Atlantic states



Key steps - inflation forecasting

Inflation is a measure of the increase in price of a standard basket of goods and services in an economy over a specific time horizon (usually one year). There are many inflation rates (in all countries), each measuring different baskets of goods, services and/ or inputs into the production process. Wood Mackenzie forecasts headline inflation, typically Consumer Price Inflation.

Wood Mackenzie's economists forecast headline inflation by assessing two main sources of inflation: demand pull and cost push in any given economy. Assessing the level of demand pull inflation is best done through the output gap, which is the difference between actual and potential output of an economy. Output gaps can be positive or negative, a positive gap occurs when actual output is less than potential, and this tends to put downward pressure on prices. When actual output is greater than potential output, the output gap is negative, and upward pressure is put on prices in the general economy as too much money chases too few goods. Cost push inflation arises when input costs rise, or the cost of imported goods rise. This is most common when commodity prices rise and/or when import prices rise due to currency depreciation.

Exhibit C

Exhibit C: Response to Selected Portions of the Synapse Report

Synapse Report	**Mountain Valley Response**
The Synapse Report focuses on pipeline capacity and demand in Virginia, North Carolina, and South Carolina. "Developers expect that the Atlantic Coast Pipeline and Mountain Valley Pipeline will primarily (1) serve new natural gas-fired electric generating units constructed to replace retiring coal units or (2) meet growing electric demand in Virginia and North Carolina."[1]	As discussed above, one of the Synapse Report's largest flaws is its micro focus on Virginia and the Carolinas as opposed to the broader Southeast and Mid-Atlantic markets. The two reports prepared by Wood Mackenzie (discussed below), which detail supply and demand projections for all states from New York to Florida, are more appropriate representations of the markets that Mountain Valley will serve.
MVP did not prepare a "modeling study to quantify the projected increase in natural gas demand."[2]	Mountain Valley commissioned, prepared, and filed two supply and demand reports that clearly demonstrate the Project is needed to satisfy the steadily increasing demand for natural gas, and in particular Appalachian Basin gas, in Mountain Valley's target markets. Mountain Valley retained Wood Mackenzie, Inc. ("Wood Mackenzie"), a highly-regarded energy consulting and market research firm, to provide detailed independent analyses of the long-term natural gas supply and demand market in the Southeast United States, which includes Virginia and the Carolinas ("Southeast Report"), and the Mid-Atlantic United States ("Mid-Atlantic Report"). Mountain Valley filed the Southeast Report on the FERC docket on January 27, 2016, eight months prior to the issuance of the Synapse Report. The Southeast Report has always been publicly available for Synapse to review and refute. The Southeast Report concluded that the Project will be needed to serve, by 2030, as much as 8.3 Bcf per day of new demand for pipeline capacity in the Southeast and existing pipeline capacity demand that is currently flowing gas production from Gulf Coast and Mid-continent

[1] Synapse Report at 8.
[2] Synapse Report at 9.

	producing basins to the Southeast. The Southeast Report made clear that the Southeast market alone has more than enough natural gas demand to support the Mountain Valley Project's entire capacity. Meanwhile, the Mid-Atlantic Report (which is filed as an attachment to this Answer) estimated the long term Mid-Atlantic market demand that can be served by Mountain Valley to be 6.1 Bcf per day by 2035, or roughly three times Mountain Valley's proposed capacity. In addition, the current market demand of 2.2 Bcf per day is greater than Mountain Valley's proposed capacity. The near and long term outlooks discussed in the Mid-Atlantic Report suggest a robust Mid-Atlantic market for the capacity and new supply offered by the MVP Project. Notably, the Synapse Report does not even consider the economic displacement, reliability, and consumer benefit rationales for building new pipeline infrastructure. Instead, the Synapse Report focuses entirely on whether pipelines are present in the study region. The Wood Mackenzie reports, on the other hand, consider these important aspects of the natural gas industry.
"[W]e relied primarily on filings from natural gas distribution companies with the public utility commissions in their respective states as the basis for our forecast of non-electric natural gas use. For the electric sector, we used the National Renewable Laboratory's Regional Energy Deployment System (ReEDS model) to simulate electric system dispatch in the Eastern Interconnection and provide the forecasted volume of peak natural gas use under our high gas use	As discussed above, an overarching flaw in Synapse's methodology is its rejection of firm pipeline contracts as the appropriate measure of the markets' demand for firm capacity, and its adoption of an inappropriate methodology. The NREL data set and ReEDS dispatch model were not designed for power market capacity or fuel planning. They are not appropriate for analyzing the demand for critical energy infrastructure. To Mountain Valley's knowledge, neither utilities nor regional grid operators rely on these tools for determining power market capacity or fuel planning. Mountain Valley's target markets are comprised of sophisticated shippers who are not economically incentivized to contract for firm capacity they do not need. These shippers are best aware of their natural gas supply requirements and of the available alternatives to satisfy those needs. Analyses that focus principally on simplified historical and forecast data discount the efficiency of the shipper market in contracting for pipeline capacity. To ensure that firm gas supplies are in place as market demand

and low gas use scenarios."[3]	increases, new firm capacity must be created.
"It is important to note that not all natural gas that originates in or passes through the region is meant for local use. We exclude gas under contract for capacity outside of the region from our estimation of the volume of gas available to contribute to in-region capacity."[4] Synapse utilizes the state-to-state pipeline capacity numbers provided by the U.S. Energy Information Administration ("EIA").[5] Throughout the report, Synapse references "supply" when discussing pipeline capacity.[6]	The Synapse Report reflects a fundamental misunderstanding of the difference between pipeline capacity, contracts, and gas supplies. Pipeline capacity reflects the ability of a pipeline to provide transportation services for all shippers. It does not reflect available capacity or the pipeline's contracts for firm service. Thus, regardless of whether the pipeline has contracts for a given transportation path or has available capacity, the total capacity of the pipeline does not change. The EIA numbers cited by Synapse reflect total pipeline capacity, not available capacity or contracted amounts. There is no indication that Synapse actually reviewed contracts or incorporated contracts into its analysis even though FERC-regulated gas pipelines are required to post information on firm transportation contracts on their public websites. In contrast, Wood Mackenzie reviewed contract information when developing its two supply and demand reports for the MVP Project. In addition, by conflating "supply" with "capacity," Synapse assumes that any pipeline present in the Virginia-Carolinas region has the ability to provide supply to that region. That is wrong. To move gas from wellhead to end user, gas buyers usually have long-term agreements with pipelines to transport the gas, upstream producers and shippers to source the gas, and downstream users to purchase the gas. The mere fact that a pipeline is present does not mean (1) that pipeline's capacity is available to meet existing or future demand in that area, (2) gas supplies are available to utilize that capacity, or (3) gas buyers and shippers would seek to utilize that capacity path even if supplies were available. Not surprisingly, gas buyers and shippers seek the lowest-priced gas supplies to transport downstream. This ultimately benefits consumers in the form of lower prices. Synapse does not even consider this basic economic rationale.

[3] Synapse Report at 10.
[4] Synapse Report at 13-14.
[5] Synapse Report at Figure 4.
[6] *See, e.g.,* Synapse Report at 3 (stating "the Atlantic Sunrise project … is expected to add the capacity to supply 254 MMcf per hour to the study region in 2017[.]"); Figure ES-2 ("anticipated natural gas supply on existing and upgraded infrastructure").

	Synapse has a deeply flawed interpretation of how pipelines can supply markets and meet demand. Both of these misunderstandings become especially important with regard to Synapse's flawed analysis of the Atlantic Sunrise project (see below).
Figure 4 shows a net capacity of 3,287 MMcf per day for existing pipes currently in place in the region and Cove Point having capacity out of the region. The report estimates the natural gas capacity available from existing pipelines during the peak hour using the following equation: Peak Hour Capacity = Net Capacity x 5.6%. Using this equation, Synapse estimates the natural gas capacity available from existing pipelines during the peak hour to be approximately 309 MMcf/hr[7]	Synapse's estimation of 3,287 MMcf per day is flawed for at least the following reasons: 1. Synapse incorrectly assumes that pipelines will grant shippers hourly variability from ratable receipts (up to 5.6%) in their receipts on peak-day and peak-hours. Historically, pipelines restrict shippers to "ratable takes" (which are equivalent to 1/24th, or 4.2%, of the firm contract maximum daily reservation quantity on an hourly basis) during peak demand periods. Synapse's estimated peak hour capacity should be reduced dramatically to account for ratable takes. However, Mountain Valley's adjusted estimate provided below uses Synapse's assumed 5.6% factor to provide a conservative comparison to Synapse's estimate. 2. Dominion Cove Point LNG is expected to turn into an export facility with an in-service date in late 2017.[8] At that time, Cove Point will have the ability to both import and export 2,233 MMcf per day with respect to the Virginia-Carolinas region. 3. In order to calculate 309 MMcf per peak hour, the net capacity must be 5,520 MMcf per day,[9] not 3,287 MMcf per day. This means that while Figure 4 of the Synapse Report shows Cove Point's capacity out of the region, the calculation did not properly reflect this result. 4. If Synapse were to properly account for Cove Point's export capacity, the estimated peak hour capacity would decrease from 309 MMcf/hr to 184 MMcf/hr.[10] This represents an approximate 40% reduction in peak hour capacity that Synapse uses for its entire study.
In addition to pipeline capacity, storage capacity	Synapse's storage capacity analysis is flawed for at least the following reasons:

[7] Synapse Report at 15.
[8] *See* https://www.dom.com/covepoint
[9] 5,520 MMcf per day x 5.6% = 309 MMcf/hr.
[10] 3,287 MMcf/d x 5.6% = 184 MMcf/hr.

is necessary for peak send-out capacity in the Virginia-Carolinas region to provide sufficient volumes of natural gas to meet demand.[11]	1. The capacity of the LNG peaking facilities in the Virginia-Carolinas market is either owned and operated by, or under contract to, LDCs and regional municipal utility companies for the primary purpose of serving core market customers in peak winter conditions. Thus, these LNG peaking facilities are unavailable and are not designed to serve other market sector or geographic demand on a firm basis. While the capacities associated with LNG peaking facilities should be removed from Synapse's analysis, Mountain Valley has included them to be conservative. 2. FERC-regulated underground storage facilities (two of which are listed in the Synapse Report) are operated on an open access basis, are likely under firm contracts, and most likely rely on the same transmission capacity previously reflected to move the gas in storage to end users. Because the geology within the referenced market is not conducive to in-ground gas storage, all such storage services must be paired with firm transportation capacity on pipelines to ensure reliable delivery into the region. Analysts should not double-count the firm rights under storage and firm transportation when determining the ability to serve a market. 3. Synapse ignores the relevance of seasonal demand patterns and the implications of storage withdrawal "ratchets." During the winter season, depleted storage inventories can trigger reductions to the daily/hourly withdrawal rights and lead to tight capacity conditions. Expanded pipeline capacity can mitigate such a risk.
Table 1 lists storage capacity with deliverability to Virginia and the Carolinas. Table 1 includes the Hardy facility in West Virginia	In order for natural gas from the Hardy facility or any other West Virginia storage facility to flow into Virginia and the Carolinas, the existing pipeline capacity into the region would need to be utilized. Hardy Storage, in particular, was designed and built in conjunction with Columbia Gas Pipeline firm transportation capacity so as to deliver during winter peak conditions. Natural gas cannot flow from the storage facility into the study region on its own. Because Synapse has already separately accounted for pipeline capacity into and out of the region, listing a West Virginia

[11] Synapse Report at 15.

	storage facility as a source to the region would double-count the applicable pipeline capacity. This further demonstrates Synapse's lack of understanding regarding pipeline capacity. Synapse's estimated peak hour capacity of 71.3 MMcf/hr for storage should be reduced by the amount listed for the Hardy facility.
Transco's Atlantic Sunrise project "would reverse the flow of the Transco pipeline and allow the company to provide 1,675 MMcf per day of incremental firm transportation capacity for natural gas from northern Pennsylvania through our study region, terminating in Alabama. . . . We assume that with the reversal of the Transco pipeline, the outflows would be eliminated, and there would be a corresponding increase of inflows, resulting in a net gain of 254 MMcf per hour of peak capacity from the Atlantic Sunrise project." [12]	As discussed above, the Synapse Report reflects a fundamental misunderstanding of how gas actually flows as well as the difference between flows and capacity. With regard to the Atlantic Sunrise project: 1. Even if Atlantic Sunrise led to physical flows on Transco reversing for certain periods, that project does not eliminate the capacity out of the region on the existing Transco system. Transco shippers would still have contracts to transport gas from the Gulf area to markets north of the Virginia-Carolinas study area, which requires Transco to have capacity to transport such volumes. 2. This error is especially troublesome considering the amount of public data available on the purpose of the Atlantic Sunrise project. Synapse even acknowledges that the Atlantic Sunrise project adds capacity "through our study region" and terminates in Alabama, which is obviously not within Synapse's Virginia-Carolinas study region. In its FERC application for the project and shipper presentations,[13] Transco made it abundantly clear that the Atlantic Sunrise project was designed to take gas to Georgia and on to Alabama feeding southeast markets. Thus, the Atlantic Sunrise project is designed to move incremental volumes through and then out of the study region. The project is not designed to meet demand in Virginia and the Carolinas. 3. In order to reach its estimated 254 MMcf per peak hour of uplift related to Atlantic Sunrise, Synapse had

[12] Synapse Report at 16.

[13] Atlantic Sunrise August 2013 Shipper Presentation at 21 (*available at* http://www.1line.williams.com/Transco/files/presentations/AtlanticSunriseAug2013ShipperPresentation.pdf); Transcontinental Gas Pipe Line Co., Application for Certificate of Public Convenience and Necessity, Docket No. CP15-138 (filed Mar. 30, 2015).

	to assume that gas was no longer exported from the study region on the existing Transco pipeline (north or south), which isn't true, and that all of the Atlantic Sunrise project volumes would stay in the study region, which also isn't true. Synapse should not have adjusted the capacity numbers for the existing Transco pipeline and should have added 1.675 Bcf per day to the import column and approximately 1.325 Bcf per day to the export column.[14] 4. Because of these errors, Synapse estimated 254 MMcf per peak hour of uplift related to Atlantic Sunrise, which would almost double Synapse's pipeline capacity estimate for Virginia and the Carolinas. To illustrate Synapse's profound errors, Synapse's estimated 254 MMcf per peak hour of uplift related to Atlantic Sunrise is equivalent to building a new 4.53 Bcf per day pipe into the study region where all project volumes stay in the study region. This does not reflect reality.

[14] It is Mountain Valley's understanding that 350 MMcf per dayof the Atlantic Sunrise Project volumes will be delivered to a pipeline interconnect in Virginia, though it is unlikely that all of those volumes would remain in the Virginia market to meet demand. To be conservative, Mountain Valley assumes here that such volumes would be used to meet Virginia demand.

Columbia's WB Xpress project is "designed to send additional shale gas supplies (about 1.3 Bcf per day) east from the Marcellus to West Virginia, Virginia, and the Cove Point LNG facility in Maryland. . . . The project … would add approximately 73 MMcf per hour of peak capacity."[15]	Similar to its errors with regard to the Atlantic Sunrise project, Synapse's analysis assumes that the full 1.3 Bcf per day of WB Xpress project capacity is available to meet demand in Virginia and the Carolinas.[16] This simply isn't true. The WB Xpress project expects to transport 0.8 Bcf per day of the total 1.3 Bcf per day of project capacity west to Tennessee Gas Pipeline's Broad Run Expansion project, which will transport natural gas west out of West Virginia and then south to the Gulf of Mexico demand markets, thus completely avoiding Virginia and the Carolinas.[17] The 0.5 Bcf per day of east-bound project capacity equates to 28 MMcf of peak hour capacity using Synapse's methodology, not 73 MMcf as stated in the Synapse Report. However, this also assumes that all of the project volumes moving towards Virginia would actually be used to meet Virginia demand, which is highly unlikely. To illustrate the basic but important errors in the Synapse Report, while the capacity of the Atlantic Sunrise project (1.6 Bcf per day) is only about 23% more than the WB Xpress project (1.3 Bcf per day), Synapse estimates that the incremental peak hour capacity provided by the Atlantic Sunrise project is 247% more than the WB Xpress project. This should have given Synapse pause with regard to its methodology and analysis.
For Virginia and the Carolinas, the "anticipated natural gas supply on existing and upgraded infrastructure is sufficient	As detailed above, the Synapse Report includes numerous errors that compound to lead to a dubious conclusion. Using the non-exhaustive set of errors described above and making conservative assumptions, Mountain Valley adjusted Synapse's calculations and estimated a peak hour capacity of

[15] Synapse Report at 17.

[16] Synapse's estimated 73 MMcf per hour of peak capacity of uplift was determined by multiplying the total project capacity by 5.6%.

[17] Columbia Gas details its intent for the WB Xpress project to take gas to the Broad Run expansion in its FERC application for the project as well as corporate presentations. *See* Columbia Pipeline Group, "Creating A Premier Pipeline, Midstream and Storage Company" (May 2015) at 19 *(available at* http://files.shareholder.com/downloads/NI/0x0x829457/e4ad5fb8-cac9-435d-8d0a-7d8f134e525b/CPGMayRoadShowDeck2015FINAL.pdf); Abbreviated Application of Columbia Gas Transmission, LLC for a Certificate of Public Convenience and Necessity, Docket No. CP16-38 (filed Dec. 30, 2015).

to meet maximum natural gas demand from 2017 through 2030. Additional interstate natural gas pipelines, like the Atlantic Coast and Mountain Valley projects, are not needed to keep the lights on, homes and businesses heated, and existing and new industrial facilities in production."[18] Synapse expects peak hour natural gas demand in Virginia and the Carolinas to increase from approximately 475 MMcf in 2016 to 597 MMcf in 2030 in the high gas use case, and from approximately 475 MMcf in 2016 to 515 MMcf in 2030 in the low gas use case.[19]

296 MMcf, which is substantially less than Synapse's estimate:

Hourly Capacity (MMcf)	Synapse Estimate	MVP Estimate Using Synapse Methodology[20]
Existing Pipeline	309	184
Storage	71	64
Expansion Pipeline	327	48
Total	**708**	**296**

Comparing this capacity estimate to Synapse's demand forecasts (both high and low cases), the Virginia-Carolinas region is currently, and will continue to be, highly underserved and needs incremental pipeline capacity to meet increasing regional demand.[21]

Further, using Synapse's peak hour methodology and assuming conservatively that all natural gas transported to the Virginia-Carolinas study region by both the MVP Project and the Atlantic Coast Project stay in that region, these two projects would add 196 MMcf of combined peak hour capacity to the region.[22] Adding this incremental growth to the 296 MMcf in the above table, the peak hourly capacity of 492 MMcf appears to be proximate to or less than Synapse's own low gas demand case, and is far less than Synapse's own high gas demand case, at both the beginning and the end of their forecast period.

While Mountain Valley has demonstrated that Synapse's methodology, analysis, assumptions, and conclusions are riddled with errors and are not legitimate, Mountain Valley notes that its adjustments to the Synapse Report prove its

[18] Synapse Report at 17.
[19] Synapse Report at Figure 5.
[20] MVP includes these estimates for illustrative purposes only. Mountain Valley generated these estimates merely to demonstrate the numerous errors in Synapse's calculations and assumptions and that Synapse's pipeline capacity estimate is lower than their own demand estimates. Mountain Valley does not support or agree with Synapse's faulty methodology, assumptions, or estimates. In addition, Mountain Valley's estimates in this table are highly conservative and in no way reflect an exhaustive adjustment to the Synapse Report.
[21] MVP includes Synapse's demand estimates for comparison purposes only. Mountain Valley does not support or agree with Synapse's methodology, assumptions, or estimates.
[22] For Mountain Valley, 2.0 Bcf per day x 5.6% = 112 MMcf; for Atlantic Coast, 1.5 Bcf per day x 5.6% = 84 MMcf.

	assertions that the Project is needed to meet regional demand for natural gas.

CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (2016), I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 3rd day of February 2017.

/s/ *Barbara Deathe*

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