FERC undermines the regulatory authority of sister federal agencies by granting permission for pipeline construction activity prior to the issuance of all required federal permits.

While FERC suggests it will not advance pipeline projects to construction prior to the issuance of all required permits, in reality FERC routinely approves pipeline construction regardless of whether or not all required permits have been secured.

In other portions of this dossier, we have discussed how FERC undermines state Clean Water Act authority by issuing Certificates of Public Convenience and Necessity prior to receiving state Section 401 Certificates. FERC similarly undermines the authority of other federal agencies by issuing premature approvals.

In its Certificates issued to natural gas infrastructure companies, FERC routinely includes the provision:

> **Prior to receiving written authorization from the Director of OEP [Office of Energy Projects] to commence construction of any project facilities**, [pipeline company] shall file with the Secretary documentation that it has received all applicable authorizations required under federal law or evidence of waiver thereof.[1]

While this provision gives the impression that a project will not commence until such time as it has fully secured all applicable agency review and approvals, has complied with all applicable laws, and has received all necessary permits and Clean Water Act Certifications, that is not in fact the case. Projects are routinely allowed to commence, with significant environmental impacts, prior to receiving all necessary approvals.

Tennessee Gas Pipeline Northeast Upgrade Project (*FERC Docket No. CP11- 161*):
The Tennessee Gas Pipeline Northeast Upgrade Project, which cut through significant areas of mature forest and forested wetlands on both public and private lands, was allowed to initiate tree felling prior to receiving Clean Water Act permits, including US Army Corps of Engineers Section 404 wetlands permits. The tree cutting significantly impacted water quality and was among the major causes of environmental harm and community impacts resulting from pipeline

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[1] Federal Authority Undermined Attachment 1,139 FERC ¶ 61,161, Tennessee Gas Pipeline Company, L.L.C., FERC Docket No. CP11-161, Order Issuing Certificate and Approving Abandonment, May 29, 2012, Appendix B, Environmental Conditions, ¶ 8 (emphasis in original).

DELAWARE RIVERKEEPER NETWORK

construction.   The project was challenged in Delaware Riverkeeper Network v. FERC, 753 F.3d 1304 (D.C. Cir. 2014). The court ultimately ruled that FERC had violated federal law in its approval of the project. However, given FERC's incremental and premature approvals for the project to proceed with eminent domain and construction, by the time this legal victory was secured, FERC had already ensured the project was fully constructed and in service.

Sabal Trail (*FERC Docket No. CP15-17*)
FERC issued a Certificate for Sabal Trail in February 2016, before either an Army Corps CWA Section 404 permit or a Rivers and Harbors Act Section 408 permit were issued. FERC began approving construction in summer 2016, including through private lands for which no court date had yet been set to settle eminent domain claims.[2] Sabal Trail was later challenged in Sierra Club v. FERC, 867, F.3d 1357, 1373 (D.C. Cir. 2017). The court ultimately ruled that FERC had violated federal law in its approval of the project. However, given FERC's incremental and premature approvals for the project to proceed with eminent domain and construction, by the time this legal victory was secured, FERC had already ensured the project was fully constructed and in service. Had FERC honored the authority of its sister agency, it is likely that the legal victory, and the obligation to comply with federal law prior to final decisionmaking, would have had an affect on the outcome of whether, how, when, and/or where this pipeline was constructed.

Constitution Pipeline (FERC Docket CP13-499):
On December 2, 2014, FERC granted a Certificate to the Constitution Pipeline despite the fact that the US Army Corps of Engineers had not issued a Section 404 wetlands permits. Thereafter, FERC granted the company the power of eminent domain, a power that the company began to exercise that same month, with the filing of 125 complaints in condemnation against NY and PA landowners. FERC then expressly permitted the Constitution Pipeline to begin elements of construction. For example, on January 8, 2016, the Constitution pipeline submitted a request to proceed which was quickly granted by FERC.[3]

Amongst other actions, FERC authorized the Constitution Pipeline company to seize and cut eighty percent of the trees in a forest in New Milford Township, Pennsylvania. On March 1, 2016, the Constitution Pipeline company began to cut the forest that has belonged to the Holleran family since the 1950s -- they live on the property, enjoy its natural beauty, and operated a growing maple syrup business that was irreparably harmed by the pipeline company's FERC approved tree cutting and other actions. (North Harford Maple).

On April 22, 2016, New York denied CWA 401 Certification for the pipeline, and as a result, the project is permanently stalled. Without this approval, the project cannot be built and the devastation

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[2] Federal Authority Undermined Attachment 2, FERC Order Issuing Certificates to Sabal Trail Transmission, LLC; Docket No. CP15-17, Feb. 2 2016, pages 1-30 of 110.
[3] See FERC Partial Notice to Proceed with Tree Felling and Variance Requests, Docket No. CP13-499, January 29, 2016.

inflicted on the Hollerans and other Pennsylvania environments, communities, and homeowners—all inflicted without CWA 404 Certification—was for naught.

Atlantic Sunrise (*FERC Docket No. CP15-138*)
FERC issued a Certificate to Transcontinental Gas Pipeline Company, LLC (Transco) for the Atlantic Sunrise Project on February 3, 2017, before an Army Corps section 404 permit was issued. On February 22, 2017, Transco filed 13 eminent domain cases in Pennsylvania. FERC granted Transco a partial Notice to Proceed on March 24, 2017, authorizing construction activities in Maryland, Virginia, North Carolina, and South Carolina.

On March 31, the Army Corps informed Transco that they would not be able to authorize Section 10 and/or 404 authorizations for the project within 90 days of FERC's certificate. Transco had proposed alternative pipeline alignments just that month but had not provided the Corps with a delineation of all waters and wetlands within the newly proposed alternative or with updated information on impacts of mitigation. The Army Corps was also still in the process of collecting public comments on the proposed alternative, and was awaiting a review of the project's mitigation plans and wetland assessments from the U.S. Environmental Protection Agency.[4]

Despite the new alternative route and missing information on the project, eminent domain proceedings and construction continued at full force throughout the summer. On August 28, 2017, FERC authorized Transco to commence partial service of the project. It was not until portions of the project were nearly in service, on August 29, 2017, that the Army Corps granted Transco Section 10/404 Clean Water Act approvals. The ramification is to prevent full and fair decisionmaking by sister agencies and to prevent the opportunity for adjustments to the route and/or construction practices that would avoid environmental harms.

Atlantic Coast Pipelines (*FERC Docket No. CP15-554*): FERC issued a certificate of public convenience and necessity for the Atlantic Coast Pipeline (ACP) on October 13, 2017 before an Army Corps section 404 permit had been issued. The company had taken private properties through eminent domain and on January 19, 2018 FERC issued its first Partial Notice to Proceed with Tree Felling. On February 9, 2018, the Army Corps issued Nationwide Permit 12 under Section 404 of the Clean Water, however, the permits have since been suspended or vacated by the Corps.[5]

Mountain Valley Pipeline (*FERC Docket No. CP16-13*): On October 13, 2017, the Commission issued an order authorizing Mountain Valley Pipeline, LLC to construct and operate its proposed Mountain Valley Pipeline project (MVP) in West Virginia and Virginia without an Army Corps section 404 permit. Just two weeks after the FERC Certificate Order issued, MVP initiated condemnation actions in three federal district courts against nearly 300 property owners.[6] FERC

[4] See Letter from the Army to Transcontinental Pipeline Company, Docket No. CP15-138, March 31, 2017.
[5] Federal Authority Undermined Attachment 3, Order Issuing Certificates, Atlantic Coast Pipeline, Docket Nos. CP15-554-000 and CP15-554-001, October 13, 2017.
[6] *See Mountain Valley Pipeline v. An Easement to Construct, Operate and Maintain An Easement*, Case No. 7:17-cv-00492 (W.D. Va. 2017); *Mountain Valley Pipeline, LLC, v. Simmons*, 307 F.Supp.3d 506 (N.D.W.

then authorized the pipeline company to proceed with construction—issuing notices to proceed with construction of certain facilities associated with the Project on January 22 and 29, and February 8, 9, 12, 13, 14, 15, and 16, 2018. While the Army Corps did issue Mountain Valley a Nationwide Permit 12 under Section 404 of the Clean Water on January 23, 2018, the permit has since been suspended.[7]

PennEast Pipeline Project *(FERC Docket No. CP15-558)*: FERC issued a Certificate of Public Convenience and Necessity for the PennEast Pipeline Project on January 19, 2018, before the Delaware River Basin Commission (DRBC) has issued a docket, and before an Army Corps section 404 permit has been issued, and before New Jersey Clean Water Act 401 Certification and Clean Water Act 404 permitting (in NJ the state has 404 authority) have been granted. Immediately following FERC's certificate approval, PennEast filed nearly 200 eminent domain cases in PA and NJ, and has been granted access to survey and construct in both states. Although PennEast has yet to request approval to proceed with tree felling—landowners have already suffered property losses for a project that is far from approved.

Further, FERC has undermined the authority of the DRBC, a cooperating agency on the PennEast Pipeline Project with jurisdiction, under federal law, over the project. On April 3, 2018, recognizing the pending threat of tree felling, the DRBC sent a letter to FERC requesting "that FERC amend its PennEast approval and condition future approvals of similar projects by prohibiting the project sponsors from felling trees within the Delaware River Basin … until such time as the DRBC issues an approval for the project or activity." The letter states:

> The DRBC is concerned that the felling of trees for such projects months or years before essential DRBC and state approvals have been issued can cause unnecessary or long-term and potentially substantial impacts to water resources, particularly in the context of very large projects involving hundreds of river, stream and wetland crossings.

DRBC also offered "to coordinate a meeting among representatives of FERC and … other resource agencies with jurisdictions overlapping DRBC's to discuss a mutually agreeable approach to this concern."

The Delaware Riverkeeper Network (DRN) discovered the letter through a Freedom of Information Act (FOIA) filed with the DRBC in September 2018. Upon finding that the letter had never been made available to the public through FERC's docket for the project and that it had been ignored completely by FERC, DRN released the letter to the press. While FERC did not reply to the DRBC directly, a FERC spokesperson replied to press inquiries about the letter, claiming that it did "not adher[e] to our Rules of Practice and Procedure", because of how it was addressed, and that "If the DRBC resends the letter in accordance with the Commission's Rules of Practice and Procedure, their request ... will be taken into consideration."

The DRBC learned that FERC had refused to consider their request for procedural reasons through

Va. 2018); and *MVP v. Mc Million et al.*, Case No. 2:17-04214 (S.D. W. Va. 2017).

[7] Federal Authority Undermined Attachment 4, Order Issuing Certificates and Granting Abandonment Authority, Docket Nos. CP16-10-000 and CP16-13-000, October 13, 2017.

FERC's statements to the press, and promptly resubmitted their request to FERC on September 27, 2018[8] (noting that per their own Rules of Practice and Procedure, FERC should have notified DRBC directly that their letter was rejected). FERC has yet to respond to the DRBC request.

Partial Construction is a Strategy

FERC permission to proceed with tree felling enables pipeline companies to argue that they have already made major investments in the construction of a project and the agencies reviewing the approvals are now compelled to issue permits regardless of potential agency concerns. And so premature approval and initiation of construction becomes an incentive for other agencies to truncate their reviews, as stopping a project that has already started and the remediation of harm already inflicted are both highly unlikely.

<u>Attachments:</u>

Federal Authority Undermined Attachment 1,139 FERC ¶ 61,161, Tennessee Gas Pipeline Company, L.L.C., FERC Docket No. CP11-161, Order Issuing Certificate and Approving Abandonment, May 29, 2012, Appendix B, Environmental Conditions, ¶ 8 (emphasis in original).

Federal Authority Undermined Attachment 2, FERC Order Issuing Certificates to Sabal Trail Transmission, LLC; FERC Docket No. CP15-17, Feb. 2 2016, pages 1-30 of 110.

Federal Authority Undermined Attachment 3, Order Issuing Certificates, Atlantic Coast Pipeline, Docket Nos. CP15-554-000 and CP15-554-001, October 13, 2017.
Federal Authority Undermined Attachment 4, Order Issuing Certificates and Granting Abandonment Authority, Docket Nos. CP16-10-000 and CP16-13-000, October 13, 2017.

Federal Authority Undermined Attachment 4, Order Issuing Certificates and Granting Abandonment Authority, Docket Nos. CP16-10-000 and CP16-13-000, October 13, 2017.

Federal Authority Undermined Attachment 5, Letter from the Delaware River Basin Commission to FERC, Docket No. CP15-558, September 27, 2018.

Complete People's Dossier: FERC's Abuses of Power and Law

available at http://bit.ly/DossierofFERCAbuse

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[8] Federal Authority Undermined Attachment 5, Letter from the Delaware River Basin Commission to FERC, Docket No. CP15-558, September 27, 2018.

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People's Dossier: FERC's Abuses of Power and Law → Undermining Federal Authority

Federal Authority Undermined Attachment 1, 139 FERC ¶ 61,161, Tennessee Gas Pipeline Company, L.L.C., FERC Docket No. CP11-161, Order Issuing Certificate and Approving Abandonment, May 29, 2012, Appendix B, Environmental Conditions, ¶ 8 (emphasis in original).

139 FERC ¶ 61,161
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Tennessee Gas Pipeline Company, L.L.C. Docket No. CP11-161-000

ORDER ISSUING CERTIFICATE AND APPROVING ABANDONMENT

(Issued May 29, 2012)

1. On March 31, 2011, Tennessee Gas Pipeline Company, L.L.C.[1] (Tennessee) filed an application under section 7(c) of the Natural Gas Act (NGA)[2] and Part 157 of the Commission's regulations[3] for a certificate of public convenience and necessity authorizing Tennessee to construct, install, modify, operate, and maintain certain pipeline and compression facilities to be located in Pennsylvania and New Jersey that will increase natural gas delivery capacity on Tennessee's existing 300 Line System by 636,000 dekatherms (Dth) per day. Tennessee also requests approval of new incremental recourse rates for service on the proposed Northeast Upgrade Project facilities and on the certificated 300 Line Project facilities, as well as authority under section 7(b) of the NGA[4] to abandon certain metering facilities that are to be replaced.

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[1] Although originally filed under Tennessee Gas Pipeline Company, Tennessee converted its corporate structure to a limited liability company and changed its name to Tennessee Gas Pipeline Company, L.L.C., effective October 1, 2011.

[2] 15 U.S.C. § 717f(c) (2006).

[3] 18 C.F.R. Part 157 (2011).

[4] 15 U.S.C. § 717f(b) (2006).

2. We will authorize Tennessee's proposals, with appropriate conditions, as discussed below.

I. Background and Proposal

3. Tennessee is a limited liability company organized and existing under the laws of the State of Delaware. Tennessee's mainline transmission system extends from its principal sources of supply in Texas, Louisiana, and the Gulf of Mexico area, through the States of Texas, Louisiana, Arkansas, Mississippi, Alabama, Tennessee, Kentucky, West Virginia, Ohio, Pennsylvania, New York, New Jersey, Massachusetts, New Hampshire, Rhode Island, and Connecticut. Tennessee is a natural gas company, as defined by section 2(6) of the NGA,[5] engaged in the transportation of natural gas in interstate commerce and is subject to the jurisdiction of the Commission.

4. On May 14, 2010, the Commission issued an order authorizing Tennessee to construct and operate pipeline facilities and replace certain compression facilities in Pennsylvania and New Jersey on its 300 Line System to both increase overall system reliability (the Reliability Component) and increase pipeline capacity by an incremental 350,000 Dth per day (the Market Component) (jointly, the 300 Line Project).[6] The Market Component included the construction of eight pipeline loop segments totaling 127.4 miles of 30-inch diameter pipe, two new compressor stations, and the upgrade/restaging of compressor units at three other compressor stations. Since the filing of Tennessee's application in the instant proceeding, Tennessee completed construction of its 300 Line Project and placed the facilities in service on November 1, 2011.[7]

A. Facilities

5. In its present proposal, Tennessee seeks authorization for its Northeast Upgrade Project, which will add an incremental 636,000 Dth per day of capacity to its existing 300 Line System. Tennessee's proposal consists of the construction of five pipeline loop segments totaling approximately 40.3 miles of 30-inch-diameter pipe (21.9 miles in

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[5] 15 U.S.C. § 717a(6) (2006).

[6] *Tennessee Gas Pipeline Co.*, 131 FERC ¶ 61,140 (2010).

[7] Tennessee's Notification of Placing Facilities In-Service dated November 4, 2011.

Pennsylvania and 18.5 miles in New Jersey) and the addition of approximately 22,310 horsepower (hp) of compression at two existing compressor stations. More specifically, Tennessee's proposed project includes the following facility construction and modifications:

Pipeline Loops

- Loop 317 – construction of 5.4 miles of 30-inch-diameter pipeline in Bradford County, Pennsylvania;
- Loop 319 – construction of 2.0 miles of 30-inch-diameter pipeline in Bradford County, Pennsylvania;
- Loop 321 – construction of 8.1 miles of 30-inch-diameter pipeline in Wayne and Pike Counties, Pennsylvania;
- Loop 323 – construction of 17.2 miles of 30-inch-diameter pipeline in Pike County, Pennsylvania and Sussex County, New Jersey;
- Loop 325 – construction of 7.6 miles of 30-inch-diameter pipeline in Passaic and Bergen Counties, New Jersey;

Compressor Stations

- Station 319 – modification of the compressor station yard and piping to accommodate new appurtenant equipment in Bradford County, Pennsylvania;
- Station 321 – addition of 10,310 hp of compression (compressor and drive), modification of the yard and station piping to accommodate the installation of the new compressor unit and compressor building, and installation of appurtenant facilities in Susquehanna County, Pennsylvania;
- Station 323 – addition of 12,000 hp of compression (compressor and drive), restaging of one existing compressor unit, modification of the yard and station piping to accommodate the installation of the new compressor unit and compressor building, and installation of appurtenant facilities in Pike County, Pennsylvania;
- Station 325 – modification of the yard and station piping to accommodate the installation of appurtenant equipment in Sussex County, New Jersey;

Meter Station and Appurtenant Facilities

- Mahwah meter station – upgrade and modification of the existing meter station, installation of two new taps, three ultrasonic meters, two gas filter-separators, and abandonment of two 12-inch orifice meters; and
- Installation of other appurtenant and auxiliary equipment, as further described in the application.[8]

B. Rates

6. Tennessee proposes to recover the costs associated with the Northeast Upgrade Project facilities through incremental recourse rates charged to shippers using the resulting capacity. The incremental firm recourse rate consists of: (1) a monthly reservation rate of $14.909 per Dth (equivalent to a daily reservation rate of $0.4902 per Dth), (2) a daily commodity rate of $0.00 per Dth, (3) applicable demand and commodity surcharges, and (4) applicable fuel and lost and unaccounted for charges. Tennessee calculated this rate using the costs and design capacities of both the proposed Northeast Upgrade Project and the Market Component facilities of Tennessee's 300 Line Project.[9] Tennessee argues that this is appropriate given that the Market Component of the 300 Line Project makes it possible for Tennessee to achieve the capacity increase of the Northeast Upgrade Project at a much lower cost than would have been possible absent construction of the 300 Line Project Market Component facilities. Tennessee states it has precedent agreements for long-term firm transportation services utilizing the full capacity of the proposed Northeast Upgrade Project with two shippers, Chesapeake Energy Marketing, Inc. (Chesapeake) and Statoil Natural Gas LLC (Statoil), under negotiated rate agreements under Rate Schedule FT-A of Tennessee's FERC Gas Tariff. Tennessee proposes to commence project service on November 1, 2013.

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[8] *See* Exhibit Z-1 of Tennessee's application for description of the appurtenant and auxiliary equipment.

[9] The 300 Line Project had two components: (1) a Replacement Component, the costs of which are to be recovered from system services, and (2) a Market Component, the costs of which are to be recovered through an incremental rate. The Commission-approved Rate Schedule FT-A initial firm recourse rate for the Market Component of the 300 Line Project consists of: (1) a monthly reservation rate of $26.94 per Dth; (2) a daily commodity rate of $0.00 per Dth; (3) applicable demand and commodity surcharges; and (4) applicable fuel and lost-and-unaccounted-for charges. *See Tennessee Gas Pipeline Co.*, 131 FERC ¶ 61,140, at P 24 (2010).

7. Tennessee proposes to use the applicable general system rates for interruptible transportation services through the Northeast Upgrade Project capacity.

C. Open Season

8. Prior to holding its open season for the project, Tennessee executed binding precedent agreements with Chesapeake and Statoil for long-term firm natural gas transportation for the full capacity of the project, subject to the outcome of the open season. Tennessee held the binding open season from February 22 to March 22, 2010. Tennessee states that in the open season it offered rates, terms, and conditions of service to potential shippers that were equivalent to those included in the precedent agreements with Chesapeake and Statoil and that no other parties submitted a bid. Tennessee also solicited turn-back of capacity that could be used to provide transportation service to shippers as part of the Northeast Upgrade Project. Tennessee states that no shippers offered to turn back capacity in response to the solicitation. Tennessee states that it awarded Chesapeake 429,300 Dth per day of capacity and Statoil 206,700 Dth per day of capacity, for a total of 636,000 Dth per day. Thus, all the capacity of the proposed project is currently subscribed under precedent agreements.

9. By committing in the open season to quantities equal to or greater than 125,000 Dth per day for a contract term of at least 20 years, Tennessee states that both Chesapeake and Statoil qualified as Anchor Shippers. Tennessee proposes that Anchor Shippers receive certain benefits, including extension rights and a negotiated rate cap for construction overrun sharing, for helping the project reach critical mass. Tennessee notes that these Anchor Shipper benefits would have been provided on a non-discriminatory basis to any other potential shipper that submitted a qualifying bid as an Anchor Shipper in the open season. Tennessee requests that the Commission approve these contract provisions as permissible material deviations to the form of service agreement contained in Tennessee's tariff.

II. Notice and Interventions

10. Notice of Tennessee's application was published in the *Federal Register* on April 20, 2011 (76 Fed. Reg. 22,093). A number of timely, unopposed motions to intervene were filed.[10] Timely, unopposed motions to intervene are granted by operation

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[10] The parties filing timely, unopposed motions to intervene are listed in Appendix A to this order.

of Rule 214(c) of the Commission's Rules of Practice and Procedure.[11] Timely notices of intervention were filed by the New York State Public Service Commission, the New Jersey Department of Environmental Protection (New Jersey DEP), the U.S. Department of the Interior on behalf of the National Park Service (NPS), and the New Jersey Board of Public Utilities. Timely notices of interventions are granted by operation of Rule 214(a) of the Commission's Rules of Practice and Procedure.[12] Chesapeake Energy Marketing, Inc. filed a motion to intervene one day late. Chesapeake demonstrated an interest in this proceeding and its late intervention will not delay or otherwise prejudice the proceeding.[13] Therefore, we will grant this motion.

III. Discussion

11. Because Tennessee seeks to construct, operate, and abandon facilities used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the proposal is subject to the requirements of sections 7(b) and (c) of the NGA.[14]

A. Application of the Certificate Policy Statement

12. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new construction.[15] The Certificate Policy Statement established criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new pipeline facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of

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[11] 18 C.F.R. § 385.214(c) (2011).

[12] 18 C.F.R. § 385.214(a) (2011).

[13] 18 C.F.R. § 385.214(d) (2011).

[14] 15 U.S.C. § 717f (2006).

[15] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128 (2000), *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

13. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to support the project financially without relying on subsidization from existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified, after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis where other interests are considered.

14. As noted above, the threshold requirement is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. Tennessee proposes to recover the costs of the proposed facilities through a new incremental rate for service which is higher than Tennessee's existing system-wide rate. Use of an incremental rate, as discussed and approved below, ensures that existing customers that do not use the facilities will not subsidize the expansion. Thus, we find Tennessee's existing shippers will not subsidize the project.

15. The construction and operation of the proposed facilities will not degrade existing customers' service. There will be no adverse impact on existing pipelines in the region or their captive customers because the proposal is not intended to replace existing customers' service on other existing pipelines. In addition, no existing pipelines or their customers have protested the proposal. Moreover, the project will help alleviate pipeline constraints in the region by increasing pipeline capacity to the high-demand markets in the northeast.

16. Regarding impacts on landowners and communities along the route of the project, Tennessee has proposed to locate the pipeline looping segments within or parallel to existing rights-of-way for approximately 84 percent of the length of the proposed segments. In addition, all the construction, installation, and modifications activities at the existing compressor stations will take place within existing Tennessee property boundaries. Tennessee participated in the Commission's pre-filing process and states that it is working diligently to address landowner concerns and questions and has made design changes, to the extent feasible, to address concerns from landowners and negotiate mutually agreeable easement agreements. Although, a number of landowners filed

comments objecting to or concerning the proposed facilities, we find that Tennessee has taken steps to minimize any adverse impacts on landowners and surrounding communities. The specific landowner comments are addressed in the Environmental Assessment (EA) for the project and in the Environmental Analysis section of this order, below.

17. Based on the benefits Tennessee's proposal will provide to the project shippers, the lack of adverse effects on existing customers and other pipelines and their captive customers, and the minimal adverse effects on landowners or communities along the route, we find, consistent with the Certificate Policy Statement and subject to the environmental discussion below, that Tennessee's proposed Northeast Upgrade Project is required by the public convenience and necessity, as conditioned in this order.

18. We also find that Tennessee's proposal to abandon certain facilities that are being replaced or will no longer be required after the proposed project is placed in service is permitted by the present and future public convenience or necessity.

B. Rates

1. Incremental Rates

19. Tennessee proposes to provide the new firm transportation service under Rate Schedule FT-A of Tennessee's tariff. As discussed below, the Commission will approve the recalculated incremental rates for service on the Northeast Upgrade Project.

20. Although Chesapeake and Statoil have elected to pay negotiated rates for service on the Northeast Upgrade Project, Tennessee is required under the Commission's Alternative Rate Policy Statement to provide recourse rates as an alternative.[16]

21. Tennessee has proposed an incremental recourse rate consisting of: (1) a monthly reservation rate of $14.909 per Dth (equivalent to a daily reservation rate of $0.4902 per Dth; (2) a daily commodity rate of $0.00 per Dth; (3) applicable demand and commodity

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[16] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines; Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order on clarification*, 74 FERC ¶ 61,194 (1996); *reh'g and clarification denied*, 75 FERC ¶ 61,024 (1996); *aff'd sub nom. Burlington Resources Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998) (Alternative Rate Policy Statement).

surcharges; and (4) applicable fuel and lost and unaccounted for charges. In calculating this rate, Tennessee uses an estimated total cost for the Northeast Upgrade Project of $376,283,376,[17] and a design capacity of 636,000 Dth per day. Tennessee's proposed $71,053,000 incremental cost of service reflects the income tax rates, capital structure and rate of return approved in Tennessee's settlement in Docket No. RP95-112-000, et al.[18] and reaffirmed in Tennessee's recent settlement in Docket No. RP11-1566-000.[19] The cost of service also reflects a straight-line depreciation rate of 2.5 percent, based on an estimated useful life of 40 years for the proposed Northeast Upgrade Project facilities. Tennessee then added the $105,345,000 cost of service approved by the Commission for the Market Component of the 300 Line Project, with its accompanying 350,000 Dth per day of design capacity.

22. Tennessee maintains that the Northeast Upgrade Project will build upon the additional capacity created by the Market Component of its 300 Line Project, which was placed into service on November 1, 2011. Tennessee also maintains that the 300 Line Project Market Component facilities have made it possible to achieve the capacity increase of the Northeast Upgrade Project at a lower cost than would have been possible absent the construction of the 300 Line Project Market Component facilities. Therefore, Tennessee contends, it is appropriate to calculate the incremental recourse rate for the Northeast Upgrade Project using a cost of service that combines the costs and design capacities of both the 300 Line Project Market Component facilities and the Northeast Upgrade Project. Tennessee suggests that failure to do so would enable the Northeast Upgrade Project shippers to inappropriately benefit from their project's relatively-cheaper expansibility (made possible by the prior construction of the Line 300 Project Market Component facilities), while the shippers of the Line 300 Project Market Component alone bear all costs of that construction.

23. Tennessee also contends that the combined rate treatment for the Northeast Upgrade Project is fully consistent with the Commission's Certificate Policy Statement, where the Commission recognized the need for certain exceptions to the application of incremental pricing for all projects. Tennessee maintains the inexpensive expansibility of

[17] Tennessee Application - Exhibit K.

[18] *Tennessee Gas Pipeline Co.*, 94 FERC ¶ 61,117 (2001); 77 FERC ¶ 61,083 (1996), *reh'g denied*, 78 FERC ¶ 61,069 (1997).

[19] *Tennessee Gas Pipeline Co., L.L.C.*, 137 FERC ¶ 61,182 (2011).

the Northeast Upgrade Project facilities is a result of the earlier, more expensive capacity created by the 300 Line Project Market Component facilities.[20] Although Tennessee is not proposing to roll the Northeast Upgrade Project costs into its general system rates, Tennessee contends its proposal to roll the project's costs into the rates of the 300 Line Project Market Component is consistent with the premise that such rolled-in rate treatment is appropriate in cases of inexpensive expansibility made possible because of earlier costly construction.

24. Tennessee further notes that in the precedent agreement that provided the market support for the 300 Line Project, Tennessee and EQT Energy, LLC agreed to a rate adjustment to the negotiated rate "to the extent a subsequent project meeting certain criteria would be constructed and eventually placed in-service within a specified time period."[21] Tennessee also explains that the parties agreed to this negotiated rate adjustment in recognition that Tennessee would likely be able to construct a subsequent project (such as the Northeast Upgrade Project) at a lower cost than would have been possible without the 300 Line Project.[22]

25. The Commission rejects Tennessee's proposal to base the initial recourse rate for the Northeast Upgrade Project on the combined costs and capacities of both the Northeast Upgrade Project and the Market Component of the 300 Line Project because to do so would result in the total costs of the 300 Line Project Market Component being reflected, and recovered, in two separate rates at the same time. Although it would have been possible to amend the previously-authorized initial rate for the 300 Line Project Market Component to reflect the costs of the instant project in an NGA section 7 proceeding before that project went into service, once the 300 Line Project Market Component went into service in November 2011, the rate for service on that project can only be changed pursuant to section 4 of the NGA. Therefore, the Commission will approve an initial incremental Rate Schedule FT-A reservation rate for service on the Northeast Upgrade Project of $9.31 per Dth per month.[23] This is without prejudice to Tennessee proposing

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[20] Tennessee's Application at 14.

[21] *Id*.

[22] *Tennessee Gas Pipeline Co.*, 131 FERC ¶ 61,140 at P 34.

[23] The $71,053,000 incremental cost of service for the Northeast Upgrade Project divided by the annualized monthly billing determinants of 636,000 Dth per day equals $9.31 Dth per month.

in an NGA section 4 proceeding to consolidate the rates of the Northeast Upgrade Project and the 300 Line Project Market Component rates into a single incremental rate.[24] In addition, this finding will not preclude Tennessee from adjusting EQT Energy, LLC's negotiated rate as it previously agreed.

26. Tennessee is directed to file a tariff record reflecting the approved initial rate not less than 30 but no more than 60 days prior to the in service date of the Northeast Upgrade Project.

2. Negotiated Rates

27. Tennessee states that the negotiated rates with Chesapeake and Statoil consist of a monthly reservation rate of $13.5354 per Dth (equivalent to a daily reservation rate of $0.4450 per Dth) and a daily commodity rate of $0.00 per Dth. Tennessee states that these reservation and commodity rates are fixed[25] for the 20-year primary term of the service agreements with the shippers and are exclusive of any applicable surcharges. In addition, Tennessee points out that Chesapeake and Statoil have agreed to pay the designated surcharges and fuel and lost and unaccounted for charges as provided in the binding precedent agreements between Tennessee and the two shippers.

28. As indicated above, Tennessee has entered into agreements with Chesapeake and Statoil to provide firm transportation service at negotiated rates. In certificate proceedings, the Commission establishes initial recourse rates, but does not make determinations regarding specific negotiated rates for proposed services.[26] In accordance with the Alternative Rate Policy Statement[27] and the Commission's negotiated rate

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[24] If Tennessee seeks to accomplish this rate change before the in-service date of the Northeast Upgrade Project, it should combine its NGA section 4 filing with a filing under section 7 to amend the initial rate approved herein.

[25] The negotiated rate agreement for Chesapeake and Statoil includes a rate adjustment mechanism for construction cost overruns.

[26] *Gulf Crossing Pipeline Co. LLC,* 123 FERC ¶ 61,100, at P 97 (2008); *ANR Pipeline Co.,* 108 FERC ¶ 61,028, at P 21 (2004); *Gulfstream Natural Gas System, LLC,* 105 FERC ¶ 61,052, at P 37 (2003); *Tennessee Gas Pipeline Co.,* 101 FERC ¶ 61,360 at n.19 (2002).

[27] *Alternative Rate Policy Statement*, 74 FERC ¶ 61,076 at 61,241.

policy,[28] Tennessee must file any negotiated rate agreements or a tariff record describing the essential elements of the negotiated rate agreements associated with this project. Tennessee shall file its negotiated rate agreements or a tariff record no less than 30 days, and not more than 60 days, prior to the commencement of service.

3. Fuel and Electric Power Cost Recovery Adjustment

29. Tennessee proposes to use its applicable Rate Schedule FT-A fuel charges for the increased transportation services associated with the proposed expansion on its existing 300 Line. Tennessee supported the use of its currently-effective Rate Schedule FT-A gas fuel charge. However, Tennessee did not provide information on how the addition of the proposed 12,000 hp electric-driven compressor will impact the Electric Power Cost Recovery Adjustment (EPCRA)[29] for its existing customers. To the extent that the incremental electric power unit costs for the project compressor are greater than the existing electric power unit costs, the existing customers could subsidize the project compression. Therefore, Tennessee is directed to file an analysis within 30 days of this order to demonstrate what impact the new compression will have on its EPCRA.

C. Non-Conforming Provisions

30. Tennessee states that there are several provisions in its precedent agreements with Chesapeake and Statoil that do not conform with its *pro forma* Rate Schedule FT-A transportation service agreement (*Pro Forma* Agreement) and requests Commission approval of these provisions.

31. Tennessee states that because Chesapeake and Statoil elected to pay negotiated rates in the Northeast Upgrade Project's open season, each was provided the right to

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[28] *See, e.g., Texas Eastern Transmission, LP*, 133 FERC ¶ 61,220 (2010).

[29] Tennessee filed its certificate application during the settlement period of Tennessee's general rate case filed on November 30, 2010, in Docket No. RP11-1566-000. The rate case, among other things, implemented surcharges for two additional tracking mechanisms: a Fuel and Loss Retention Adjustment, which tracks and adjusts for over or under collections of Tennessee's fuel and losses, and the EPCRA, which tracks and adjusts for over or under collections of Tennessee's electric power costs. *See* Sheet Nos. 400, 401 and 402 to Tennessee's FERC Gas Tariff, Sixth Revised Volume No. 1.

extend the 20-year primary term of their respective Firm Transportation Agreements for successive 5-year terms, at the negotiated rate, so long as Chesapeake and Statoil provide written notice to Tennessee at least 24 months prior to the end of the primary term of the Firm Transportation Agreement, or the extended term, as applicable. Tennessee believes that it is reasonable to provide these two Anchor Shippers with this relatively-limited extension provision to address their future capacity needs. Tennessee asserts that this provision was an integral part of the arrangements under which Chesapeake and Statoil agreed to provide firm contractual support for the Northeast Upgrade Project. Tennessee also contends that it was prepared to offer the same extension rights that it offered to Chesapeake and Statoil to any other potential shipper that submitted a qualifying bid as an Anchor Shipper during the open season.

32. Tennessee also states that Chesapeake and Statoil have agreed to be subject to an adjustment to each shipper’s negotiated rate due to cost escalations and/or construction cost overruns, which would increase both Chesapeake and Statoil’s negotiated rate up to a rate cap of $0.47 per Dth. Tennessee contends that because the precedent agreements pre-date the actual construction of the Northeast Upgrade Project, it is reasonable that Chesapeake and Statoil share the construction risk with Tennessee through this negotiated rate adjustment provision to reflect cost overruns. Tennessee maintains that this provision was an integral part of the transaction that led to Chesapeake and Statoil’s support of the Northeast Upgrade Project and will not affect the terms of service once the facilities are placed in-service.

33. In addition, Tennessee states that there will necessarily be a few additional, minor differences between its firm transportation agreements with Chesapeake and Statoil and its pro forma firm transportation agreement. The project transportation agreements will: (1) contain a “Whereas” clauses describing the specific transaction; (2) address the commencement date of the agreements; (3) indicate that Tennessee will construct the project facilities; (4) state that the execution of the firm transportation agreements will supersede the precedent agreements; (5) not contain language through which individual rate components may be adjusted downward or upward (because Chesapeake and Statoil have agreed to pay negotiated rates); and (6) indicate the sections that will survive the execution and effectiveness of the Firm Transportation Agreements.

34. Tennessee states that the executed service agreements with Chesapeake and Statoil will provide the firm contractual support for the project and reflect the contractual incentives that were necessary for the Shippers to make binding commitments. Tennessee argues that, absent these contractual commitments, the project would not proceed. Therefore, Tennessee asserts, other shippers or potential shippers cannot be viewed as being similarly situated to Chesapeake and Statoil. Tennessee argues that, under the Commission’s existing negotiated rate and discount policies, project sponsors may provide rate incentives to shippers on a number of grounds, including volumes to be transported, without constituting undue discrimination. For these reasons, Tennessee

does not believe that any aspect of the service agreements executed with Chesapeake and Statoil constitutes a material deviation from the *pro forma* Agreement contained in its tariff.

35. Tennessee argues that, even if the Commission construes these non-conforming provisions in the Shipper's firm transportation agreements to constitute material deviations from Tennessee's *pro forma* Agreement, none of these provisions are unduly discriminatory. Tennessee explains that it agreed to the non-conforming provisions in exchange for the shippers' long-term commitment to the project, and Tennessee claims that absent these contractual commitments, the shippers would not have subscribed to the project. Tennessee further asserts that these deviations simply reflect certain facts about the project, certain justified shipper benefits, and the fact that it cannot provide the services under the firm transportation agreements until it receives the necessary authorizations and constructs the project facilities. Due to the shippers' unique status as project sponsors, Tennessee states that none of the identified provisions create the risk of undue discrimination. Therefore, Tennessee requests that the Commission review and approve these provisions in the firm transportation agreement for each shipper in this certificate proceeding, subject to Tennessee filing such agreements as specified in Commission regulations or this order. Similarly, Tennessee requests a determination from the Commission that even if some contractual provisions could be construed to constitute a material deviation from the *pro forma* service agreement, no provision of the precedent agreements is unduly discriminatory.

36. As required by the Commission's regulations, Tennessee states it intends to file the firm transportation agreements and negotiated/discounted rate agreements and identify any material deviations or non-conforming provisions in each agreement. However, Tennessee requests the Commission address the potentially non-conforming provisions in this proceeding to forgo revisiting any issues raised by these agreements after Tennessee incorporates the subject provisions into executed service agreements filed with the Commission.

37. The Commission finds that the incorporation of non-conforming provisions in Chesapeake's and Statoil's service agreements constitutes material deviations from Tennessee's *pro form*a service agreement.[30] However, in other proceedings, the Commission has found that non-conforming provisions may be necessary to reflect the unique circumstances involved with the construction of new infrastructure and to provide

[30] Tennessee Application at section VII.

the needed security to ensure the viability of a project.[31] We find that the non-conforming provisions identified by Tennessee are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[32]

38. Tennessee must file at least 60 days before the in-service date of the proposed facilities, an executed copy of each non-conforming agreement disclosing and reflecting all non-conforming language as part of Tennessee's tariff and a tariff record identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations.[33] This required disclosure includes any transportation provision or agreement detailed in a precedent agreement that survives the execution of the service agreement. In addition, the Commission emphasizes that the above determinations relate only to those items as described by Tennessee in section VII of its application and not to the entirety of the precedent agreements or the language contained in the precedent agreements.[34]

D. Environmental Analysis

39. Commission staff began its environmental review of the Northeast Upgrade Project following approval for Tennessee to use the pre-filing process on July 20, 2010, in Docket No. PF10-23-000. As part of the pre-filing review, the staff issued a *Notice of Intent to Prepare an Environmental Assessment for the Planned Northeast Upgrade Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meetings* (NOI) on October 8, 2010. The NOI was published in the *Federal Register*[35]

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[31] *See, e.g., Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089, at P 82 (2008) and *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 78 (2006).

[32] *See, e.g., Gulf South Pipeline Co., L.P.*, 115 FERC ¶ 61,123 (2006) and *Gulf South Pipeline Co.*, 98 FERC ¶ 61,318, at 62,345 (2002).

[33] 18 C.F.R. § 154.112 (2011).

[34] We note we are only ruling herein on the specific provisions of the agreements highlighted by Tennessee in its application. The full agreements will be reviewed upon their filing.

[35] 75 Fed. Reg. 64,303 (October 19, 2010).

and mailed to over 1,500 parties including federal, state, and local government officials; agency representatives; environmental and public interest groups; Native American tribes; local libraries and newspapers; and affected property owners. Staff held three public scoping meetings in communities near the proposed facilities to provide the public with an opportunity to learn more about the project and to comment on environmental issues that should be addressed in the Environmental Assessment (EA). The three scoping meetings were attended by a total of 121 individuals.[36]

40. On July 27, 2011, Commission staff issued an additional notice, after Tennessee filed its project application on March 31, 2011, requesting comments from landowners and other stakeholders potentially affected by route alternatives for Loop 323 in Montague Township, Sussex County, New Jersey. The notice was mailed to over 320 landowners and stakeholders. Tennessee revised its proposed alignment of Loop 323 on August 31, 2011 to incorporate into its proposed route one of these route alternatives in order to reduce impacts on a continuous forest block and the federally-endangered bog turtle.

41. We received written and verbal comments during the public scoping process from affected landowners, concerned citizens, government agencies, and other organizations. The primary issues raised during scoping were the request that the Commission complete an Environmental Impact Statement (EIS) rather than an EA; the development of natural gas from the Marcellus Shale[37] in Pennsylvania and the need to consider the cumulative impacts of shale gas development as part of our review of the project; route alternatives in proximity to the Delaware Water Gap National Recreation Area (Delaware Water Gap NRA); impacts on recreation and special interest areas; impacts on water resources, forest, and wildlife; operational noise at modified compressor stations; impacts on landowners and their homes, including property values; and the need for complete information for state permitting purposes.

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[36] The public scoping meetings were held in Ringwood, New Jersey, and Milford and Wyalusing, Pennsylvania, on November 1, 3, and 4, 2010, respectively.

[37] The unconventional development and production of natural gas resources in shale formations has increased in the United States in recent years. In Pennsylvania, this development is occurring in the Marcellus Shale, which extends primarily from New York through Pennsylvania and into West Virginia and Ohio. EA at 2-121.

1. **Pre-EA Scoping Comments**

42. Commentors on the NOI, including Skylands Clean, New Jersey Highlands Coalition, and New Jersey Conservation Foundation, contended that the project would result in significant impacts on the human environment and, therefore, an EIS would be required. The EA addresses whether an EIS should have been prepared. It explains that the Commission's regulations implementing the National Environmental Policy Act of 1969 (NEPA) require preparation of an EIS for "[m]ajor pipeline construction projects…."[38] Our regulations do not define or explain what constitutes a "major" pipeline; however, the Commission's years of experience with NEPA implementation for pipeline projects indicate that a new 40.3-mile-long, 30-inch-diameter pipeline that will be co-located within or adjacent to existing rights-of-way for 84 percent of its length normally would not fall under the "major" category for which an EIS is automatically prepared.[39]

43. The Council on Environmental Quality (CEQ) regulations implementing NEPA state that one of the purposes of an EA is to assist agencies in determining whether to prepare an EIS or a finding of no significant impact. Here, Commission staff prepared an EA to determine whether the Northeast Upgrade Project would have significant impact, thus necessitating the preparation of an EIS. As explained below, the EA concludes, and we agree, that the Northeast Upgrade Project would not constitute a major federal action

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[38] EA at 1-2 (citing 18 C.F.R. § 380.6(a)(3) (2011)).

[39] *See, e.g., Tennessee Gas Pipeline Co.*, 131 FERC ¶ 61,140 (2010) (EA issued for Tennessee's 300 Line Project consisting of 127.4 miles of 30-inch-diameter pipeline loops through six counties in Pennsylvania and two counties in New Jersey); *Magnum Gas Storage, LLC*, 134 FERC ¶ 61,197 (2011) (EA issued for new Magnum Gas Storage Project which included gas storage field on 2,050-acre site in Millard County, Utah, and associated 61.6-mile, 36-inch-diameter pipeline traversing three counties in Utah); *Colorado Interstate Gas Co.*, 131 FERC ¶ 61,086 (2010) (EA issued for Colorado Interstate Gas Co.'s Raton 2010 Expansion Project which included two new 16-inch-diameter pipeline laterals totaling 118 miles in length traversing four counties in southeastern Colorado); *Equitrans L.P.*, 117 FERC ¶ 61,184 (2006) (EA issued for Big Sandy Pipeline Project which included 68 miles of new 20-inch-diameter pipeline traversing four counties in eastern Kentucky).

significantly affecting the quality of the human environment.[40] Therefore, an EIS is not required.[41]

44. Some commentors also argued an EIS would be necessary to fully consider the impact of the development of natural gas from the Marcellus Shale in the environmental review of the project. As explained in more detail below, the EA addresses the cumulative impact of other jurisdictional natural gas pipelines, natural gas facilities associated with the project but that are not under the Commission's jurisdiction, unrelated projects, and development of Marcellus Shale. The EA considers the general development of the Marcellus Shale in proximately to the project within the context of cumulative impacts in the project area. The EA notes that the more detailed analysis of Marcellus Shale impacts sought by commentors is outside the scope of the project analysis because the exact location, scale, and timing of future facilities are unknown. Moreover, the EA concludes that the potential cumulative impacts of Marcellus Shale development are not sufficiently causally related to the project to warrant the comprehensive consideration of those impacts in our staff's analysis.[42]

45. Commentors also raised concerns regarding project impacts on recreation and special interest areas including the Delaware River, Appalachian National Scenic Trail, New Jersey Highlands Region, state parks, and properties enlisted in the New Jersey Green Acres program, among others. The EA describes each recreation and special interest area that would be crossed by or within 0.25 mile of the project, and discusses the impacts of the project on each area and Tennessee's consultations with applicable permitting agencies. Tennessee provided state-specific Environmental Construction Plans (ECPs) describing the measures that it will implement to minimize construction and

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[40] EA at 4-1. Under 40 C.F.R. § 1508.18 of the CEQ's regulations, "a 'major federal action' includes actions with effects that may be major and which are potentially subject to Federal control and responsibility. Major reinforces but does not have a meaning independent of significantly. (Sec. 1508.27)." "Significantly" requires consideration of both the context and intensity of the project. *See* 40 C.F.R. § 1508.27 (2011).

[41] CEQ regulations state that, where an EA concludes in a finding of no significant impact, an agency may proceed without preparing an EIS. *See* 40 C.F.R. §§ 1501.4(e), 1508.13 (2011).

[42] EA at 2-125.

operational impacts of the project. Tennessee also provided site-specific crossing plans for the above mentioned recreation and special interest areas and committed to continued consultation with the agencies responsible for these areas regarding the need for any additional mitigation measures. As stated in the EA, our staff reviewed the site-specific plans and found them acceptable.

46. Individuals, non-government organizations, and state agencies raised concern regarding adverse impacts on natural resources, primarily surface water, forest, and wildlife resources. The EA examines project impacts on these and other resources, and describes the mitigation measures that Tennessee will implement to avoid or reduce impacts, as well as the local, state, and federal agency consultations and required permits for the project.

47. Many of the commentors stated concerns that the project could threaten important drinking water resources in the region, including the Delaware River between Pennsylvania and New Jersey, and the Monksville Reservoir in Passaic County, New Jersey. The EA explains that Tennessee would cross both of these waterbodies by the horizontal directional drill (HDD) method. Tennessee's HDD contingency plans include provisions to minimize the impact of an inadvertent release of drilling mud (typically bentonite, a naturally occurring clay) into waterbodies. Tennessee would also implement other measures described in the EA and detailed in its state-specific ECPs to minimize construction-related impacts on other surface waters such as a Spill Prevention, Control and Countermeasure Plan that prohibits fueling and fuel storage within 100 feet of a waterbody. Based on the implementation of the construction and restoration methods described in Tennessee's application, the EA concludes that impacts on waterbodies would be minor and temporary and that operation of the project would not pose a threat to drinking water resources in the area.[43]

48. The EA discusses how Tennessee will further minimize impacts on forest and other vegetation by implementing erosion control measures detailed in its ECPs and by controlling the spread of invasive plant species through implementation of its Invasive Species Management Plan, which includes monitoring for and control of invasive species for at least 5 years after construction. Tennessee has also committed to comply with New Jersey's No Net Loss Reforestation Act to restore or mitigate for all forested habitat impacted on state-owned lands, and with restoration and mitigation measures that may be

[43] EA at 2-12.

required by the U.S. Army Corps of Engineers (Corps) in conjunction with permits under section 404 of the Clean Water Act (CWA).[44]

49. Four federally-listed threatened or endangered species were identified in the project area: the bog turtle, dwarf wedgemussel, Indiana bat, and small whorled pogonia. Tennessee consulted with the U.S. Fish and Wildlife Service (FWS) regarding these species and the FWS assisted us in preparing the EA, which contains our Biological Assessment (BA). As discussed below, Tennessee filed additional survey reports and we have continued consultation with the FWS. Environmental recommendations 13 and 14 are included in this order to ensure compliance with the Endangered Species Act (ESA) as Environmental Condition Nos. 13 and 14.

50. The EA identifies state-listed species of concern in the project area and discusses the field surveys conducted to date, potential impacts on the species, and measures that Tennessee will implement to avoid or minimize impacts on these species. The EA recognizes Tennessee's on-going consultation with appropriate state agencies to complete surveys and develop measures as necessary to avoid adverse impacts on rare, state-listed species. The EA recommends that Tennessee file the results of outstanding surveys for state-listed species and to identify additional mitigation measures developed in consultation with the state agencies (environmental recommendation 16). Since issuance of the EA, Tennessee and the New Jersey Department of Environmental Protection (New Jersey DEP) have filed updates and comments pertaining to state-listed species of concern. Therefore, environmental recommendation 16 is included as Environmental Condition No. 15 to this order. These updates and comments are discussed in more detail below.

51. Several landowners from the Fawn Lake community in Pike County, Pennsylvania expressed concern regarding the potential for increased operational noise at modified Compressor Station 323. The EA evaluates the predicted noise levels from the modified Compressor Station 323 at the nearest noise-sensitive areas and finds that the potential noise increase would be barely noticeable. Environmental Condition No. 18 to this order, requires Tennessee to file the results of noise surveys after placing the authorized units at Compressor Stations 321 and 323 in service and requires Tennessee to install noise controls if noise levels exceed the threshold.

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[44] 33 U.S.C. § 1344 (2006).

52. In response to landowner concerns, the EA discusses Tennessee's special construction techniques to minimize project impacts on residential properties and states that Tennessee would repair, replace, or compensate landowners for project-related damages. The EA includes site-specific residential construction plans for those residences within 50 feet of the construction work area and requests that landowners provide comment on these plans. The EA recommends that Tennessee file evidence of landowner concurrence with the residential construction plan for the residence at milepost (MP) 8.3 of Loop 323. After the issuance of the EA, Tennessee provided that landowner concurrence; therefore, the recommended condition in the EA is not included as a condition to this order. The EA concludes that implementation of the special construction methods and site-specific residential construction plans will minimize disruption to residential areas to the extent practicable and facilitate restoration of these areas as soon as possible upon completion of construction.

53. In its scoping comments, New Jersey DEP cited deficiencies and discrepancies in information it had received from Tennessee in support of its application for the state permits and federally-delegated permitting under section 401 of the CWA.[45] New Jersey DEP requested that we delay issuance of the EA until the outstanding information was submitted and reviewed by the New Jersey DEP and other applicable state agencies. The EA discusses the state's need for complete information for its permitting purposes, but concludes that the information in the EA was sufficient for the purpose of the Commission's NEPA analysis. The EA states that no more than nine percent of the proposed facilities in New Jersey remain to be surveyed due to lack of landowner permission, and that a substantial amount of environmental information was obtained from federal, state, and local resources, including for those areas not accessible for survey. The EA also explains that Tennessee has committed to obtaining all necessary environmental permits and would be required to complete and file with the Commission the results of all resource surveys upon gaining access to unsurveyed properties prior to construction. Further, Environmental Condition No. 8 requires Tennessee to provide documentation that it has received all necessary federal authorizations before construction will be allowed to proceed. This includes the section 401 permit under consideration by the New Jersey DEP.

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[45] 33 U.S.C. § 1341 (2006).

2. Late Scoping Comments

54. We also received late scoping comment letters from three affected landowners (George Feighner (two letters), Joseph and Chris Butto, and Stanley Buczek[46]) and one state agency (New Jersey DEP).[47] In addition, a form letter was filed by several non-governmental organizations (NGO)[48] and approximately 150 individuals who are not landowners affected by the project. Some individuals added additional specific concerns to these form letters. These comments were filed just before the issuance of the EA and were too late to be included. However, the majority of the late letters and comments on the EA reiterate comments previously received and are thoroughly addressed in the EA. The remaining, substantive environmental comments are addressed below.

55. In both of his late scoping comments, George Feighner states that he does not oppose the project, but opposes the proposed alignment of Loop 323, which crosses his property in Montague Township, Sussex County, New Jersey. Mr. Feighner notes that the proposed alignment, which deviates from Tennessee's existing right-of-way to avoid crossing the Delaware Water Gap NRA and requires about 3.5 miles of additional pipeline, could adversely affect air quality, animal migration routes, drainage patterns, and visual resources in the area. We note that other late commentors provided additional scoping comments on the proposed route and alternatives around the Delaware Water Gap NRA. Mr. Feighner also states concerns that the project would require removal of old growth trees and impact the water supply well and septic system on his property. In addition, Mr. Feighner and additional commentors noted their concerns about the impact on cultural resources, steep slopes, vernal pools, wetlands, and waterbodies.

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[46] In its comments on the EA filed on December 21, 2011, Tennessee responded to the comments received from both George Feighner and Stanley Buczek.

[47] Tennessee filed a response to the New Jersey DEP late scoping comment on December 13, 2011.

[48] The letter was filed jointly by New Jersey Chapter of Sierra Club, Delaware Riverkeeper Network, New Jersey Highlands Coalition, Earthjustice, New Jersey Audubon Society, Pequannock River Coalition, New Jersey Conservation Foundation, North Jersey Public Policy Network, ClimateMama, Morris County Trust for Historic Preservation, and Burham Park Association.

56. As explained in the EA, Tennessee's existing pipeline crosses the Delaware Water Gap NRA for 1 mile in Pike County, Pennsylvania and Sussex County, New Jersey, and was installed prior to 1965 when the Delaware Water Gap NRA was established. The EA analyzes two route alternatives that would cross the Delaware Water Gap NRA and finds that each of the alternatives would result in fewer environmental impact than the proposed alignment in this area. However, the EA does not recommend either alternative because of a substantial land use conflict. The EA explains that the legislation that created Delaware Water Gap NRA precludes the NPS, which manages the Delaware Water Gap NRA, from approving any route across the Delaware Water Gap NRA without federal legislation allowing it to do so, and the NPS has stated its opposition to any routing across the Delaware Water Gap NRA. Therefore, if the Commission were to approve one of the alternatives crossing the Delaware Water Gap NRA, Tennessee would still not be able to construct the project as approved. As a result, the EA concludes that while the alternative routes may be environmentally preferable, the proposed route for Loop 323, with the mitigation proposed by Tennessee and recommended by staff, is considered environmentally acceptable and would not result in significant impacts.

57. Mr. Feighner contends that the 3.5 miles of additional pipeline on Loop 323 to route around the Delaware Water Gap NRA would create the need for increased compression which would result in an increase of greenhouse gas emissions. While we agree that there would be some decrease in downstream pressure because of the additional pipe, the increased compression to compensate for this pressure drop would not result in an appreciable amount of associated greenhouse gas emissions. Any increase in greenhouse gas emissions would be minimal when comparing these 3.5 extra miles to the scope of the project facilities.

58. The EA discusses the environmental concerns raised by Mr. Feighner and other commentors and describes how Tennessee's construction plans would minimize impacts on these resources including those specific to their properties. The EA states that Tennessee would be required complete all remaining surveys, conduct any necessary agency consultations, and implement measures to address issues identified by the surveys. We believe that this process, coupled with the construction and restoration measures described in the EA and input from Mr. Feighner and other landowners, will minimize effects on property impacted by the project to the greatest extent practicable. The loss of some mature trees may be unavoidable; however, any construction-related damages are a point of negotiation between landowners and Tennessee, and Tennessee will compensate landowners for damages and the temporary and permanent easement on their land.

59. Joseph and Chris Butto are homeowners near MP 8.1 of Loop 323 in Montague Township, Sussex County, New Jersey. The Buttos' late scoping comments stated their concern that the project could impact the federally-endangered bog turtle as well as wetlands, springs, and steep slopes in the area. The EA states that Tennessee would be

required to complete its bog turtle surveys prior to construction. On January 11, 2012, Tennessee filed with the Commission, and provided to FWS, the results of its bog turtle survey for the segment of Loop 323 near the Buttos' property. The FWS concurred that the survey did not document any suitable bog turtle habitat on the referenced segment of Loop 323.

60. The Buttos also asked whether Tennessee is required to identify the potential impact radius of the pipelines and requested that information. The U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that pipeline operators identify the potential impact radius at all points along their pipelines as part of determining high consequence areas. The EA addresses the methodology for identifying high consequence areas by using pipeline class locations, the associated potential impact radius, and potential impact circle.[49]

61. Stanley Buczek's late comments relay his concern that he would be unable to cross the pipeline, thereby rendering approximately 25 acres to the rear of his property unusable. In a filed response to these comments, Tennessee noted that it met with Mr. Buczek on a number of occasions, but was not granted access to his property to complete an evaluation of his concerns. Tennessee informed Mr. Buczek that it is possible to construct the pipeline in a manner that would allow heavy equipment to cross over the pipeline, allowing him access to the rear of his property. We believe that Tennessee and Mr. Buczek can resolve this issue during the easement negotiation process.

62. The general form letter requested that the Commission hold public meetings in New Jersey for the purpose of taking comments on a draft of the EA and to consider potential project impacts on drinking water resources, including the Monksville Reservoir in Passaic County, New Jersey. Three commentors filed an expanded version of the general form letter that contained a section of specific issues of importance to the commentor. In a version of the form letter, the New Jersey Chapter of Sierra Club, along with several other NGOs, added that the project would result in significant harm to critical habitat for rare, threatened, and endangered species, core forest, and native plants. The Food and Water Watch and Cornucopia Network of New Jersey added concerns of excess erosion and residential impacts from the project, respectively. Judith Sullivan added her concern regarding cumulative impacts on historic roads and Native American

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[49] The potential impact circle is a circle with a radius equal to the potential impact radius.

cultural resources in New Jersey. Ms. Sullivan's comments are addressed in greater detail below.

63. Regarding the request for additional public meetings, we believe that our process has allowed the public sufficient opportunity to comment on the project. As previously described, our environmental review process included a 30-day public scoping period and three public scoping meetings. In addition, we continued to accept and address comments until the EA was ready to be printed After the EA was issued , landowners and other stakeholders had an additional 30-day opportunity to comment on the project. Although the EA comment period closed on December 21, 2011, we continued to accept comments on the EA. Based on this, we find that interested individuals and groups had sufficient opportunity to provide comments and input on our environmental review of the project. We also find that the environmental issues raised in the form letters are adequately addressed in the EA or in the response to comments on the EA contained in this order without the need for additional public meetings.

3. EA and Post-EA Comments

64. To satisfy the requirements of the NEPA,[50] Commission staff prepared an EA for the Northeast Upgrade Project. FWS and the Corps participated in the preparation of the EA as cooperating agencies. On November 21, 2011, the EA was placed into the public record of this proceeding[51] and issued for a 30-day comment period. The EA addresses geology and soils, water resources, fisheries and wetlands, vegetation and wildlife, land use, recreation and visual resources, socioeconomics, cultural resources, air quality and noise, reliability and safety, cumulative impacts, and alternatives. As summarized below, the EA also addresses all substantive issues raised during the scoping process or otherwise identified prior to the issuance of the EA.

65. We received comments on the EA from a number of individuals, agencies, and NGOs including: the Environmental Protection Agency (EPA); the New Jersey DEP; three county agencies in Pennsylvania: Pike County Planning Commission, Pike County Conservation District, and Bradford County Office of Community Planning and Grants (Bradford County); one county agency in New Jersey: Bergen County Department of

[50] 42 U.S.C. §§ 4321-4370f (2006).

[51] A notice announcing the availability of the EA was published in the *Federal Register* on November 29, 2011. 76 Fed. Reg. 73,618 (2011).

Planning and Economic Development; three NGOs filing jointly: New Jersey Chapter of the Sierra Club, Delaware Riverkeeper Network, and New Jersey Highlands Coalition (referred to henceforth collectively as Sierra Club); William Anastasio, an affected landowner in Pennsylvania; George Feighner, an affected landowner in New Jersey; Jean Public and Steven Vitale, two concerned citizens; and Tennessee.[52] The NPS filed a statement that it had no comments on the EA. The New Jersey State Historic Preservation Office (SHPO), Ramapough Lenape Indian Nation (Ramapough Lenape), and Ms. Judith Sullivan each filed comment letters concerning cultural resource issues and our responsibilities under section 106 of the National Historic Preservation Act (NHPA),[53] that were not in response to the EA.

66. In comments on the EA, New Jersey DEP states that NPS approval will be required if the project activity of Loop 325 constitutes a conversion of federally-protected parkland funded by the Land and Water Conservation Fund. Environmental Condition No. 8 of this order requires Tennessee to file with the Commission documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof) prior to receiving authorization to commence construction of any project facilities. Therefore, Tennessee is required to resolve the Land and Water Conservation Fund issues prior to construction.

67. The New Jersey DEP also recommends that Tennessee conduct field investigations to determine whether Loop 325 will cross historical quarries or underground mines, including the former Monks and Board mines. As discussed in the EA, previous field surveys, mapping, and title searches did not identify any mines crossed by the project. The opening to the former Monks mine was found to be 125 feet south of Tennessee’s existing pipeline and historical descriptions indicate that the mine shafts extend southeasterly, away from the existing pipeline. Loop 325 will be installed on the north side of the existing pipeline at this location, opposite of the mine, and Tennessee states that the existing pipeline has not been affected by the mine. No indication of the former Board mine was found during initial field surveys, but Tennessee has agreed to revisit the area to determine if the former mine workings can be located, and will file its findings prior to any construction.

[52] Tennessee filed its comments on the EA on December 21, 2011. Tennessee filed a response to comments that were received on the EA on January 27, 2012.

[53] 16 U.S.C. § 470f (2006).

68. New Jersey DEP recommends that blasting be conducted in accordance with New Jersey Department of Labor codes. As described in the EA, blasting will comply with federal, state, and local regulations. Tennessee notes in its response to comments that the New Jersey Department of Labor regulations do not specify a distance for conducting monitoring from blast sites.

69. We also received additional comments regarding blasting concerning the impacts of blasting on underground mines. The EA discloses that approximately 32.7 miles (82 percent) of the proposed pipeline loops would cross areas of shallow bedrock that may require blasting but would not cross any known underground mines. It also identifies Tennessee's Blasting Plan to minimize the effects of blasting and ensure the safety of its existing pipeline and nearby structures during blasting operations. In its blasting Plan, Tennessee states that all blasting techniques would comply with federal, state, and local regulations governing the safe storage, handling, firing, and disposal of explosive materials. Considering the limited, controlled nature of blasting that would be used to excavate the narrow, shallow trench, blasting is not anticipated to impact underground mines and will have minimal impact to other resources. Tennessee will be responsible for any construction-related damages, including from any blasting activities.

70. Regarding project construction and operation on state-owned lands and Natural Heritage Priority Sites, New Jersey DEP comments that some botanical surveys remain to be completed and recommends that surveys for invasive plant species be extended 150 feet from the edge of the construction work space. New Jersey DEP requests that Tennessee conduct invasive species monitoring over the life of the project, fund an independent botanist to monitor construction and restoration activities, post a bond to ensure that sufficient funds will exist to monitor for and manage invasive species and repair other biological impacts, and evaluate alternatives to minimize project impacts. As discussed in the EA, Tennessee will complete any remaining botanical surveys in the spring or early summer of 2012 and provide the survey results to the Commission and New Jersey DEP. The EA references Tennessee's Invasive Species Management Plan which discusses the extent and duration of invasive species surveys, monitoring, and management practices that Tennessee will implement. Tennessee has agreed to continue to discuss invasive species management with New Jersey DEP, as well as the posting of a bond for work on state lands.

71. The EA discusses Tennessee's environmental inspection program, which will consist of trained individuals to ensure implementation of appropriate measures to minimize impacts and ensure compliance with federal, state, and local permit stipulations. In addition, Tennessee has agreed to fund a third-party environmental monitoring program that will include full-time personnel working under the direction of the Commission. Regarding alternatives to minimize impacts, the EA includes a detailed analysis of alternatives to avoid or reduce project impacts. In addition, Tennessee's Freshwater Wetlands and Flood Hazard Area Individual Permit applications to

New Jersey DEP include an alternatives analysis and an avoidance and minimization measures summary that specifically address the minimization measures that Tennessee will employ on state-owned lands.

72. Regarding impacts on wildlife, New Jersey DEP recommends measures to minimize impacts on the state-listed eastern floater (mussel) in Holiday Lake (Loop 323), repeats its earlier concern regarding potential impacts on state-listed snake species, comments that the pipeline trench needs to include animal escape slopes, recommends that the permanent right-of-way be maintained in a low shrub state, and recommends that tree clearing timing restrictions be imposed along the entire length of Loops 323 and 325 to protect Indiana bats and state-listed bat species. New Jersey DEP also recommends that Tennessee develop a detailed construction plan for the project.

73. In response, Tennessee states that landowners surrounding Holiday Lake have opposed draining the lake in order to conduct a dry crossing. Therefore, Tennessee proposes a wet crossing of Holiday Lake using barges and turbidity curtains, similar to the method used to replace the existing 24-inch-diameter pipeline in 2003, to avoid significant impact on the eastern floater. Tennessee also commits to continue to work with New Jersey DEP on the Holiday Lake crossing. With regard to potential project impacts on state-listed snake species, Tennessee will implement measures to avoid, minimize and mitigate for impacts and will employ biological monitors if required by New Jersey DEP permit conditions. Similarly, Tennessee will comply with state permit conditions requiring animal escape ramps from open trenches. As described in the EA, Tennessee will maintain the permanent right-of-way in an herbaceous and low shrub cover type to comply with safety requirements and protocol. Regarding tree clearing timing restrictions related to the federally-listed Indiana bat, we are including Environmental Condition No. 13 to this order to protect the Indiana bat in New Jersey by prohibiting the clearing of trees greater than 5-inch-diameter breast height from April 1 to September 30 between mileposts 13.9 and 16.4 on loop 323. We believe that implementation of this condition will also be protective of other bat species in the area. Finally, Environmental Condition No. 6 of this order requires Tennessee to submit an Implementation Plan for our review and approval detailing how Tennessee will implement the construction procedures and mitigation measures described in its application materials, supplements, and this order.

74. New Jersey DEP provides several comments concerning the applicability analysis completed for this project with regards to the federal General Conformity regulations. New Jersey DEP inquired whether the air emissions associated with the Corps' Philadelphia District permit was included in the General Conformity Applicability Analysis. As the lead federal agency for analyzing the applicability of the General Conformity program requirements, Commission staff's EA analyzes all emission sources that are associated with the project, including actions such as wetland and waterbody crossings that are under the jurisdiction of the Corps. New Jersey DEP also states that

the EPA's NONROAD Model should be used when calculating the non-road air emissions for the project using the latest and most accurate emission estimation techniques available for the applicability analysis. In addition, New Jersey DEP questioned whether the scope of the General Conformity Applicability Analysis includes all direct and indirect emissions from the project construction in 2012 and 2013 and from all air emission sources (e.g., pipe/contractor yards). We reviewed Tennessee's calculation methodologies and verified the scope of the General Conformity Applicability Analysis to confirm the EA's conclusion that the reasonably foreseeable direct and indirect emissions from the project will not exceed the General Conformity thresholds by county or by the project as a whole. Therefore, the project does not require a General Conformity Determination.

75. New Jersey DEP notes that it continues finalizing the review of all properties within the New Jersey Green Acres program that will be disturbed by the project. In response, Tennessee states that it will continue to coordinate with the New Jersey Green Acres program to obtain all necessary approvals.

76. New Jersey DEP notes that trench dewatering permits will be required for the portion of Loop 323 in Montague Township. As stated in the EA, Tennessee would obtain the necessary permits and approvals prior to any construction in New Jersey and Pennsylvania.

77. New Jersey DEP Land Use Regulation Program (LURP) does not believe that the project schedule can be met largely because Tennessee has not filed administratively complete LURP permit applications and approval of Loop 325 has not been received from the New Jersey Highlands Council or New Jersey DEP's Division of Watershed Management. The LURP also notes discrepancies pertaining to access roads, wetland impacts, vegetation impacts, construction methods, and construction timing restrictions between the information presented in the EA and information submitted to the New Jersey DEP for state permitting purposes. The LURP reasserts its contention that, because of these discrepancies, the Commission cannot clearly understand the full impact of the project and urges the Commission to deny approval until Tennessee rectifies the discrepancies.

78. We recognize New Jersey DEP's need for complete information for its permitting purposes, but conclude that the information in the EA is adequate for the purpose of our analysis. Tennessee has also stated that it recognizes the multiple state permits and approvals to be obtained for the project and has committed to continue to work with the Highlands Council, New Jersey DEP, and LURP to obtain the necessary approvals. In addition, as a component of its state permit applications, Tennessee has agreed to compensatory mitigation in the form of land acquisition or monetary compensation acceptable to the New Jersey DEP for unavoidable project impacts on wetlands, forest, and other natural resources.

79. In conclusion, we believe that construction, monitoring, and operation of the project in accordance with Tennessee's plans and our required measures, and Tennessee's continued commitment to work with the New Jersey DEP in finalizing and implementing state permitting requirements, will minimize and compensate for impacts on state lands to the greatest extent practicable.

80. In its comments on the EA, the EPA notes that the degree of co-location of the project with Tennessee's existing facilities will help to minimize impacts on the environment, provided Tennessee implements best management practices during project construction and operation. EPA also agreed that secondary and cumulative impacts are likely to occur as described in the EA, but expressed non-specific concern regarding cumulative impacts on water quality, air quality, and loss of forested land and other sensitive wildlife habitat.

81. In the EPA's view, the EA did not adequately analyze potential project impacts on sensitive surface water resources. We disagree. The EA describes potential impacts on waterbodies and explains that the greatest potential impact will be increased sediment loading and turbidity during construction, which will be minimized by implementing dry crossing methods at nearly all waterbodies and completing most in-stream construction within 24 to 48 hours. Tennessee will also install and maintain erosion control adjacent to waterbodies for the project in accordance with its ECPs, implement its Spill Prevention, Control and Countermeasure Plan to avoid fuel and other product spills into waterbodies, have absorbent materials available if spills occur, and restore the stream bed and bank after construction. The EPA also clarifies that it delegated CWA section 404 program authority to the New Jersey DEP, but retains oversight authority of the program in cooperation with the state.[54]

82. The EPA notes that some forest impacts in New Jersey will be mitigated under New Jersey's No Net Loss Reforestation Act and recommends that Tennessee commit to the same level of mitigation for forest impacts in Pennsylvania. We believe that the mitigation proposed by Tennessee and required by this order are sufficient to minimize impacts on forested areas in Pennsylvania and New Jersey. However, as discussed in the EA, Tennessee has committed to obtaining all necessary environmental permits and will construct, operate, and maintain the proposed facilities in compliance with the required permits and applicable federal and state regulations and guidelines.

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[54] The EA mistakenly refers to delegation by the Corps. EA at 2-22.

83. Pike County Planning Commission reiterated its objection to the proposed alignment of Loop 323 around the Delaware Water Gap NRA and indicated that it prefers the co-location of Loop 323 with the existing pipeline, which staff analyzed in the EA as Delaware Water Gap Alternative 1. Pike County Planning Commission also restated its opinion that an EIS should be conducted to fully evaluate the environmental impacts of the project. The issue of EA versus EIS is addressed in more detail later in this order.

84. Pike County Planning Commission contends that the proposed alignment would require 6.3 miles more of large diameter pipe and additional compression when compared to Delaware Water Gap Alternative 1. For clarification and as described in more detail in the EA, the proposed route will actually be a total of 3.5 miles longer than Delaware Water Gap Alternative 1 and will not require additional compression.[55]

85. In addition to Pike County Planning Commission's comments regarding the routing of Loop 323, we received either written or verbal comments from Pike County Conservation District and four landowners affected by the proposed route around the Delaware Water Gap NRA who also favored Delaware Water Gap Alternative 1. In contrast, the NPS, Save the Park, and Burnham Park Association opposed an alignment across the Delaware Water Gap NRA. Of the four affected landowners who filed comments, three are located in Montague Township, New Jersey and one is located in Pike County, Pennsylvania. Based on Tennessee's alignment sheets, ten landowners in Pike County will be affected by the segment of Loop 323 around the Delaware Water Gap NRA. The EA fully analyzes three possible routes near the Delaware Water Gap NRA and concludes that Tennessee's proposed route, outside of the Delaware Water Gap NRA, will not result in a significant environmental impact. While we recognize that the other route alternatives could have less environmental impact, they would require federal legislation and NPS support, which are absent. The rationale for not recommending the use of either of the alternative routes through the Delaware Water Gap NRA was discussed previously.

86. Pike County Planning Commission states that the proposed alignment of Loop 323 would create a bottleneck in Tennessee's system, resulting in gas velocities within the existing 24-inch-diameter pipeline that would increase safety risks to Pike County residents. This is not the case. Although the pipelines will not be adjacent, the new pipeline and the existing pipeline will operate together to transport the additional capacity. Based on our engineering review, this will not result in an increase of natural

[55] EA at 3-5.

gas velocity above safety design standards in the existing or proposed pipelines. The EA did consider a system alternative that would involve construction of Loop 323 as proposed, with the exception of the one mile crossing of the Delaware Water Gap NRA. For this system alternative, Loop 323 would follow Tennessee's existing pipeline up to the boundaries of the Delaware Water Gap NRA where it would tie into the existing pipeline and only the existing 24-inch-diameter pipeline would traverse the Delaware Water Gap NRA. This would essentially create a mile gap in Loop 323 across the Delaware Water Gap NRA. This system alternative was determined to be infeasible because it would have potentially resulted in a situation where the velocity of the natural gas in the single 24-inch-diameter pipeline across the Delaware Water Gap NRA would have to exceed design standards to transport the same volume of natural gas that would be carried by the existing pipeline and proposed larger diameter loop.[56]

87. Pike County Planning Commission reiterates its position that the proposed alignment would result in increased environmental impacts on forest, sensitive surface waters, cultural resources, and other resources, and would impact private landowners that are currently unaffected by a pipeline right-of-way. Pike County Planning Commission is concerned that the added length of pipeline would pose a greater operational safety concern to the citizens of Pike County and notes that the proposed alignment is within approximately 750 feet of a public school and 300 feet of a senior care facility.

88. Regarding Pike County Planning Commission's concern that the proposed alignment would result in an increased safety risk due to its added length, we note that the proposed alignment in Pike County will traverse wooded, undeveloped land for 82 percent of its length and will be installed by HDD for the remainder of its length near the developed area along the Delaware River. The public school and senior care center referenced by the Pike County Planning Commission are located in this area of the HDD so Loop 323 will be approximately 30 to 50 feet below ground level at its nearest approach to these facilities. The EA discusses the design and operational safety features of interstate natural gas pipeline systems and the requirement that Tennessee must construct and operate the project in accordance with applicable DOT regulations. The EA concludes, and we agree, that the project will pose only a slight increase in risk to the nearby public.

89. In its comments on the EA, Pike County Conservation District states that the environmental consequences of the project are understated because the EA relies on

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[56] EA at 3-3.

pipeline construction and restoration techniques that do not adequately protect water and land resources. Pike County Conservation District's primary concern is that the construction and restoration measures do not adequately control stormwater runoff or promote successful revegetation of the right-of-way. Pike County Conservation District also argues that additional temporary workspace could be utilized more judiciously and urged the Commission to deny Tennessee's request for additional temporary workspace within 50 feet of a wetland or waterbody. Pike County Conservation District also noted additional concerns about cumulative impacts, soils, wetland and waterbody crossings, fisheries, impact on vegetation and wildlife, residential impacts, and access road impacts, all of which we believe were adequately addressed in the EA or in this Order.

90. As the EA explained, Tennessee's ECPs are based on our Upland Erosion Control, Revegetation, and Maintenance Plan (Plan) and Wetland and Waterbody Construction and Mitigation Procedures (Procedures), which contain measures that are specifically designed to avoid or minimize the environmental impacts associated with the construction of interstate natural gas transmission projects and promote restoration of the right-of-way. Based on Tennessee's detailed alignment sheets, site-specific construction plans, and site visits, and considering standard industry practices and our experience in pipeline construction, we determined that Tennessee's proposed construction workspace, including additional temporary workspace, is appropriate and justified. The EA clarifies that, with implementation of Tennessee's proposed measures and the staff's recommended mitigation measures, the project would not significantly impact the human environment. Furthermore, Tennessee has committed to work with Pike County Conservation District to address its concerns and has agreed to fund a full-time, third-party environmental compliance monitoring program during project construction, which will help ensure Tennessee's compliance with the approved construction and restoration methods and other environmental permit stipulations that do not conflict with any authorization issued by this Commission. We also note that Pike County Conservation District administers both the Pennsylvania Chapter 102 Erosion and Sediment Control and Stormwater Management and the CWA National Pollutant Discharge Elimination System programs in Pike County, including permit application and plan reviews and approvals, site inspections, complaint investigations and technical assistance.

91. Pike County Conservation District states that the proposed Wayne County, Pennsylvania wetland mitigation site was not appropriate for impacts in Pike County. We note that the Corps has regulatory oversight for wetland impact mitigation in Pennsylvania; therefore this issue should be brought before the Corps rather than the Commission.

92. Pike County Conservation District asserts that the Northeast Upgrade Project is related to Tennessee's previously authorized 300 Line Project and questions why the Commission allowed these projects to be submitted and approved in a "piecemeal" fashion. We authorized the 300 Line Project almost two years ago in May 2010, which

was a stand-alone project and designed to provide a contracted-for volume of gas to a certain customer within a certain timeframe. The proposed project is designed to provide another contracted-for volume of gas within a different timeframe to different customers. Commission policy does not allow the overbuilding of capacity so that customers are not paying for facilities that are not being used and to minimize impacts on landowners and communities for facilities that are not needed.[57] The 300 Line Project is currently in operation and is not dependent on the Northeast Upgrade Project facilities. The impacts associated with the 300 Line Project are included in the cumulative impacts discussion in the EA.

93. Pike County Conservation District also notes concerns with tree clearing occurring well before the start of construction and the project remaining unstabilized for long periods. Tennessee must complete tree clearing in the fall, winter, or early spring to comply with the Migratory Bird Treaty Act and other federal and state regulations to minimize impacts on threatened, endangered, and sensitive species. However, once the ground is disturbed, Tennessee will be required to install the appropriate erosion and sedimentation controls as described in its state-specific ECPs.

94. Bradford County comments that pipelines being constructed in the county are essential to transport natural gas from the Marcellus Shale to market, but requests that Tennessee be required to comply with county land use ordinances and submit for county approval land development applications, plans, and associated data for proposed pipe/contractor yards in the county. The county states its belief that this land development process will not hinder, prohibit, or unreasonably delay the construction or operation of Commission-approved facilities.

95. In its response to comments on the EA, Tennessee asserts its belief that Bradford County approval is not required because the proposed pipe/contractor yards in Bradford County do not meet the definition of a "land development" under the county's land use ordinances. We encourage the cooperation of Tennessee with local jurisdictions such as Bradford County and expect Tennessee to abide by all state, local, or municipal permit stipulations to the extent they do not conflict with any authorization issued by this Commission. This does not mean that state, local, or municipal agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.

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[57] *See* Certificate Policy Statement, 88 FERC ¶ 61,227 at 61,750.

96. In its comments on the EA, Bergen County, New Jersey recommends that, for project activities on Bergen County parkland, Tennessee conduct an ecological community assessment and invasive species inventory within 150 feet adjacent to the project right-of-way, post a bond to fund environmental monitoring during construction and restoration and retain an independent botanist/ecologist to monitor construction and restoration activities, conduct alternatives analysis to minimize impacts on high priority and critical habitat areas, provide a plan regarding work crews needed on Bergen County parkland, and comply with all New Jersey DEP requirements to protect the natural environment.

97. As indicated in the EA, Tennessee has conducted the majority of the biological surveys required for state permitting purposes, but some surveys remain to be completed due to its lack of property access. The EA also references Tennessee's state-specific Invasive Species Management Plan developed for Pennsylvania and New Jersey, which we typically require for all interstate projects under our jurisdiction. The EA describes the environmental inspection and compliance monitoring programs that will ensure the project is constructed and restored in accordance with applicable authorizations and permit stipulations. The EA also includes a detailed analysis of alternatives that would minimize environmental impacts. Through comments filed by the New Jersey DEP, we are aware that Tennessee has worked with the New Jersey DEP to reduce project impacts, including in Bergen County, which is located in the New Jersey Highlands Preservation Area.

98. Tennessee responded to Bergen County's comments and commits to consult with the New Jersey DEP to ensure that all areas requiring survey are covered during biologic and invasive species surveys. Tennessee also states that it will post a performance bond for work in the Highlands area and is discussing the terms of the bond with the New Jersey DEP. Further, Tennessee agrees to provide Bergen County with project plans and give advanced notice to the county prior to construction, and commits to comply with all New Jersey DEP permit requirements to protect the natural environment and enjoyment of public parkland. Other Bergen County comments concerning the Mahwah Meter Station, cultural resources, recreational land impacts, and the use of Bear Swamp Road and Bear Swamp Bridge are discussed in the EA or addressed below in this order.

99. William and Amy Anastasio comment that the proposed alignment of Loop 321 on their 28-acre property in Pike County, Pennsylvania, would place the pipeline within 120 feet of their residence and 100 feet of their water supply well, and would require the removal of hundreds of mature trees that are home to a variety of wildlife. The Anastasios recommend that Loop 321 be routed along the north side of the existing Tennessee easement to avoid forest impacts and provide further separation from their residence and well.

100. On the Anastasio property, the existing 300 Line pipeline is located along the southern border of an approximate 100-foot-wide electric transmission corridor containing overhead power lines. Loop 321 will be off-set from the existing pipeline by 25 feet to the south, further from the electric transmission lines but nearer to the Anastasio residence. As proposed, the construction workspace will be 100 feet wide across the majority of the property, consisting of 25 feet of Tennessee's currently maintained right-of-way, 25 feet of new operational right-of-way, and 50 feet of additional temporary workspace. The construction workspace will approach within approximately 80 feet of the Anastasio residence, and an approximate 50-foot-wide buffer of trees will remain between the residence and construction workspace.

101. The Anastasios' recommended route change would place the pipeline only 60 feet from the transmission towers, making it extremely difficult to install the pipeline between the existing pipeline and the towers. Based on our review, an alignment along the north side of the electric transmission corridor would result in increased permanent impacts on forest resources. This alternative alignment would establish a new, 50-foot-wide operational right-of-way through a largely forested area rather than expand Tennessee's existing permanent right-of-way by 25 feet. Such an alignment would also place the construction workspace and pipeline similarly close to another residence. Therefore, an alignment along the north side of the electric transmission corridor is not environmentally preferable to the proposed alignment.

102. Since issuance of the EA, Tennessee states that it has modified the original construction plan for the Anastasio property to reduce the new permanent right-of-way and temporary workspace near the residence. This modification will reduce the number of trees that will be permanently removed and provide a greater forested buffer between the Anastasio residence and construction workspace. Tennessee also states that it intends to review the modified construction plan with the Anastasios and will report the results to the Commission. Therefore, we have added Environmental Condition No. 19 of this order to require that Tennessee provide the modified construction plan and results of communications with the Anastasios to the Director of Office of Energy Projects (OEP) for review and written approval, prior to construction on the Anastasio property.

103. Steven Vitale provided information regarding a proposed elementary school within the Delaware Water Gap NRA near where Tennessee's existing 24-inch-diameter pipeline crosses the Delaware River. Mr. Vitale appears to advocate for replacement of the existing 24-inch-diameter pipeline in its current location to meet Class 3 standards if the school is constructed. In addition, Mr. Vitale recommends installation of Loop 323 in

a new right-of-way at least 2,000 feet to the south of the existing pipeline and proposed school site.[58]

104. As described in the EA, Loop 323 will avoid this area by routing to the north, around the Delaware Water Gap NRA. As proposed, Loop 323 will be at least 1 mile from the elementary school site identified by Mr. Vitale. Similar to the Pike County Planning Commission, Mr. Vitale is concerned that the proposed alignment of Loop 323 would result in increased natural gas velocities above design standards. As discussed above, the proposed alignment will result in a continuous loop of the existing pipeline and will not result in gas velocities above design standards in the existing 24-inch-diameter pipeline.

105. Mr. Vitale also provided additional recommendations for an alternative that would use Tennessee's existing right-of-way across the Delaware Water Gap NRA. While this alternative was not raised by any party during the scoping process, Mr. Vitale states that Tennessee should replace the existing 24-inch-diameter pipeline with a new 36-inch-diameter pipeline to obviate the need for Tennessee's proposed route outside of the Delaware Water Gap NRA. We note that because of concerns with the Delaware River being designated as National Scenic and Recreational River within the Delaware Water Gap NRA and the possible presence of the federally-listed endangered dwarf wedgemussel, this alternative would require an HDD to avoid impacts. An HDD at this river location would require workspace outside of Tennessee's existing easement on NPS property, which would still require congressional approval. Tennessee would also be required to take its existing line out of service to install the new line within the same trench. As a result, this alternative would require Tennessee to stop service for an extended amount of time during construction and would prevent it from supplying gas to fulfill its existing contractual obligations. Therefore, as mentioned above for the other alternatives within the Delaware Water Gap NRA, we consider this alternative infeasible due to the NPS opposition, the permitting conflicts within the Delaware Water Gap NRA, and contractual obligation conflicts for operation of Tennessee's existing line.

[58] Our review of Delaware Valley School Board meeting minutes indicate that the school board is considering three sites for the future elementary school and is aware of Tennessee's existing pipeline near the site of concern to Mr. Vitale.

106. In October and November 2011, Tennessee filed final survey results for the federally-listed Indiana bat in New Jersey and Pennsylvania, respectively, in support of our continued consultation with the New Jersey and Pennsylvania Field Offices of the FWS under section 7 of the ESA.[59]

107. After review of the final Indiana bat survey report for New Jersey, the New Jersey FWS indicates in a January 24, 2012 consultation letter that no seasonal restriction on tree clearing is necessary in New Jersey except for the eastern 2.5 miles of Loop 323 (MPs 13.9-16.4). The 2.5-mile segment is within the foraging range of a known maternity colony of Indiana bat (the EA includes a typographical error identifying the maternity colony near the eastern 2.5 miles of Loop 325).[60] The New Jersey FWS recommends that, among other things, Tennessee: (1) submit a draft plan to limit habitat impacts around the known colony, (2) provide updated estimates of temporary and permanent forest loss in New Jersey, and (3) provide a draft mitigation plan to help offset permanent and temporary loss of Indiana bat habitat. New Jersey FWS states that this mitigation plan should include preferential planting of tree species that provide suitable bat roosts as part of both on-site reforestation and off-site compensatory mitigation as required by other authorities (e.g., impacts on state lands, the Highlands Preservation Area, and wetlands/riparian areas in New Jersey).

108. After review of the final Indiana bat survey report for Pennsylvania, the Pennsylvania FWS recommends in a January 18, 2012 consultation letter that Tennessee implement a seasonal tree clearing restriction from April 1 to October 14 within 2.5 miles of a site along Loop 321 where an Indiana bat had been captured in August, 2010 (the 2.5-mile radius corresponds to approximate MPs 3.2-8.1 of Loop 321). Pennsylvania FWS also recommends that Tennessee either submit a plan for Pennsylvania FWS review that addresses Indiana bat habitat loss within 2.5 miles of the capture site or make an appropriate contribution to the Indiana Bat Conservation Fund. Pennsylvania FWS states that, with implementation of their recommendations, the effects of the project on the Indiana bat will be insignificant or discountable.

109. In its response to comments on the EA, Tennessee agreed to provide the information and plans requested by the New Jersey FWS, and states that it is evaluating the mitigation measures recommended by the Pennsylvania FWS and will provide a

[59] 16 U.S.C. § 1536 (2006).

[60] EA at 2-19.

response to the Pennsylvania FWS and the Commission. We have incorporated the EA's environmental recommendation 14 into Environmental Condition No. 13 of this order. In addition we have amended environmental recommendations 13 and 15 from the EA to reflect the final survey results, our on-going consultation with both FWS offices, and Tennessee's commitments and incorporated them as Environmental Condition Nos. 13 and 14 of this order.

110. The EA includes environmental recommendation 13 that Tennessee file the results of a habitat assessment and surveys for the federally-listed dwarf wedgemussel in New Jersey. On December 5, 2011, Tennessee filed these outstanding reports and, based on its review of the final reports and Tennessee's contingency plan for minimizing the impact of an inadvertent release of drilling mud during the HDD installation of Loop 323 beneath the Delaware River, the Pennsylvania and New Jersey offices of FWS concurred that the project is not likely to adversely affect the dwarf wedgemussel. Thus, our consultation with the FWS concerning the dwarf wedgemussel is concluded and Environmental Condition No. 13 of this order has been amended accordingly.

111. The EA also recommends that Tennessee file the results of a Phase I survey for the federally-listed bog turtle between approximate MPs 7.6 and 9.3 of Loop 323 in New Jersey. On January 11, 2012, Tennessee filed the outstanding survey and New Jersey FWS concurred that the survey did not document any suitable bog turtle habitat along the referenced segment of Loop 323. New Jersey FWS reiterated an earlier request that Tennessee provide project construction plans and a draft Fencing and Monitoring Plan for wetland W003 on Loop 323, consistent with New Jersey FWS conservation measures outlined in a June 16, 2010 letter to Tennessee. The New Jersey FWS also requested that Tennessee provide an electronic copy of the New Jersey ECP.

112. In its response to comments on the EA, Tennessee commits to provide the requested construction plans and draft Fencing and Monitoring Plan for wetland W003 to the New Jersey FWS. Environmental Condition No. 13 of this order specifies that Tennessee shall not begin construction of Loop 323 until we complete any necessary consultation with the New Jersey FWS concerning the bog turtle.

113. Tennessee provided an update regarding two bald eagle nests identified in the project area. As discussed in the EA, the nests were located approximately 350 feet and 2,450 feet from proposed Loop 323 in Pike County, Pennsylvania. Tennessee conducted additional aerial and ground surveys and monitoring in 2011 and determined that the farther nest was active whereas the nearer nest was inactive. In a letter dated September 2, 2011, the Pennsylvania FWS stated that, based on the survey results, it does not anticipate that the project will disturb bald eagles. As a result, Tennessee does not intend to limit construction activities and other disturbances within buffers specified under the National Bald Eagle Management Guidelines for the nearer, inactive nest. The

farther nest is outside the buffers recommended in the National Bald Eagle Management Guidelines.

114. Tennessee provided several updates[61] regarding the status of surveys for state-listed species of concern including rare plants and snakes, and reiterated its commitment to complete and submit the survey results to appropriate state agencies and the Commission. As previously noted, the EA recommends that, prior to construction, Tennessee file the results of any outstanding surveys for state-listed species and to identify additional mitigation measures developed in consultation with applicable state agencies. This recommendation is included as Environmental Condition No. 15 to this order.

115. Tennessee provides clarification in its comments on the EA that it will temporarily divert hikers to the Iris Trail during specific construction activities at the Appalachian National Scenic Trail crossing. Loop 323 will cross the Appalachian National Scenic Trail at MP 14.4 in Sussex County, New Jersey. As discussed in the EA, Tennessee consulted with the NPS and Appalachian Trail Conservancy in developing a plan to minimize potential interruptions to trail users during construction and to restore the crossing location after construction.

116. The EA includes a recommendation that prior to construction, Tennessee file a plan with the Director of OEP detailing the additional noise mitigation measures that Tennessee would use to ensure that the noise levels attributable to the 24-hour HDD activities do not exceed an L_{dn} of 55 dBA at the noise sensitive areas near the Susquehanna River HDD entry site. In its comments on the EA, Tennessee requests that the recommendation be amended to require submittal and approval of the noise mitigation plan "prior to initiation of HDD activities at the Susquehanna River," rather than "prior to construction" as indicated in the recommendation. We concur with this clarification and have phrased Environmental Condition No. 17 of this order accordingly.

117. The alignment of Loop 325 crosses land historically occupied by the Ramapough Lenape, which is a Native American tribe recognized by the State of New Jersey. The Ramapough Lenape, through Judith Joan Sullivan, have continued to express concern that some of its known cultural resources sites were missed by Tennessee's inventory surveys, its local experts were not consulted, potential impacts from blasting on cultural

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[61] Updates to biological surveys were filed on November 4 and 7, 2011, December 5, 2011, January 11, 2012, and February 6, 2012.

resources sites were not fully considered, and cumulative impacts were not considered for an historic road, bridge, and Mahwah Meter Station site that would be used for both the Northeast Upgrade Project and the New Jersey-New York Expansion Project (Docket No. CP11-56-000). The Ramapough Lenape also assert that their participation in the project under the NHPA was compromised by a lack of funding and an abbreviated review period. New Jersey DEP and Bergen County acknowledged the Ramapough Lenape concerns and indicated that any deficiencies in the identification of cultural resources should be addressed.

118. The EA thoroughly explains the process that was undertaken to identify cultural resources and describes potential project impacts on historic properties. The EA also discusses Tennessee's consultation with the relevant SHPOs, federal agencies, Native American tribes, and interested parties regarding potential project impacts on cultural resources. As described in the EA, Tennessee conducted Phase I field surveys for the majority of the project's area of potential effect (APE), and has committed to completing all remaining surveys. Phase II evaluative studies are underway for some sites and Tennessee will either avoid or conduct further study of potentially eligible or unevaluated sites. Tennessee also identified five historic architecture sites within the project APE, all of which are considered potentially eligible for listing on the National Register of Historic Places, and is consulting with us and the SHPOs to design measures to avoid impacts on the sites.

119. In its response to comments, Tennessee notes that the APE for direct impacts is a 300-foot-wide survey corridor centered on the pipeline alignment, and sites known to the Ramapough Lenape outside of this corridor may not have been identified. Tennessee and Commission staff visited areas of concern with the Ramapough Lenape on March 2, 2012, and Tennessee has committed to re-examine portions of the right-of-way that may contain burial sites, identify areas of potential blasting and address potential blasting impacts on historic properties, and continue consultation with the Ramapough Lenape. Tennessee will report the additional field inventory results in a revised Phase IB report, as required by Environmental Condition No. 16. Additionally, because the information provided by the Ramapough Lenape suggests that portions of the project area have a high probability for burials, we are requiring Tennessee to update their unanticipated discoveries plan in consultation with the Ramapough Lenape and the New Jersey SHPO.

120. The EA discloses that Tennessee and Algonquin Gas Transmission, LLC (Algonquin) will each construct new aboveground facilities at the existing Mahwah Meter Station for the Northeast Upgrade Project and the New Jersey-New York

Expansion Project, respectively. Tennessee and Algonquin filed drawings depicting the location of the proposed facilities for each project[62] and clarified that Tennessee will develop the entire footprint at the site, with each company constructing and operating their own facilities. The construction-related impacts for the site are included in the EA and will take place within the 10-acre parcel owned by Algonquin. Tennessee commits to avoid and/or mitigate impacts on archaeological sites within the APE for the Mahwah Meter Station, and to continue consulting with the New Jersey SHPO.

121. Tennessee will also make minor modifications to Bear Swamp Road, which will serve as a temporary access road during construction and as a permanent access road to the Mahwah Meter Station by both companies. The road modifications will be accomplished entirely within the existing road bed. Use of Bear Swamp Road will include the Bear Swamp Bridge (also known as the Cleveland Bridge). In response to comments concerning the historic significance and potential cumulative impacts on the bridge, Tennessee stated its belief that the bridge does not retain sufficient historic integrity to be considered eligible for National Register or Historic Places listing. The issue will be addressed in Tennessee's revised Phase IB report.

122. Cumulative impacts associated with construction and operation of the Tennessee and Algonquin facilities at the Mahwah Meter Station are discussed in the EA including a temporary increase of traffic on Bear Swamp Road during construction. The EA concludes that, due to the implementation of specialized construction techniques, the relatively short construction timeframe, and carefully developed resource protection and mitigation plans, only minimal cumulative effects are anticipated when the impacts of Tennessee's project are added to on-going projects in the area, including Algonquin's proposed New Jersey - New York Expansion Project.

123. We have modified the originally recommended condition 18 in the EA and included it as Environmental Condition No. 16 to this order to reflect information provided by Tennessee, the New Jersey SHPO, and the Ramapough Lenape regarding the cultural resources reports. This condition ensures that the Commission's responsibilities under section 106 of the NHPA and its implementing regulations are met prior to Tennessee's construction and use of the facilities associated with the project, including at the Mahwah Meter Station.

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[62] Algonquin and Tennessee filed their drawings on December 9, 2011 and December 15, 2011, respectively.

EA vs. EIS

124. Echoing concerns raised earlier during scoping, the Sierra Club argues that the Commission staff's EA is inadequate and cannot support a finding of no significant impact and that, therefore, we should prepare a full EIS to satisfy the Commission's obligations under NEPA.

125. The Sierra Club starts by arguing the EA is too long and an EIS should have been prepared instead. Sierra Club cites CEQ guidance that states that agencies should avoid preparing lengthy EAs except in unusual cases, where a proposal is so complex that a concise document cannot meet the goals of 40 C.F.R. § 1508.9 and where it is extremely difficult to determine whether the proposal could have a significant impact. Sierra Club specifically asserts the CEQ has generally advised agencies to limit EAs to not more than 10-15 pages and that since the Commission's EA is over 250 pages of text, tables, maps, and appendices the Commission should have undertaken an EIS.

126. The CEQ's advisory memorandum is general guidance to agencies that urges brevity in the preparation of an EA and does not require an agency to prepare an EIS after issuance of an EA with more than 15 pages. The CEQ's guidance recognizes that a lengthy EA may be appropriate in cases of complexity, and while a lengthy EA may suggest that an EIS may be needed in some cases, the CEQ's guidance does not establish a blanket requirement. In this case, the broad range of environmental issues in the resource reports and the workability of the required mitigation to reduce the project's effects below the level of significance warranted a relatively lengthy EA, but not further analysis in an EIS. The EA adequately addresses the myriad of issues as concisely and briefly as possible as Commission and CEQ regulations require. The fact that all the analysis of environmental issues consumed approximately 250 pages does not imply that an EIS is warranted. Moreover, the CEQ guidance cited by Sierra Club is over thirty years old.[63] Courts have held that the length of an EA "has no bearing on the necessity of an EIS."[64] "What ultimately determines whether an EIS rather than an EA is required is the scope of the project itself, not the length of the agency's report."[65] A rule requiring an

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[63] http://ceq.hss.doe.gov/nepa/regs/40/40P1.HTM (originally published in the *Federal Register* on March 23, 1981 (46 Fed. Reg. 18,026)).

[64] *Tomac v. Norton*, 433 F.3d 852, 862 (D.C. Cir. 2005) (citing *Sierra Club v. Marsh*, 769 F.2d 868, 875 (1st Cir. 1985)).

EIS for any EA over a certain number of pages would create a perverse incentive for agencies to produce bare-bones EAs.[66]

127. The Sierra Club also argues that the Commission should have prepared an EIS as opposed to an EA because it believes the project will significantly affect the quality of the human environment. Sierra Club argues that both the context and intensity of the project mandates a finding of significant impacts. Under the CEQ regulations, context refers to "society as a whole (human, national), the affected region, the affected interests, and the locality."[67] The Sierra Club argues that the context of the project includes the rapid development of the Marcellus Shale and that the looping segments will be constructed in high-value resource areas and special protection waters, including habitat for federal and state endangered and threatened species. "Intensity" "refers to the severity of the impact" and Sierra Club argues that intensity factors 2 through 10 listed in 40 C.F.R. § 1508.27(b) weigh in favor of a finding of severe and significant impacts necessitating an EIS rather than an EA.[68] We disagree. We will address the Sierra Club's arguments regarding cumulative impacts, intensity factor 7, in a separate section of this order. We address Sierra Club's arguments with respect to the other intensity factors below.

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[65] *Id.* quoting *Heartwood, Inc. v. U.S. Forest Serv.*, 380 F.3d 428, 434 (8th Cir. 2004).

[66] *Heartwood, Inc. v. U.S. Forest Serv.*, 380 F.3d at 434.

[67] 40 C.F.R. § 1508.27(a) (2011).

[68] Sierra Club cites intensity factors 2 through 10 (40 C.F.R. §§ 1508.27(b)(2) through (b)(10) (2011)) arguing that the project: poses a significant threat to public health and safety (27(b)(2)); will affect numerous unique geographic areas and may cause destruction of significant scientific, cultural, and historical resources (27(b)(3) and (b)(8)); will have environmental impacts likely to be highly controversial (27(b)(4)); could have possible effects on the quality of the human environment that are highly uncertain (27(b)(5)); is likely to establish a precedent for future actions with significant effects (27(b)(6)); will have cumulatively significant impacts on the environment (27(b)(7)); may adversely affect several endangered and threatened species and their habitat (27(b)(9)); and might violate federal, state, and local law requirements imposed for the protection of the environment (27(b)(10)).

128. Sierra Club argues that the project poses a significant threat to public health and safety, the second intensity factor.[69] Sierra Club argues that Tennessee's safety record, the age of the original pipeline, and the proximity of the project to hazardous waste sites pose numerous and significant public health and safety concerns. Sierra Club states that in the past year, three pipeline segments owned and operated by Tennessee have exploded and two segments experienced significant failures in the same time period. Sierra Club argues that the original pipeline was installed in the 1950s and older pipelines have a higher frequency of corrosion incidents. In addition, Sierra Club points out that the EA identifies 35 hazardous sites within 1700 feet of the project, including the Ringwood Mines/Landfill Site in Ringwood, NJ, located 500 feet from the pipeline where hazardous materials continue to be found.[70] As a result, Sierra Club argues the Commission must conduct an EIS to fully assess the risks.

129. Commission staff addresses the potential threat of the project to public health and safety in the EA and determined that the operation of the project would only represent a slight increase in risk to the nearby public.[71] Tennessee will be required to design, install, inspect, test, construct, operate, replace, and maintain the certificated facilities in accordance with PHMSA's *Minimum Federal Safety Standards* in 46 C.F.R. Part 192.[72] As discussed in more detail in the EA, these rules prescribe that each pipeline operator is required to establish an emergency plan that includes procedures for: receiving, identifying, and classifying events, gas leakage, fires, explosions, and natural disasters; establishing communications with local authorities; emergency system shutdown and safe restoration of service; and other requirements.[73] Tennessee's past safety record and the age of the existing 300 Line pipeline are outside the scope of our environmental review.

130. As for hazardous waste sites in the project's vicinity, there is no evidence that any sites will impact, or be impacted by, the project, including the Ringwood Mines/Landfill site. As discussed in the EA, the EPA reports that human exposure and groundwater

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[69] 40 C.F.R. § 1508.27(b)(2) (2011).

[70] EA at 2-80.

[71] EA at 2-121.

[72] EA at 2-115.

[73] EA at 2-116.

mitigation is under control at the site and Tennessee is committed to continuing site research with EPA and New Jersey DEP. In addition, Tennessee will implement the protocols prescribed in its ECPs and Spill Prevention, Control, and Countermeasure Plan, which have been reviewed by the relevant resource agencies, in the event contaminated material is encountered.

131. We are confident, therefore, that if Tennessee constructs and operates the project as required by this authorization and PHMSA's standards, the project would only result in a slight increase in risk to the nearby general public, as described in the EA.

132. Sierra Club also argues that the project will affect numerous unique geographic areas and may cause destruction of significant scientific, cultural, and historical resources, the third and eighth intensity factors, respectively.[74] Sierra Club argues that a number of unique resource areas will be adversely affected by the project, including the Susquehanna River, U.S. Route 6 Grand Army of the Republic Highway Trail, Delaware State Forest, High Point State Park, Appalachian Trail National Scenic Trail, Clove Brook Road Corridor Important Bird Area, Delaware River, Highlands Region, Long Pond Ironworks State Park, Monksville Reservoir, and Ringwood State Park. Sierra Club also points out that the project will also cross seven miles of farmland, dozens of high quality coldwater and warmwater fisheries and almost 50 acres of wetlands. In addition, Sierra Club states that the project area will serve as habitat for four federally-listed threatened or endangered species, the bald eagle, and 65 state endangered, threatened, or special concern species and permanently convert 85 acres of forested land and degrade an additional 265.4 acres of forested land.

133. The EA addresses the effects of the project on unique geographic areas and significant scientific, cultural, and historical resources and describes Tennessee's intention to implement general mitigation measures and provide site-specific measures for each special interest area as determined by the managing agency or permitting authority. In addition, the EA specifically addresses impacts to each special interest area.[75] For example, the EA analyzes impacts to the Susquehanna River, concluding that construction and operation would not result in direct impact on the river because Tennessee will use Horizontal Directional Drilling (HDD) to cross the river.

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[74] 40 C.F.R. §§ 1507.27(b)(3), (8) (2011).

[75] EA at 2-68-79.

134. Sierra Club also argues that staff failed to adequately address how affected wetlands would continue to provide important ecological functions, how wildlife temporarily relocated during construction would be expected to return, and why permanent conversion of wildlife habitat would be minor because wildlife would be expected to return.

135. As explained in the EA, Tennessee will implement a series of mitigation measures to reduce wetland impacts and, where impacts cannot be sufficiently reduced, Tennessee will provide compensatory mitigation pursuant to agreements with the Corps and state agencies. Regarding wildlife habitat, the EA concludes that project impacts on non-forested lands will be temporary and limited, based on Tennessee's ECPs, lasting only several weeks or several months in a given area. Forested lands will experience long-term and permanent impacts because the permanent right-of-way will be maintained in an herbaceous state, however, forested land makes up only a small portion of the project area.[76] Where forested lands are impacted, Tennessee's proposed right-of-way is primarily widening an existing right-of-way rather than a new greenfield pipeline through forested land. Although some project impacts are permanent we do not believe them to be significant.[77]

136. The EA considers all of these issues in depth, satisfying our responsibility to take a hard look at the project's impacts, and concludes with a finding of no significant impact.

137. Sierra Club also argues that the degree to which possible effects of the project on the quality of the human environment are likely to be highly controversial, the fourth intensity factor.[78] Sierra Club argues that a major federal action is controversial when "a substantial dispute exists as to the size, nature, or effect of the . . . action."[79] Sierra Club then argues that many facts in the EA are disputed, including the effects of the project on soil in the project area, movement of sensitive species, increase in undesirable species,

[76] EA at 2-70.

[77] Impacts on federally-listed and state species are addressed below.

[78] 40 C.F.R. § 1508.27(b)(4) (2011).

[79] Citing *LaFlamme v. FERC*, 852 F.2d 389, 400–01 (9th Cir. 1988) (citations and quotations omitted).

increased forest fragmentation, and degradation in habitat conditions. Sierra Club also argues that agencies cannot assume restorative measures will succeed. Therefore, Sierra Club argues the controversial nature of the project supports the preparation of an EIS.

138. Sierra Club, however, misapprehends the meaning of “controversial” in the context of the Commission review of the project. While the existence of a controversy over the effect of an agency action is one factor to consider in determining whether the agency should prepare an EIS,[80] a federal action is “controversial” “where a substantial dispute exists as to the size, nature, or effect” of the action “rather than to the existence of opposition to a use.”[81] Furthermore, the use of the word “highly” to modify “controversial” “means that information merely favorable” to Sierra Club’s position in the EA “does not necessarily raise a substantial question about the significance of the project’s environmental effects.”[82] Sierra Club cannot cherry pick information and data out of the administrative record to support its argument that the project is highly controversial.[83] In this case, no substantial dispute as to the effects of the project exists. Although Sierra Club presents some evidence of the potential for the degradation of habitat, those effects were properly addressed in the EA and staff’s discussion of those effects does not make the effects of the project highly controversial.

139. The EA concludes that the impact of fragmentation will be minimal because the project will mostly expand the width of the existing right-of-way which already has edge habitat. Edge habitat will not be created in these cases, but will be offset from its existing location to the new right-of-way edge. As discussed in the EA, in the limited areas where a new right-of-way is created, wildlife may be adversely affected by forest fragmentation and there would be a shift from forest species to species that are more adapted to edge habitat at the border of the new right-of-way and inward for a distance.[84] The EA also

[80] 40 C.F.R. § 1508.27(b)(4) (2011).

[81] *Foundation for North American Wild Sheep v. U.S. Dept. of Agriculture*, 681 F.2d 1172, 1182 (9th Cir. 1982) (quoting *Rucker v. Willis*, 484 F.2d 158, 162 (4th Cir. 1973)) (internal quotations omitted).

[82] *Native Ecosystems Council v. U.S. Forest Serv.*, 428 F.3d 1233, 1240 (9th Cir. 2005).

[83] *Id*.

[84] EA at 2-43.

states that Tennessee will restore the topographic conditions after construction. The EA evaluates stream and wetland crossings and the efficacy of Tennessee's ECPs. These plans contain best management practices that reduce impacts on streams and wetlands during construction and promote their restoration after construction. Based on the analysis in the EA, which includes and references best management practices, mitigation, and the required restoration measures Tennessee has adopted, we continue to affirm that the project will not have a significant impact on streams or wetlands.

140. The EA includes a reference to and provides some measures that are included in Tennessee's Invasive Species Management Plan. As stated in Tennessee's ECP, it has developed specific procedures in coordination with the appropriate agency to prevent the introduction or spread of noxious weeds and soil pests resulting from construction and restoration activities. This Invasive Species Management Plan is in compliance with the Commission's requirement and provides specific details by state as to what species need to be monitored for and how this monitoring will occur. Tennessee will monitor invasive species within their certificated and approved right-of-way, but will not have access or the right to monitor for invasive species outside of their certificated right-of-way.

141. Although the Sierra Club and others object to the project and Commission staff preparation of an EA, numerous state and federal agencies participated in staff's preparation of the EA. Both the FWS and the Corps acted as cooperating agencies in preparing the EA. Other state and federal agencies participated in the EA process by submitting comments and recommending mitigation. In many cases, the EA recommends, and we adopt here, mitigation measures put forth by other agencies. As for restoration, Tennessee is required to restore the areas affected by project construction to the greatest extent practicable. We retain compliance management oversight of the pipeline until such time as construction and restoration is complete and will require Tennessee to do what is necessary to restore the affected lands. Although some disagreement exists as to the effects of the project, we do not find that a substantial dispute exists as to the size, nature, or effect of the project.

142. Sierra Club also argues that the Commission failed to properly evaluate the "degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks," the fifth intensity factor.[85] Sierra Club alleges that the EA failed to gather and assess information regarding the geology of the projects area (incomplete field studies on landslides, karst formations, and the potential for blasting),

[85] 40 C.F.R. § 1508.27(b)(5) (2011).

the effect of the project on revegetation, potential for harm to water resources, affects on threatened and endangered species (incomplete surveys for the bog turtle, dwarf wedgemussel, small whorled pogonia, and bald eagle), and the effect of the project on cultural resources (due to incomplete survey results). Sierra Club argues that NEPA does not permit agencies to "act first and study later."[86] Therefore, the Sierra Club argues the Commission must collect and assess this missing information in an EIS.

143. We disagree. The EA discloses that the majority of the project is located in an area considered to be moderately to highly susceptible to landslides. If an area susceptible to landslides is identified, Tennessee will implement specific measures to minimize the potential for landslides and erosion, like installing water bars diagonally across the right-of-way on steep slopes, installing trench breakers within the pipeline trench, inspecting erosion control devices on a daily basis, and reestablishing vegetative cover as soon as possible following final grading.[87] During construction, field surveys will be conducted to assess the necessary mitigation measures to employ.

144. The EA discusses karst and discloses that there could be areas prone to sinkhole development in the proximity to Loop 323. If karst features are identified during construction, Tennessee will implement measures to stabilize the trench and minimize impacts associated with surface water runoff, erosion, and the discharge of hydrostatic test water. Tennessee will restore the project area to pre-construction contours and elevations to maintain the existing drainage at the site and to prevent diversion of stormwater into areas prone to sinkhole development. Tennessee will monitor the area identified by the New Jersey Geologic Society on an annual basis following construction to identify any evidence of sinkhole development and implement mitigation measures as needed.[88] We also note that for a majority of its length the new pipeline will be located within 25 feet of the existing pipeline, which has been in service for well over 50 years and has not been adversely affected by geologic hazards.

145. The EA discloses that approximately 32.7 miles (82 percent) of the proposed pipeline loops would cross areas of shallow bedrock that may require blasting. It also

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[86] Sierra Club Comments at 11 citing *Nat'l Parks & Conservation Ass'n v. Babbit*, 241 F.3d 722, 734 (9th Cir. 2001) (*NPCA*).

[87] EA at 2-2.

[88] *Id*.

identifies Tennessee's *Blasting Plan* prepared to minimize the effects of blasting and ensure the safety of its existing pipeline during blasting operations. All blasting techniques would comply with federal, state, and local regulations governing the safe storage, handling, firing, and disposal of explosive materials. Based on the above information, we reiterate that project impacts on geological resources and impacts from geological resources on the project would be minimal.

146. As noted above, Tennessee's ECPs are designed to minimize impacts associated with the construction of the project and promote the restoration of the right-of-way. In forested areas, Tennessee will clear the right-of-way and will install erosion control measures to minimize erosion and sedimentation impacts. Following construction, Tennessee will reseed all previously vegetated workspace areas and monitor disturbed areas for a minimum of two growing seasons. After construction on open land, Tennessee will reseed and restore the right-of-way and the EA states that vegetation impacts on this type of land are typically temporary to short-term. As for agricultural land, Tennessee will test the topsoil and subsoil for compaction at regular intervals and strictly control traffic on agricultural land to minimize compaction and rutting. Tennessee will segregate topsoil, as stipulated in landowner agreements, and store it separately from subsoil. Tennessee will also monitor the crops during the first and second growing seasons after seeding to determine if additional restoration is necessary.[89] Although much of the right-of-way is underlain by stony, rocky, or droughty soils and restoration may be difficult,[90] Tennessee's mitigation and restoration measures will help to ensure that the right-of-way is restored as close as practicably possible to its original condition.

147. The EA also evaluated stream and wetland crossings and the efficacy of Tennessee's ECPs. These plans contain best management practices that reduce impacts on streams and wetlands during construction and promote their restoration after construction. Based on the analysis in the EA, which includes and references best management practices, mitigation, and the required restoration measures Tennessee has adopted, we affirm that the project will not have a significant impact on streams or wetlands.[91]

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[89] EA at 2-37.

[90] EA at 2-6.

[91] EA at 2-22.

148. As noted in the EA, Tennessee will develop a Comprehensive Mitigation Plan for the construction and operation of the project through the Highlands Region. The New Jersey Highlands Council issued a Highlands Act Consistency Determination on February 16, 2012 and will have to approve any mitigation, the results of which will not be known until after the New Jersey Highlands Council acts, but Tennessee will be required to carry out the identified mitigation.

149. Sierra Club argues possible effects are uncertain where, as here, an EA reveals significant gaps in data collection and, thus, a finding of no significant impact cannot be supported "where uncertainty may be resolved by further collection of data, or where the collection of such data may prevent speculation of potential effects."[92] However, Sierra Club omits the beginning of the cited language in which the Ninth Circuit explains that an agency must generally prepare an EIS if the effects of the proposed action are "highly uncertain."[93] As the Ninth Circuit explained, the use of the word "highly" to modify "uncertain" means that information merely favorable to Sierra Club's position does not necessarily raise a substantial question about the significance of the project's effects.[94] Based on the evidence in the EA and above discussion, we believe that the EA appropriately assessed the impacts of the project on the areas identified by Sierra Club and reasonably concluded that the risks were neither highly uncertain, unique, nor unknown.

150. Sierra Club also argues that the Commission should have prepared an EIS because the project is likely to establish precedent for future actions with significant effects, the sixth intensity factor.[95] Sierra Club argues that the inquiry here is whether "approval of a single action will establish a precedent for other actions which may cumulatively have a negative impact on the environment."[96] Sierra Club argues there is a serious risk that the Commission will feel bound, when reviewing other certificate applications in the

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[92] *NPCA*, 241 F.3d at 732-33.

[93] *Id.* at 731-732.

[94] *Native Ecosystems Council v. U.S. Forest Serv*., 428 F.3d 1233, 1240 (9th Cir. 2005).

[95] 40 C.F.R. § 1508.27(b)(6) (2011).

[96] *Anderson v. Evans*, 371 F.3d 475, 493 (9th Cir. 2004).

Marcellus Shale region, like the New York-New Jersey Expansion Project, Docket No. CP11-56-000, to the conclusions presented in the EA for the Northeast Upgrade Project. Therefore, Sierra Club argues, the Commission should conduct a full EIS because the precedential value of the project is substantial and the issuance of a finding of no significant impacts could open the floodgates to detrimental impacts on highly valued natural resources.

151. As explained above, when deciding whether to prepare an EIS or an EA the Commission's NEPA regulations explain that an EIS is only necessary for "[m]ajor pipeline construction projects…",[97] a category into which the Northeast Upgrade Project does not fit. Sierra Club's argument that Commission staff's EA for the project would establish a precedent is without merit because the EA is a non-binding document and creates no precedent to which the Commission is bound.[98] Each proposed project is unique and has different effects on different resources. In determining whether to prepare an EIS or an EA, Commission staff relies upon the Commission's regulations and makes an individual determination for each new proposal. Just because Commission staff has decided one action requires an EA, does not mean that a seemingly similar action will not require an EIS. Specifically, it is important to point out that the Commission prepared an EIS for the New York-New Jersey Expansion Project evincing the independence of our review and lack of precedential value in our decision whether to prepare an EA for each individual project.

152. Sierra Club argues that the Commission must consider the degree to which our action "may adversely affect an endangered or threatened species or its habitat that has been determined to be critical under the Endangered Species Act of 1973,"[99] the ninth intensity factor.[100] Sierra Club argues that the Supreme Court has held that the loss of any endangered species has been determined by Congress to be environmentally

[97] 18 C.F.R. § 380.6(a)(3) (2011).

[98] *See e.g. Town of Cave Creek v. FAA*, 325 F.3d 320, 332 (D.C. Cir. 2003) (finding that the Federal Aviation Administration reasonably concluded that an EIS was unnecessary and preparing an EA for the agency review of high-altitude arrival and departure procedures would not be binding precedent).

[99] 16 U.S.C. §§ 1531-1544 (2006).

[100] 40 C.F.R. § 1508.27(b)(9) (2011).

significant.[101] In addition, Sierra Club argues that incomplete survey information cannot be relied upon to support a finding of no significant impact and mandates the further collection of data and an EIS.[102] Sierra Club states that although mitigation plans have been used in the past to avoid preparing an EIS, courts have a high standard for what constitutes a sufficient mitigation plan and have held that plans need to be thoroughly developed to be valid.[103] Sierra Club argues that the EA cites to incomplete surveys for the Indiana bat (a federally-endangered species), the bog turtle (a federally-threatened species), and the dwarf wedgemussel (a federally-endangered species).

153. Specifically, Sierra Club argues that Indiana bat surveys around portions of Loop 321 and all of Loop 323, where bats are likely to be present, were never conducted and that the EA fails to discuss mitigation plans in depth. Further, that although Tennessee has agreed to a seasonal restriction of vegetation clearing, it has not committed to the additional aspects of FWS recommended measures.

154. As explained above, Tennessee has now completed the necessary Indiana bat surveys in Pennsylvania and New Jersey. According to the New Jersey FWS, to avoid any effects of the project on the Indiana bat in New Jersey, Tennessee must implement a seasonal tree-clearing restriction for the eastern 2.5 miles of Loop 323. Pennsylvania FWS recommends mitigation and states that with the implementation of the mitigation, the effects of the project on Indiana bats will be insignificant or discountable. Environmental Condition Nos. 13 and 14 of this order require a tree-clearing restriction on Loops 321 and 323 to protect the Indiana bat, and other bat species, and requires Tennessee to file a plan that addresses Indiana bat habitat loss with the Pennsylvania FWS and the Secretary before starting construction over those loops.

155. As for the bog turtle, Sierra Club states that bog turtle survey methodology is not included in the EA. Sierra Club states that Commission staff's recommendation that Tennessee not begin construction until (1) certain bog turtle surveys are completed, (2) staff completes ESA section 7 consultation, and (3) Tennessee receives written notification from the Director of OEP that construction may begin, does not ensure these measures will be implemented. Sierra Club argues that framing these conditions as

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[101] *Tennessee Valley Auth. v. Hill*, 437 U.S. 153, 188 (1978).

[102] *NPCA*, 241 F.3d at 734.

[103] *NPCA*, 241 F.3d at 734.

"recommendations" here and throughout the EA casts doubt on whether measures to mitigate harms to the species in the project area will ever be undertaken.

156. As explained above, Tennessee filed the outstanding bog turtle survey with the Commission in January 2012, and the New Jersey FWS concurred that the survey did not document any suitable bog turtle habitat between approximate MPs 7.6 and 9.3 of Loop 323 in New Jersey. Sierra Club seems to misunderstand the role of the EA within the Commission. Commission staff prepares the EA to provide recommendations to the Commission and aid the Commission in its decision-making. The EA is not a final order approved by the Commission. Instead, we take the recommendations made by staff under consideration when we issue our final order. Generally, we adopt many of the EA's recommendations as final environmental conditions to our orders. In this case, as mentioned above, we adopt Commission staff's environmental recommendation concerning the bog turtle and modify it as Environmental Condition No. 13 to this order.

157. Sierra Club points out that the EA concludes that no additional surveys are needed for the dwarf wedgemussel "so long as the crossing of the Delaware River can be completed using the HDD crossing method."[104] Sierra Club also points out that Tennessee has not yet completed surveys for a 2.9-mile segment of Loop 323 and argues that the EA prematurely concludes that the project is not likely to adversely affect the dwarf wedgemussel.[105] Sierra Club argues that reliance on HDD to justify a lack of additional surveying is premature because Tennessee has not developed a contingency crossing method for the Delaware River HDD; it adds that although the EA mentions a frac-out as a possibility, it does not address any mitigation measures to address and minimize the potential for habitat destruction. Therefore, Sierra Club argues, the EA does not sufficiently consider the potential effect of the project on endangered and threatened species.

158. As explained above, Tennessee filed the necessary reports on the effects of the project on the dwarf wedgemussel and the Pennsylvania and New Jersey FWS offices concurred that the project is not likely to adversely affect the species, thus concluding the Commission's consultation with FWS regarding the dwarf wedgemussel.

[104] EA at 2-48.

[105] EA at 2-51.

159. The EA does not address the possibility of a frac-out, because such an occurance is unlikely under the circumstances. The proposed action that the EA considers is the HDD crossing of the Delaware River. Although, a frac-out may occur, it is not reasonably foreseeable. The EA generally describes the potential impacts of an HDD-drilling fluid release on fisheries and other aquatic organisms. The EA also notes that Tennessee filed site-specific plans for each HDD and a frac-out contingency plan that describes how Tennessee would monitor for and respond to an inadvertent release of drilling fluid on land or into water. The EA summarizes the process that Tennessee would implement to minimize the likelihood of a frac-out, monitor for frac-outs, and notify agencies in the event of a frac-out. Tennessee included the contingency plan in its application and details how a land release would be cleaned up. If a release would occur in water, Tennessee would consult with applicable agencies within 24 hours after detection of the frac-out and implement containment and cleanup measures to the satisfaction of governing agencies and any affected party. In the event that a successful crossing using by HDD is not achievable, Tennessee will notify the Commission and consult with the applicable state and federal agencies to obtain the necessary permits prior to initiating another crossing method.[106] The EA concludes, and we concur, that Tennessee's site-specific HDD plans and frac-out contingency plan will adequately reduce the potential for, and impact of, a drilling fluid release.[107]

160. Sierra Club argues that incomplete survey data mandates the preparation of an EIS. In this case, although some surveys were incomplete at the time of the EA, a substantial amount of the project area had already been surveyed. As explained above, no more than nine percent of the proposed facilities in New Jersey remain to be surveyed due to lack of landowner permission and a substantial amount of environmental information was obtained from federal, state, and local resources, including for those areas not accessible for survey. The EA discloses the lack of this data and recommends the Commission require Tennessee to perform the studies before construction could begin on the limited areas where additional study was necessary. Since the issuance of the EA, Tennessee has completed several of the studies necessary for ESA section 7 consultations, including surveys for Indiana bat and the bog turtle. All other necessary outstanding surveys are required by the environmental conditions attached to this order prior to construction of the affected pipeline sections. Therefore, Tennessee will not receive our approval to proceed until it completes the studies that confirm the project will

[106] EA at 2-17.

[107] EA at 2-18-19.

be consistent with our and other agencies' authorizations. As the Commission has found, "if the studies do not support such a finding, the project cannot proceed until it is modified or measures are put in place to ensure the project will not cause any unacceptable adverse environmental impacts."[108]

161. Finally, Sierra Club argues that the project will threaten a violation of federal, state, or local law or requirements imposed for the protection of the environment, the tenth intensity factor.[109] Specifically, Sierra Club alleges that the project will violate the Endangered Species Act; the Migratory Bird Treaty Act and the Bald and Golden Eagles Protection Act; the New Jersey Endangered and Nongame Species Conservation Act, the New Jersey Natural Heritage Program, and the Division of Land Use Regulation; the New York Endangered Species Act; Pennsylvania Endangered Species laws; the Clean Water Act; the Federal Safe Water Drinking Act; and the Pennsylvania Clean Streams Act.

162. With respect to the ESA, Sierra Club points out that FWS requested the Commission consider the effects on the federally-petitioned Northern long-eared bat, but argues that the analysis in the EA is so cursory that it ignores the threat of future violation of federal law. In addition, Sierra Club argues the EA ignores the possibility of effects on the American eel in the case of frac-out. Although the Northern long-eared bat is currently not a federally-protected species, the EA addresses impacts to that bat as well as the Indiana bat and concludes that the requirement that Tennessee clear trees only between September 1 and March 31 in Pennsylvania and August 1 and March 14 in New Jersey will be protective of both species of bat within the project area. Impacts from a potential frac-out are addressed above.

163. Sierra Club also argues that there is a risk of violation of the Migratory Bird Treaty Act and the Bald and Golden Eagles Protection Act based on the two bald eagles' nests that were identified.[110] As discussed above, based on additional surveying, one of the identified bald eagles' nests is outside the buffer zone recommended in the National Bald Eagle Management Guidelines and the other nest is currently inactive. Tennessee

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[108] *AES Sparrows Point LNG, LLC,* 129 FERC ¶ 61,245 (2009) (citing *Cal. Public Utilities Comm'n*, 900 F.2d 269, 282 (D.C. Cir. 1990)).

[109] 40 C.F.R. § 1508.27(b)(10) (2011).

[110] EA at 2-53.

has explicitly agreed to the tree-clearing limitations, and we believe these limitations will protect migratory bird habitat effectively.

164. Sierra Club also alleges that the project implicates 46 threatened, endangered, and special concern species in New Jersey protected under the New Jersey Endangered and Nongame Species Conservation Act, the New Jersey Natural Heritage Program, and the Division of Land Use Regulation. Accordingly, Sierra Club asserts the EA fails to adequately address the project's affect on protected species. For example, Sierra Club argues the EA fails to evaluate route deviations or mitigation measures that are designed to protect the timber rattlesnake at the Mahwah meter station site. In addition, Sierra Club states that the results of surveys on red-shouldered hawks and barred owls are still pending. Sierra Club states that regarding mussel species of concern, Tennessee will use the HDD crossing method to avoid impacts.

165. We note that at the Mahwah Meter Station there exists habitat for the timber rattlesnake, a New Jersey state protected species. Tennessee has continued to provide updates to its surveys for protected species and will provide additional survey information as it is completed in the spring of 2012. Both Tennessee and Algonquin propose work at the site and have provided updates on their respective work proposals at the meter station because the work could have a cumulative impact on protected species. Tennessee and Algonquin note that while both companies are completing work within the same area, Tennessee would be responsible for developing the footprint of the site. The EA discloses numerous measures Tennessee would take to avoid or minimize impact on any protected species within New Jersey. The EA notes that the only area of direct habitat impact for the timber rattlesnake is Mahwah Meter Station and that no northern copperheads were identified within the project area. We note that Tennessee is required to submit all outstanding surveys and any mitigation that is developed with the state of New Jersey for protected state species. Concerning mussel species, we reiterate that Tennessee will employ its site specific HDD plans which include a frac-out contingency plan.

166. In New York, Sierra Club states that rare species are protected under the New York Endangered Species Act.[111] Sierra Club points out that a bald eagle was found in the vicinity of the Port Jervis, New York pipe yard.[112] Sierra Club argues that the EA

[111] N.Y. Envtl. Conserv. Law § 11-0535 (Consol. 2012).

[112] EA at 2-55.

offers no analysis of which species may be implicated by the law, instead indicating that Tennessee would transplant individual plants to locations outside the construction workspace or right-of-way.[113] Sierra Club argues that according to the Fifth Circuit, this "mere perfunctory or conclusory language will not be deemed to constitute an adequate record and cannot serve to support the agency's decision not to prepare an EIS."[114]

167. The Port Jervis pipe yard is the only project element located in New York State. Based on aerial photographs and descriptions from Tennessee, the Port Jervis Yard consists of a cleared lot with one or two commercial buildings on the property. The yard is situated in a mixed commercial and residential area, with buildings or roads on three sides, and a small wooded area on the fourth side. The EA discusses the bald eagle in the vicinity of the Port Jervis pipe yard. Tennessee contacted the New York FWS and the New York Natural Heritage Program. Based on these discussions Tennessee committed to working with the New York State Department of Environmental Conservation to determine whether adverse impacts on bald eagle could occur and to limit construction activities and other disturbances within buffers established under the National Bald Eagle Management Guidelines.[115] Therefore, no impacts on the bald eagle are expected. It should also be noted that the New York State Department of Environmental Conservation stated that "historical records of the dragonfly and plants in the vicinity of the pipe yard do not require habitat surveys." [116] Nevertheless, Tennessee has committed to completing surveys and would attempt to relocate workspaces to avoid impacts on state-protected plants. If impacts are unavoidable, Tennessee would mitigate them by preserving seed banks and rootstocks or transplanting individual plants.[117]

168. Sierra Club states that Pennsylvania law also protects and monitors the taking of endangered species.[118] Sierra Club argues that the EA conducts the same superficial

[113] EA at 2-56.

[114] Citing *Citizen Advocates for Responsible Expansion, Inc. (I-Care) v. Dole*, 770 F.2d 423, 434 (5th Cir. 1985).

[115] EA at 2-53.

[116] EA at 2-56.

[117] EA at 2-56.

[118] 30 Pa. Cons. Stat. § 2305 (2012).

review that it does for all endangered species. Specifically, Sierra Club argues that although timber rattlesnakes were documented along portions for Loop 321, the EA fails to supply information on snakes that were not gestating or what the habitat implications would be.

169. Pennsylvania currently lists the timber rattlesnake as a candidate species, rather than threatened or endangered. The EA notes that a report of denning surveys was pending, but that Tennessee would: avoid direct impacts on any dens that may be identified by reducing the workspace or implementing a route deviation, employ snake monitors to remove any snakes from the right-of-way on a daily basis, and restore gestation habitat after construction.[119] At the request of the Pennsylvania Fish and Boat Commission, Tennessee conducted the final denning survey on October 26, 2011, as staff was preparing the EA. The report documented three dens near the Loop 321 construction right-of-way and none near Loop 323. Although none of the dens near Loop 321 are located within the construction right-of-way, the report documented potential denning, gestating, and basking habitat. Tennessee also committed to train its construction workers to recognize species of snakes and contact the snake monitor and add snake fencing and signage along the right-of-way near the dens. In addition, Environmental Condition No. 15 to this order, originally environmental recommendation 16 in the EA, requires Tennessee to file the results of any outstanding surveys for Pennsylvania and New Jersey state-listed species and identify any additional mitigation measures developed in consultation with the applicable state agencies prior to construction. Based on the mitigation measures Tennessee has committed to, and its consultation with the Pennsylvania Fish and Boat Commission, we do not believe the project will result in a violation of Pennsylvania's endangered species law.

170. As for the CWA, Sierra Club argues that the EA contains little analysis of proposed dredge and fill activities and relies on the assumption that Tennessee will meet permit requirements. In addition, Sierra Club argues that the EA fails to explain the impact of the project on wetlands and sensitive waterbodies, including the Monksville Reservoir and Valentine Brook.[120]

171. It is not unreasonable for the EA to assume that Tennessee will comply with permit requirements because other agencies will require Tennessee to do so. Multiple

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[119] EA at 2-54.

[120] EA at 2-13.

agencies, including New Jersey DEP, Pennsylvania DEP, the Corps, and others must issue separate authorizations for many of the planned construction activities and environmental impacts. As pointed out throughout the EA and in this order, many of the resource areas addressed in the EA are protected by different federal and state laws to which Tennessee is obligated to adhere. By assuming that Tennessee will adhere to these different requirements, the Commission is not abdicating its responsibility; rather we are looking at the impacts of the project within that context. Sierra Club offers no evidence why it is inappropriate to assume Tennessee will adhere to its permit requirements.[121]

172. Tennessee must cross wetlands and waterbodies in accordance with Tennessee's ECPs and federal and state permit requirements, minimizing impacts. The EA also addresses impacts to the Valentine Brook, stating that Loop 323 would cross one minor, unnamed tributary to the brook that is classified as intermittent and located approximately 1.7 miles upstream of the Milford Township Water Authority water withdrawal. The project will also cross the Monksville Reservoir, for which Tennessee will use the HDD method which would avoid direct impacts from trenching within this waterbody. The EA discusses at length the impacts that are anticipated for waterbody and wetland crossings associated with the project.

173. Sierra Club also argues the project may violate the Federal Safe Drinking Water Act.[122] Sierra Club points out that when discussing impacts to the New Jersey Highlands Planning and Preservation areas, the EA addresses Tennessee's mitigation plans by stating Tennessee "would" develop comprehensive mitigation plan that "would" be submitted as part of a Highland Applicability Determination.[123] Sierra Club argues that the lack of developed mitigation plan and reliance on hypothetical future scenario interferes with the ability to assess the impact of drinking water. In addition, Sierra Club

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[121] *See, e.g., Sierra Club v. Hassell*, 636 F.2d 1095, 1098 (5th Cir. 1981) (Finding that the Federal Highway Administration acted reasonably in not preparing an EIS for the reconstruction of a hurricane-damaged bridge linking an island to the mainland. The court found laws which restricted development and use on the island, including construction permit requirements, regulation of fish habitat, and prohibition on development on sand dunes, were sufficient to protect the island, stating "[a]ppellants have failed to establish why this regulatory scheme is insufficient to protect against adverse environmental effects resulting from increased development or otherwise.").

[122] 42 U.S.C §§ 300f-300j-26 (2006).

[123] *See* EA at 2-11.

argues that the EA fails to address the impacts of potential hazardous waste contamination, hydrostatic testing, and the effect of a possible frac-out.

174. As noted above, Tennessee has received a Highlands Act Consistency Determination in order to construct within the Highlands area. In addition, Tennessee will be required to develop a mitigation plan as part of its approval process, separate from Commission approval.

175. Impacts to drinking water related to construction and operation of the project are expected to be minimal, as it relates to both the Monksville Reservoir and Valentine Brook. The Monksville Reservoir HDD would avoid direct impacts to the waterbody and Valentine Brook would not be directly crossed (an intermittent tributary would be). The EA concludes that crossing waterbodies in accordance with the construction and restoration methods proposed within Tennessee's ECP and outlined in the EA, and any other federal or state requirements, will ensure that any potential impacts on waterbodies are minimal.

176. Sierra Club argues that the project threatens a violation of the Pennsylvania Clean Streams Act[124] because, it asserts, Tennessee has a history of violations of the Clean Streams Act and these violations imply a near certainty that the project will violate clean water laws, and, therefore, requires the preparation of an EIS. Tennessee's compliance with the Pennsylvania Clean Streams Act is the responsibility of the Pennsylvania DEP to which Tennessee will answer if it does not comply. Tennessee's alleged past history of non-compliance of this law has no bearing in this proceeding and, consequently, does not raise the potential of a violation of state law.

177. As discussed above, the EA thoroughly addresses the potential impact of the project on all the federal, state, and local laws cited by Sierra Club. We find that the project, as authorized, will not likely result in a violation of any of these laws. Accordingly, we reject Sierra Club's assertion that an EIS is required.

Cumulative Impact of Marcellus Shale Region

178. Sierra Club argues that the project will have cumulatively significant impacts on the environment, the seventh intensity factor, and that the Commission, therefore, should

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[124] 35 Pa. Cons. Stat. § 691.401 (2012).

have prepared an EIS rather than an EA.[125] Sierra Club argues that the EA's treatment of the cumulative impacts falls short of what NEPA requires by failing to consider the full scope of impacts of the project. Sierra Club also argues that the cumulative impacts analysis is devoid of detailed, reasoned conclusions and quantified information. Further, Sierra Club argues that instead of performing an independent assessment of cumulative impacts, the EA impermissibly relies on Tennessee's assumed compliance with other agencies' permitting requirements. Therefore, Sierra Club argues, the cumulative impacts analysis is insufficient and the EA cannot support the finding of no significant impact.

179. Under CEQ's NEPA regulations, agencies must consider the three types of impacts: direct, indirect, and cumulative.[126] The regulations state that "direct effects" of a proposed action are "caused by the action and occur at the same time and place."[127] "Indirect effects" are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[128] "Cumulative impact" is defined as the "impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions."[129]

180. The EA includes an analysis of the cumulative impacts of related past, present, and reasonably foreseeable activities in the project area.[130] As noted above, the EA describes the impacts of existing and pending jurisdictional natural gas pipelines, natural gas facilities associated with the project but that are not under the Commission's jurisdiction, unrelated projects, and development of Marcellus Shale.

181. The EA considers the general development of the Marcellus Shale region in the vicinity of the project. For example, the EA identifies that 1,454 Marcellus Shale wells

[125] 40 C.F.R. § 1508.27(b)(7) (2011).

[126] 40 C.F.R. § 1508.25 (2011).

[127] 40 C.F.R. § 1508.8(a) (2011).

[128] 40 C.F.R. § 1508.8(b) (2011).

[129] 40 C.F.R. § 1508.7 (2011).

[130] EA at 2-121-134.

were drilled in Pennsylvania in 2010 and approximately 1,740 wells would be drilled in 2011 based on January through July data, according to the Pennsylvania DEP. The project facilities closest to active Marcellus Shale drilling activities are Loops 317 and 319 in Bradford County and the modifications at existing Compressor Station 321 in Susquehanna County. The EA concludes that it is likely that drilling would continue through the period of construction of the project, but that the exact extent of the drilling is unknown.[131]

182. However, notwithstanding the EA's description of Marcellus Shale development in the project area, and contrary to Sierra Club's assertion, we are not required to include a fuller discussion in the cumulative effects analysis. Development of the Marcellus Shale region is neither causally-related to the project, nor reasonably foreseeable and, as the EA concludes, a more specific analysis is outside the scope of the cumulative impact analysis in the EA because the exact location, scale, and timing of future Marcellus Shale facilities are unknown.[132]

183. When looking at project impacts, the Supreme Court held in *U.S. Dep't of Transp. v. Public Citizen* (*Public Citizen*),[133] that NEPA requires a "reasonably close causal relationship" between the environmental effect and the alleged cause.[134] The Court further explained that this is similar to "the familiar doctrine of proximate cause from tort law."[135] In *Public Citizen*, the Court upheld the Federal Motor Carrier Safety Administration's (FMCSA) decision not to consider the potential environmental impacts of an increased number of Mexican trucks on U.S. roads in its EA assessing new safety regulations governing Mexican motor carriers. The Court based its decision upon the agency's finding that the relationship between the increased number of trucks and the safety regulations was not a reasonably close causal relationship.[136] Similarly, there is

[131] EA at 2-125.

[132] EA at 2-125.

[133] 541 U.S. 752, 767 (2004).

[134] *Public Citizen,* 541 U.S. at 767 (citing *Metropolitan Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, 774 (1983)).

[135] *Id*.

[136] *Id*.

not a reasonably close causal relationship between the development of Marcellus Shale in Pennsylvania and our approval of the Northeast Upgrade Project.

184. Sierra Club argues that the Commission cannot rely upon *Public Citizen*, where the Court found that the critical feature of the case was that FMCSA had "no ability" to prevent Mexican motor carriers from operating within the United States.[137] In contrast, Sierra Club argues that the Commission's exclusive jurisdiction over the interstate pipeline system grants the Commission substantial authority to affect development of Marcellus Shale upstream activities.

185. We disagree. The EA notes that natural gas development in the Marcellus Shale region in Pennsylvania began in 2005 and has rapidly expanded. The EA adds that Pennsylvania is forecast to produce approximately 7.5 billion cubic feet (Bcf) of natural gas per day by 2015 and 13.4 Bcf per day by 2020.[138] In contrast, the Northeast Upgrade Project will only transport 636,000 Dth per day – a very small percentage of the projected growth. Natural gas development in the Marcellus Shale region will continue with or without the project and will find other avenues to market. Furthermore, the Commonwealth of Pennsylvania regulates new permits, wells, gathering lines, and other facilities and determines whether gas will be developed in Pennsylvania, whereas, the Commission's NGA section 7 jurisdiction is limited only to the construction, operation, and maintenance of the project and natural gas in interstate commerce. The Commission, therefore, has no statutory authority to prevent the types of impacts involved in the development of the Marcellus Shale region. Even if we decided not to issue a certificate for the project, there is no evidence to show that would prevent impacts from the construction and operation of well pads, access roads, gathering lines, and compressor stations that Sierra Club is concerned about. Certainly, there is a relationship between the project and Marcellus Shale development (Tennessee states in its application that the project will provide shippers access to natural gas supplies being produced in the Marcellus Shale supply area); however, this link is not the "close causal relationship" the Supreme Court described in *Public Citizen*.

186. Similarly, the Commission cannot be said to be the "gatekeeper" for approval of development of Marcellus Shale upstream activities as Sierra Club argues. Sierra Club

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[137] *Id*. at 766.

[138] EA at 2-125.

relies on *Humane Society of U.S. v. Johanns* (*Humane Society*),[139] to argue that the Commission is able to promote, prevent, or otherwise affect upstream development in the Marcellus Shale region noting that "when an agency serves effectively as a gatekeeper for private action, that agency can no longer be said to have no ability to prevent a certain effect."[140] However, *Humane Society* is inapplicable here. In that case, the district court found that the U.S. Department of Agriculture violated NEPA by failing to prepare either an EIS or an EA for the promulgation of a rule governing inspectors of horse-slaughter facilities, and found that the environmental effects of horse slaughter should have been assessed under NEPA prior to the promulgation of the horse-slaughter rule.[141] In this case, Commission staff prepared a detailed and in-depth EA in compliance with NEPA, which, as described above, assesses all the impacts of the project and, after review, recommends a finding of no significant impact.

187. Consideration of the project's cumulative impacts does not change the analysis of impacts under *Public Citizen*, where the Court also held that the FMCSA appropriately examined the cumulative impacts of its safety rule.[142] As we recently explained in *Central New York Oil and Gas Co*. (*Central New York*), the Ninth Circuit analogized cumulative impacts to links in a single chain:

> Environmental impacts are in some respects like ripples following the casting of a stone in a pool. The simile is beguiling but useless as a standard. So employed it suggests that the entire pool must be considered each time a substance heavier than a hair lands upon its surface. This is not a practical guide. A better image is that of scattered bits of broken chain, some segments of which contain numerous links, while others have only one or two. Each segment stands alone, but each link within a segment does not.[143]

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[139] 520 F.Supp 2d 8, 25 (D.D.C. 2007).

[140] *Id*. (internal quotations omitted).

[141] *Humane Society of U.S. v. Johanns*, 520 F.Supp 2d at 27.

[142] *Public Citizen*, 541 U.S. at 769-770.

[143] *Central New York.*, 137 FERC ¶ 61,121, at P 88 (2011), *order on reh'g, clarification and stay*, 138 FERC ¶ 61,104 (2012) (quoting *Sylvester v. U.S. Army Corps of Engineers*, 884 F.2d 394, 400 (9th Cir. 1989)).

188. The EA considers past, present, and future Marcellus Shale activities and logically concludes that the project and impacts from Marcellus Shale production activities are not links in the same chain. Specifically, the EA states the purpose of the project is to expand the natural gas delivery capacity to the northeast U.S., meet market demand for new transportation services, and help alleviate the already constrained pipeline capacity in the region. All four pipeline systems in the region are currently fully subscribed during the peak heating season and, even when underground storage in northwestern Pennsylvania and New York is used to meet peak day requirements, pipeline capacity must still be used to reach market areas. In addition, according to Tennessee, natural gas deliveries into its system in the region have increased from about 25 million cubic feet per day to 1 Bcf per day within the last 2 years. Development of natural gas resources in the Marcellus Shale region will continue even without the project and unregulated developers will continue to build new wells and gathering systems to serve the shale gas. The Northeast Upgrade Project is designed as a high-pressure, high-capacity pipeline to transport natural gas in interstate commerce supporting Tennessee's entire system, not as a gathering system for low-pressure shale gas produced in the region.

189. In addition, future Marcellus Shale drilling activities and the potential associated environmental impacts are not reasonably foreseeable. As explained in the EA, the exact location, scale, and timing of future actions are unknown.[144] Sierra Club disagrees, noting that publicly available maps prepared by Bradford County and the Pennsylvania DEP provide quantitative and geographic data on the location of permitted gas wells in Pennsylvania and show the locations of existing and proposed wells in the counties crossed by the project. Therefore, Sierra Club argues, the Commission can ascertain with relative certainty the locations of wells the project will facilitate by looking at maps that identify Chesapeake-owned permits and active wells along a proposed gathering pipeline that would connect with the Tennessee's system.

190. However, the available maps do not provide the degree of specificity necessary for an in-depth review and meaningful analysis in the EA. Knowing the location of a permitted, yet unconstructed, well does not mean that other specific factors are known such as the specific location of gathering lines, access roads, and other associated infrastructure and related facilities, information that is not provided in the maps cited by Sierra Club. In addition, although Pennsylvania has issued thousands of well permits, and continues to do so, it is unknown when, or even if, these wells will be drilled. The EA concludes, and we agree, that the factors necessary for meaningful analysis of when,

[144] EA at 2-125.

where, and how Marcellus Shale development will occur are ultimately unknowable and not reasonably foreseeable at this time. The EA provides general information on the number and general location of wells permitted in order to provide public disclosure of environmental issues. However, this information does not inform our finding of no significant impact.

191. Sierra Club argues that this situation is analogous to *Thomas v. Peterson*,[145] where the court considered an EA prepared by the Forest Service for a timber road through a National Forest and held that the cumulative impacts of the road and any future timber sales had to be considered together. The court rejected the argument that "sales are too uncertain and too far in the future for their impacts to be analyzed along with the road" reasoning that "if sales are sufficiently certain to justify construction of the road, then they are sufficiently certain for their environmental impacts to be analyzed along with the road."[146] Similarly, Sierra Club argues, the Commission cannot claim that the effects of past, present, and reasonably foreseeable upstream Marcellus shale development do not have a "reasonably close causal relation" to the project, or that they are entirely unknown and, thus, outside the scope of analysis.

192. However, *Thomas v. Peterson* is inapplicable here. In that case, the court held that the Forest Service's plan to prepare separate EAs for the forest road approval and timber sales approvals was an impermissible segmentation of connected actions.[147] The court first found the approval of the new road and timber sales were "connected actions" under NEPA,[148] stating that "[w]here agency actions are sufficiently related so as to be 'connected' within the meaning of NEPA, the agency may not escape compliance with the regulations by proceeding with one action while characterizing the others as remote

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[145] 753 F.2d 754 (9th Cir. 1985).

[146] *Id.* at 760.

[147] *Id*. at 759.

[148] CEQ regulations state that "Connected actions, which means they are closely related and therefore should be discussed in the same impact statement. Actions are connected if they: (i) Automatically trigger other actions which may require environmental impact statements. (ii) Cannot or will not proceed unless other actions are taken previously or simultaneously. (iii) Are interdependent parts of a larger action and depend on the larger action for their justification." 40 C.F.R. § 1508.25 (2011).

or speculative."[149] Therefore the issue in *Thomas v. Peterson* was the Forest Service's attempt to segment several federal actions into small enough parts to avoid the preparation of an EIS. Our review and approval of the project, and impacts from the development of the Marcellus Shale region, are not connected actions within the meaning of NEPA. As we stated before, development of the Marcellus Shale region will proceed with or without the project and the Commission has no control over the siting and drilling of natural gas wells and related infrastructure in Pennsylvania.

193. More analogous to the instant case is *Sylvester v. U.S. Army Corps of Engineers* (*Sylvester*),[150] where the court addressed the scope of analysis that federal agencies must conduct in determining whether their actions, when combined with private actions, require an EIS under NEPA.[151] The court in *Sylvester* upheld the Corps decision to limit its NEPA review to impacts of the construction of a golf course for which the Corps issued a permit, rather than look at the impacts of the larger resort complex.[152] The court explicitly distinguished *Sylvester* from *Thomas v. Peterson* finding that the federal actions in *Thomas v. Peterson* were joined to each other as links in the same chain in a way that the golf course and resort were not.[153] The court explained that the golf course and the resort complex were separate segments of chain and, although the golf course and resort complex would each benefit from the other's presence, each project could exist without the other.[154] The Northeast Upgrade Project and development of the Marcellus Shale region are related in a similar way as the golf course and the resort in *Sylvester*: separate segments of chain each of which can exist without the other. Marcellus Shale development will continue with or without the project and there is no "reasonably close causal relationship" between the alleged impacts and the project.

194. Sierra Club and other commentors also argue that the EA fails to adequately address the cumulative impacts of related existing and reasonably foreseeable pipelines

[149] *Thomas v. Peterson*, 753 F.2d at 760.

[150] 884 F.2d 394 (9th Cir. 1989).

[151] *Id.* at 398.

[152] *Id*. at 401.

[153] *Id*. at 400.

[154] *Id*.

within the Commission's jurisdiction. Sierra Club points out that the EA identifies ten existing or proposed pipelines totaling approximately 240 miles of new or improved pipelines and argues that the EA does not say what the cumulative effects might be or provide a basis that mitigation will be sufficient. In particular, the Sierra Club argues that to the extent the Northeast Upgrade Project and the 300 Line Project are connected and similar actions, the impact of both should have been considered in the EA but that the EA fails to analyze the cumulative impact of the 300 Line Project.

195. We disagree. The EA addresses other jurisdictional pipelines, including the 300 Line Project, in its cumulative impacts analysis. The EA concludes that the impacts from most of the other jurisdictional pipelines in the region are too far away from the project (over 25 miles) to significantly contribute to cumulative impacts in the project area. In addition, EA concludes that the majority of the recently-approved MARC 1 Hub Line Project would also be located a substantial distance from the project and most of the impact would be ameliorated by the time Tennessee begins construction of its project. As for the 300 Line Project, most of the construction impacts were temporary in nature and will be separated by time and distance from the impacts of the Northeast Upgrade Project. In addition, both projects either have been or would be required to implement construction practices and restoration measures that minimize overall environmental impacts and, thus, reduce potential cumulative effects of the projects to less than significant levels. For these reasons and considering that the Northeast Upgrade Project is primarily an expansion of an existing right-of-way, the EA properly concludes that only minor cumulative impacts will result when the impact of Tennessee's proposal are added to impacts from other projects in the area, including the 300 Line Project.

196. We also disagree with Sierra Club's assertion that the EA fails to adequately consider the cumulative effects to groundwater resources, vegetation and wildlife, land use and visual resources, and recreation. The EA explains that project construction could have a minor, temporary, and localized effect on groundwater resources, including increased turbidity, reduced water levels, contamination, and damage to nearby water wells. These impacts would be greatest during construction and would quickly diminish after construction, as Tennessee restores and revegetates the right-of-way. In addition, Tennessee will monitor nearby wells and will repair affected wells and compensate owners.[155] The EA also addresses the cumulative impacts on vegetation and wildlife explaining that other projects in the same general location and time frame could have a cumulative impact on local vegetation and wildlife, but concludes that the scale and short

[155] EA at 2-129-130.

time frame for construction of the project, other nearby jurisdictional projects, and a proposed electric generation plant would not contribute significantly to cumulative impacts on vegetation and wildlife.[156]

197. With respect to cumulative impacts on land use, visual resources, and recreation, the EA concludes that construction and operation of the project would not significantly impact these resource areas. The EA explains that effects on land use, visual resources, and recreation will be temporary in nature and minimized by the use of the existing right-of-way. In addition, the project will not cross the Delaware Water Gap NRA, avoiding impacts to this federal recreation area, and Tennessee will minimize impacts to the Appalachian National Scenic Trail through consultation with the NPS.[157] Tennessee has also developed site-specific plans for working in special interest areas and will obtain all necessary permits and approvals.

198. The purpose of the requirement that agencies consider the cumulative impacts of its actions "is to prevent agencies from dividing one project into multiple individual actions 'each of which individually has an insignificant environmental impact, but which collectively have a substantial impact.'"[158] Such is not the case here. The cumulative impacts analysis in the EA identifies recently completed, ongoing, and planned projects in the project area, including, to a limited extent, development of natural gas reserves in the Marcellus Shale. The EA concludes, and we agree, due to the implementation of specialized construction techniques, the relatively short timeframe in any one location, and carefully developed resource protection and mitigation plans, only small cumulative impacts are anticipated when the impacts of the Northeast Upgrade Project are added to identified, ongoing projects in the project area.[159]

199. Finally, Sierra Club argues that the EA impermissibly relies on compliance with other agencies' permitting requirements as a basis for a finding of no significant impact. Sierra Club argues that Commission staff abdicates its NEPA responsibility by deferring

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[156] EA at 2-131.

[157] EA at 2-132.

[158] *Natural Resources Defense Council, Inc. v. Hodel*, 865 F.2d 288, 297 (D.C. Cir. 1988) (quoting *Thomas v. Peterson*, 753 F.2d at 758).

[159] EA at 1-134.

to standards administered by other agencies without independently assessing the impacts. Sierra Club argues that the EA subverts the purpose of NEPA by repeatedly pointing to oil and gas well permitting standards as a reason for concluding that the project will have no significant cumulative impact when considered in the context of Marcellus Shale development. For example, Sierra Club points to the fact that the EA notes that non-jurisdictional facilities in Pennsylvania will be required to implement best management practices developed by the Pennsylvania DEP which the EA determines would avoid or minimize cumulative impacts. Sierra Club argues that the EA's reliance on other agencies' regulations does not supplant the requirement of a thorough EA analysis and does not suffice as a hard look under NEPA.[160]

200. As explained above, we are not required to look at the impacts of the development of Marcellus Shale in the EA because the project and such development do not have a reasonably close causal connection, nor are the impacts from Marcellus Shale development reasonably foreseeable. Nonetheless, staff looked at the general impacts of Marcellus Shale development to inform the public. The EA thoroughly analyzes each aspect of the project and its impacts, as detailed throughout this order. The EA does not defer our NEPA responsibilities to other agencies; rather it explains that based on Tennessee's compliance with other laws and mitigation required by the Commission and other agencies, the EA can recommend a finding of no significant impact. The Commission is not abdicating its responsibility under NEPA. The EA acknowledges the reality that Tennessee will be required to comply with other federal and state laws not administered by the Commission and implement additional mitigation measures required by other federal and state agencies. The EA also finds that based on the regulation of natural gas producers by Pennsylvania, the Susquehanna River Basin Commission, the Delaware River Basin Commission, and other federal agencies, cumulative impacts of the project will not be significant. The fact that we take these laws and measures into account in assessing the environmental impact of the project is not an abdication of our responsibility.

201. In conclusion, we have reviewed the information and analysis contained in the record, including the EA, regarding the potential environmental effect of the project. Based on our consideration of this information, we agree with the conclusions presented in the EA and find that if constructed and operated in accordance with Tennessee's

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[160] Citing *Limerick Ecology Action, Inc. v. U.S. Nuclear Regulatory Comm'n*, 869 F.2d 719, 729 (3d Cir. 1989); *Calvert Cliffs' Coordinating Comm. v. U.S. Atomic Energy Comm'n*, 449 F.2d 1109 (D.C. Cir. 1971).

application, as supplemented, and the conditions imposed herein, approval of this proposal would not constitute a major federal action significantly affecting the quality of the human environment.

202. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this certificate. The Commission encourages cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction, replacement, or operation of facilities approved by this Commission.[161]

IV. Conclusion

203. For all of the reasons discussed above, and with the conditions imposed herein, the Commission finds that Tennessee's proposal is required by the public convenience and necessity and we are issuing the requested certificate and abandonment authorizations.

204. The Commission on its own motion received and made a part of the record in this proceeding all evidence, including the application and exhibits thereto, submitted in support of the authorizations sought herein, and upon consideration of the record,

The Commission orders:

(A) A certificate of public convenience and necessity is issued authorizing Tennessee to construct and operate the facilities, as more fully described in the application and in this order.

(B) Tennessee is authorized to abandon the facilities, as more fully described in the application and this order.

(C) Tennessee shall complete the construction of the facilities and make them available for service within one year of the date of the order, pursuant to section 157.20(b) of the Commission's regulations.

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[161] *See, e.g.*, *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988); *National Fuel Gas Supply v. Public Service Comm'n*, 894 F.2d 571 (2d Cir. 1990); and *Iroquois Gas Transmission System, L.P.*, 52 FERC ¶ 61,091 (1990) and 59 FERC ¶ 61,094 (1992).

(D) The authorization in Ordering Paragraph (A) is conditioned on Tennessee's compliance with the provisions of all applicable Commission regulations and the NGA, including, but not limited to, sections 157.20 (a), (c), (e), and (f) of the Commission's regulations.

(E) The authorization in Ordering Paragraph (A) is conditioned upon Tennessee's compliance with the environmental mitigation measures set forth in the Appendix B to this order.

(F) Tennessee shall notify the Commission's environmental staff by telephone, electronic mail, and/or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Tennessee. Tennessee shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(G) Tennessee is directed to file actual tariff records to implement its proposed Northeast Upgrade Project rates not less than 30 but not more than 60 days prior to the proposed facilities being placed into service.

(H) Tennessee's incremental recourse rates for firm services and applicable general system rate under Rate Schedule IT for any interruptible service on the Northeast Upgrade Project are approved, as described above. This approval is subject to Tennessee filing, within 30 days of the date of this order, an analysis demonstrating what impact operation of the new compressor will have on the Electric Power Cost Recovery Adjustment for existing customers.

(I) Tennessee must file not less than 30 but not more than 60 days before the in service date of the proposed facilities an executed copy of each non-conforming agreement as a tariff record reflecting the non-conforming language and a tariff record identifying these agreements as non-conforming agreements, consistent with section 154.112 of the Commission's regulations.

(J) Tennessee must execute firm natural gas transportation contracts equal to the level of service and in accordance with the terms of service represented in its precedent agreements prior to commencing construction.

(K) The motion to intervene out of time is granted.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix A

Parties Filing Timely, Unopposed Interventions

Atmos Energy Corporation
Atmos Energy Marketing LLC
Calpine Energy Services, L.P.
Consolidated Edison of New York, Inc. and Orange and Rockland Utilities, Inc.
Constellation Energy Commodities Group, Inc.
Delaware Riverkeeper Network
EQT Energy, LLC
George C. Feighner
Ellen Hay and Milton Newman
Inergy Midstream, LLC
Louisville Gas & Electric Company
Millennium Pipeline Company, LLC
National Fuel Gas Distribution Corporation
National Grid Gas Delivery Companies
New England Local Distribution Companies[162]
New Jersey Chapter of the Sierra Club
New Jersey Highlands Coalition
New Jersey Natural Gas Company
NJR Energy Services Company
Piedmont Natural Gas Company, Inc.
ProLiance Energy, LLC
PSEG Energy Resources & Trade LLC
Statoil Natural Gas LLC
UGI Distribution Companies[163]

[162] Bay State Gas Company d/b/a Columbia Gas of Massachusetts, The Berkshire Gas Company, Connecticut Natural Gas Corporation, Fitchburg Gas and Electric Company, City of Holyoke, Massachusetts Gas and Electric Department, Northern Utilities, Inc., NSTAR Gas Company, The Southern Connecticut Gas Company, Westfield Gas & Electric Department, and Yankee Gas Services Company.

[163] UGI Utilities, Inc., UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc.

Appendix B

Environmental Conditions

As recommended in the Environmental Assessment (EA), this authorization includes the following conditions:

1. Tennessee Gas Pipeline Company (Tennessee) shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests) and as identified in the EA, unless modified by the Order. Tennessee must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);
    b. justify each modification relative to site-specific conditions;
    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and
    d. receive approval in writing from the Director of Office of Energy Projects (OEP) before using that modification.

2. The Director of OEP has delegated authority to take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the project. This authority shall allow:

    a. the modification of conditions of the Order; and
    b. the design and implementation of any additional measures deemed necessary (including stop-work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction and operation.

3. **Prior to any construction**, Tennessee shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, Environmental Inspectors (EIs), and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the EA, as supplemented by filed alignment sheets. **As soon as they are available, and before the start of construction**, Tennessee shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of

environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

Tennessee's exercise of eminent domain authority granted under Natural Gas Act (NGA) section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Tennessee's right of eminent domain granted under NGA section 7(h) does not authorize it to increase the size of its natural gas facilities to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

5. Tennessee shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area**.

This requirement does not apply to extra workspace allowed by Tennessee's Environmental Construction Plans (ECPs) and/or minor field realignments per landowner needs and requirements which do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;
b. implementation of endangered, threatened, or special concern species mitigation measures;
c. recommendations by state regulatory authorities; and
d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **At least 60 days prior to construction**, Tennessee shall file an Implementation Plan with the Secretary for review and written approval by the Director of OEP. Tennessee must file revisions to the plan as schedules change. The plan shall identify:

a. how Tennessee will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EA, and required by the Order;
b. how Tennessee will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;
c. the number of EIs assigned per loop segment and aboveground facility sites, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;
d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;
e. the location and dates of the environmental compliance training and instructions Tennessee will give to all personnel involved with construction and restoration (initial and refresher training as the project progresses and personnel change, with the opportunity for OEP staff to participate in the training sessions);
f. the company personnel (if known) and specific portion of Tennessee's organization having responsibility for compliance;
g. the procedures (including use of contract penalties) Tennessee will follow if noncompliance occurs; and
h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:
    (1) the completion of all required surveys and reports;
    (2) the environmental compliance training of onsite personnel;
    (3) the start of construction; and
    (4) the start and completion of restoration.

7. Beginning with the filing of its Implementation Plan, Tennessee shall file updated status reports with the Secretary on a **weekly basis until all construction and restoration activities are complete**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. an update on Tennessee’s efforts to obtain the necessary federal authorizations;
b. the construction status of the project, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally-sensitive areas;
c. a listing of all problems encountered and each instance of noncompliance observed by the EIs during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

d. a description of the corrective actions implemented in response to all instances of noncompliance, and their cost;
e. the effectiveness of all corrective actions implemented;
f. a description of any landowner/resident complaints which may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and
g. copies of any correspondence received by Tennessee from other federal, state, or local permitting agencies concerning instances of noncompliance, and Tennessee's response.

8. **Prior to receiving written authorization from the Director of OEP to commence construction of any project facilities**, Tennessee shall file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

9. Tennessee must receive written authorization from the Director of OEP **before placing each phase of the project into service**. Such authorization will only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the project are proceeding satisfactorily.

10. **Within 30 days of placing the authorized project facilities in service**, Tennessee shall file an affirmative statement with the Secretary, certified by a senior company official:

a. that the facilities have been constructed and/or abandoned in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or
b. identifying which of the Certificate conditions Tennessee has complied with or will comply with. This statement shall also identify any areas affected by the project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

11. **Within 30 days of placing the facilities in service**, Tennessee shall file a report with the Secretary identifying all water supply wells/systems damaged by construction and how they were repaired. The report shall also include a discussion of any other complaints concerning well yield or water quality and how each problem was resolved.

12. **Prior to construction**, Tennessee shall file with the Secretary for review and written approval from the Director of OEP a revised Pennsylvania ECP that includes in-stream construction timing windows consistent with section V.B.1 of the FERC's Wetland and Waterbody Construction and Mitigation Procedures.

13. Tennessee **shall not begin construction of Loop 323 in New Jersey until**:

a. Tennessee files with the New Jersey Field Office of the U.S. Fish and Wildlife Service (FWS) and the Secretary the results of all outstanding small whorled pogonia surveys. If small whorled pogonia are identified in any of the proposed construction work spaces, Tennessee shall consult with the FWS for measures that avoid impacts on this species;
b. Tennessee adopts a seasonal restriction for clearing trees greater than 5-inch-diameter breast height from April 1 to September 30 between mileposts (MP) 13.9 and 16.4;
c. the FERC staff completes any necessary ESA section 7 consultation with the NJFWS for the small whorled pogonia, Indiana bat, and bog turtle; and
d. Tennessee receives written notification from the Director of OEP that construction and/or use of mitigation (including implementation of conservation measures) may begin.

14. Tennessee **shall not begin construction of Loops 321 until**:

a. Tennessee files with the Pennsylvania Field Office of the FWS and the Secretary a plan that addresses Indiana bat habitat loss between approximate MPs 3.2 and 8.1;
b. Tennessee adopts a seasonal restriction for clearing trees greater than 5-inch-diameter breast height from April 1 to October 14 between MPs 3.2 and 8.1;
c. the FERC staff completes any necessary ESA section 7 consultation with the FWS; and
d. Tennessee receives written notification from the Director of OEP that construction and/or use of mitigation (including implementation of conservation measures) may begin.

15. **Prior to construction**, Tennessee shall file the results of any outstanding surveys for Pennsylvania and New Jersey state-listed species and identify any additional mitigation measures developed in consultation with the applicable state agencies.

16. Tennessee **shall not begin construction** of facilities, including the pipeline loops and compressor stations, meter stations, and/or use of all staging, storage, or temporary work areas and new or to-be-improved access roads **until:**

a. Tennessee files with the Secretary:

(1) any Phase IB survey reports for areas of denied access, and/or Phase IB survey reports revised to address comments;

(2) Phase I cultural resources survey report(s) for any previously unreported areas for Pennsylvania and New Jersey, including proposed wetland mitigation sites;
(3) Phase II site evaluation reports, as required, to provide National Register of Historic Places-eligibility recommendations for sites in Pennsylvania and New Jersey, including additional geomorphological testing;
(4) a revised unanticipated discovery plan developed in consultation with the Ramapough Lenape and New Jersey SHPO;
(5) any other reports, plans, or special studies not yet filed, including archaeological site avoidance and treatment plans, and historic architectural avoidance plans;
(6) comments on the cultural resource reports and plans from the Pennsylvania State Historic Preservation Office, New Jersey State Historic Preservation Office, and any comments from other consulting parties not yet filed; and
(7) the records of continued consultation with the Ramapough Lenape Indian Nation, Delaware Nation, Delaware Tribe of Indians, Oneida Indian Nation, Eastern Shawnee Tribe of Oklahoma, and Stockbridge Munsee Community of Wisconsin, and any other American Indian tribe that have not yet been filed.

b. the Advisory Council on Historic Preservation is afforded an opportunity to comment if historic properties would be adversely affected; and
c. the FERC staff reviews and the Director of OEP approves the cultural resources reports and plans, and notifies Tennessee in writing that treatment plans/mitigation measures may be implemented and/or construction may proceed.

All material filed with the Commission containing **location, character, and ownership** information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: **"CONTAINS PRIVILEGED INFORMATION--DO NOT RELEASE."**

17. **Prior to initiation of horizontal directional drilling (HDD) activities at the Susquehanna River**, Tennessee shall file for the review and written approval of the Director of OEP a plan detailing the additional noise mitigation measures Tennessee would use to ensure that the noise levels attributable to the 24-hour HDD activities do not exceed a day-night sound level of 55 decibels on the A-weighted scale (L_{dn}) at the noise-sensitive areas near the Susquehanna River HDD entry site.

18. Tennessee shall file noise surveys with the Secretary **no later than 60 days** after placing the authorized units at the Compressor Stations 321 and 323 in service. If the noise attributable to the operation of all of the equipment at the identified compressor stations at full load exceeds an L_{dn} of 55 dBA at the nearby noise sensitive areas, Tennessee shall install additional noise controls to meet the level **within 1 year** of each stations in-service date. Tennessee shall confirm compliance with the above requirement by filing a second set of noise surveys with the Secretary **no later than 60 days** after it installs the additional noise controls.

19. **Prior to construction of Loop 321 on the Anastasio property near milepost 6.7 in Lackawaxen Township, Pike County, Pennsylvania,** Tennessee shall file with the Secretary for review and written approval from the Director of OEP the results of Tennessee's communication with the Anastasios and the finalized construction plan for crossing the Anastasio property.

Document Content(s)

People's Dossier: FERC's Abuses of Power and Law → Undermining Federal Authority

Federal Authority Undermined Attachment 2, FERC Order Issuing Certificates to Sabal Trail Transmission, LLC; FERC Docket No. CP15-17, Feb. 2 2016, pages 1-30 of 110.

154 FERC ¶ 61,080
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Florida Southeast Connection, LLC	Docket Nos.	CP14-554-000
Transcontinental Gas Pipe Line Company, LLC		CP15-16-000
Sabal Trail Transmission, LLC		CP15-17-000

ORDER ISSUING CERTIFICATES AND APPROVING ABANDONMENT

(Issued February 2, 2016)

1. On September 26, 2014, Florida Southeast Connection, LLC (Florida Southeast) filed an application in Docket No. CP14-554-000, pursuant to section 7(c) of the Natural Gas Act[1] (NGA) and Part 157 of the Commission's regulations,[2] for authorization to construct and operate the Florida Southeast Connection Project (Florida Southeast Project), a new 126-mile natural gas pipeline and related facilities.[3] The Florida Southeast Project will provide up to 640,000 dekatherms per day (Dth/d) of firm transportation service. Florida Southeast also requests a blanket certificate under Part 157, Subpart F of the Commission's regulations to perform certain routine construction activities and operations, and a blanket certificate under Part 284, Subpart G of the Commission's regulations to provide open access transportation services.

2. On November 18, 2014, Transcontinental Gas Pipe Line Company, LLC (Transco) filed an application in Docket No. CP15-16-000 under sections 7(b) and 7(c) of the NGA and Part 157 of the Commission's regulations, requesting authorization to

[1] 15 U.S.C. § 717f(c) (2012).

[2] 18 C.F.R. Pt. 157 (2015).

[3] Commission staff's draft and final Environmental Impact Statement for this proceeding refer to Florida Southeast as "FSC" and the Florida Southeast Project as "FSC Project."

construct and operate the Hillabee Expansion Project and abandon the capacity on the Hillabee Expansion Project by lease to Sabal Trail Transmission, LLC (Sabal Trail). The Hillabee Expansion Project will include approximately 43.5 miles of pipeline looping facilities and 88,500 horsepower (hp) of compression at one new and three existing compressor stations in Alabama. Sabal Trail will utilize the project capacity to provide up to 1,131,730 Dth/d of firm transportation service.

3. On November 21, 2014, Sabal Trail filed an application in Docket No. CP15-17-000 requesting a certificate of public convenience and necessity under section 7(c) of the NGA and Part 157 of the Commission's regulations authorizing Sabal Trail to construct and operate the Sabal Trail Project. The Sabal Trail Project will include approximately 515 miles of new pipeline, six compressor stations, and six meter stations in Alabama, Georgia, and Florida to provide up to 1,075,000 Dth/d of firm transportation service. Sabal Trail also requests authorization to lease the capacity created by the Hillabee Expansion Project; a blanket certificate pursuant to Subpart F of Part 157 of the Commission's regulations for Sabal Trail to perform certain routine construction, operation, and abandonment activities; and a blanket certificate pursuant to Subpart G of Part 284 of the Commission's regulations authorizing Sabal Trail to provide open access transportation services.

4. These applications propose three separate but connected natural gas transmission pipeline projects. The upstream project, Transco's Hillabee Expansion Project, will create capacity for Sabal Trail's customers to access upstream natural gas supplies. The middle project, the Sabal Trail Project, will extend from an interconnect with Transco's system at the Tallapoosa Interconnection in Tallapoosa County, Alabama, to an interconnect with the downstream project, the Florida Southeast Project, near Intercession City, Florida. From there, the Florida Southeast Project will extend to a delivery point with Florida Power & Light Company (Florida Power & Light) at its Martin Clean Energy Center near Indiantown, Florida. In total, the projects will involve the construction and operation of approximately 685.5 miles of natural gas transmission pipeline and 339,400 hp of compression to provide transportation service for up to approximately 1.1 billion cubic feet per day of natural gas to markets in Florida and the southeast United States.

5. For the reasons stated below, we grant the requested authorizations, subject to conditions.

I. <u>Background and Proposals</u>

6. Transco is a natural gas pipeline company with a transmission system extending from Texas, Louisiana, and the offshore Gulf of Mexico area through Mississippi, Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, and New Jersey, to its termini in the New York City metropolitan area.

7. Sabal Trail is a limited liability company organized and existing under the laws of the State of Delaware. Sabal Trail, a joint venture owned by Spectra Energy Partners, LP (Spectra), a newly formed NextEra Energy, Inc. (NextEra) subsidiary named US Southeastern Gas Infrastructure, LLC, and Duke Energy, is a newly formed company and currently does not own any existing pipeline facilities and is not engaged in any natural gas operations. Upon commencing the operations proposed in its application, Sabal Trail will become a natural gas company within the meaning of section 2(6) of the NGA[4] and will be subject to the Commission's jurisdiction. Sabal Trail states that Sabal Trail Management, LLC will operate the new proposed pipeline.

8. Florida Southeast is a limited liability company organized and existing under the laws of the State of Delaware. Florida Southeast, a wholly owned subsidiary of NextEra, is a newly formed company and currently does not own any existing pipeline facilities and is not engaged in any natural gas operations. Upon commencing the operations proposed in its application, Florida Southeast will become a natural gas company within the meaning of section 2(6) of the NGA[5] and will be subject to the Commission's jurisdiction.

9. Florida Southeast and Sabal Trail are outgrowths of Florida Power & Light's request for proposals (RFP) announced in December 2012. Florida Power & Light initiated the RFP in response to a 2009 order issued by the Florida Public Service Commission, directing Florida Power & Light to hold an RFP to seek proposals for a new pipeline to accommodate Florida's long-term natural gas needs.[6]

10. Florida Power & Light's RFP requested proposals for an upstream pipeline extending from Transco's Station 85 to central Florida where a new Central Florida Hub would be created to interconnect the new upstream pipeline to the existing Gulfstream Natural Gas System, L.L.C. (Gulfstream) and Florida Gas Transmission Company, LLC (Florida Gas Transmission) pipelines, as well as to a new downstream pipeline from the Central Florida Hub to Florida Power & Light's Martin Clean Energy Center. Of the entities showing interest in constructing a new pipeline, Florida Power & Light selected Sabal Trail to construct the upstream pipeline and Florida Southeast to construct the downstream pipeline.

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[4] 15 U.S.C. § 717a(6) (2012).

[5] 15 U.S.C. § 717a(6) (2012).

[6] FPSC Order No. PSC-09-0715-FOF-EI, In re: Petition to determine need for Florida EnergySecure Pipeline by Florida Power & Light Company at 5, FPSC Docket No. 090172-EI (issued October 28, 2009).

A. **Hillabee Expansion Project**

11. Transco requests authority to construct and operate pipeline looping and compression facilities on its existing mainline to provide a total of 1,131,730 Dth/d of incremental firm transportation service. Transco proposes to lease the capacity to Sabal Trail. Because Sabal Trail seeks to lease the new capacity incrementally over three phases, Transco will construct the project facilities in three phases. Transco estimates that in total the proposed facilities will cost approximately $459,750,346.

12. In Phase I, Transco will conduct the following activities on its mainline system in order to lease capacity to Sabal Trail sufficient for Sabal Trail to provide 818,410 Dth/day of firm transportation service for its shippers commencing May 1, 2017:

- construct approximately 5.3 miles of 42-inch-diameter pipeline loop from mile post (MP) 911.12 to MP 916.455 in Coosa County, Alabama (Proctor Creek Loop);
- construct approximately 2.6 miles of 42-inch-diameter pipeline loop from MP 924.27 to MP 926.85 in Coosa County, Alabama (Hissop Loop);
- construct approximately 7.5 miles of 42-inch-diameter pipeline loop from MP 941.83 to MP 949.38 in Tallapoosa County, Alabama (Alexander City Loop);
- construct approximately 4.7 miles of 48-inch-diameter pipeline loop from MP 885.95 to MP 890.55 in Autauga and Chilton Counties, Alabama (Billingsley Loop);
- install a new 16,000 hp gas turbine driven compressor unit and rewheel two existing compressors at the existing Compressor Station No. 95 in Dallas County, Alabama (Compressor Station 95);
- install a new 20,500 hp gas turbine driven compressor unit at Transco's existing Compressor Station No. 105 in Coosa County, Alabama (Compressor Station 105);
- construct a new compressor station at MP 782.80 in Choctaw County, Alabama, consisting of two 16,000 hp (ISO) Solar Mars 100 gas turbine driven compressor units (Compressor Station 84);
- install three pipeline taps connecting to the Sabal Trail Meter Station; and
- construct related appurtenant underground and aboveground facilities.

13. In Phase II, Transco will conduct the following activities on its mainline system in order to lease Sabal Trail capacity sufficient to provide an additional 206,660 Dth/day of incremental firm transportation service (total of 1,025,070 Dth/d), commencing May 1, 2020:

- construct approximately 6.7 miles of 42-inch-diameter pipeline loop from MP 784.68 to MP 791.40 in Choctaw County, Alabama (Rock Springs Loop);
- construct approximately 3.9 miles of 42-inch-diameter pipeline loop from MP 905.72 to MP 909.65 in Chilton County, Alabama (Verbena Loop);
- install a new 16,000 hp gas turbine driven compressor unit and rewheel three existing compressors at the existing Compressor Station 95 in Dallas County, Alabama;
- uprate an existing electric motor driven compressor unit from 42,000 hp to 46,000 hp at Transco's existing Compressor Station No. 100 in Chilton County, Alabama (Compressor Station 100); and
- construct related appurtenant underground and aboveground facilities.

14. In Phase III, Transco will conduct the following activities on its mainline system in order to lease Sabal Trail capacity sufficient to provide an additional 106,660 Dth/day of incremental firm transportation service for its shippers (total of 1,131,730 Dth/d), commencing May 1, 2021:

- construct approximately 5.3 miles of 42-inch-diameter pipeline loop from MP 791.40 to MP 796.70 in Choctaw County, Alabama (Butler Loop);
- construct approximately 7.5 miles of 42-inch-diameter pipeline loop from MP 890.67 to MP 898.15 in Autauga and Chilton Counties, Alabama (Autauga Loop);
- rewheel an existing compressor at the existing Compressor Station 100 in Chilton County, Alabama; and
- construct related appurtenant underground and aboveground facilities.

B. Sabal Trail Project

1. Facilities and Service

15. Sabal Trail states that its proposed Sabal Trail Project will enable it to provide up to 1,075,000 Dth/d of firm transportation service. Sabal Trail states it will transport gas

from receipt points upstream of Transco's Compressor Station 85 to a new market interconnection hub, known as the Central Florida Hub, in Osceola County, Florida, utilizing capacity on its Sabal Trail system and leased capacity from Transco.

16. Sabal Trail proposes to construct, install, and operate approximately 516.2 miles of natural gas pipeline, consisting of mainline transmission pipeline and two lateral pipelines. The 36-inch-diameter mainline transmission pipeline will extend roughly 481.6 miles from the Tallapoosa Interconnection in Tallapoosa County, Alabama, through Georgia, and terminate at the Central Florida Hub in Osceola County, Florida. There, the Sabal Trail Project will interconnect with Florida Gas Transmission's and Gulfstream's existing systems, and Florida Southeast's new system.

17. Gulfstream and Florida Southeast's interconnects will be located near Sabal Trail's proposed Reunion Compressor Station in Osceola County. Florida Gas Transmission's interconnect will be located at the end of the new 13.1-mile-long, 36-inch-diameter lateral (Hunter Creek Line), extending from the proposed Reunion Compressor Station to Florida Gas Transmission's system in Orange County, Florida. All interconnections will be bidirectional.

18. Sabal Trail will also construct a 21.5-mile-long, 24-inch-diameter lateral pipeline (Citrus County Line) extending from a point in Marion County, Florida, to Duke Energy Florida's proposed electric generation plant in Citrus County, Florida.

19. In addition, Sabal Trail proposes to construct five compressor stations in Tallapoosa County, Alabama; Dougherty County, Georgia; and Suwannee, Marion, and Osceola Counties, Florida. Sabal Trail will also construct pig launchers/receivers, mainline valves, and six meter and regulating stations. Sabal Trail estimates that the proposed facilities will cost approximately $3,220,241,225.

20. Sabal Trail will construct the proposed facilities over three phases. In Phase I, Sabal Trail will construct the following facilities to provide an initial design capacity sufficient to provide 830,000 Dth/d of firm transportation service with a proposed in service date of May 1, 2017:

- approximately 474 miles of 36-inch-diameter mainline pipeline extending from the Tallapoosa Interconnection to an interconnection with Florida Southeast's proposed pipeline in Osceola County, Florida;

- the Hunter Creek Line, approximately 13miles of 36-inch-diameter pipeline extending from the proposed Reunion Compressor Station at MP 474.4 to Florida Gas Transmission's 24-inch-diameter mainline in the Hunters Creek area of Florida;

- the Citrus County Line, approximately 21miles of 24-inch-diameter pipeline extending from the proposed Dunnellon Compressor Station at MP 389.8 to an interconnection with Duke Energy Florida's proposed electric generation facility in Citrus County, Florida;

- the Alexander City Compressor Station at MP 0.00 near Alexander City in Tallapoosa County, Alabama, with a total of approximately 71,000 hp of gas turbine driven compression;

- the Hildreth Compressor Station at MP 296.3 near Lake City in Suwannee County, Florida, with a total of approximately 20,500 hp of gas turbine driven compression;

- the Reunion Compressor Station at MP 474.4 near Intercession City in Osceola County, Florida, with a total of approximately 36,400 hp of gas turbine driven compression;

- the Transco Hillabee Meter Station in Tallapoosa County, Alabama, at mainline MP 0.0;

- the Florida Gas Transmission Suwannee Meter Station in Suwanee County, Florida, at mainline MP 299.7;

- the Gulfstream Meter Station in Osceola County, Florida, at mainline MP 474.4;

- the Florida Southeast Meter Station in Osceola County, Florida, at mainline MP 474.4;

- the Florida Gas Transmission Meter Station in Orange County, Florida, at MP 13.1 on the Hunter Creek Line; and

- the Duke Energy Florida Citrus County Meter Station in Citrus County, Florida, at MP 21.4 on the Citrus County Line.

21. In Phase II, Sabal Trail will construct the following facilities to provide an additional 169,000 Dth/d of firm transportation service, for a total of 999,000 Dth/d, with a proposed in service date of May 1, 2020:

- the Albany Compressor Station at MP 159.3 near Albany in Dougherty County, Georgia, with a total of approximately 20,500 hp of gas turbine driven compression; and

- the Dunnellon Compressor Station at MP 389.8 near Ocala in Marion County, Florida, with a total of approximately 20,500 hp of gas turbine driven compression.

22. In Phase III, Sabal Trail will construct the following facilities to provide an additional 76,000 Dth/d of transportation service, for a total of 1,075,000 Dth/d, with a proposed in service date of May 1, 2021:

- 20,500 hp of additional gas turbine driven compression at the Albany Compressor Station, for a station total of approximately 41,000 hp of gas turbine driven compression; and

- 20,500 hp of additional gas turbine driven compression at the Hildreth Compressor Station, for a station total of approximately 41,000 hp of gas turbine driven compression.

23. On June 26, 2013, Sabal Trail signed a precedent agreement with Florida Power & Light to provide 600,000 Dth/d of firm transportation service, with 400,000 Dth/d to be provided during Phase I increasing to 600,000 Dth/d in Phase II, for a 25-year primary term. Florida Power & Light's precedent agreement will automatically extend for three successive periods of five years unless Florida Power provides written notice.[7]

24. On July 8, 2013, Sabal Trail signed a 25-year term precedent agreement with Duke Energy Florida for a total of 400,000 Dth/d of firm transportation service, of which 300,000 Dth/d will be provided during Phase I and the additional 100,000 will be provided thereafter.[8]

25. In addition, Sabal Trail held an open season from August 26, 2013, through September 25, 2013, to solicit requests for firm transportation service. Sabal Trail states it has had discussions with potential shippers and end-users in Alabama and Georgia, and

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[7] In addition to the 600,000 Dth/d of firm transportation service that Florida Power & Light committed to, Florida Power & Light has the right to elect up to an additional 200,000 Dth/d of firm transportation service on or before January 1, 2020, and an additional 200,000 Dth/d of firm transportation service on or before January 1, 2024. *See* Sabal Trail Application, Exhibit I, Precedent Agreement at 14.

[8] Duke Energy's precedent agreement permits Duke Energy to select a date between May 1, 2018, and May 1, 2021, on which the incremental 100,000 Dth/d of firm transportation service will commence. *See* Sabal Trail Application at Exhibit I, Precedent Agreement with Duke Energy, page 8.

has agreed to install two side-taps on its mainline system in Dougherty and Colquitt Counties, Georgia. Sabal Trail, however, did not receive any bids during its open season. In sum, Sabal Trail will provide 700,000 Dth/d of firm transportation service in Phase I and 1,000,000 Dth/d of firm transportation service in Phase II, leaving 75,000 Dth/d of transportation service still available.

26. Sabal Trail proposes to offer cost-based firm transportation service (Rate Schedule FTS), interruptible transportation service (Rate Schedule ITS and Rate Schedule HUB), and park and loan service (Rate Schedule PAL). Sabal Trail states that these services will be provided on an open access, non-discriminatory basis pursuant to Part 284 of the Commission's regulations and the terms and conditions of its proposed FERC Tariff. Sabal Trail states that Florida Power & Light and Duke Energy Florida have agreed to a negotiated rate for their transportation service.

2. Blanket Certificates

27. Sabal Trail requests a blanket certificate of public convenience and necessity pursuant to section 157.204 of the Commission's regulations authorizing future facility construction, operation, and abandonment as set forth in Part 157, Subpart F of the Commission's regulations.[9]

28. Sabal Trail requests a blanket certificate of public convenience and necessity pursuant to section 284.221 of the Commission's regulations authorizing Sabal Trail to provide transportation service to customers requesting and qualifying for transportation service under its proposed FERC Gas Tariff, with pre-granted abandonment authorization.[10]

C. Florida Southeast Connection Project

1. Facilities and Service

29. The Florida Southeast Project will enable Florida Southeast to provide 640,000 Dth/d of firm transportation service. Florida Southeast proposes to construct, install, operate, and maintain the following facilities:

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[9] 18 C.F.R. § 157.204 (2015).

[10] 18 C.F.R. § 284.221 (2015).

- approximately 77 miles of 36-inch-diameter pipeline extending from an interconnect with Sabal Trail at the Central Florida Hub in Osceola County, Florida, to Okeechobee, Florida;

- approximately 49 miles of 30-inch-diameter pipeline extending from Okeechobee County, Florida, to an interconnect with the Martin Clean Energy Center in Martin County, Florida;

- a meter station at the Martin Clean Energy Center; and

- pig launching and receiving facilities, mainline valves, and other appurtenant pipeline facilities.

30. Florida Southeast estimates that the proposed facilities will cost approximately $537,260,000.

31. Florida Southeast entered into a binding precedent agreement with Florida Power & Light for 400,000 Dth/d of firm transportation service beginning May 1, 2017, with Florida Power & Light having the option to increase to 600,000 Dth/d beginning May 1, 2020, for a 25-year primary contract term. Florida Southeast asserts that these commitments represent approximately 94 percent of the Florida Southeast Project's total project design capacity. Florida Southeast also held an open season from August 26, 2013, to September 25, 2013. Florida Southeast, however, did not receive other bids.

32. Florida Southeast proposes to offer cost-based firm transportation service (Rate Schedule FT), interruptible transportation service (Rate Schedule IT), and park and loan service (Rate Schedule PAL). Florida Southeast states that these services will be provided on an open access, non-discriminatory basis pursuant to Part 284 of the Commission's regulations and the terms and conditions of its proposed FERC Tariff. Florida Southeast states it and Florida Power have agreed to a negotiated rate for the contracted transportation service.

2. **Blanket Certificates**

33. Florida Southeast requests a blanket certificate of public convenience and necessity pursuant to section 157.204 of the Commission's regulations authorizing future facility construction, operation, and abandonment as set forth in Part 157, Subpart F of the Commission's regulations.

34. Florida Southeast requests a blanket certificate of public convenience and necessity pursuant to section 284.221 of the Commission's regulations authorizing Florida Southeast to provide transportation service to customers requesting and qualifying for transportation service under its FERC Gas Tariff, with pre-granted abandonment authorization.

D. Sabal Trail's Lease of Capacity on Transco's System

35. Transco and Sabal Trail have entered into a Capacity Lease Agreement that provides that Transco will construct and operate the Hillabee Expansion Project facilities and abandon by lease to Sabal Trail the incremental capacity associated with the proposed facilities. In turn, Sabal Trail proposes to acquire that capacity to provide transportation service under its open access tariff. As noted above, Sabal Trail will lease capacity incrementally over three phases. In Phase I, Sabal Trail will lease capacity sufficient to provide 818,410 Dth/d of firm transportation service effective May 1, 2017; in Phase II, capacity sufficient to provide 1,025,000 Dth/d of firm transportation service effective May 1, 2020; and in Phase III, capacity sufficient to provide 1,131,730 Dth/d of firm transportation service effective May 1, 2021.

36. As proposed, the leased capacity would extend from three receipt points[11] to the proposed interconnection between Transco and Sabal Trail in Tallapoosa County, Alabama. Also, as proposed, Sabal Trail and its shippers would not have rights to receive or deliver gas from any other points on Transco's system. Further, Sabal Trail and its shippers would not have rights to backhaul or reverse flow gas from east to west on the Transco mainline. As discussed below, we find such provisions to be anticompetitive and require the Capacity Lease Agreement to be revised to remove them in accordance with Commission policy.

37. The Capacity Lease Agreement provides for an initial 25-year primary term and will automatically extend for three successive 5-year terms unless Sabal Trail provides prior written notice to terminate the agreement. Thereafter, the Capacity Lease Agreement will extend year to year until terminated by Transco or Sabal Trail.

38. During the primary term, Sabal Trail will pay a monthly lease charge, which is the leased capacity each day during the month multiplied by the applicable rate per dekatherm for each phase. Transco states that the revenues under the Capacity Lease Agreement are less than the Hillabee Expansion Project's annual cost of service. However, Transco states that it will not reflect in its system rates any costs or revenues associated with the leased capacity, and that it will separately account for the costs and revenues associated with the leased capacity and segregate those costs and revenues from

[11] The three receipt points are: (1) Transco's existing Zone 4 point of interconnection between Transco's mainline and the Mobile Bay Lateral (generally referred to as Transco's Zone 4 Pool); (2) the point of interconnection between Transco and Midcontinent Express Pipeline LLC's system; and (3) the point of interconnection between Transco and Gulf South Pipeline Company, LLC's system. All three receipt points are located at MP 784.66 in Choctaw County, Alabama.

its other system costs.[12] Further, Transco explains that the lease payment is no higher than a maximum recourse rate would be if Transco were to provide transportation service through the project facilities on a stand-alone basis.

II. Procedural

A. Notice, Interventions, Protests, and Answers

39. Notice of Transco's application in Docket No. CP15-16-000 was published in the *Federal Register* on December 11, 2014 (79 Fed. Reg. 73,571). Notice of Sabal Trail's application in Docket No. CP15-17-000 was published in the *Federal Register* on December 11, 2014 (79 Fed. Reg. 73,570). Notice of Florida Southeast's application in Docket No. CP14-554-000 was published in the *Federal Register* on October 24, 2014 (79 Fed. Reg. 63,613).

40. In each docket, numerous timely and late motions to intervene were filed.[13] Timely, unopposed motions to intervene are granted automatically pursuant to Rule 214 of the Commission's Rules of Practice and Procedure.[14]

41. Florida Southeast opposes all late motions to intervene in its proceeding, Docket No. CP14-554-000, other than the motion by Pivotal Utility Holdings, Inc.[15] Florida Southeast argues that the Commission should deny these late motions to intervene because those seeking intervention demonstrate no genuine interest in the Florida Southeast Project, are not located within the project's vicinity, and do not explain how the project affects them. Florida Southeast asserts that the late intervenors are concerned with the Sabal Trail Project, not the Florida Southeast Project. Florida Southeast adds

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[12] Transco Application at 11.

[13] Commenters state that their interventions are timely up until the comment period of the draft EIS ends. Specifically, our regulations provide that interventions are timely if filed during the comment period on the notice of the application or if filed on environmental grounds during the comment period of the draft EIS. 18 C.F.R. §§ 157.10, 380.15, 214(c) (2015). Thus, if interventions are filed in between these periods, the intervention is late. *See Alcoa Power Generating, Inc.*, 144 FERC ¶ 61,218, at n.4 (2013). As we note below, however, the Commission has a liberal policy of accepting late interventions in natural gas certificate proceedings.

[14] 18 C.F.R. § 385.214(c) (2015).

[15] Florida Southeast January 7, 2015 Answer at n.11.

that the late interventions fail to conform to the Commission's standard for late interventions,[16] and that allowing late intervention at this point in the proceeding would create prejudice. Specifically, Florida Southeast asserts that the late intervenors do not offer nor have an excuse, for filing late, arguing that, as active participants in the Sabal Trail Project, the late intervenors had notice that the Commission combined the environmental review of the three projects.

42. In considering late intervention requests in natural gas certificate proceedings, the Commission typically finds that, at the early stage of the proceeding, granting late intervention will neither disrupt the proceeding nor prejudice the interests of any other party. Thus, the Commission liberally allows late interventions at the early stages of such proceedings, but is more restrictive as a proceeding nears its conclusion.[17]

43. While many late intervenors in Docket No. CP14-554-000 direct their comments to the Sabal Trail Project, several late intervenors note that the projects are related and request that the Commission consolidate the proceedings. Thus, we find that all individuals filing late motions to intervene have a demonstrable interest in the respective proceedings. Granting the late interventions at this stage of the proceedings will not cause undue delay or disrupt or otherwise prejudice the applicant or other parties.[18] Accordingly, the Commission grants the late motions to intervene in each proceeding. All parties to each proceeding are listed in Appendix A of this order.

44. In addition to receiving interventions, we received numerous comments, both in support of the proposed projects and raising concerns on environmental and safety matters, including air quality, noise, and property value impacts. Sabal Trail filed multiple answers to the protests, comments, and other pleadings filed in response to this application.[19] Although the Commission's Rules of Practice and Procedure generally do

[16] 18 C.F.R. § 385.214(d) (2015).

[17] *Sabine Pass Liquefaction, LLC*, 139 FERC ¶ 61,039, at P 15 (2012); *Cameron LNG, LLC*, 118 FERC ¶ 61,019, at PP 21-22 (2007).

[18] 18 C.F.R. § 385.214(d) (2015).

[19] Sabal Trail filed answers in Docket No. CP15-17-000 on January 9, April 1, April 20, May 22, June 15, June 16, June 29, July 8, July 17, July 22, and August 14, 2015. Sabal Trail's answers responded to comments by Kiokee-Flint et al.; Southern Natural Gas Company, L.L.C. (Southern Natural); G.B.A. Associates and Gregory K. Isaacs (G.B.A. Associates); the City of Albany, Georgia; and various landowners.

not permit answers to protests, [20] we will accept Sabal Trail's answers because they clarify the concerns raised and provide information that has assisted in our decision making.

45. The environmental and safety concerns raised in this proceeding are addressed in the final Environmental Impact Statement (final EIS), as well as the environmental section of this order.

B. Requests for a Hearing or Technical Conference, Consolidation, and Procedural Schedule for Project Review

46. On December 23, 2014, the Kiokee-Flint Group and its individual members (Kiokee-Flint), the Georgia Chapter of the Sierra Club (Sierra Club), Flint Riverkeeper, and Chattahoochee Riverkeeper (collectively, Kiokee-Flint et al.)[21] filed a motion requesting an evidentiary, trial-type hearing, the formal consolidation of the certificate proceedings, and a new procedural schedule for review of the three certificate proceedings.[22] Florida Southeast and Sabal Trail each filed an answer to Kiokee-Flint et al.'s motions on January 7, and January 9, 2015, respectively.

1. Formal Evidentiary Hearing and Technical Conference

47. Intervenors request an evidentiary, trial-type hearing to address disputed material facts regarding the need for the projects, Sabal Trail's requested return on equity, subsidization of the projects by captive ratepayers, the projects' environmental and safety impacts, and proposed alternatives. In addition, AZ Ocala Ranch LLC (AZ Ocala), a residential developer, recommended that the Commission hold a technical conference in Docket No. CP15-17-000 on Sabal Trail's proposed pipeline route adjustments.[23]

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[20] 18 C.F.R. § 385.213(a)(2) (2015).

[21] Kiokee-Flint, Sierra Club, Flint Riverkeeper, and Chattahoochee Riverkeeper filed separate motions to intervene and have filed separate and joint pleadings. Where these parties file joint pleadings, we refer to them as Kiokee-Flint et al.

[22] Kiokee-Flint et al. December 23, 2015 Motion in Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000.

[23] AZ Ocala July 1, 2015 Comments at 3. Southern Natural also requested a technical conference in Docket No. CP15-17-000 to determine the necessity of the number of Sabal Trail Project's proposed crossings of Southern Natural's pipeline.

(continued…)

48. An evidentiary, trial-type hearing and technical conference are necessary only where there are material issues of fact in dispute that cannot be resolved on the basis of the written record.[24] Neither Kiokee-Flint et al. nor AZ Ocala has raised a material issue of fact that the Commission cannot resolve on the basis of the written record. As demonstrated by the discussion below, the existing written evidentiary record provides a sufficient basis for resolving the issues relevant to this proceeding. The Commission has satisfied the hearing requirement by giving interested parties an opportunity to participate through evidentiary submission in written form.[25]

2. **Consolidation**

49. Intervenors request that the Commission should consolidate these three applications because the projects are dependent on one another. Kiokee-Flint et al. asserts that without consolidation the cumulative environmental impacts of the projects will be downplayed, the rate impacts obfuscated, and the potential to export gas concealed. Kiokee-Flint et al. adds that not consolidating the dockets hampers public participation because members of the public do not know they should intervene in all three dockets.

50. Sabal Trail and Florida Southeast argue that formal consolidation is unwarranted. While both agree that the three projects are related, they argue that there are no common issues of law or fact that cannot be adequately addressed in the individual dockets. Sabal Trail and Florida Southeast state that the projects are submitted by three different entities and have different routes, rates, pipeline sizes, tariffs, and purposes. Moreover, they state that the Commission is already evaluating the projects within the same environmental impact statement as connected actions. In addition, Sabal Trail adds that consolidation is not necessary to understand the potential export of the transported natural gas because there is no proposal to connect facilities to an LNG export terminal.

51. Although the separate applications filed by Sabal Trail, Transco, and Florida Southeast in the three proceedings raise similar issues, the existing records in the three dockets are sufficient for us to consider and address all three contemporaneously.

Southern Natural's recent filing on October 26, 2015, however, indicates that it no longer is concerned with the number of pipeline crossings.

[24] *See, e.g.*, *Southern Union Gas Co. v. FERC*, 840 F.2d 964, 970 (D.C. Cir. 1988); *Dominion Transmission, Inc*., 141 FERC ¶ 61,183, at P 15 (2012).

[25] *Moreau v. FERC*, 982 F.2d 556, 568 (D.C. Cir. 1993).

Therefore, consistent with prior orders, we find no need for formal consolidation.[26] Further, we see no purpose in consolidating the three certificate proceedings in view of the fact that we address all issues in each proceeding in this order without need for an evidentiary, trial-type hearing.[27]

52. Our decision to not formally consolidate the dockets will not prejudice landowners as Kiokee-Flint et al. contends. Landowners have had ample notice that the three projects are connected. On February 18, 2014, Commission staff issued a notice stating its intent to prepare an environmental impact statement for all three projects. Landowners had two opportunities to timely intervene in the proceeding: during the initial comment period and during the comment period for the draft EIS. As discussed above, the Commission has also accepted late interventions. In any event, landowners' interests are well represented in the proceeding; over seventy interventions were filed in each docket, many of them by landowners. In addition, landowners can and have participated in the proceeding without formally intervening. Commission staff considered hundreds of comments from landowners throughout the proceeding, without regard to whether the commentors had also submitted motions to intervene.

3. <u>Schedule</u>

53. Kiokee-Flint et al. requests that the Commission establish a procedural schedule for the project, including deadlines by which the parties may submit additional comments and expert testimony. Commission staff issued initial and revised procedural schedules for the draft and final EIS. No other procedural schedule is required. Moreover, the draft and final EIS, as well as this order, address timely and late comments to the extent possible.[28]

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[26] *Williams Natural Gas Co*., 67 FERC ¶ 61,252, at 61,826 (1994).

[27] *See, e.g., Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089, at P 27 (2008), *order denying reh'g and granting clarification*, 127 FERC ¶ 61,164 (2009).

[28] Intervenors also requested that the Commission extend the comment period on the projects' applications by 90 days. Commission staff considered late comments throughout the proceeding to the extent possible.

C. Completeness of Application

54. Kiokee-Flint et al. objects to Sabal Trail's "abbreviated application" and asks that the Commission require Sabal Trail to file a "full application."[29] Kiokee-Flint et al. states that an abbreviated application is inappropriate given the project's substantial impacts on landowners and the environment.

55. The Commission's regulations provide that a company may file an abbreviated application and omit certain exhibits when those exhibits are not necessary to fully disclose the nature of the proposal.[30] The applicant must only file information necessary to fully explain the proposed project, its economic justification, and its effect on the applicant's operations and on the public proposed to be served.[31] Sabal Trail omitted Exhibit H, which provides for information on total gas supply, specifically a description of the production areas accessible that contain existing or potential supplies for the proposed project.

56. Sabal Trail provided sufficient information relevant to each exhibit to fully disclose the nature of the project, and therefore demonstrated to Commission staff that it met the requirements set forth in the Commission's regulations. There is no question that there is sufficient natural gas accessible through Transco and its interconnected upstream pipelines to supply the proposed projects. Information on total gas supply is not necessary to complete our public convenience and necessity analysis. Moreover, since the advent of open access, natural gas shippers, not natural gas pipelines, have been responsible for obtaining natural gas supplies, and therefore, Exhibit H is not needed to determine whether adequate natural gas is available to supply the proposed project.

D. Request for Fast Tracking and Alternative Dispute Resolution

57. G.B.A. Associates and Gregory K. Isaacs (G.B.A. Associates), a commercial developer and an investor, request to use a fast tracking processing and Alternative Dispute Resolution pursuant to Rule 206 of the Commission's Rules of Practice and Procedure in Docket No. CP15-17-000.[32] Specifically, they seek to resolve a

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[29] Kiokee-Flint et al. December 22, 2014 Comments in Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000 at 25-26 (Accession No. 20141222-5162) (Kiokee-Flint et al. December 22, 2014 Filing).

[30] 18 C.F.R. § 157.7 (2015).

[31] *Id.*

[32] G.B.A. Associates April 16, 2015 Filing in Docket No. CP15-17-000 at 4.

disagreement regarding Sabal Trail's rerouting its mainline pipeline from colocating with Southern Natural Gas Company, L.L.C. (Southern Natural) to being located on their property.

58. The Commission has specific regulations applicable to complaint proceedings, including a fast tracking process. The Commission also has an Alternative Dispute Resolution process. Complaints are covered under Rule 206 of the Commission's Rules of Practice and Procedure, and the Commission's Alternative Dispute Resolution process is covered under Rule 604.

59. Under Rule 206, entities seeking to file formal complaints must allege a contravention or violation of a statute, rule, or order, or must allege any other wrong over which the Commission may have jurisdiction. In addition, entities seeking to file formal complaints must comply with the relevant regulations that specify the contents of a complaint.[33] G.B.A. Associates fails to satisfy a large number of these requirements. G.B.A. Associates does not allege any contravention or violation of a statute, rule, or order, or any other alleged wrong, but merely notes its disagreement regarding Sabal Trail rerouting its pipeline. In addition, G.B.A. Associates fails to set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the complainant; make a good faith effort to quantify the financial impact or burden created for the complainant as a result of the action or inaction complained of; and indicate the practical, operational, or other nonfinancial impacts imposed as a result of the action or inaction. Because G.B.A. Associates fails to comply with the Commission's regulations for filing complaints, we conclude that it did not file a formal complaint. Consequently, we address G.B.A. Associates' concerns as a protest to Sabal Trail's application.

60. As for Alternative Dispute Resolution, G.B.A. Associates may submit a written proposal to the Commission to use alternative means of dispute resolution to resolve its disagreement with Sabal Trail.[34] Our regulations, however, require that all participants to a pending matter concur in the use of alternative dispute resolution. Here, Sabal Trail has noted its opposition to such a proceeding.[35]

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[33] 18 C.F.R. § 385.206 (2015).

[34] 18 C.F.R. § 385.604(d) (2015).

[35] Sabal Trail May 22, 2015 Answer to G.B.A. Associates.

III. Discussion

61. Since the proposed facilities will be used to transport natural gas in interstate commerce, subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA. In addition, Transco's proposed abandonment of capacity by lease to Sabal Trail and Sabal Trail's acquisition of that capacity are subject to the requirements of sections 7(b) and 7(c) of the NGA, respectively.

A. Application of Certificate Policy Statement

62. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new pipeline construction.[36] The Certificate Policy Statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

63. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis where other interests are considered.

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[36] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

1. Section 7(c) Projects

a. Hillabee Expansion Project

64. Transco's proposal satisfies the threshold requirement that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. While the monthly lease payments Transco will charge Sabal Trail will not recover the full costs of the project, Transco states that during the term of the lease agreement it will not reflect in its system rates any costs or revenues associated with the leased capacity and that it is prepared to financially support the cost of the Hillabee Expansion Project.[37] Moreover, Transco will separately account for leased capacity related to fuel and lost and unaccounted-for gas costs when it makes its period tracker filings to ensure that its fuel retention costs are properly allocated between services to existing shippers and the incremental services to the Sabal Trail. As such, the proposed project will not result in any subsidization by Transco's existing shippers.

65. The proposed project will not adversely impact Transco's existing customers or other pipelines and their customers. The proposed facilities are designed to increase the capacity of Transco's system to accommodate the lease agreement with Sabal Trail without degrading the service of Transco's existing customers. There is no evidence that service on other pipelines will be displaced or bypassed, and no pipeline companies have objected to the proposed project. We conclude that Transco's proposal will not have adverse impacts on its existing shippers or other existing pipelines and their captive customers.

66. We also find that Transco's proposed project will have minimal adverse impacts on landowners and communities. Transco states that it expects to negotiate settlements with all affected landowners for all necessary easements and property rights. To the extent parties are unable to reach mutual agreement, it is for the courts to decide the appropriate levels of compensation for necessary property rights.[38]

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[37] Transco Application at 11.

[38] 15 U.S.C. § 717(f) (h) (2012).

b. <u>Sabal Trail Project</u>

67. Sabal Trail is a new pipeline company that has no existing customers. As such, there is no potential for subsidization on Sabal Trail's system or degradation of service to existing customers.[39]

68. With regard to adverse economic effects on competing pipelines and such pipelines' captive customers, the Sabal Trail Project should serve to benefit other pipelines and their customers. Through Sabal Trail's new interconnections at the Central Florida Hub, Sabal Trail will be able to deliver gas to existing pipeline systems, i.e., Gulfstream and Florida Gas Transmission, in the event of supply or facility disruption and enhance market competition.

69. In its October 26, 2015 comments, Southern Natural states that because the Sabal Trail pipeline will cross Southern Natural's pipeline system numerous times, Southern Natural may have to pass on to its customers substantial costs for restoration, cathodic protection systems, and maintenance activities.[40] Southern Natural further indicated that it anticipates that Sabal Trail will reimburse it for such costs through a Parallel Construction Agreement, but that Southern and Sabal Trail had not yet reached agreement.[41] On November 9, 2015, Sabal Trail filed comments stating that it continues to work with Southern Natural on that agreement.[42] The issues that Southern Natural raises regarding economic impacts to its customers are outside the scope of this proceeding. To the extent Southern Natural and Sabal Trail are unable to reach an agreement, questions regarding damages incurred during construction are for a court of appropriate jurisdiction to adjudicate.

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[39] Kiokee-Flint et al. states that the Sabal Trail Project will result in subsidization because the Florida Public Service Commission issued an order stating that Florida Power & Light may pass the costs of the pipeline onto its ratepayers. *See* Kiokee-Flint et al. December 22, 2014 Filing at 28. The Commission does not consider it subsidization for Florida Power & Light to pay rates designed to recover the costs of a pipeline system being constructed to provide it with natural gas transportation service. The extent to which it is appropriate for Florida Power & Light to in turn pass those costs through to its rate payers is not with the Commission's jurisdiction.

[40] Southern Natural Oct. 26, 2015 Comments in Docket No. CP15-17-000 at 3.

[41] *Id*.

[42] Sabal Trail Nov. 9, 2015 Comments on Draft EIS at 15.

70. Regarding impacts on landowners and communities along the route of the project, Sabal Trail proposes to locate the pipeline within or parallel to existing rights-of-way where feasible.[43] Sabal Trail's proposed pipeline route colocates with existing rights-of-way or previously disturbed corridors for approximately 308.1 miles (60 percent) of the total pipeline lengths. The remaining approximately 207.5 miles (40 percent) of the pipeline route will deviate from these rights-of-way and corridors.

71. While we are mindful that Sabal Trail has been unable to reach easement agreements with some landowners, for purposes of our consideration under the Certificate Policy Statement, we find that Sabal Trail has taken sufficient steps to minimize adverse economic impacts on landowners and surrounding communities. Sabal Trail participated in the Commission's pre-filing process in Docket No. PF14-1-000. During pre-filing and initial project planning, Sabal Trail considered 282 route variations, almost all of which were identified by landowners, government officials, and other stakeholders.[44] Sabal Trail incorporated 214 of those route variations into its proposed route. Further, in the final EIS, Commission staff considered 12 major route alternatives, many of which were requested by landowners.

72. G.B.A. Associates requested that the Commission not grant Sabal Trail eminent domain authority over its land.[45] The Commission itself, however, does not confer eminent domain powers. Congress gave the Commission jurisdiction to determine if the construction and operation of proposed pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination, under NGA section 7(h), a certificate holder is authorized by Congress to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[46] While the Sabal Trail Project will traverse G.B.A. Associates' land, we note that Sabal Trail incorporated a route variation on G.B.A. Associates' land that will closely follow property lines and reduce impacts on G.B.A. Associates' future development activities.

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[43] 18 C.F.R. § 380.15 (2015). Section 380.15 of the Commission's regulations requires the Commission to consider a landowner's preferences, not necessarily reach their preferred outcome. *See Impulsora Pipeline, LLC*, 153 FERC ¶ 61,204, at P 12 (2015).

[44] Final EIS at 4-24.

[45] G.B.A. Associates April 16, 2015 Filing in Docket No. CP15-17-000 at 4.

[46] 15 U.S.C. § 717f(h) (2012).

c. Florida Southeast Connection Project

73. Florida Southeast is a new pipeline company that has no existing customers. As such, there is no potential for subsidization on Florida Southeast's system or degradation of service to existing customers.

74. The Florida Southeast Project will transport gas to meet increased demand for natural gas in Florida. No transportation service provider or captive customer in the same market has protested the project. Moreover, the two existing interstate pipelines that serve central and southern Florida, i.e., Florida Gas Transmission and Gulfstream, are either fully or near fully subscribed.

75. Regarding impacts on landowners and communities along the project route, Florida Southeast proposes to locate the pipeline within or parallel to existing rights-of-way where feasible. The Florida Southeast Project pipeline route will be colocated with existing roads and utilities for approximately 101.9 miles (81 percent) of the total pipeline length. The remaining 24.5 miles (19 percent) of the pipeline route will deviate from these rights-of-way or corridors. Florida Southeast proposes to minimize the use of eminent domain to the greatest extent possible by negotiating easement agreements for permanent easements and temporary workspace required for the project. In addition, Florida Southeast participated in the Commission's pre-filing process in Docket No. PF14-2-000, during which Florida Southeast considered 19 route variations and addressed landowners' concerns and questions. We therefore find that Florida Southeast has taken sufficient steps to minimize adverse economic impacts on landowners and surrounding communities.

d. Need for the Projects

76. Several intervenors challenge the public need for the projects.[47] Many intervenors assert that project demand can be satisfied by renewable energy alternatives, such as solar and wind power, or energy efficiency gains. Intervenors also contend that other pipelines in Florida, including Florida Gas Transmission's pipeline, are not at full capacity and can provide transportation services. In addition, many intervenors contest that the gas will not be used to satisfy demand in Florida, but will be exported to foreign markets.

77. Kiokee-Flint adds that project need for the Sabal Trail Project is overstated. Kiokee-Flint asserts that Florida Power & Light committed only to 400,000 Dth/d of firm service, with the option to subscribe an additional 200,000 Dth/d of service to be

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[47] Kiokee-Flint filed comments raising this issue both individually and jointly with Sierra Club, Flint Riverkeeper, and Chattahoochee Riverkeeper.

provided in Phase II of the Sabal Trail Project.[48] Similarly, members of the Gulf Restoration Network assert that the proposed pipeline has over twice the capacity needed to meet Florida Power & Light's projected additional demand through 2021.[49] Kiokee-Flint also appears to allege that the projects are engaged in self-dealing, as Sabal Trail's and Florida Southeast's precedent agreements are with affiliates: the parent company of Florida Southeast Connection, NextEra, is also the parent of Florida Power & Light, and Duke Energy, the parent company of Duke Energy Florida, has an interest in the Sabal Trail Project.[50] In addition, Kiokee-Flint argues that Energy Information Administration data does not indicate a need for the project nor will compliance with the Environmental Protection Agency's Clean Power Plan regulations require the project to be built.[51]

78. Kiokee-Flint et al. also asserts that Florida Power & Light may have inflated its demand for natural gas.[52] In support, Kiokee-Flint et al. contends that Florida Power & Light's reserve margin is double the generally approved standard in Florida. Kiokee-Flint et al. also points out that the Florida Public Service Commission may find there is no need for Florida Power & Light's proposed natural gas power generating facility, the Okeechobee Clean Energy Center.

79. In addition, Kiokee-Flint argues that the Certificate Policy Statement only finds that a fully subscribed project is prima facie significant evidence of project need, which the Sabal Trail Project does not meet because it is undersubscribed at 93 percent of its total design capacity.[53] Parties also cite various cases unrelated to the Commission's

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[48] Kiokee-Flint October 28, 2015 Draft EIS Comments in Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000 at 8-9 (Kiokee Flint Oct. 28 Filing).

[49] Gulf Restoration Network Members and Supporters October 26, 2015 Filing in Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000 at 1.

[50] Kiokee-Flint Oct. 28 Filing at 8-9.

[51] *Id*. at 10-12.

[52] Kiokee-Flint et al. October 27, 2015 Comments on Draft EIS in Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000 at 1-4 (Kiokee-Flint et al. Oct. 27 Filing).

[53] Kiokee-Flint October 28 Filing at 8.

Certificate Policy Statement to argue that the Commission incorrectly relies on precedent agreements to find project need.[54]

80. The Certificate Policy Statement established a new policy under which the Commission would allow an applicant to rely on a variety of relevant factors to demonstrate need, rather than continuing to require that a percentage of proposed capacity be subscribed under long-term precedent or service agreements.[55] These factors might include, but are not limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[56] The Commission stated that it will consider all such evidence submitted by the applicant regarding project need. Nonetheless, the Certificate Policy Statement made clear that, although precedent agreements are no longer required to be submitted, they are still significant evidence of project need or demand.[57]

81. We find that Transco, Sabal Trail, and Florida Southeast have sufficiently demonstrated that there is market demand for their respective projects. Transco has entered into a *pro forma* lease agreement with Sabal Trail to abandon and lease the entire incremental capacity created by the Hillabee Expansion Project to Sabal Trail for a 25-year primary term. Sabal Trail has entered into precedent agreements with Florida Power & Light and Duke Energy Florida for 1,000,000 Dth/d, approximately 93 percent of the 1,075,000 Dth/d of service that will be made available by the Sabal Trail Project, also for a 25-year term. Florida Southeast has entered into a precedent agreement with Florida Power & Light for 400,000 Dth/d of service, 62.5 percent of the total design capacity that will be created by the Florida Southeast Project, with an option to subscribe to an additional 200,000 Dth/d of service, again for a 25-year term.

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[54] Kiokee-Flint cites *1000 Friends of Wisconsin, Inc. v. U.S. Dep't of Transp.*, No. 11-C-0545, 2015 WL 2454271, at *1 (E.D. Wis. 2015) (holding that the environmental impact statement prepared to authorize a highway expansion did not explain the methodology for determining specific traffic volumes and did not explain why it did not use updated population data). *See* Kiokee-Flint October 28 Filing at 12. Kiokee-Flint et al. cites *Lakehead Pipeline Co., LP v. Ill. Commerce Comm'n*, 296 Ill.App.3d 942, 957 (1998) (involving an oil pipeline's certificate application before the Illinois Commerce Commission). *See* Kiokee-Flint et al. October 27 Filing at 4.

[55] Certificate Policy Statement, 88 FERC at 61,747.

[56] *Id*.

[57] *Id*.

82. Kiokee-Flint mistakenly asserts that Florida Power & Light committed only to 400,000 Dth/d of service on Sabal Trail with the option to commit to 200,000 Dth/d in 2020. The precedent agreement between Florida Power & Light and Sabal Trail states that Florida Power & Light will subscribe to 600,000 Dth/d, of which 400,000 Dth/d will be provided in Phase I and the additional 200,000 Dth/d to be provided in Phase II.[58] In addition, the precedent agreement states that Florida Power & Light has the option to subscribe to an additional 200,000 Dth/d by January 1, 2020, and another additional 200,000 Dth/d by January 1, 2024.[59]

83. We note that Duke Energy Florida does have the option to not subscribe to its 100,000 Dth/d of Phase II service.[60] Our finding that Sabal Trail has demonstrated need for its proposed project is not affected by whether or not Duke Energy Florida exercises its option. Even without Duke Energy Florida's 100,000 Dth/d Phase II increment, we find subscription of 84 percent of the project's total capacity is evidence of sufficient public benefit to outweigh the residual adverse effects on the economic interests as discussed above.[61]

84. An affiliation between project shippers and the owners of the pipelines is not, by itself, evidence of self-dealing which might call into question the need for the projects. Sabal Trail and Florida Southeast will be required to execute firm contracts for the capacity levels and terms of service represented in the signed precedent agreements before commencing construction. Sabal Trail's and Florida Southeast's recourse rates will be based on the design capacity of their pipelines, thereby placing them at risk for any unsubscribed capacity.

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[58] Sabal Trail Application at Exhibit I, Precedent Agreement by and between Sabal Trail Transmission, LLC and Florida Power & Light Company at 12.

[59] *Id*. at 15. We note that the proposed Sabal Trail pipeline would not, without future expansion, be able to accommodate an additional 400,000 Dth/d of incremental firm service. No such expansion of the Sabal Trail pipeline could be constructed without prior Commission authorization.

[60] Sabal Trail Application at Exhibit I, Precedent Agreement with Duke Energy, page 10.

[61] *Cf. Turtle Bayou Gas Storage Co., LLC*, 135 FERC ¶ 61,233, at P 33 (2011), which found that the applicant had not sufficiently demonstrated the need for its particular project where the applicant did not conduct an open season or submit precedent or service agreements for the project's capacity and provided only vague and generalized evidence of need for natural gas at the regional and national level.

85. We also have no reason to contest Florida Power & Light's purported demand for natural gas. The Florida Public Service Commission issued an order finding that Florida Power & Light had demonstrated a need for additional firm capacity.[62] Florida Power & Light has indicated that its commitments on Sabal Trail's and Florida Southeast's systems are to provide gas to existing natural gas-fired plants.[63] Because the Okeechobee Clean Energy Center is not an existing plant, whether the Florida Power Service Commission approves the plant does not bear on Florida Power & Light's specified demand for the Sabal Trail and Florida Southeast Projects set forth in its application.

86. Allegations that the projects will be used to export gas also do not persuade us to find that the applicants have not demonstrated project need. Neither Sabal Trail nor Florida Southeast has proposed to connect to any LNG export facilities. In addition, Florida Power & Light stated that it lacks legal authority to export natural gas, and that it is contracting for capacity to serve its natural gas plants. Florida Power & Light adds that it is not an owner of the Floridian LNG project in Martin County, Florida, nor is any of its affiliates.[64] Moreover, the Commission does not have jurisdiction over the exportation and importation of natural gas. Such jurisdiction resides with the U.S. Department of Energy (DOE), which must act on any applications for natural gas export and import authority.[65]

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[62] Florida Southeast Application at Exhibit Z-1.

[63] Florida Power & Light December 23, 2014 Motion to Intervene and Comments in Docket No. CP15-17-000 at 6.

[64] *Id*. at 4, 6.

[65] Section 3(a) of the NGA provides, in part, that "no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so." 15 U.S.C. § 717b(a) (2012). In 1977, the Department of Energy Organization Act transferred the regulatory functions of section 3 of the NGA to the Secretary of Energy. 42 U.S.C. § 7151(b) (2012). Subsequently, the Secretary of Energy delegated to the Commission authority to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports." DOE Delegation Order No. 00-004.00A (effective May 16, 2006). The proposed facilities are not located at a potential site of exit for natural gas exports. Moreover, the Secretary of Energy has not delegated to the Commission any authority to approve or disapprove the import or export of the commodity itself, or to consider whether the exportation or importation of natural gas is consistent with the

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87. As discussed above, 93 percent of the total design capacity of the Sabal Trail project is subscribed under precedent agreements with initial terms of 25 years. This is persuasive evidence of market need for this project. Even though the market, in its consideration of alternative means for addressing energy needs, could have selected renewable energy alternatives and energy efficiency gains, we find that the precedent agreements sufficiently demonstrate the need for the project.[66] Florida Power & Light has specifically determined that it needs service from a new pipeline extending from Transco's Station 85 to a new Central Florida Hub where it will interconnect with the existing Gulfstream and Florida Gas Transmission pipelines. The expansion of existing pipelines in Florida will not satisfy the identified need of a new transportation option.

e. Conclusion

88. In view of the considerations above, we find that Transco, Sabal Trail, and Florida Southeast have demonstrated a need for the Hillabee Expansion Project, Sabal Trail Project, and Florida Southeast Project, respectively, and that each project's benefits to the market will outweigh any adverse effects on other pipelines and their captive customers, and on landowners and surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, we find that the public convenience and necessity requires approval of Transco's, Sabal Trail's, and Florida Southeast's proposals, as conditioned in this order.

2. Blanket Certificate

89. Sabal Trail and Florida Southeast have each applied for a Part 157, Subpart F blanket construction certificate, which is generally applicable to all interstate pipelines. A Part 157, Subpart F blanket certificate will authorize Sabal Trail and Florida Southeast to perform certain routine activities and abandon certain services and facilities automatically, or pursuant to simplified prior notice requests, as is specified in sections 157.208 through 157.218 of the Commission's regulations. Each type of blanket

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public interest. *See Corpus Christi Liquefaction, LLC*, 149 FERC ¶ 61,283, at P 20 (2014) (*Corpus Christi*). *See also National Steel Corp.*, 45 FERC ¶ 61,100, at 61,332-33 (1988) (observing that DOE, "pursuant to its exclusive jurisdiction, has approved the importation with respect to every aspect of it except the point of importation" and that the "Commission's authority in this matter is limited to consideration of the place of importation, which necessarily includes the technical and environmental aspects of any related facilities").

[66] Final EIS at 4-1 to 4-2.

certificate project includes requirements for landowners to be notified before construction of the project.

90. Kiokee-Flint et al. requests that the Commission deny Sabal Trail's request for a blanket certificate pursuant to Part 157, Subpart F because Sabal Trail is a new pipeline with no proven safety or reliability record. Kiokee-Flint et al. also requests that the Commission consider the environmental impacts, including cumulative effects, of the blanket certificate and require mitigation of such impacts in its environmental review pursuant to the National Environmental Policy Act of 1969 (NEPA).[67]

91. The Commission routinely grants a pipeline company a blanket certificate along with the pipeline's certificate to construct and operate its initial facilities. Kiokee-Flint et al. provides no adequate explanation for us to depart from Commission practice. In addition, given that Sabal Trail has not proposed to conduct any activity under a Part 157 blanket certificate, it would be premature for Commission staff to assess the environmental impacts of, or require mitigation for, such potential activities. Commission staff has no information regarding the location, scope, or timing of any potential activity on which to base its environmental review. In the event that Sabal Trail proposes to conduct under its blanket certificate an activity that causes ground disturbance or changes to operational air or noise emissions, Sabal Trail must notify landowners and adhere to the guidance set forth in section 380.15(a) and (b) of the Commission's regulations.[68] Therefore, because Sabal Trail and Florida Southeast will become interstate pipelines with the issuance of a certificate to construct and operate the proposed facilities, we will issue to Sabal Trail and Florida Southeast the requested Part 157, Subpart F blanket certificates.

92. Sabal Trail and Florida Southeast also request Part 284, Subpart G blanket certificates to provide open access transportation services. Under a Part 284 blanket certificate, Sabal Trail and Florida Southeast will not require individual authorizations to provide transportation services to particular customers. Sabal Trail and Florida Southeast

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[67] Kiokee-Flint et al. December 22, 2014 Filing at 26-27. Kiokee-Flint also individually argues that the draft EIS does not sufficiently examine the added impacts of a blanket certificate on landowners along the pipeline route. Kiokee-Flint October 28, 2015 Filing at 22-23.

[68] Section 380.15(a) and (b) state that siting, construction, and maintenance of facilities shall be undertaken in a way that avoids or minimizes effects on scenic, historic, wildlife, and recreational values, and require a pipeline to take into account the desires of landowners in the planning, location, clearing, and maintenance of rights-of-way and the construction of facilities on their property. 18 C.F.R. § 380.15(a)-(b) (2015).

each filed a *pro forma* Part 284 tariff to provide open access transportation services. Since a Part 284 blanket certificate is required for Sabal Trail and Florida Southeast to offer these services, we will grant Sabal Trail and Florida Southeast Part 284 blanket certificates, subject to the conditions imposed in this order.

B. Lease Agreement

93. As explained above, Sabal Trail and Transco have entered into a Capacity Lease Agreement whereby Transco will abandon to Sabal Trail the firm capacity that will be created by Transco's proposed Hillabee Expansion Project. In turn, Sabal Trail will acquire that capacity from Transco and use the leased capacity to provide service under the terms of its FERC Tariff.

94. Historically, the Commission views lease arrangements differently from transportation services under rate contracts. The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline.[69] To enter into a lease agreement, the lessee generally needs to be a natural gas company under the NGA and needs section 7(c) certificate authorization to acquire the capacity. Once acquired, the lessee in essence owns that capacity and the capacity is subject to the lessee's tariff. The leased capacity is allocated for use by the lessee's customers. The lessor, while it may remain the operator of the pipeline system, no longer has any rights to use the leased capacity.[70]

95. The Commission's practice has been to approve a lease if it finds that: (1) there are benefits for using a lease arrangement; (2) the lease payments are less than, or equal to, the lessor's firm transportation rates for comparable service over the terms of the lease on a net present value basis; and (3) the lease arrangement does not adversely affect existing customers.[71] We find that the transportation lease agreement between Sabal Trail and Transco, as modified below, satisfies these requirements.

96. First, the Commission has found that leases in general have several potential public benefits. Leases can promote efficient use of existing facilities, avoid construction of duplicative facilities, reduce the risk of overbuilding, reduce costs, and minimize

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[69] *Texas Eastern Transmission Corp.,* 94 FERC ¶ 61,139, at 61,530 (2001).

[70] *Texas Gas Transmission, LLC,* 113 FERC ¶ 61,185, at P 10 (2005) (*Texas Gas*).

[71] *Id.*; *Islander East Pipeline Co., L.L.C.*, 100 FERC ¶ 61,276, at P 69 (2002) (*Islander East*).

People's Dossier: FERC's Abuses of Power and Law → Undermining Federal Authority

Federal Authority Undermined Attachment 3, Order Issuing Certificates, Atlantic Coast Pipeline, Docket Nos. CP15-554-000 and CP15-554-001, October 13, 2017.

161 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

Atlantic Coast Pipeline, LLC	Docket Nos. CP15-554-000 CP15-554-001
Dominion Transmission, Inc.	CP15-555-000
Atlantic Coast Pipeline, LLC Piedmont Natural Gas Company, Inc.	CP15-556-000

ORDER ISSUING CERTIFICATES

(Issued October 13, 2017)

1. On September 18, 2015, Atlantic Coast Pipeline, LLC (Atlantic) filed an application in Docket No. CP15-554-000, pursuant to section 7(c) of the NGA[1] and Part 157 of the Commission's regulations,[2] for authorization to construct and operate the Atlantic Coast Pipeline Project (ACP Project). On March 11, 2016, Atlantic filed an amendment to its application in Docket No. CP15-554-001. In its amendment, Atlantic proposed several route changes and additional compression at its proposed compressor station in Buckingham County, Virginia. The ACP Project, as amended, consists of approximately 604 miles of new interstate pipeline and related facilities extending from Harrison County, West Virginia, to the eastern portions of Virginia and North Carolina,[3] and 130,345 horsepower (hp) of compression. The ACP Project is designed to provide up to 1.5 million dekatherms per day (Dth/d) of natural gas transportation service. Atlantic also requests approval of its *pro forma* tariff, a blanket certificate under Part 284,

[1] 15 U.S.C. § 717f(c) (2012).

[2] 18 C.F.R. pt. 157 (2017).

[3] The ACP Project extends from West Virginia, southeast to Greensville County, Virginia, then splits into two legs; one leg extending east to the City of Chesapeake, Virginia, and the other leg extending southwest into North Carolina.

Subpart G of the Commission's regulations to provide open-access transportation services, and a blanket certificate under Part 157, Subpart F of the Commission's regulations to perform certain routine construction activities and operations.

2. On September 18, 2015, Dominion Transmission, Inc. (DETI)[4] filed an application in Docket No. CP15-555-000, under sections 7(b) and 7(c) of the NGA[5] and Part 157 of the Commission's regulations,[6] requesting authorization to construct and operate approximately 38 miles of pipeline looping facilities and other facility upgrades and modifications to DETI's existing system in Pennsylvania and West Virginia (Supply Header Project). The Supply Header Project is designed to provide up to 1,511,335 Dth/d of natural gas transportation service from supply areas on the DETI system to the proposed ACP Project. DETI also requests authorization to abandon two previously-certificated gathering compressor units in Wetzel County, West Virginia.

3. Also, on September 18, 2015, Atlantic and Piedmont Natural Gas Company, Inc. (Piedmont) filed a joint application in Docket No. CP15-556-000, pursuant to section 7(c) of the NGA[7] and Part 157 of the Commission's regulations,[8] for approval of a lease pursuant to which Atlantic will lease 100,000 Dth/d of capacity on Piedmont's system for use by Atlantic in providing service under Atlantic's FERC Gas Tariff (Capacity Lease). Additionally, Piedmont requests a limited jurisdiction certificate to carry out its responsibilities under the lease agreement.

4. As explained herein, we find that the benefits that the ACP Project, Supply Header Project, and Capacity Lease will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Further, as set forth in the environmental discussion below, we agree with Commission staff's conclusion in the Environmental Impact Statement (EIS) that, if constructed and operated in accordance with applicable laws and regulations and with the implementation of the applications' proposed mitigation and staff's recommendations, now adopted as conditions in the attached Appendix A of this order, the projects will result in some adverse and significant environmental impacts, but that

[4] On May 12, 2017, Dominion Transmission, Inc. changed its name to Dominion Energy Transmission, Inc.

[5] 15 U.S.C. § 717f(b) and (c) (2012).

[6] 18 C.F.R. pt. 157 (2017).

[7] 15 U.S.C. § 717f(c) (2012).

[8] 18 C.F.R. pt. 157 (2017).

these impacts will be reduced to acceptable levels. Therefore, we grant the requested authorizations, subject to conditions.

I. **Background**

5. Atlantic, a limited liability company organized and existing under the laws of Delaware, was formed to develop, own, and operate the ACP Project and does not currently own any existing pipeline facilities and is not engaged in any natural gas operations. Atlantic is composed of four ownership interests: Dominion Atlantic Coast Pipeline, LLC, a Delaware limited liability company and subsidiary of Dominion Resources, Inc. (48 percent ownership); Duke Energy ACP, LLC, a Delaware limited liability company and subsidiary of Duke Energy Corporation (40 percent ownership); Piedmont ACP Company, LLC, a North Carolina limited liability company and subsidiary of Duke Energy Corporation (7 percent ownership);[9] and Maple Enterprise Holdings, Inc., a Georgia corporation and subsidiary of The Southern Company[10] (5 percent ownership).[11] Upon commencing the operations proposed in its application, Atlantic will become a natural gas company within the meaning of section 2(6) of the NGA[12] and will be subject to the Commission's jurisdiction.

6. DETI, a Delaware corporation,[13] is a natural gas company, as defined in section 2(6) of the NGA.[14] DETI provides natural gas transportation and storage services in Ohio, West Virginia, Pennsylvania, New York, Maryland, and Virginia.

7. Piedmont, a North Carolina corporation, is a local distribution company primarily engaged in the distribution of natural gas to residential, commercial, and industrial utility

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[9] On October 3, 2016, Duke Energy Corporation purchased Piedmont Natural Gas Company, Inc. and became the parent company of Piedmont ACP Company, LLC. Effective on October 3, 2016, Piedmont ACP Company, LLC assigned 3 percent of its original 10 percent ownership interest in Atlantic to Dominion Atlantic Coast Pipeline, LLC.

[10] The Southern Company merged with AGL Resources Inc. in a transaction that closed on July 1, 2016.

[11] *See* Atlantic February 28, 2017 Data Response.

[12] 15 U.S.C. § 717a(6) (2012).

[13] DETI is wholly-owned subsidiary of Dominion Gas Holdings, LLC, which, in turn, is a wholly-owned subsidiary of Dominion Resources, Inc.

[14] 15 U.S.C. § 717a(6) (2012).

customers in North Carolina, South Carolina, and Tennessee. Piedmont is a "public utility" under Chapter 62 of the North Carolina General Statutes and its North Carolina rates and services are regulated by the North Carolina Utility Commission (NCUC).

II. Proposals

A. Atlantic Coast Pipeline Project

1. Facilities and Services

8. The ACP Project, as amended, consists of two mainlines, three lateral lines, three compressor stations, and nine metering and regulating (M&R) stations. Generally, the ACP Project will receive natural gas at the terminus of the Supply Header Project's TL-635 Loop in Harrison County, West Virginia, and transport up to 1.5 million Dth/d to receipt points in West Virginia, Virginia, and North Carolina. The ACP Project will involve the construction of the following facilities:

- approximately 333.1 miles of 42-inch-diameter mainline pipeline originating in Harrison County, West Virginia, and terminating at the location of the proposed Compressor Station 3 in Northampton County, North Carolina (AP-1 Mainline);

- approximately 186.0 miles of 36-inch-diameter mainline pipeline originating at Compressor Station 3 in Northampton County, North Carolina, and terminating at the existing Piedmont pipeline system in Robeson County, North Carolina (AP-2 Mainline);

- approximately 83.2 miles of 20-inch-diameter lateral pipeline originating at Compressor Station 3 in Northampton County, North Carolina, and extending east to an interconnect with the existing Virginia Natural Gas pipeline system in the City of Chesapeake, Virginia (AP-3 Lateral);

- approximately 0.4 miles of 16-inch-diameter lateral pipeline originating at an interconnect point with the AP-1 Mainline near Lawrenceville in Brunswick County, Virginia, and extending west to Dominion Virginia Power's Brunswick Power Station (AP-4 Lateral);

- approximately 1.0 miles of 16-inch-diameter lateral pipeline originating at an interconnect point with the AP-1 Mainline in Greensville County, Virginia, and extending to Dominion Virginia Power's proposed Greensville Power Station (AP-5 Lateral);

- a new compressor station consisting of four natural gas-fired, turbine-driven units, one 20,500 hp unit, one 15,900 hp unit, one 10,915 hp unit, and one 7,700 hp unit, for a total of 55,015 hp, located near milepost (MP) 7.6 of the AP-1 mainline at the proposed Kincheloe M&R station in Lewis County, West Virginia (Compressor Station 1 or Marts Compressor Station);

- a new compressor station consisting of four natural gas-fired, turbine-driven units, one 20,500 hp unit, one 15,900 hp unit, one 10,915 hp unit, and one 6,200 hp unit, for a total of 53,515 hp, located near MP 191.5 of the AP-1 mainline in Buckingham County, Virginia (Compressor Station 2 or Buckingham Compressor Station);

- a new compressor station consisting of three natural gas-fired, turbine-driven units, one 10,915 hp unit, one 6,200 hp unit, and one 4,700 hp unit, for a total of 21,815 hp, located near MP 300.1 of the AP-1 mainline in Northampton County, North Carolina (Compressor Station 3 or Northampton Compressor Station);

- nine new meter stations in West Virginia, Virginia, and North Carolina; and

- various appurtenances.

Atlantic estimates that the proposed facilities will cost $5,071,226,515.

9. Atlantic states that it conducted a non-binding open season from April 16, 2014, to May 9, 2014, for the proposed firm transportation services offered by the project. Atlantic executed binding precedent agreements with the following six shippers for a total of 1.44 million Dth/d of firm transportation service: (1) Duke Energy Progress, LLC (Duke Energy Progress);[15] (2) Duke Energy Carolinas, LLC (Duke Energy Carolinas);[16] (3) Piedmont;[17] (4) Virginia Power Services Energy Corp., Inc.;[18] (5) Public

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[15] Duke Energy Progress, an electricity generator and provider, is a subsidiary of Duke Energy Corporation, which has a 47 percent ownership in Atlantic through its subsidiaries.

[16] Duke Energy Carolinas, an electricity generator and provider, is also a subsidiary of Duke Energy Corporation.

[17] As stated above, on October 3, 2016, Duke Energy Corporation purchased Piedmont.

[18] Virginia Power Services Energy Corp., Inc. is a subsidiary of Virginia Electric and Power Company, which is a subsidiary of Dominion Resources, Inc. Dominion Resources, Inc. has a 48 percent ownership interest in Atlantic through its subsidiaries.

Service Company of North Carolina, Inc.;[19] and (6) Virginia Natural Gas Company, Inc.[20] Atlantic also conducted a binding open season from October 21, 2014, to November 10, 2014, and no additional customers executed binding precedent agreements.

10. Atlantic also requests approval of its proposed *pro forma* tariff. Atlantic proposes initial maximum and minimum recourse reservation and usage rates set forth under Rate Schedules FT (Firm Transportation Service) and IT (Interruptible Transportation Service).

2. Blanket Certificates

11. Atlantic requests a Part 284, Subpart G blanket certificate of public convenience and necessity pursuant to section 284.221 of the Commission's regulations, authorizing Atlantic to provide transportation service to customers requesting and qualifying for transportation service under its proposed FERC Gas Tariff, with pre-granted abandonment authorization.[21]

12. Atlantic also requests a blanket certificate of public convenience and necessity, pursuant to section 157.204 of the Commission's regulations, authorizing future facility construction, operation, and abandonment as set forth in Part 157, Subpart F of the Commission's regulations.[22]

B. DETI Supply Header Project

13. DETI proposes to construct and operate the Supply Header Project, which will provide 1,511,335 Dth/d of transportation service from supply areas on DETI's system to

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Virginia Power Services Energy Corp., Inc. provides fuel, including natural gas, to Dominion's affiliates.

[19] Public Service Company of North Carolina, Inc., a local distribution company, is a subsidiary of SCANA Corporation and has no affiliation with the ACP Project's sponsors.

[20] Virginia Natural Gas Company, Inc., a local distribution company, is a subsidiary of The Southern Company, which has a five percent ownership interest in Atlantic through Maple Enterprise Holdings, Inc.

[21] 18 C.F.R. § 284.221 (2017).

[22] 18 C.F.R. § 157.204 (2017).

the upstream end of the ACP Project in Harrison County, West Virginia. Specifically, DETI proposes to construct:

- approximately 3.9 miles of 30-inch-diameter pipeline that will loop DETI's existing LN-25 pipeline and connect with DETI's existing TL-591 pipeline in Westmoreland County, Pennsylvania (TL-636 Loop);
- approximately 33.6 miles of 30-inch-diameter natural gas pipeline that will loop DETI's existing TL-360 pipeline in Harrison, Doddridge, Tyler, and Wetzel Counties, West Virginia (TL-635 Loop);
- one 20,500 hp natural gas-fired, turbine-driven compressor unit and ancillary equipment at DETI's existing JB Tonkin Compressor Station in Westmoreland County, Pennsylvania;
- one 7,700 hp natural gas-fired, turbine-driven compressor unit and ancillary equipment at DETI's existing Crayne Compressor Station in Greene County, Pennsylvania;
- two 20,500 hp natural gas-fired, turbine-driven compressor units and ancillary equipment at DETI's existing Mockingbird Hill Compressor Station in Wetzel County, West Virginia; and
- six valve sites and two sets of pig launcher and receiver sites.

14. Additionally, DETI requests authorization to abandon Compressor Units 1 and 2 at its Hastings Compressor Station in Wetzel County, West Virginia. DETI states that, in 2006, the Commission approved the refunctionalization of the compressor units from transmission to gathering, but because DETI intended to continue to use the compressor units, the Commission explained that DETI would need to seek abandonment authority from the Commission in the future as necessary.[23] DETI proposes to replace Hastings Compressor Units 1 and 2 with new, more efficient units that will meet the applicable state and federal air quality requirements.[24] DETI asserts that the replacement units will continue to serve a non-jurisdictional function.

[23] *Dominion Transmission, Inc.*, 114 FERC ¶ 61,266 (2006).

[24] DETI states that the proposed units at its Mockingbird Hill Compressor Station will be included in the same Title V air permit as DETI's Hastings Compressor Station and Lewis Wetzel Compressor Station. DETI asserts that its initial design studies indicated that the additional compression needed for the Supply Header Project could

15. The total estimated cost for the Supply Header Project is $486,388,831. DETI conducted a binding open season between October 21, 2014, and November 17, 2014, for the Supply Header Project's proposed firm transportation services.[25] As a result of the open season, DETI executed a binding precedent agreement with Atlantic for 1,450,882 Dth/d of firm transportation service. DETI and Atlantic have entered into a negotiated rate agreement for service on the Supply Header Project.

C. Atlantic's Lease of Capacity on Piedmont's System

16. Atlantic and Piedmont seek approval of a lease, pursuant to which Atlantic will lease capacity on Piedmont's system for use by Atlantic in providing service under Atlantic's FERC Gas Tariff, principally for Public Service Company of North Carolina, Inc. (PSNC). Specifically, Atlantic would lease 100,000 Dth/d on Piedmont's system from the point of interconnection between the ACP Project and Piedmont in Johnson County, North Carolina, to a delivery point between Piedmont and PSNC near Clayton, North Carolina. The Capacity Lease would continue for a primary term of 20 years, consistent with the term of Atlantic's precedent agreement with PSNC.

17. The Capacity Lease requires Atlantic to pay Piedmont a monthly lease charge for the leased capacity. The leased capacity will be treated as part of Atlantic's system for nomination and scheduling purposes, with points identified and made available on Atlantic's electronic scheduling system. Atlantic and Piedmont state that the Capacity Lease will allow Atlantic to provide service to PSNC (or any other customer that may take service off the capacity leased on Piedmont's system) without requiring a direct interconnect between the ACP Project and PSNC's system, thus avoiding the need for the additional construction and environmental disturbance that would be associated with extending the ACP Project to PSNC's system.

18. Piedmont also requests a limited jurisdiction certificate in order to enter into the Capacity Lease with Atlantic to allow for the interstate transportation of natural gas through Piedmont's facilities. Last, Piedmont seeks a determination that the Capacity Lease will not affect its status as a local distribution company not otherwise subject to Commission jurisdiction.

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potentially exceed air quality limits unless the two 500 hp Hasting Compressor units are replaced.

[25] DETI states that it conducted a reverse open season during the same time period but received no bids in response.

III. Procedural Issues

A. Notice, Interventions, Protests, and Comments

19. Notice of applications in Docket Nos. CP15-554-000, CP15-555-000, and CP15-556-000 was published in the *Federal Register* on October 8, 2015 (80 Fed. Reg. 60,886). Notice of the amendment to Atlantic's application in Docket No. CP15-554-001 was published in the *Federal Register* on March 31, 2016 (81 Fed. Reg. 18,623). In each docket, a number of timely and late motions to intervene were filed.[26] Timely, unopposed motions to intervene are granted automatically pursuant to Rule 214 of the Commission's Rules of Practice and Procedure.[27] On November 8, 2016, and January 18, 2017, the Commission issued notices granting numerous late motions to intervene. We grant the remaining unopposed late motions to intervene.[28]

20. Numerous landowners and environmental groups filed protests in response to Atlantic's and DETI's applications. The NCUC protested certain rate and tariff proposals. On December 4, 2015, Atlantic and DETI filed a joint answer to the protests. Shenandoah Valley Network, Friends of the Central Shenandoah, and Friends of Wintergreen filed answers in response to Atlantic and DETI's Answer. Although the Commission's Rules of Practice and Procedure generally do not permit answers to protests or answers to answers,[29] our rules also provide that we may, for good cause, waive this provision.[30] We will accept all the responsive pleadings filed in this proceeding because they have provided information that assisted us in our decision-making process.

21. In addition, we received numerous comments in support of the ACP Project, asserting it would, among other things, bring jobs to the area, increase economic growth,

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[26] The Commission's regulations provide that interventions are timely if filed during the comment period on the notice of the application or if filed on environmental grounds during the comment period of the draft EIS. 18 C.F.R. §§ 157.10, 380.10(a), 385.214(c) (2017). Thus, if interventions are filed outside of these periods, the intervention is late. *See Florida Southeast Connection, LLC*, 154 FERC ¶ 61,080, at P 40 n.13 (2016).

[27] 18 C.F.R. § 385.214(c) (2017).

[28] 18 C.F.R. § 385.214(d) (2017).

[29] 18 C.F.R. § 385.213(a)(2) (2017).

[30] 18 C.F.R. § 385.101(e) (2017).

and provide affordable natural gas supplies to consumers, and a large number of comments raising concerns over the need for and the environmental impacts of the proposed projects. These concerns are addressed in the EIS and below.

B. Request for Evidentiary Hearing

22. Some interveners and commenters object to Atlantic's use of shortened procedures pursuant to Rules 801 and 802 of the Commission's Rules of Practice and Procedure,[31] and request an evidentiary hearing. Conservation Groups[32] argue that allegations concerning the need for the proposed projects cannot be resolved on the basis of the written record. In its June 21, 2017 Motion for an Evidentiary Hearing, Conservation Groups aver that the disputed facts will depend on live testimony from multiple, conflicting experts offering opinions on complex technical issues related to pipeline financing, electricity demand forecasting, existing pipeline capacity, and renewable energy forecasting. Conservation Groups state that expert testimony and cross examination is essential for the Commission to effectively evaluate the credibility and reliability of each witness.

23. Section 7 of the NGA provides for a hearing when an applicant seeks a certificate of public convenience and necessity, but does not require that all such hearings be formal, trial-type hearings.[33] An evidentiary trial-type hearing is necessary only when there are material issues of fact in dispute that cannot be resolved on the basis of the written record.[34] The issues raised in this proceeding, including those concerning the need for the proposed projects, have been adequately argued, and a determination can be made on the basis of the existing record in this proceeding. All interested parties have been afforded a full complete opportunity to present their views to the Commission through numerous written submissions. We find that there is no material issue of fact that we cannot resolve on the basis of the written record in the proceeding. Therefore, we will deny the request for a formal, trial-type hearing.

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[31] 18 C.F.R. §§ 385.801 and 385.802 (2017).

[32] Conservation Groups are Shenandoah Valley Network, Highlanders for Responsible Development, Virginia Wilderness Committee, Shenandoah Valley Battlefields Foundation, Natural Resources Defense Council, Cowpasture River Preservation Association, Friends of Buckingham, and Winyah Rivers Foundation.

[33] *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240, at P 25 (2012).

[34] *See, e.g., Southern Union Gas Co. v. FERC*, 840 F.2d 964, 970 (1988); *Dominion Transmission, Inc.*, 141 FERC ¶ 61,183, at P 15 (2012).

IV. <u>Discussion</u>

24. Since the proposed facilities will be used to transport natural gas in interstate commerce, subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA.

A. <u>Application of Certificate Policy Statement</u>

25. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new pipeline construction.[35] The policy statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. It explains that, in deciding whether to authorize the construction of major new facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

26. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, and landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis where other interests are considered.

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[35] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

1. Atlantic Coast Pipeline Project

a. Subsidization and Impacts on Existing Customers

27. As discussed above, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without subsidization from existing customers. Friends of the Central Shenandoah argue that because a subsidiary and parent are one unit,[36] the ACP Project is subsidized by the affiliated shippers' captive ratepayers. Friends of the Central Shenandoah assert that lower cost options for natural gas transportation are available and these affiliated shippers will pass on the higher costs of the ACP Project to their ratepayers.

28. The Commission's test regarding subsidization analyzes the impacts on existing customers of the pipeline, not customers of the affiliated shippers.[37] Atlantic is a new pipeline entrant with no existing customers. Thus, there is no potential for subsidization on Atlantic's system or degradation of service to existing customers. Issues concerning proposed service to affiliated shippers are discussed more fully below.

b. Need for the Project

29. Several parties and commenters challenged the need for the ACP Project. They raise a variety of arguments including: (1) the availability of existing infrastructure to serve markets; (2) insufficient demand for natural gas in Virginia and North Carolina; (3) insufficient production growth in the Appalachian Basin; (4) the availability of renewable energy to meet future demand for electricity generation; (5) the need for a regional analysis to determine if the project is needed; and (6) the use of precedent agreements with affiliated utilities to demonstrate project need. The commenters also challenged the studies submitted by Atlantic showing that the project is needed to serve demand growth in Virginia and North Carolina. On December 4, 2015, Atlantic filed an answer to the initial comments.[38]

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[36] Friends of the Central Shenandoah cite *Copperweld Corp. v. Independence Tube Corp*., 467 U.S. 752 (1984), where the Court stated that a subsidiary and its parent are "in reality, one unit." Friends of the Central Shenandoah April 3, 2017 Comments at 11.

[37] Certificate Policy Statement, 88 FERC at 61,745.

[38] Atlantic's answer was filed in response to comments made during the initial notice of application comment period. Since that time, additional comments related to the need for the proposed project have been filed. All comments concerning project need are addressed here.

i. **Existing Infrastructure to Serve Markets**

30. Commenters argue that there is not currently a supply constraint in the region and that there is adequate natural gas infrastructure to serve future market demand in Virginia and North Carolina. Commenters assert that a study conducted by Synapse Energy Economics Inc. (Synapse),[39] which compares the region's existing natural gas supply capacity to its expected future peak demand for natural gas, concluded that, given the existing pipeline and natural gas storage capacity, the expected flow reversal on the Transcontinental Gas Pipe Line Company, LLC (Transco) pipeline system under the Atlantic Sunrise Project,[40] and the expected upgrade of an existing Columbia Gas Transmission (Columbia) pipeline,[41] the capacity of the Virginia-Carolinas region's natural gas infrastructure is more than sufficient to meet expected future peak demand.[42] Commenters also note that both Duke Energy Progress and Duke Energy Carolinas have testified before their state commission that adequate pipeline capacity already exists for their planned construction projects.[43]

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[39] Synapse Energy Economics Inc., *Are the Atlantic Coast Pipeline and Mountain Valley Pipeline Necessary?* (Sept. 12, 2016) (filed Dec. 20, 2016) (Synapse Study).

[40] The Atlantic Sunrise Project, approved by the Commission on February 3, 2017, will provide up to an additional 1.7 million Dth/d of firm transportation service from northern Pennsylvania to Alabama. *Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 (2017) (*Transco*).

[41] The Synapse Study cites the WB Express Project, which would provide up to an additional 1.3 million Dth/d of bi-directional firm transportation service on Columbia's system, which is located in the ACP Project area. The WB Express Project is currently pending before the Commission, in Docket No. CP16-38-000.

[42] Specifically, the Synapse Study analyzes the winter peak hour gas usage under various scenarios, and finds that, even under the highest gas usage scenario modeled, natural gas supply exceeds demand by approximately 100 MMcf through 2030. Synapse Study at Figure ES-2.

[43] *See, e.g.,* Friends of Nelson July 5, 2017 Comments at 29 (citing Direct Testimony of Swati V. Daji, NCUC Docket No. E-100-147, at 14 (Feb. 16, 2017) ("Currently, Duke Energy has agreements in place that provide firm transportation to eleven current and future gas generation facilities in North and South Carolina including all of Duke Energy's current and approved combined cycle facilities as well as several combustion turbine sites")).

31. Commenters also state that the U.S. Department of Energy (DOE) found that average pipeline utilization between 1998 and 2013 is only 54 percent and that with changes to existing infrastructure, new natural gas pipelines will not likely be needed to supply gas to Southeastern markets.[44] Additionally, commenters note that the Commission has repeatedly found that if pipeline projects are not built, production would reach markets by alternative means.

32. Moreover, commenters assert that relying on Transco's and Columbia's systems has the added benefit of providing shippers more diverse supply sources. Commenters state that the lower cost of gas from the Appalachian Basin is offset by Atlantic's high transportation costs. Thus, commenters conclude that supplying gas by reconfiguring existing infrastructure through pipeline reversals or expansions of existing systems would be more economical and have less of an impact on the environment.

ii. Insufficient Demand for Natural Gas in Virginia and North Carolina

33. Commenters also contend that there is a lack of need for additional natural gas in the markets being served by the ACP Project. Commenters assert that neither Virginia nor North Carolina is expected to experience an increase in natural gas demand, calling into question whether additional natural gas-fired generation will be built.[45]

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[44] *See, e.g.,* Shenandoah Valley Network October 23, 2015 Motion to Intervene at 12 (citing U.S. DEP'T OF ENERGY, *NATURAL GAS INFRASTRUCTURE IMPLICATIONS OF INCREASED DEMAND FROM THE ELECTRIC POWER SECTOR*, (Feb. 2015), http://energy.gov/epsa/ downloads/report-natural-gas-infrastructure-implications-increased-demand-electricpower-sector).

[45] Commenters cite: (1) the utilities downward revisions to their load forecasts; (2) the U.S. Energy Information Administration's (EIA) 2017 Energy Outlook, which estimates that South Atlantic demand for natural gas for electricity generation will decrease from 2015 to 2020; and (3) a study by ICF International, which found that Virginia is not likely to experience a significant increase in natural gas demand. *See, e.g.*, Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing (citing Direct Testimony of James F. Wilson, Va. State Corp. Comm., Case No. PUE-2016-00049 (Aug. 17, 2016); U.S. Energy Information Admin., Annual Energy Outlook 2017 Reference Case Table A2, (Jan. 2017), https://www.eia.gov/outlooks/aeo/; ICF International, *The Economic Impacts of the Atlantic Coast Pipeline* (February 9, 2015)).

34. Commenters further contend that the Integrated Resource Plans of Dominion Virginia Power,[46] Duke Energy Progress, and Duke Energy Carolinas overestimate future demand.[47] Specifically, commenters state that Duke Energy Progress' and Duke Energy Carolinas' 2016 plans may overestimate demand because they (1) assume a peak winter load for the first time; (2) underestimate the growth of renewable generation; and (3) include high reserve margins.[48] With respect to Dominion Virginia Power, commenters note that for 2027, PJM Interconnection's (PJM)[49] 2017 forecast is approximately 3,500 Megawatts (MW) less than Dominion Virginia Power's own projection from its 2016 plan.[50]

35. The 2016 Synapse Study, submitted by several commenters, finds that the EIA projections relied upon by Atlantic to show a need for additional capacity in the region are out of date and have been significantly modified.[51] Commenters further contend that Atlantic wrongly relies on the Clean Power Plan to support claims of natural gas demand

[46] Dominion Virginia Power will receive gas from the ACP Project from Virginia Power Services Energy Corp., Inc.

[47] Moreover, commenters note that Duke Energy Carolinas' and Duke Energy Progress' most recent integrated resource plans do not mention the ACP Project as a source of natural gas supply. *See, e.g.,* Friends of Nelson July 5, 2017 Comments at 29 (citing Duke Energy Progress, Integrated Resource Plan (Annual Report) at 16, NCUC Docket E-100-141 (Sept. 1, 2014); Duke Energy Carolinas, Integrated Resource Plan (Annual Report) at 16, NCUC Docket E-100-141 (Sept. 1, 2014)).

[48] *See, e.g.*, Public Interest Groups April 5, 2017 Comments at 23.

[49] PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[50] *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing (citing Direct Testimony of James F. Wilson, Va. State Corp. Comm., Case No. PUE-2016-00049 at 15-17 (Aug. 17, 2016)).

[51] Synapse Study at 14-15. Commenters further note that EIA, PJM, and the individual utilities have all revised their projections downward from their 2014 assessments, when the ACP Project was initially conceived. *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing at 5.

growth because the Clean Power Plan has been stayed and the current administration is not likely to pursue its implementation.[52]

36. Next, commenters assert that the ACP Project is not needed to supply gas to the Greensville and Brunswick Power Stations, two power plants directly connected to the ACP Project, because those plants are already being served from the same supply region by Transco at a lower rate.[53] Commenters further state that when the power plants were approved by the Virginia State Corporation Commission, Virginia Electric and Power Company cited existing pipelines as its source for natural gas and did not rely on the fact that either plant was connected to the ACP Project.[54] Additionally, commenters note that supplying these same two power plants has already been cited for the approval of two Transco expansion projects.[55] With respect to the potential to supply future generating facilities, commenters note that the location and timing of those generating facilities is not currently known.[56]

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[52] On October 10, 2017, the U.S. Environmental Protection Agency issued a notice of proposed rulemaking to repeal the regulations implementing the Clean Power Plan.

[53] Comparing the recourse rates for the ACP Project to the Transco Southside Expansion Project, which supplies gas to the Brunswick Power Station, commenters state that transporting gas via the ACP Project results in an additional $218.5 million in costs for the first year. *See, e.g.,* Friends of the Central Shenandoah April 3, 2017 Comments at 14.

[54] *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing at 23 (citing State Corporation Commission of Virginia, "Final Order," Case No. PUE-2012-00128 (Aug. 2, 2013) and Application of Virginia Electric and Power Company for Approval and Certification of the Proposed Greensville County Power Station Electric Generation and Related Transmission Facilities Under §§ 56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for Approval of a Rate Adjustment Clause, Designated Rider GV, Under § 56-585.1 A 6 of the Code of Virginia, Case No. PUE-2015-00075, at 7).

[55] Transco's Southside Expansion Project, which was approved by the Commission and went into service in 2015, connects to the Brunswick Power Station. The Greensville Power Station will be served by Transco's Southside Expansion Project II, which was approved by the Commission in 2016.

[56] *See, e.g.,* Friends of Nelson April 5, 2017 Comments (citing Atlantic's December 8, 2016 Data Response at Question 3). Commenters state that although the ACP Project is expected to be online by 2019, Duke Energy Carolinas and Duke Energy Progress do not plan to bring new generation online before 2022. With respect to

37. Last, commenters argue that since additional natural gas is not needed to serve market demand in Virginia and North Carolina, the real purpose of the project is to deliver gas to DETI's Cove Point LNG terminal. Commenters contend that the Commission should not grant a certificate for the ACP Project if its primary purpose will be to export natural gas.

iii. **Insufficient Natural Gas Production in the Appalachian Basin**

38. Commenters argue that there is not sufficient production from the Appalachian Basin to justify the ACP Project and other proposed projects in the region.[57] Commenters assert that shale production will peak around 2020 and then decline significantly, absent a change in natural gas prices. Commenters contend that the EIA projections ignore that shale wells decline quickly (75 to 85 percent in first 3 years) and that the most productive areas of shale plays have already been developed. Thus, they say, it is not realistic to presume that there will be enough supply for the useful life of the ACP and other projects, and that doing so may lead to stranded pipeline and generation assets.

39. Commenters note that industry experts and executives have stated that production in the Appalachian Basin is slowing and takeaway capacity is expected to be overbuilt.[58] Commenters argue that because the price of natural gas has fallen, many shale gas producers may be unable to produce gas at a profitable price and will subsequently shut down their production.

Dominion Virginia Power, commenters note that it has not applied for or obtained approval to construct any new natural gas-fired facilities, much less any plant that will rely exclusively on the ACP Project for fuel supply. *See, e.g.,* Shenandoah Valley Network June 21, 2017 Motion for Evidentiary Hearing.

[57] Commenters cite FERC Office of Enforcement Division of Energy Market Oversight, 2014 State of the Markets Presentation at Slide 8 (March 19, 2015); Joanna Wu, *US Gas Insight*: *Midstream Madness,* Bloomberg New Energy Finance (Mar. 8, 2016); Jeremiah Shelor, *Marcellus/Utica On Pace for Pipeline Overbuild, Says Braziel*, NGI's Daily Gas Price Index (June, 8 2016). *See, e.g.,* Friends of the Central Shenandoah April 3, 2017 Comments at 22-24.

[58] *See, e.g.* Appalachian Mountain Advocates June 2, 2016 Comments at Attachment (Institute for Energy Economics and Financial Analysis, *Risks Associated with Natural Gas Pipeline Expansion in Appalachia* at 11-13 (April 2016) (IEEFA Study)).

iv. <u>**Use of Renewable Energy to Serve Electricity Demand**</u>

40. Commenters argue that under the NGA, the Commission should reject proposals when alternative proposals would better serve public convenience and necessity, even when the Commission lacks the authority to mandate the alternative.[59] Thus, commenters aver that the Commission should consider whether renewable energy could better serve the need for additional generation in Virginia and North Carolina.[60]

41. Commenters assert that renewable energy may replace the need for the project in the future. Citing the Clean Power Plan and the decreasing costs of renewable energy, commenters note that states will be increasingly moving toward renewable energy to meet emission targets, which may result in stranded natural gas assets. Additionally, commenters note that large energy consumers are increasingly demanding or planning to switch to 100 percent renewable energy to meet their needs. Moreover, Appalachian Mountain Advocates (AMA)[61] assert that unlike renewable energy, which has a fixed fuel cost, natural gas-fired generation poses risks to consumers if natural gas prices fluctuate.

42. Commenters also argue that approval of natural gas infrastructure will foreclose investment in renewable energy sources in the future. Commenters argue that instead of investing in natural gas-fired electricity, utilities should invest in renewable resources, which more closely align with long-term goals to reduce greenhouse gases. Oil Change International argues that any assessment of need for a proposed project should consider climate goals.

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[59] Commenters cite *City of Pittsburgh v. FPC*, 237 F.2d 741, at 756 n.28 (D.C. Cir. 1956).

[60] Commenters state that the Commission must also consider colocation with other pipelines and utility rights-of-way and whether modifications to existing infrastructure can serve the same markets with fewer environmental impacts. The final EIS evaluated these alternatives. *See* Final EIS at § 3.0.

[61] AMA filed comments on behalf of Allegheny Defense Project, Appalachian Voices, Center for Biological Diversity, Chesapeake Climate Action Network, Christians for the Mountains, Citizens Climate Lobby, Dominion Pipeline Monitoring Coalition, Eight Rivers Council, Friends of Water, Mountain Lakes Preservation Alliance, Ohio Valley Environmental Coalition, Sierra Club, Virginia Chapter of the Sierra Club, West Virginia Highlands Conservancy, and Wild Virginia.

v. Regional Plan for Natural Gas Pipeline Infrastructure

43. Commenters contend that the Commission should evaluate the need for new pipeline infrastructure on a region-wide basis. As noted above, commenters argue that there is insufficient supply in the Appalachian Basin for all of the proposed pipeline projects and there is insufficient need for new pipeline capacity serving markets in Virginia and North Carolina. Commenters argue that if all the projects serving the Appalachian Basin are built, ratepayers will be paying for unused capacity.[62] AMA argues that the Commission must conduct an independent investigation of the actual need for the ACP Project in order to protect consumers, as required by the NGA. Commenters further assert that even if more pipeline capacity is needed to serve southern markets, other pipeline projects may be more environmentally advantageous.[63]

vi. Precedent Agreements with Affiliated Shippers

44. Commenters argue that because all but one of the shippers on the ACP Project are affiliated with the project's developers, those contracts are not sufficient to demonstrate project need. Commenters argue that the Certificate Policy Statement requires the Commission to examine "all relevant factors reflecting on the need for the project"[64] and states that "traditional factors for establishing the need for a project, such as contracts and precedent agreements, may no longer be a sufficient indicator that a project is in the public convenience and necessity."[65] Additionally, commenters emphasize that the

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[62] *See, e.g.,* Public Interest Groups April 5, 2017 Comments (citing IEEFA Study at 12).

[63] The Synapse Study avers that considering each new pipeline proposal in isolation ignores important alternatives, such as upgrades to existing pipelines and storage facilities, which would increase regional natural gas supply capacity and avoid the adverse impacts on communities or the environment. Synapse Study at 4. Similarly, the IEEFA Study argues that the Commission should evaluate regional requirements for additional pipeline capacity similar to other infrastructure programs such as electric transmission and highways. IEEFA Study at 6.

[64] *See, e.g.,* Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,747).

[65] *See, e.g.,* Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 90 FERC at 61,390). Commenters also cite to former Chairman Norman Bay's statement that the Commission should look beyond precedent agreements and reevaluate its test for need. *See, e.g.,* Friends of Nelson April 5, 2017 Comments (citing

Certificate Policy Statement states that "[a] project that has precedent agreements with multiple new customers may present a greater indication of need than a project with only a precedent agreement with an affiliate"[66] and "using contracts as the primary indicator of market support for the proposed pipeline project . . . raises additional issues when the contracts are held by pipeline affiliates."[67] Friends of the Central Shenandoah note that in Order No. 497, the Commission stated that there is an economic incentive for the pipeline to favor "transactions conducted on a pipeline that benefits the pipeline or the corporate group of which it is a part."[68]

45. Commenters further contend that Atlantic's failure to provide a study showing that the ACP Project is needed conflicts with the Certificate Policy Statement. Commenters note that the policy statement states that when, as here, a new pipeline will serve markets already reached by existing infrastructure, "the evidence necessary to establish the need for the project will usually include a market study."[69]

46. Next, Commenters argue that, without looking behind the precedent agreements supporting the ACP Project, the Commission cannot determine whether the shipper commitments represent a genuine growth in market demand to warrant construction. Commenters assert that affiliated shippers have no incentive to seek out the lowest cost transportation for their gas. Instead, the shippers are incentivized to contract with their affiliate since all costs, including the rate of return of 14 percent, are recoverable from captive ratepayers.[70] Thus, all the risks associated with the pipeline project are shifted to

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Separate Statement of Chairman Bay in *National Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017)).

[66] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,748).

[67] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,744).

[68] Friends of the Central Shenandoah April 3, 2017 Comments at 10 (citing *Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines*, Order No. 497, FERC Stats. & Regs. ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, FERC Stats. & Regs. ¶ 30,868 (1989)).

[69] *See, e.g.*, Friends of Nelson April 5, 2017 Comments (citing Certificate Policy Statement, 88 FERC at 61,748).

[70] Commenters claim that Dominion Resources, Inc. and Duke Energy Corporation will likely realize more profits from sales of electricity from gas-fired

captive ratepayers.[71] Moreover, Public Interest Groups urge the Commission to view with skepticism precedent agreements that were not connected to the open season process.[72]

47. Last, AMA avers that the public utility regulators in Virginia and North Carolina have not conducted a meaningful review of the precedent agreements and whether the shippers' should recover the costs of the contracts from ratepayers. AMA asserts that it is unlikely that state regulators will have the opportunity to examine the economic necessity for the pipeline prior to a decision on Atlantic's certificate application.[73] AMA states that even though the North Carolina Utilities Commission authorized Duke Energy Progress, Duke Energy Carolinas, and Piedmont to enter into affiliated contracts with Atlantic in 2014, it did not evaluate the necessity for the pipeline or consider whether the affiliated contracts would allow an unnecessary project to proceed.[74] Moreover, AMA notes that those approvals occurred nearly three years ago, and, according to Duke Energy's own analysis, the market demand for natural gas for electricity generation in North Carolina has since dropped.

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generators because they own the ACP Project, rather than simply purchasing natural gas and counting it as an expense.

[71] However, the IEEFA Study acknowledges that investors are subject to some risk regarding the project if state regulators refuse to let the affiliated shippers pass through the costs of the transportation contracts to ratepayers. IEEFA Study at 21.

[72] Public Interest Groups April 5, 2017 Comments at 28 (citing *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277, at 62,141 (2002) (citing *Independence Pipeline Co.*, 89 FERC ¶ 61,283, at 61,840 (1999)) ("The proffered precedent agreement was not the result of, or related to, Independence's open season. For this reason, we found that the DirectLink agreement did not constitute reliable evidence of market need to support a finding that the proposal was required by the public convenience and necessity.")).

[73] Similarly, the IEEFA Study, which was submitted by multiple commenters, concludes that the state regulatory processes do not have the ability to prevent overbuilding because any prudency determination by a state regulator would likely occur after the pipeline is already placed into service and any challenge to the rates charged by the interstate pipeline would be under the Commission's exclusive jurisdiction.

[74] AMA notes that Dominion Virginia Power has not sought approval from the Virginia State Corporation Commission for its affiliate contracts to accept gas from the pipeline, and the Virginia State Corporation Commission will not review contracts for gas purchases on the ACP Project until after pipeline construction concludes.

vii. Inadequacy of Atlantic's Studies

48. Several commenters filed a 2015 review, conducted by Synapse, of the ICF International analysis and the Chmura Economics and Analytics analysis filed by Atlantic with its application.[75] The 2015 Synapse Report concluded that the analyses overestimated the benefits of the pipeline.[76] Specifically, the 2015 Synapse Report finds that the ICF International analysis wrongly assumes, without support, that the price differential between the Dominion South point and Henry Hub will be between $1.50 and $1.75. The 2015 Synapse Report notes that in 2015, on average, the price spread was only $0.81[77] and that the prices at the Dominion South point and Henry Hub are converging.[78] Moreover, the 2015 Synapse Report finds that even assuming the price differential reported by ICF International, because of higher transportation costs associated with the project, there are no annual net savings from the ACP Project until 2027.[79]

49. Next, the 2015 Synapse Report states that it is unclear whether ICF International's energy cost savings for Virginia residents is properly calculated. The 2015 Synapse Report notes that due to the state's membership in PJM, any cost savings would be distributed throughout the entire region and not be solely allocated to Virginia customers.[80] The 2015 Synapse Report also states that the ICF International analysis wrongly asserts that the proposed project will help consumers by reducing volatility in the market because volatility in the wholesale markets do not create volatility in the

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[75] Synapse Energy Economics Inc., *Atlantic Coast Pipeline Benefits Review* (June 12, 2015) (filed June 12, 2016) (2015 Synapse Report).

[76] The ICF International analysis, the Chmura Economics and Analytics analysis, and 2015 Synapse Study discuss the effects of the ACP Project on jobs and the economy of the region. These socioeconomic effects are discussed in the final EIS and below. Here, we review only those issues related to the need for the proposed project.

[77] Commenters also note that as more takeaway capacity from the Marcellus shale is built, the price differential will decrease even more.

[78] 2015 Synapse Report at 2-3.

[79] *Id*. at 4. The IEEFA Study comes to similar conclusions when analyzing Atlantic's claims. IEEFA Study at 19.

[80] 2015 Synapse Report at 6-7.

regulated retail markets.[81] Last, the 2015 Synapse Report asserts that ICF International wrongly states that the proposed project will enhance electric reliability in the region. The 2015 Synapse Report asserts that any improvement in electric reliability would be the result of new generation being built and not because of the pipeline being in place.[82]

viii. Atlantic's Answer

50. In its December 4, 2015 answer, Atlantic states that it has entered into precedent agreements with end users for 96 percent of its capacity. Atlantic notes that the genesis for the project was a response to a solicitation by Duke Energy Corporation and Piedmont for competitive firm transportation to North Carolina to serve its growing need for natural gas. Additionally, Virginia Power Services Energy Corporation also requested proposals for firm transportation to serve natural gas-fired generation in Virginia. Atlantic states that these customers viewed the ACP Project as the best way to support their growing need for natural gas. Atlantic notes that all the project's customers and several producer groups have filed comments supporting the project.

51. Atlantic contends that the Commission's long-standing policy is that contracts are strong evidence of market demand and commenters wrongly assert that market studies are the best evidence of demand for a project. Atlantic further notes that EIA studies document growing demand for natural gas in Virginia and North Carolina and that the Clean Power Plan encourages utilities to switch from coal-fired generation to natural gas. Moreover, Atlantic asserts that the ACP Project will improve electric reliability by enhancing gas supply security and providing flexibility and optionality to generators. Atlantic contends that the ACP Project will result in a net energy cost savings to consumers of $377 million between 2019 and 2038.

52. Next, Atlantic asserts that existing and proposed pipelines cannot replace the need for the ACP Project. Atlantic states that its customers chose the ACP Project as the best means to meet their needs and the Commission has no basis to second guess those commercial decisions. With respect to unused capacity on existing pipelines, Atlantic notes that the historic load factor does not suggest that firm transportation is available to Atlantic's customers. Atlantic acknowledges that flow reversals of existing pipelines are occurring, but states that those projects have their own customers.

53. With respect to renewable energy, Atlantic states that natural gas-fired generation provides flexibility for the region's utilities to continue working to incorporate renewable energy into their portfolios. Atlantic notes that its customers have determined that more

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[81] *Id.* at 7.

[82] *Id.*

natural gas generation is required and the ACP Project is the best way to serve those generators.

ix. **Commission Determination**

54. The Certificate Policy Statement established a new policy under which the Commission would allow an applicant to rely on a variety of relevant factors to demonstrate need, rather than continuing to require that a percentage of the proposed capacity be subscribed under long-term precedent or service agreements.[83] These factors might include, but are not limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[84] The Commission stated that it would consider all such evidence submitted by the applicant regarding project need. Nonetheless, the policy statement made clear that, although precedent agreements are no longer required to be submitted, they are still significant evidence of project need or demand.[85] As the court affirmed in *Minisink Residents for Environmental Preservation & Safety v. FERC*, the Commission may reasonably accept the market need reflected by the applicant's existing contracts with shippers.[86] Moreover, it is current Commission policy to not look behind precedent or service agreements to make judgments about the needs of individual shippers.[87]

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[83] Certificate Policy Statement, 88 FERC at 61,747. Prior to the Certificate Policy Statement, the Commission required a new pipeline project to have contractual commitments for at least 25 percent of the proposed project's capacity. *See* Certificate Policy Statement, 88 FERC ¶ 61,227 at 61,743. The ACP Project, at 96 percent subscribed, would have satisfied this prior, more stringent, requirement.

[84] Certificate Policy Statement, 88 FERC at 61,747.

[85] *Id*.

[86] *Minisink Residents for Envtl. Pres. & Safety v. FERC*, 762 F.3d 97, 110 n.10 (D.C. Cir. 2014); *see also Sierra Club v. FERC*, 867 F.3d 1357, 1379 (D.C. Cir. 2017) (finding that pipeline project proponent satisfied the Commission's "market need" where 93 percent of the pipeline project's capacity has already been contracted for).

[87] Certificate Policy Statement, 88 FERC at 61,744 (citing *Transcontinental Gas Pipe Line Corp.*, 82 FERC ¶ 61,084, at 61,316 (1998)).

55. We find that Atlantic has sufficiently demonstrated that there is market demand for the project. Atlantic has entered into long-term, firm precedent agreements with six shippers for 1,440,000 Dth/d of firm transportation service, approximately 96 percent of the system's capacity.[88] Further, Ordering Paragraph (K) of this order requires that Atlantic and DETI file a written statement affirming that they have executed final contracts for service at the levels provided for in their precedent agreements prior to commencing construction. The shippers on the ACP Project supply gas to end users and electric generators, and those shippers have determined that natural gas will be needed and the ACP Project is the preferred means of obtaining that gas. We find that the contracts entered into by those shippers are the best evidence that additional gas will be needed in the markets that the ACP Project intends to serve. We also find that end users will generally benefit from the project because it would develop gas infrastructure that will serve to ensure future domestic energy supplies and enhance the pipeline grid by connecting sources of natural gas to markets in Virginia and North Carolina.[89]

56. We disagree with commenters' assertion that the Commission should examine the need for pipeline infrastructure on a region-wide basis. Commission policy is to examine the merits of individual projects and each project must demonstrate a specific need.[90] While the Certificate Policy Statement permits the applicant to show need in a variety ways, it does not suggest that the Commission should examine a group of projects together and pick which projects best serve an estimated future regional demand. In fact, projections regarding future demand often change and are influenced by a variety of factors, including economic growth, the cost of natural gas, environmental regulations, and legislative and regulatory decisions by the federal government and individual states. Given the uncertainty associated with long-term demand projections, such as those presented in the Synapse Study and other studies cited by commenters, where an applicant has precedent agreements for long-term firm service, the Commission deems

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[88] *Constitution Pipeline Company, LLC*, 154 FERC ¶ 61,046, at P 21 (2016) ("Although the Certificate Policy Statement broadened the types of evidence certificate applicants may present to show the public benefits of a project, it did not compel an additional showing … [and] [n]o market study or other additional evidence is necessary where … market need is demonstrated by contracts for 100 percent of the project's capacity.").

[89] *See ETC Tiger Pipeline, LLC*, 131 FERC ¶ 61,010, at P 20 (2010).

[90] With respect to comments requesting the Commission to assess the market demand for gas to be transported by other proposed interstate pipeline projects, we note that the Commission will evaluate the proposals in those proceedings in accordance with the criteria established in our Certificate Policy Statement.

the precedent agreements to be the better evidence of demand. Thus, the Commission evaluates individual projects based on the evidence of need presented in each proceeding. Where, as here, it is demonstrated that specific shippers have entered into precedent agreements for project service, the Commission places substantial reliance on those agreements to find that the project is needed.

57. With respect to the use of existing infrastructure or new renewable generation to meet the project's need, our environmental review considered the potential for energy conservation and renewable energy sources, and the availability of capacity on other pipelines, to serve as alternatives to the ACP Project and concluded that they do not presently serve as practical alternatives to the project.[91] Thus, contrary to commenters' assertions, we are not persuaded that authorization of the ACP Project would lead to the overbuilding of pipeline infrastructure.

58. In addition, we are not persuaded by commenters' contention that there is insufficient supply in the Appalachian Basin to support the pipeline. While we agree, and Atlantic acknowledges, the intended source of supply for the ACP Project will be production in the Appalachian Basin, the ACP Project is also connected to other interstate pipelines, such as DETI[92] and Transco, which could potentially supply gas to the project from other areas of supply. Additionally, because, as the commenters note, the amount of gas that will be produced from the region is reflective of, among other things, the price of natural gas, projections regarding the amount of gas available for the ACP Project are speculative.

59. Moreover, the fact that five of the six shippers on the ACP Project are affiliated with the project's sponsors does not require the Commission to look behind the precedent agreements to evaluate project need.[93] When considering applications for new

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[91] *See* Final EIS at 5-38 (concluding that existing pipelines do not have the capacity to transport the required volumes of gas and that generation of electricity from renewable energy sources or the gains realized from increased energy efficiency and conservation are not transportation alternatives and cannot function as a substitute for the proposed projects).

[92] DETI's Supply Header Project would receive natural gas from two interstate pipelines, Rockies Express Pipeline, LLC and Texas Eastern Transmission, and from regional production at two receipt points. Atlantic's September 18, 2015 Application at Exhibit I.

[93] *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277 at P 57 ("as long as the precedent agreements are long-term and binding, we do not distinguish between

certificates, the Commission's primary concern regarding affiliates of the pipeline as shippers is whether there may have been undue discrimination against a non-affiliate shipper.[94] Here, no such allegations have been made, nor have we found that the project sponsors have engaged in any anticompetitive behavior. As discussed above, Atlantic held both a non-binding and binding open season for capacity on the project and all potential shippers had the opportunity to contract for service. Moreover, Atlantic's tariff, as discussed below, ensures that any future shipper will not be unduly discriminated against.

60. We also do not find merit in the commenters' argument that the proposed project will be subsidized by the affiliated shippers' captive ratepayers. First, to the extent a ratepayer receives a beneficial service, paying for that service does not constitute a "subsidy."[95] Further, as several commenters and the Institute for Energy Economics and Financial Analysis, *Risks Associated with Natural Gas Pipeline Expansion in Appalachia* study (IEEFA study) note, state utility regulators must approve any expenditures by state-regulated utilities. We disagree with commenters who suggest that once the Commission has made a determination in this proceeding, state regulators cannot effectively review the expenditures of utilities that they regulate. In fact, any attempt by the Commission to look behind the precedent agreements in this proceeding might infringe upon the role of state regulators in determining the prudency of expenditures by the utilities that they regulate. Here, the North Carolina Utilities Commission has already approved the precedent agreements between Atlantic and Duke Energy Progress, Duke Energy Carolinas, and Piedmont. With respect to the precedent agreement to supply natural gas to Virginia Electric and Power Company, issues related to the utility's ability to recover costs associated with its decision to subscribe for service on the ACP Project involve matters to be determined by the Virginia State Corporation Commission; those concerns are beyond the scope of the Commission's jurisdiction. Should they elect to construct the projects before affirmative action by the state regulators, the applicants will be at risk of not being able to recover some, or any, of their costs.

61. Further, we disagree with commenters claim that because Greensville and Brunswick Power Stations are already served by Transco's pipeline, the ACP Project is not needed. The fact that these two generating facilities are already connected to interstate pipelines does not diminish the reliability benefits of having alternative sources

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pipelines' precedent agreements with affiliates or independent marketers in establishing the market need for a proposed project").

[94] *See* 18 C.F.R. § 284.7(b) (2017) (requiring transportation service to be provided on a non-discriminatory basis).

[95] *See* Certificate Policy Statement, 90 FERC ¶ at 61,393.

of natural gas for those generators in case of a supply disruption. In addition, the ACP Project will be able supply additional existing generation units through interconnections with existing pipelines. For example, Atlantic cited 14 Dominion Virginia Power and 5 Duke Energy Progress facilities that could be served by the ACP Project.[96]

62. Lastly, allegations that the project is not needed because gas may be exported are not persuasive. The Commission does not have jurisdiction to authorize the exportation or importation of natural gas. Such jurisdiction resides with the DOE, which must act on any applications for natural gas export or import authority.[97] Moreover, the ACP Project's shippers are domestic end users of natural gas and there is no evidence in the record that these end users intend to use their capacity to provide gas to an export terminal.

63. In conclusion, we find that the ACP Project will provide reliable natural gas service to end use customers. Precedent agreements signed by Atlantic for approximately 96 percent of the project's capacity adequately demonstrate that the project is needed.

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[96] Atlantic's December 8, 2016 Data Response at Question 3.

[97] Section 3(a) of the NGA provides, in part, that "no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so." 15 U.S.C. § 717b(a) (2012). In 1977, the Department of Energy Organization Act transferred the regulatory functions of section 3 of the NGA to the Secretary of Energy. 42 U.S.C. § 7151(b) (2012). Subsequently, the Secretary of Energy delegated to the Commission authority to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports." DOE Delegation Order No. 00-004.00A (effective May 16, 2006). The proposed facilities are not located at a potential site of exit for natural gas exports. Moreover, the Secretary of Energy has not delegated to the Commission any authority to approve or disapprove the import or export of the commodity itself, or to consider whether the exportation or importation of natural gas is consistent with the public interest. *See Corpus Christi Liquefaction, LLC*, 149 FERC ¶ 61,283, at P 20 (2014) (*Corpus Christi*). *See also National Steel Corp.*, 45 FERC ¶ 61,100, at 61,332-33 (1988) (observing that DOE, "pursuant to its exclusive jurisdiction, has approved the importation with respect to every aspect of it except the point of importation" and that the "Commission's authority in this matter is limited to consideration of the place of importation, which necessarily includes the technical and environmental aspects of any related facilities").

c. Existing Pipelines and their Customers

64. The ACP Project is designed to transport domestically sourced gas from Appalachian Basin supply areas to markets in West Virginia, Virginia, and North Carolina. Commenters assert that the project will negatively impact existing pipelines because any natural gas transported by the ACP Project would not be available for transport on an existing pipeline. As stated above, the EIS analyzed the availability of capacity on other pipelines to serve as alternatives to the ACP Project, and concluded that they do not presently serve as practical alternatives to the project.[98] Further, no transportation service provider or captive customer in the same market has protested this project. Therefore, we find that the ACP Project will have no adverse impact on existing pipelines or their captive customers.

d. Landowners and Communities

65. Regarding impacts on landowners and communities along the project route, Atlantic proposes to locate its pipeline within or parallel to existing utility corridors where feasible. Approximately nine percent of Atlantic's pipeline rights-of-way will be collocated or adjacent to existing pipeline, roadway, railway, or utility rights of way.[99] Atlantic also proposes to use available capacity on the Piedmont system to avoid duplicative pipeline construction on undisturbed lands. Atlantic participated in the Commission's pre-filing process and has been working to address landowner and community concerns and input. Specifically, Atlantic incorporated 201 route variations, totaling 199 miles, into its proposed route for various reasons, including landowner requests, avoidance of sensitive resources, or engineering considerations.[100] Additionally, Atlantic has stated that it will make good faith efforts to negotiate with landowners for any needed rights, and will resort only when necessary to the use of the eminent domain. Accordingly, while we are mindful that Atlantic has been unable to reach easement agreements with many landowners, for purposes of our consideration under the Certificate Policy Statement, we find that Atlantic has generally taken sufficient steps to minimize adverse impacts on landowners and surrounding communities.

66. A number of commenters request that the Commission not grant Atlantic eminent domain authority. The Commission itself, however, does not confer eminent domain powers. Under NGA section 7, the Commission has jurisdiction to determine if the

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[98] Final EIS at 5-38.

[99] *Id*. at 2-20.

[100] *Id*. at 3-51.

construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination, it is NGA section 7(h) that authorizes a certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[101]

67. Next, commenters state that the Certificate Policy Statement creates a balancing test whereby the Commission balances the need for the project against the impact on landowners. Commenters contend that in this case, the balancing test requires denial of the ACP Project because of Atlantic's lack of colocation with existing rights-of-way, its extensive use of private land,[102] and its negative effects on property values and economic activity.

68. The Certificate Policy Statement "allows the Commission to take into account the different interests that must be considered."[103] In this vein, the policy statement specifically noted that where a pipeline has acquired property rights for a proposed project, the benefits needed to be shown would be less than in a case where no land rights had been previously acquired by negotiation.[104] Thus, the Certificate Policy Statement specifically contemplated a scenario where, if a company might not be able to acquire a perhaps significant amount of property rights through negotiation, the Commission might deny the application if there has not been a sufficient demonstration of need.[105] However, here, as discussed above, Atlantic has demonstrated public benefits for the proposed project. Approximately 96 percent of the ACP Project is subscribed under long-term firm transportation precedent agreements, a strong showing of need.[106]

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[101] 15 U.S.C. § 717f(h) (2012).

[102] Commenters note that the amount of land that will be acquired through eminent domain is not publically available, but suggest that it is significant.

[103] Certificate Policy Statement, 88 FERC at 61,749.

[104] *Id*.

[105] *See Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,190 (2016), *reh'g denied*, 157 FERC ¶ 61,194; *Turtle Bayou Gas Storage Company, LLC,* 135 FERC ¶ 61,233 (2011).

[106] Certificate Policy Statement, 88 FERC at 61,749 ("if an applicant had precedent agreements with multiple parties for most of the new capacity, that would be strong evidence of market demand and potential public benefits").

69. With respect to the lack of colocation with existing rights-of-way, the final EIS evaluated numerous alternatives where the pipeline would be collocated with existing rights-of-way and found that many of those alternatives did not offer significant environmental advantages or were technically infeasible when compared to Atlantic's proposed route. As a result of input from Commission staff and stakeholders during the pre-filing process, Atlantic revised its route to parallel various existing infrastructure corridors and thus added nearly 60 miles of colocation to the project. Therefore, we find that Atlantic has made a reasonable effort to collocate its pipeline with existing rights-of-way.

e. Conclusion

70. We find that the benefits that the ACP Project will provide to the market outweigh any adverse economic effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, we find that the public convenience and necessity requires approval of Atlantic's proposal, as conditioned in this order.

2. DETI Supply Header Project

71. As stated, the threshold requirement for pipelines proposing new projects is that the applicant must be prepared to financially support the project without relying on subsidization from its existing customers. The Commission has determined, in general, that where a pipeline proposes to charge incremental rates for new construction that are higher than the company's existing system rates, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers.[107] Here, DETI proposes an incremental firm transportation base reservation rate, which is higher than its existing system-wide rate, to recover the costs of the project. The proposed incremental rates are calculated to recover all construction, installation, operation, and maintenance costs associated with the project. Accordingly, we find that the Supply Header Project will not be subsidized by existing customers and satisfies the threshold no-subsidy requirement under the Certificate Policy Statement.

72. We also find that the proposal will not adversely affect DETI's existing customers because there will be no degradation of existing service. In addition, other pipelines and

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[107] *See Transcontinental Gas Pipe Line Corp.*, 98 FERC ¶ 61,155, at 61,552 (2002) (noting that the Commission has previously determined that where a pipeline proposes to charge an incremental rate for new construction, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers) (citations omitted); *see also, Dominion Transmission, Inc.*, 155 FERC ¶ 61,106 (2016) (same).

their captive customers will not be adversely impacted because the proposal is not intended to replace service on other pipelines. Rather, the project would allow DETI to provide additional transportation services to Atlantic on its system. Further, no pipeline or their captive customers have protested the application.

73. Moreover, DETI has designed the Supply Header Project to minimize impacts on landowners and surrounding communities. Approximately 31 percent of the right-of-way for the proposed project will be collocated or adjacent to existing pipeline, roadway, railway, or utility rights of way.[108] Additionally, most of the project facility installations will be on lands that are either owned by DETI or on which DETI holds leaseholder or easement rights.

74. We also find that DETI's proposed abandonment of facilities is permitted by the public convenience and necessity.[109] As stated above, the two compressor units at the Hastings Compressor Station currently serve a gathering function. Therefore, their abandonment would not affect any of DETI's jurisdictional transportation or storage customers. Last, no shipper affected by the proposed abandonment has filed comments in opposition to DETI's proposal.

75. We find that the benefits that the Supply Header Project will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental discussion below, we find that the public convenience and necessity requires approval of DETI's proposal, as conditioned in this order.

3. Eminent Domain Authority

76. Bold Alliance, Bold Education Fund, Friends of Nelson, and individual landowners (collectively, Bold Alliance) filed a petition for declaratory order and injunctive relief in Federal District Court for the District of Columbia.[110] Bold Alliance alleges that the eminent domain provisions of the NGA and the Commission's Certificate

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[108] Final EIS at 2-20.

[109] 15 U.S.C. § 717f(b) (2012).

[110] The petition was filed with the Commission on September 6, 2017.

Policy Statement do not further a public use, and therefore, violate the Due Process Clause and Takings Clause of the Fifth Amendment.[111]

77. As stated above, the Commission itself does not confer eminent domain powers. Under NGA section 7, the Commission has jurisdiction to determine if the construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination and issues a natural gas company a certificate of public convenience and necessity, it is NGA section 7(h) that authorizes that certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[112]

78. While this matter is currently before the court, we note that Bold Alliance's legal theory is unfounded. Bold Alliance generally argues that the Commission's certification process falls short of the standard required by the Constitution for a taking: that the exercise of eminent domain is for a "public use." As noted above, Congress provided in NGA section 7(h) that a certificate holder was entitled to use eminent domain. Congress did not suggest that there was a further test, beyond the Commission's determination under NGA section 7(c)(e),[113] that a proposed pipeline was required by the public convenience and necessity, such that certain certificated pipelines furthered a public use, and thus were entitled to use eminent domain, while others did not. The Commission has interpreted the section 7(c)(e) public convenience and necessity determination as requiring the Commission to weigh the public benefit of the proposed project against the project's adverse effects.[114] We undertake this balancing through our application of the

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[111] On September 25, 2017, Bold Alliance filed comments raising the same issues discussed in their petition for declaratory order. We reject Bold Alliance's comments as untimely.

[112] 15 U.S.C. § 717f(h) (2012).

[113] 15 U.S.C. § 717f(e).

[114] As the agency that administers the Natural Gas Act, and in particular as the agency with expertise in addressing the public convenience and necessity standard in the Act, the Commission's interpretation and implementation of that standard is accorded deference. *See Chevron, USA, Inc. v. Nat. Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984); *Delaware Riverkeeper Network v. FERC*, 857 F.3d 388, 392 (D.C. Cir. 2017); *Office of Consumers Counsel v. FERC*, 655 F.2d 1132, 1141 (D.C. Cir. 1980); *Total Gas & Power N. Am., Inc. v. FERC*, No. 4:16-1250, 2016 WL 3855865, at *21 (S.D. Tex. July 15, 2016), aff'd, 859 F.3d 325 (5th Cir. 2017); *see also MetroPCS Cal., LLC v. FCC*, 644 F.3d 410, 412 (D.C. Cir. 2011) (under Chevron, the Court "giv[es] effect to

Certificate Policy Statement criteria, under which we balance the public benefits of a project against the residual adverse effects.[115] Thus, through this balancing process we make findings that support our ultimate conclusion that the public interest is served by the construction of the proposed project.[116] Accordingly, once a natural gas company obtains a certificate of public convenience and necessity, it may exercise the right of eminent domain in a U.S. District Court or a state court.

79. The Commission, having determined that the ACP Project is in the public convenience and necessity, need not make a separate finding that the project serves a "public use" to allow the certificate holder to exercise eminent domain. In short, the Commission's public convenience and necessity finding is equivalent to a "public use" determination.[117] In enacting the NGA, Congress clearly articulated that the transportation and sales of natural gas in interstate commerce for ultimate distribution to the public is in the public interest.[118] This congressional recognition that natural gas

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clear statutory text and defer[s] to an agency's reasonable interpretation of any ambiguity").

[115] Certificate Policy Statement, 88 FERC at 61,747-49,

[116] *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000) (because the Commission declared that the subject pipeline would serve the public convenience and necessity, the takings complained of did serve a public purpose); *see also Guardian Pipeline, L.L.C. v. 529.42 Acres of Land*, 210 F. Supp. 2d 971, 974 (N.D. Ill. 2002) (no evidence of public necessity other than the Commission's determination is required).

[117] *See Midcoast Interstate Transm., Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000); *see also*, *e.g.*, *Troy Ltd. v. Renna*, 727 F.2d 287, 301 (3rd Cir. 1984) ("authoriz[ing] an occupation of private property by a common carrier . . . engaged in a classic public utility function" is an "exemplar of a public use"); *E. Tenn. Natural Gas Co. v. Sage*, 361 F.3d 808 (4th Cir. 2004) ("Congress may, as it did in the [Natural Gas Act], grant condemnation power to 'private corporations . . . execut[ing] works in which the public is interested.'") (quoting *Miss. & Rum River Boom Co. v. Patterson*, 98 U.S. 403, 406 (1878)).

[118] 15 U.S.C. § 717(a) (2012) (declaring that the "business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest"). *See also Thatcher v. Tennessee Gas Transmission Co.*, 180 F.2d 644, 647 (5th Cir. 1950)*(Thatcher)*, *cert. denied*, 340 U.S. 829 (1950) (explaining that Congress, in enacting the NGA, recognized that "vast reserves of natural gas are located in States of our nation distant from other States which have no similar supply, but do have a vital

transportation furthers the public interest is consistent with the Supreme Court's emphasis on legislative declarations of public purpose in upholding the power of eminent domain.[119]

80. Bold Alliance erroneously cites to *Transco*,[120] where the Commission, after evaluating record evidence of need for the project at issue, found that there was a need for the project for purposes of section 7(c) of the NGA[121] and that the project served a public purpose sufficient to satisfy the Takings Clause.[122] We have done the same here. The proposed projects in this proceeding are designed to primarily serve natural gas demand in Virginia and North Carolina. Through the distribution of natural gas from the projects, the public at large will benefit from increased reliability of natural gas supplies. Furthermore, upstream natural gas producers will benefit from the project by being able to access additional markets for their product. Therefore, we conclude that the proposed project is required by the public convenience and necessity.

81. Notwithstanding the fact that we addressed a takings argument raised in *Transco* and here, such a question is beyond our jurisdiction; only the courts can determine whether Congress' action in passing section 7(h) of the NGA conflicts with the Constitution. We note, however, that courts have found eminent domain authority in section 7(h) of the NGA to be constitutional.[123]

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need of the product; and that the only way this natural gas can be feasibly transported from one State to another is by means of a pipe line.").

[119] *Kelo v. City of New London, Conn.*, 545 U.S. 469, 479-80 (2005) (upholding a state statute that authorized the use of eminent domain to promote economic development); *see also id.* at 480 (noting that without exception the Court has defined the concept of "public purpose" broadly, reflecting the Court's longstanding policy of deference to the legislative judgments in this field).

[120] *Transco*, 158 FERC ¶ 61,125.

[121] *Id.* PP 20-33.

[122] *Id.* PP 66-67.

[123] *See Thatcher*, 180 F.2d at 647. In addition, the eminent domain authority in many federal statutes mirror the authority in section 7(h) of the NGA. For instance, section 21 of the Federal Power Act (FPA), 16 U.S.C. § 814 (2012), provides that when a licensee cannot acquire by contract lands or property necessary to construct, maintain, or operate a licensed hydropower project, it may acquire the same by the exercise of the right of eminent domain in a U.S. District Court or a state court. The U.S. Supreme

4. **Antitrust Complaint**

82. On May 12, 2016, Mr. Michael Hirrel filed with the Commission an undated copy of a filing addressed to the Federal Trade Commission (FTC), in which he alleged that Dominion Resources and Duke Energy were in violation of section 2 of the Sherman Act and section 5 of the Federal Trade Commission Act, and asked the FTC to file comments in this proceeding.[124] On June 24, 2016, Mr. Hirrel filed with the Commission a June 23, 2016 letter from the Virginia Chapter of the Sierra Club to the FTC supporting Mr. Hirrel's complaint. On August 30, 2016, DETI and Atlantic filed a response to which Mr. Hirrel responded to on November 4, 2016.

83. Mr. Hirrel's initial filing was made with the FTC, not with the Commission, and accordingly is a matter for the FTC to review. However, Mr. Hirrel is correct when he states in his response[125] that questions regarding competition, including antitrust concerns, may be considered by the Commission in making its public convenience and necessity findings.[126] Here, the Commission has, pursuant to the policy statement, found that the proposed project will not have negative impacts on existing pipelines and their customers, and, to the extent that the filings raised issues concerning the need for the proposed projects and the precedent agreements with affiliated shippers, those issues were discussed above. We see no reason to further address Mr. Hirrel's allegations.

5. **Compressor Station Spacing**

84. Mr. Richard Laska alleges that the ACP Project is overbuilt because the compressor stations on the project are located over 200 miles apart, even though the typical range between compressor stations is 40 to 100 miles. Additionally, Blue Ridge Environmental Defense League questions whether three compressor stations are sufficient for the ACP Project and if other compressor stations are planned, but have not been disclosed. In response to Commission staff's November 23, 2016 data request, Atlantic states that case-specific hydraulics, along with the location of receipt and

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Court has not questioned the constitutionality of section 21 of the FPA. *See FPC v. Tuscarora Indian Nation*, 362 U.S. 99, 123-24 (1960). Similarly, Congress included the same eminent domain authority for permit holders for electric transmission facilities when it enacted the Energy Policy Act of 2005. 16 U.S.C. § 824p(e)(1) (2012).

[124] The FTC has not filed comments.

[125] November 4, 2016 response at 18.

[126] *See NAACP v. FPC*, 425 U.S. 662, 670, n.6. (1976) (citations omitted) (stating that "the Commission has authority to consider conservation, environmental, and antitrust questions").

delivery points, dictate the appropriate location of compression facilities. Atlantic asserts that its system is designed for a specific situation, and therefore, the distance between compressor stations will vary from the general ranges cited by Mr. Laska.

85. Based upon its review of the pipeline design, hydraulic models, and explanation of how the location of compressor stations are determined, Commission staff determined that Atlantic has properly designed its pipeline system based upon design and location constraints. Mr. Laska's allegations that the pipeline is over-built because of the distances between compressor stations exceed the typical range of 40 to 100 miles apart does not take into consideration the specific transportation requirements nor the design and operating conditions that are unique to the project.

B. Blanket Certificates

86. Atlantic requests a Part 284, Subpart G blanket certificate in order to provide open-access transportation services. Under a Part 284 blanket certificate, Atlantic will not require individual authorizations to provide transportation services to particular customers. Atlantic filed a *pro forma* Part 284 tariff to provide open-access transportation services. Since a Part 284 blanket certificate is required for Atlantic to offer these services, we will grant Atlantic a Part 284 blanket certificate, subject to the conditions imposed herein.

87. Atlantic has also applied for a Part 157, Subpart F blanket certificate. The Part 157 blanket certificate gives an interstate pipeline NGA section 7 authority to automatically, or after prior notice, perform certain activities related to the construction, acquisition, abandonment, and replacement and operation of pipeline facilities. Because Atlantic will become an interstate pipeline with the issuance of a certificate to construct and operate the proposed facilities, we will issue to Atlantic the requested Part 157, Subpart F blanket certificate.

C. Lease Agreement

88. As described above, Atlantic and Piedmont have entered into a Capacity Lease Agreement whereby Atlantic will lease 100,000 Dth/d of capacity on Piedmont's system and use the leased capacity to provide service under the terms of its FERC Tariff.

89. Historically, the Commission views lease arrangements differently from transportation services under rate contracts. The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline.[127] To enter into a lease agreement, the lessee generally needs to be a natural gas company under the NGA and needs section 7(c) certificate

[127] *Texas Eastern Transmission Corp.*, 94 FERC ¶ 61,139, at 61,530 (2001).

authorization to acquire the capacity. Once acquired, the lessee in essence owns that capacity and the capacity is subject to the lessee's tariff. The leased capacity is allocated for use by the lessee's customers. The lessor, while it may remain the operator of the pipeline system, no longer has any rights to use the leased capacity.[128]

90. The Commission's practice has been to approve a lease if it finds that: (1) there are benefits from using a lease arrangement; (2) the lease payments are less than, or equal to, the lessor's firm transportation rates for comparable service over the terms of the lease on a net present value basis; and (3) the lease arrangement does not adversely affect existing customers.[129] The lease agreement between Atlantic and Piedmont satisfies these requirements.

91. First, the Commission has found that capacity leases in general have several potential public benefits. Leases can promote efficient use of existing facilities, avoid construction of duplicative facilities, reduce the risk of overbuilding, reduce costs, minimize environmental impacts, and result in administrative efficiencies for shippers.[130] Here, the lease arrangement will provide Atlantic the ability to serve markets in North Carolina without construction of duplicative facilities which would essentially parallel the Piedmont system. The leased capacity allows for the efficient use of the available capacity on Piedmont, avoids the environmental impact and impacts on landowners associated with constructing duplicative facilities, substantially reduces the costs of constructing Atlantic's system, and allows Atlantic's system to be placed into service earlier than if redundant facilities were constructed. The lease will provide Atlantic's shippers with seamless access, under a single firm transportation contract, from the Appalachian Basin to delivery points in North Carolina.

92. Second, Atlantic states that the monthly lease charge it will pay to Piedmont is less than Piedmont's maximum applicable transportation rates for comparable service. Piedmont states that comparable transportation service is offered under Rate Schedule 113, which has an annual average daily rate of $0.23 per Dth.[131] According to Atlantic and Piedmont's October 3, 2016 data response, Atlantic will make a monthly payment of

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[128] *Texas Gas Transmission, LLC*, 113 FERC ¶ 61,185, at P 10 (2005).

[129] *Id.*; *Islander East Pipeline Co., L.L.C.*, 100 FERC ¶ 61,276, at P 69 (2002).

[130] *See, e.g.*, *Dominion Transmission, Inc.*, 104 FERC ¶ 61,267, at P 21 (2003); *Islander East Pipeline Co. L.L.C.*, 100 FERC ¶ 61,276 at P 70.

[131] In Rate Schedule 113, Piedmont offers two seasonal rates, a summer rate and a winter rate. For our analysis of the lease payments, we used an average daily rate based on the entire year.

$228,125 to Piedmont for the leased capacity of 100,000 Dth/d. This equates to a daily demand charge of $0.075 per Dth, which is lower than the rate for comparable transportation service on Piedmont's system.

93. Third, the lease will use existing capacity on Piedmont's system and will not adversely affect Piedmont's existing customers. Piedmont's existing customers will not subsidize the costs of providing capacity for Atlantic, and Piedmont states that it will not pass on any costs associated with the lease to its existing customers.[132] In addition, the North Carolina Utilities Commission has authorized Piedmont to enter into the lease in an order issued October 28, 2014.[133]

94. Because the lease payments are satisfactory, there are significant benefits, and those benefits outweigh any potential harm to Piedmont's customers, we find that the proposed lease is required by the public convenience and necessity.

95. To enable Piedmont to carry out its responsibilities under the lease agreement, we will issue Piedmont a limited jurisdiction certificate. The Commission looks closely at proposals that would create dual jurisdiction facilities, i.e., facilities that would be subject to state and federal jurisdiction, in order to avoid duplicative and/or potentially inconsistent regulatory schemes over the same facilities. However, here, although federal regulation of Piedmont will be "limited," Piedmont and Atlantic will both be subject to exclusive federal regulation regarding the lease of 100,000 Dth/d of capacity on the Piedmont system and any issues that may arise thereunder. The limited jurisdiction certificate will enable Piedmont to operate the leased capacity being used for NGA jurisdictional services subject to the terms of the lease and subject to Atlantic's open-access tariff.[134] The limited jurisdiction certificate will require Piedmont to operate the leased capacity in a manner that ensures Atlantic's ability to provide services, including interruptible transportation, using the leased capacity on an open-access, non-discriminatory basis. We have approved similar leases in the past involving intrastate

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[132] Atlantic and Piedmont's Joint Application at 13.

[133] "Order Accepting Affiliated Agreements For Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153 and Authorizing Piedmont to Enter into Related Redelivery Agreements," issued by the NCUC in its Docket No. G-9, Sub 655, on Oct. 28, 2014.

[134] Atlantic and Piedmont also request a waiver of the Commission's "shipper must have title" rule to allow Atlantic to transport gas on the leased Piedmont capacity for Atlantic's customers using gas owned by those customers. This waiver is not necessary as the leased capacity will now be considered part of Atlantic's system and is subject to the terms and conditions of Atlantic's tariff.

pipelines and local distribution companies,[135] and our finding that Piedmont is NGA-jurisdictional is limited to its role as lessor-operator of capacity used by Atlantic to provide Atlantic's interstate services. Piedmont will remain non-jurisdictional as to its intrastate activities.

96. We will require Atlantic to file with the Commission a notification in this docket, within 10 days of the date of acquisition of the capacity leased from Piedmont, providing the effective date of the acquisition.[136] We also remind the applicants that when the lease terminates, Atlantic is required to obtain authority to abandon the leased capacity.[137]

D. Rates

1. Atlantic Coast Pipeline Project

a. Atlantic's Initial Rates

97. Atlantic proposes to provide firm (Rate Schedule FT) and interruptible (Rate Schedule IT) transportation services under Part 284 of the Commission's regulations at cost-based recourse rates, and also requests the authority to offer service at negotiated rates. Atlantic proposes a maximum FT reservation recourse rate of $1.7249 per Dth and a FT commodity charge of $0.0041 per Dth.[138] The maximum IT recourse rate of $1.7290 per Dth is based on the maximum daily FT reservation rate plus the FT commodity charge.[139] Atlantic states that it designed its initial recourse rates consistent

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[135] *See, e.g.*, *The East Ohio Gas Co.*, 133 FERC ¶ 61,076 (2010).

[136] *Nexus Gas Transmission, LLC*, 160 FERC ¶ 61,022, at P 70 (2017).

[137] *Transcontinental Gas Pipe Line Company, LLC*, 156 FERC ¶ 61,092, at P 57 (2016).

[138] Atlantic proposes to include in its Statement of Applicable Rates, on *pro forma* tariff record 10.20, the applicable DETI rates that will be assessed to customers utilizing the capacity Atlantic contracted on the DETI Supply Header Project, pursuant to section 29 (Off-System Capacity) of the General Terms & Conditions (GT&C).

[139] Atlantic states that its fuel retention percentage will be adjusted on a quarterly basis and that any over- or under- recoveries of fuel will be tracked and flowed through in future period fuel retention percentages, pursuant to GT&C section 31. Atlantic states that it will submit a tariff filing 30 to 60 days prior to going into service to establish its initial Transportation Fuel Retainage Percentage, which is currently stated as "TBD" in its *pro forma* tariff.

with the Straight-Fixed Variable rate design methodology based on the full design capability of 1,500,000 Dth/d and first-year cost of service of $946,320,533. Atlantic developed its proposed first year cost of service utilizing a capital structure of 50 percent debt and 50 percent equity, with a debt cost of 6.8 percent, a return on equity (ROE) of 14 percent, and a depreciation rate of 2.5 percent.

98. The NCUC states that Atlantic has failed to provide any analysis of current financial markets and/or current investor expectations to justify the proposed 14 percent ROE.[140] The NCUC suggests that it would not be reasoned decision-making to establish recourse rates for over $5.1 billion of investment without requiring Atlantic to comply with its statutory obligation of demonstrating that its proposed project is required by the public convenience and necessity based on current market conditions.[141] The NCUC asserts that Atlantic's first-year pre-tax return of 15 percent accounts for approximately three quarters of Atlantic's first-year cost of service and the ROE chosen to compute the recourse rates has a material impact on those rates.[142] Further, the NCUC suggests that the cases cited by Atlantic in its application are not as relevant as the Commission's more recent Opinion No. 524-A, where the Commission reaffirmed a decision using a discounted cash flow analysis that resulted in a median ROE of 10.28 percent.[143] The NCUC cited a number of other cases in which the Commission approved ROEs much lower than 14 percent;[144] however, the NCUC also recognizes that the ROEs approved in those cases were for existing pipeline companies rather than new companies such as Atlantic.[145]

99. Many commenters also cite the IEEFA Study, which concludes that the Commission policy allowing an ROE of 14 percent for new pipeline construction leads to overbuilding of pipelines because the ROE is higher than that of other regulated utilities.

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[140] NCUC Protest at 6.

[141] *Id*.

[142] *Id*. (citing Atlantic Initial Application at Exhibit P, Page 3, Lines 8-9).

[143] *Portland Natural Gas Transmission Sys.*, Opinion No. 524-A, 150 FERC ¶ 61,107, at P 195 (2015).

[144] *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040, at P 686 (2013); *Portland Natural Gas Transmission Sys.*, Opinion No. 510-A, 142 FERC ¶ 61,198, at P 250 (2013), *order on reh'g*, 150 FERC ¶ 61,106 (2015); *Kern River Gas Transmission Co.*, Opinion No. 486-F, 142 FERC ¶ 61,132, at P 263 (2013).

[145] NCUC Protest at 7.

The IEEFA Study notes that the average ROE granted by state public utilities commissions to investor-owned electric utilities was 9.92 percent and the Commission recently lowered its allowed return on equity for electric transmission companies in New England to a maximum of 11.74 percent. The IEEFA Study also notes that a study by the Natural Gas Supply Association found that a majority of pipeline companies earned returns on equity greater than 12 percent, with two of those companies earning returns on equity in excess of 24 percent.

100. In its answer, Atlantic states that the NCUC provides no basis for Atlantic to be treated differently than all other new pipeline projects approved in recent years. Additionally, Atlantic asserts that the Commission has never found that changed financial conditions over the past ten years have warranted a reduction in the ROE allowed for new pipelines, which stands at 14 percent.[146] Atlantic reiterates that its proposed 14 percent ROE reflects the construction, financial, regulatory, and contractual risks faced by new pipelines and few of the approved cases spanning the past decade contain the sort of "analysis of current financial markets and/or current investor expectations" that the NCUC seeks.[147]

101. In section 7 certificate proceedings, the Commission reviews initial rates for service using proposed new pipeline capacity under the public convenience and necessity standard, which is a less rigorous standard than the just and reasonable standard under NGA sections 4 and 5.[148] The Commission does not believe that conducting a discounted

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[146] Atlantic Initial Application at 30 n.24. *See, e.g., Constitution Pipeline Co., LLC*, 149 FERC ¶ 61,199, at PP 48-49 (2014) (50/50 capital structure and ROE 14%); *Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192, at P 39 n.28 (2014) (70/30 capital structure and ROE 14%); *Ruby Pipeline L.L.C.*, 136 FERC ¶ 61,054, at P 11 (2011) (50/50 capital structure and ROE 14%).

[147] Atlantic Answer at 25-26.

[148] *Atlantic Refining Co. v. Public Serv. Comm'n of New York*, 360 U.S. 378 (1959) (*CATCO*). In *CATCO*, the Court contrasted the Commission's authority under sections 4 and 5 of the NGA to approve changes to existing rates using existing facilities and its authority under section 7 to approve initial rates for new services and services using new facilities. The Court recognized "the inordinate delay" that can be associated with a full-evidentiary rate proceeding and concluded that was the reason why, unlike sections 4 and 5, section 7 does not require the Commission to make a determination that an applicant's proposed initial rates are or will be just and reasonable before the Commission certificates new facilities, expansion capacity, and/or services. *Id.* at 390. The Court stressed that in deciding under section 7(c) whether proposed new facilities or services are required by the public convenience and necessity, the Commission is required to "evaluate all factors bearing on the public interest," and noted that an

cash flow analysis in individual certificate proceedings would be the most effective or efficient way for determining the appropriate ROE. While parties have the opportunity in section 4 rate proceedings to file and examine testimony with regard to the composition of the proxy group to use in a discounted cash flow analysis, the growth rates used in the analysis, and the pipeline's position within the zone of reasonableness with regard to risk, it would be difficult, if not impossible, to complete this type of analysis in section 7 certificate proceedings in a timely manner, and attempting to do so would unnecessarily delay proposed projects with time sensitive in-service schedules.[149]

102. As noted by Atlantic, in prior cases, the Commission has allowed a 14 percent ROE for greenfield pipeline projects based on a capital structure that contains no more than 50 percent equity. The Commission's policy of approving equity returns of up to 14 percent with an equity capitalization of no more than 50 percent reflects the fact that greenfield pipelines undertaken by a new entrant in the market face higher business risks than existing pipelines proposing incremental expansion projects.[150] Thus, approving Atlantic's requested 14 percent return on equity in this instance is not merely "reflexive"; it is in response to the risk Atlantic faces as a new market entrant, constructing a new greenfield pipeline system. Moreover, the returns approved for electric utilities and local distribution companies are not relevant because there is no showing that these companies face the same level of risk as faced by greenfield projects proposed by a new natural gas pipeline company.[151]

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applicant's proposed initial rates are not "the only factor bearing on the public convenience and necessity." *Id.* at 391. Thus, as explained by the Court, "[t]he Congress, in § 7(e), has authorized the Commission to condition certificates in such manner as the public convenience and necessity may require when the Commission exercises authority under section 7," *id.*, and the Commission therefore has the discretion in section 7 certificate proceedings to approve initial rates that will "hold the line" and "ensure that the consuming public may be protected" while awaiting adjudication of just and reasonable rates under the more time-consuming ratemaking sections of the NGA. *Id.* at 392.

[149] *Id*. at 391.

[150] *See, e.g., Rate Regulation of Certain Natural Gas Storage Facilities,* Order No. 678, FERC Stats. & Regs. ¶ 31,220, at P 127 (2006) (explaining that existing pipelines who need only acquire financing for incremental expansions face less risk than "a greenfield project undertaken by a new entrant in the market").

[151] The Commission has previously concluded that distribution companies are less risky than a pipeline company. *See, e.g. Trailblazer Pipeline Co.*, 106 FERC ¶ 63,005, at

103. Further, as explained below, we are requiring Atlantic to file a cost and revenue study at the end of its first three years of actual operation to justify its existing cost-based rates. The three-year study will provide an opportunity for the Commission and the public to review Atlantic's original estimates, upon which its initial rates are based, to determine whether Atlantic is over-recovering its cost of service with its approved initial rates, and whether the Commission should exercise its authority under section 5 of the NGA to establish just and reasonable rates. Alternatively, Atlantic may elect to make a NGA section 4 filing to revise its initial rates. The public would have an opportunity to review Atlantic's proposed return on equity and other cost of service components at that time and would have an opportunity to raise issues relating to the rate of return, as well as all other cost components. As such, we find that Atlantic's proposed rates will "ensure that the consuming public may be protected" until just and reasonable rates can be determined through the more thorough and time-consuming ratemaking sections of the NGA.[152]

104. We have reviewed Atlantic's proposed cost of service and initial rates and find they reasonably reflect current Commission policy for a new pipeline entity. Therefore, we accept Atlantic's proposed recourse rates as the initial rates for service on its pipeline.

b. Three-Year Filing Requirement

105. Consistent with Commission precedent, Atlantic is required to file a cost and revenue study no later than three months after the end of its first three years of actual operation to justify its initial cost-based firm and interruptible recourse rates.[153] In its filing, the projected units of service should be no lower than those upon which Atlantic's approved initial rates are based. The filing must include a cost and revenue study in the form specified in section 154.313 of the Commission's regulations to update cost of service data.[154] Atlantic's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Atlantic is advised to include, as part of the eFiling description, a reference to Docket No. CP15-554-000 and the cost and

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P 94 (2004) (rejecting inclusion of local distribution companies in a proxy group because they face less risk than a pipeline company.).

[152] *CATCO*, 360 U.S. at 392.

[153] *Rover Pipeline, LLC*, 158 FERC ¶ 61,109, at P 82 (2017); *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224, at P 57 (2009); *MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165, at P 34 (2008).

[154] 18 C.F.R. § 154.313 (2017).

revenue study.[155] After reviewing the data, the Commission will determine whether to exercise its authority under NGA section 5 to investigate whether the rates remain just and reasonable. In the alternative, in lieu of this filing, Atlantic may make a general NGA section 4 rate filing to propose alternative rates to be effective no later than three years after the in-service date for its proposed facilities.

2. DETI Supply Header Project

106. DETI proposes to establish as its recourse rates an initial monthly incremental transportation base reservation charge of $4.7459 per Dth and its existing system maximum base usage charge of $0.0083 per Dth.[156] The reservation charge was based on a first year cost of service of $86,072,419 and full design capacity of 1,511,335 Dth/d.[157] In developing its first year cost of service, DETI uses a pre-tax return of 13.70 percent and its system depreciation rate of 2.5 percent, which DETI states were approved in a settlement in Docket No. RP97-406-000.[158] Further, DETI plans to charge all other applicable rates, charges, and surcharges under its Rate Schedule FT, including its Transportation Cost Rate Adjustment and Electric Power Cost Adjustment charges, the maximum usage charge, and maximum system fuel retention percentage.

107. The NCUC protested DETI's proposed recourse rates stating DETI has not demonstrated that use of a pre-tax return of 13.70 percent to calculate its proposed recourse rates is reflective of current financial market conditions. The NCUC believes the use of a pre-tax return from a rate case filed over 15 years ago means that a major element of the proposed recourse rates does not reflect current costs.[159] The NCUC asserts that DETI's first-year pre-tax return of 13.70 percent will be over three quarters of DETI's cost of service underlying the proposed recourse rates, and because DETI simply followed the Commission's policy of using the last return on file without regard to whether the pre-tax return reflects current market conditions, DETI's application is devoid of any evidence which would permit an analysis of the majority of the cost of service underlying its proposed recourse rates. The NCUC asserts that application of the Commission's policy may result in reasonable recourse rates when a pipeline's rate of

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[155] *Electronic Tariff Filings*, 130 FERC ¶ 61,047, at P 17 (2010).

[156] DETI March 15, 2016 Data Response at Question 5.

[157] DETI March 15, 2016 Data Response, Question 5 at Page 3 of Attachment 2.

[158] *CNG Transmission Corp.*, 85 FERC ¶ 61,261, at 62,051 (1998).

[159] NCUC Protest at 7.

return, debt costs, and capital structure were recently, or are being concurrently, reviewed; however, that is not the case here.

108. The NCUC states financial markets are very different now than when DETI's ROE was last approved and that the Commission's most recent pronouncements on ROE provide valuable perspective on the reasonableness of DETI's proposed 13.70 percent pre-tax return. For example, the NCUC points out that the Commission recently reaffirmed a decision using a discounted cash flow analysis, based on the six-month period ending March 31, 2011, which resulted in a median ROE of 12.08 percent.[160] In addition, the NCUC states the Commission has approved an ROE of 10.55 percent for El Paso Natural Gas Company, 12.99 percent for Portland Natural Gas Transmission System, and 11.55 percent for Kern River Gas Transmission Company.[161] The NCUC recognizes that these ROEs are not directly comparable to the pre-tax return proposed by DETI; however, the lack of specified ROE, debt costs, and capital structure in DETI's application precludes any apples-to-apples comparison.

109. In its answer, DETI states that it has developed a large number of projects on its system with incremental rates and the Commission has consistently approved the 13.70 percent pre-tax rate of return. DETI asserts that the use of the pre-tax return follows well-established Commission policy and the Commission has considered and rejected the same argument advanced by the NCUC with regards to DETI's Allegheny Storage Project.[162]

110. As the NCUC acknowledges, the Commission's consistent policy in section 7 certificate proceedings is to require that a pipeline's cost-based recourse rates for incrementally-priced expansion capacity be designed using the rate of return from its most recent general rate case approved by the Commission under section 4 of the NGA in which a specified rate of return was used to calculate the rates.[163] DETI's proposed

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[160] *Portland Natural Gas Transmission Sys.*, Opinion No. 524-A, 150 FERC ¶ 61,107 at P 195.

[161] *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040 at P 686; *Portland Natural Gas Transmission Sys.*, Opinion No. 510-A, 142 FERC ¶ 61,198 at P 250, *order on reh'g*, 150 FERC ¶ 61,106; and *Kern River Gas Transmission Co.*, Opinion No. 486-F, 142 FERC ¶ 61,132 at P 263.

[162] *Dominion Transmission, Inc.*, 141 FERC ¶ 61,240 at P 41.

[163] *See, e.g.*, *Trunkline Gas Co., LLC*, 135 FERC ¶ 61,019, at P 33 (2011); *Florida Gas Transmission Co., LLC*, 132 FERC ¶ 61,040, at P 35 n.12 (2010); *Northwest Pipeline Corp.*, 98 FERC ¶ 61,352, at 62,499 (2002); and *Mojave Pipeline Co.*, 69 FERC ¶ 61,244, at 61,925 (1994). *See also Dominion Cove Point LNG, LP*,

incremental recourse rate for the Supply Header Project is based on the specified pre-tax return of 13.70 percent underlying the design of its approved settlement rates in Docket No. RP97-406-000.[164] While DETI has twice entered into settlements with its customers reaffirming its rates while providing certain rate relief, neither of those settlements specified the rate of return or most other cost of service components used to calculate the settlement rates.[165] Therefore, DETI calculated its proposed incremental rates in this certificate proceeding consistent with Commission policy by using the last Commission-approved specified pre-tax return.

111. The Commission's current policy of calculating incremental rates for expansion capacity using the Commission-approved ROEs underling pipelines' existing rates is an appropriate exercise of its discretion in section 7 certificate proceedings to approve initial rates that will "hold the line" until just and reasonable rates are adjudicated under section 4 or 5 of the NGA.[166] As discussed above, we do not believe that conducting discounted cash flow analyses in individual certificate proceedings would be the most effective or efficient way for determining the appropriate ROEs for proposed pipeline expansions.

112. DETI's proposed incremental monthly recourse reservation charge of $4.7459 per Dth is higher than the generally applicable Rate Schedule FT reservation

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115 FERC ¶ 61,337, at P 132 (2006), *order on reh'g*, 118 FERC ¶ 61,007, at PP 120, 122-123 (2007) (allowing, on rehearing, Dominion Cove Point LNG to recalculate incremental rates using the rates of return ultimately approved in its pending rate case, as opposed to its proposed rates of return). If a pipeline's most recent general section 4 rate case involved a settlement that did not specify a rate of return or pre-tax return, the Commission's policy requires that incremental rates in the pipeline's certificate proceedings be calculated using the rate of return or pre-tax return from its most recent general section 4 rate case (or rate case settlement) in which a specified return component was used to calculate the approved rates. *See, e.g.*, *Equitrans, L.P.*, 117 FERC ¶ 61,184, at P 38 (2006). This policy applies even if a pipeline calculated its proposed incremental rates for expansion capacity using a rate of return *lower* than the most recently approved specified rate of return. *Id.* (rejecting Equitrans's proposed use of 14.25 percent ROE component for incremental rates for mainline extension and requiring recalculation using the specified pre-tax rate of return of 15 percent that was approved in its rate case).

[164] *CNG Transmission Corp.*, 85 FERC ¶ 61,261 at 62,051.

[165] *See Dominion Transmission, Inc.*, 146 FERC ¶ 61,068 (2014); *Dominion Transmission, Inc.*, 111 FERC ¶ 61,285 (2005).

[166] *See Transcontinental Gas Pipe Line Co.*, 156 FERC ¶ 61,092 at PP 26-29; *Transcontinental Gas Pipe Line Co.*, 156 FERC ¶ 61,022, at PP 23-26 (2016).

charge of $3.8820 per Dth contained in DETI's tariff. Additionally, DETI's proposes to use its existing system maximum base usage charge of $0.0083 per Dth.[167] We find that DETI's proposed recourse rates are consistent with the Certificate Policy Statement and therefore approve them as the initial recourse rates for firm service using the incremental capacity created by the project.

113. DETI proposes to charge its system-wide fuel retention rate for the project. In order to ensure that existing shippers do not subsidize the project, DETI provided a fuel study which shows that the total estimated fuel used by the project facilities during the Summer Design Day[168] is 9,300 Dth. Using DETI's current fuel retention rate of 1.95 percent for the total Maximum Daily Transportation Quantity (MDTQ) of 1,511,335 Dth results in a total daily fuel retention of 30,057 Dth. The total daily fuel retention exceeds the projected maximum daily fuel used by the project facilities; consequently no subsidization by existing customers will occur and DETI's proposal to charge its system-wide fuel retention rate is appropriate.

114. We will require DETI to keep separate books and accounting of costs and revenues attributable to the proposed incremental services and capacity created by the Supply Header Project as required by section 154.309 of the Commission's regulations. The books should be maintained with applicable cross-reference as required by section 154.309. This information must be in sufficient detail so that the data can be identified in Statements G, I, and J in any future NGA section 4 or 5 rate case, and the information must be provided consistent with Order No. 710.[169]

3. Negotiated Rates

115. DETI and Atlantic propose to provide service to their shippers under negotiated rate agreements. DETI and Atlantic must file either their negotiated rate agreements or tariff records setting forth the essential elements of the agreements in accordance with the

[167] DETI March 15, 2016 Data Response at Question 5.

[168] The Summer Design Day is used to determine the incremental fuel because DETI projects it to be the day that will have the highest daily fuel usage by the project's facilities.

[169] 18 C.F.R. § 154.309 (2017).

Alternative Rate Policy Statement[170] and the Commission's negotiated rate policies.[171] DETI and Atlantic must file the negotiated rate agreements or tariff records at least 30 days, but no more than 60 days, before the proposed effective date for such rates.

E. **Non-Conforming Contract Provisions**

116. Atlantic and DETI entered into precedent agreements that contained certain contractual rights not available to other customers, which they state may be viewed as material deviations, but are necessary incentives to secure the level of contractual commitments to develop the projects. Atlantic and DETI request that the Commission approve these non-conforming contract provisions.

117. If a pipeline and a shipper enter into a contract that materially deviates from the pipeline's form of service agreement, the Commission's regulations require the pipeline to file the contract containing the material deviations with the Commission.[172] In *Columbia Gas Transmission Corp.*, the Commission clarified that a material deviation is any provision in a service agreement that: (1) goes beyond filling in the blank spaces with the appropriate information allowed by the tariff and (2) affects the substantive rights of the parties.[173] The Commission prohibits negotiated terms and conditions of service that result in a shipper receiving a different quality of service than that offered other shippers under the pipeline's generally applicable tariff or that affect the quality of service received by others.[174] However, not all material deviations are impermissible. As the Commission explained in *Columbia*, provisions that materially deviate from the

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[170] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines; Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *order on reh'g and clarification*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066, *reh'g dismissed*, 75 FERC ¶ 61,291 (1996), *petition denied sub nom. Burlington Res. Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998) (Alternative Rate Policy Statement).

[171] *Natural Gas Pipeline Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 (2003), *order on reh'g and clarification*, 114 FERC ¶ 61,042, *dismissing reh'g and denying clarification,* 114 FERC ¶ 61,304 (2006).

[172] 18 C.F.R. §§ 154.1(d), 154.112(b) (2017).

[173] *Columbia Gas Transmission Corp.*, 97 FERC ¶ 61,221, at 62,002 (2001) (*Columbia*).

[174] *Monroe Gas Storage Co., LLC*, 130 FERC ¶ 61,113, at P 28 (2010).

corresponding *pro forma* agreement fall into two general categories: (1) provisions the Commission must prohibit because they present a significant potential for undue discrimination among shippers and (2) provisions the Commission can permit without a substantial risk of undue discrimination.[175] In other proceedings, we have also found that non-conforming provisions may be necessary to reflect the unique circumstances involved with constructing new infrastructure and to provide the needed security to ensure the viability of a project.[176]

118. As discussed below, with the exception of Atlantic's special no-notice service, we find that Atlantic's and DETI's proposals are permissible material deviations. At least 30 days, but not more than 60 days, before providing service to any project shipper under a non-conforming service agreement, Atlantic and DETI must file an executed copy of their non-conforming service agreements and identify and disclose all non-conforming provisions or agreements affecting the substantive rights of the parties under the tariff or service agreement. This required disclosure includes any such transportation provision or agreement detailed in a precedent agreement that survives the execution of the service agreement. Consistent with section 154.112 of the Commission's regulations, Atlantic and DETI must also file a tariff record identifying the agreements as non-conforming agreements.[177] In addition, the Commission emphasizes that the above determination relates only to those items identified by Atlantic and DETI and not to the entirety of the precedent agreements or the language contained in the precedent agreements.[178]

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[175] *Columbia*, 97 FERC at 62,003-04. *See also Equitrans, L.P.*, 130 FERC ¶ 61,024, at P 5 (2010).

[176] *Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089, at P 82 (2008); *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 78 (2006).

[177] 18 C.F.R. § 154.112 (2017).

[178] A Commission ruling on non-conforming provisions in a certificate proceeding does not waive any future review of such provisions when the executed copy of the non-conforming agreement(s) and a tariff record identifying the agreement(s) as non-conforming are filed with the Commission, consistent with section 154.112 of the Commission's regulations. *See, e.g.*, *Tennessee Gas Pipeline Co., L.L.C.*, 150 FERC ¶ 61,160, at P 44 n.33 (2015).

1. **Atlantic**

119. Atlantic entered into precedent agreements with two categories of shippers: Foundation Shippers and Anchor Shippers.[179] Atlantic states that its Foundation and Anchor Shippers have been granted certain contractual rights not available to other customers, which may be viewed as material deviations, but are necessary incentives to secure the level of contractual commitments to develop the project. In particular, Atlantic identifies six provisions as non-conforming: (a) contract extension rights and a contractual right of first refusal (ROFR); (b) expansion rights; (c) special no-notice service via a "pack account"; (d) reduction rights; and (f) DETI capacity rights.[180] Atlantic states that all prospective customers were given the opportunity to become a Foundation or Anchor Shipper through the open season process.

120. As discussed more fully below, we find the (1) contract extension rights; (2) reduction rights; (3) DETI capacity rights; and (4) expansion rights to be permissible material deviations from Atlantic's *pro forma* service agreements. However, as proposed, the special no-notice service via a "pack account" is not a permissible material deviation.

a. **Extension Rights and Reduction Rights**

121. Atlantic has provided its Foundation and Anchor Shippers with a contractual right to extend their initial 20-year primary term contracts by additional five-year extension periods, which may be exercised up to four times per Article III.A of the precedent agreements. At the end of the final five-year extension period, Atlantic has provided shippers with a contractual ROFR per General Terms and Conditions section 25 of Atlantic's *pro forma* tariff. Atlantic has also provided Foundation Shippers with a right to specify a reduction in their MDTQs to be applied upon commencement of each extended five-year term.

122. The Commission has approved non-conforming provisions that reflect the unique circumstances involved with the construction of new infrastructure and provide the

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[179] A Foundation Shipper is defined as a shipper that contracts for at least 300,000 Dth/d of firm transportation capacity for a term of at least 20 years, and an Anchor Shipper is defined as a shipper that contracts for at least 150,000 Dth/d, but less than 300,000 Dth/d, for a term of at least 20 years. Atlantic Initial Application at 13.

[180] Atlantic provided public versions of the *pro forma* service agreements in redline/strikeout identifying the non-conforming language verbatim in its August 19, 2016 data response.

needed security to ensure that the project gets built.[181] Here, Atlantic states that these provisions were necessary to ensure contractual commitments without which the project could not go forward. We find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[182]

b. DETI Capacity Rights

123. Prior to the termination date of Atlantic's firm transportation service agreement with DETI, Atlantic will determine if any initial shipper elects to extend its DETI capacity right, and if so, Atlantic will contract with DETI accordingly. If any initial shipper elects not to maintain its DETI capacity rights, such rights will be removed from the affected service agreements. We find that the DETI capacity rights provision is not unduly discriminatory because General Terms and Conditions section 29.2.A of Atlantic's *pro forma* tariff provides all firm transportation shippers the same rights. Therefore, we find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.

c. Expansion Rights

124. Exhibit A of the Foundation Shipper precedent agreements contains contractual incentives for the shippers to request that Atlantic undertake an expansion of its system at any time between the in-service date of the initial pipeline project and the fourth anniversary of such date.[183] Foundation and Anchor Shippers will have a one-time option to elect to contract for an additional quantity up to one-third of their MDTQs, for a new 20-year term, in the first expansion of the pipeline. Atlantic has also agreed, in Exhibit B of the applicable precedent agreements, upon the rate methodology to be used in calculating charges for the optional capacity to be charged to the Foundation and Anchor Shippers for the requested optional incremental expansion service. Atlantic also provides, in Exhibit A, Part 4 of the Foundation Shipper precedent agreements, that Foundation Shippers have the right to request that Atlantic consider undertaking a second expansion either (1) at the time of Customer's election of Optional Quantities or (2) after

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[181] *See, e.g.*, *Tennessee Gas Pipeline Co. L.L.C.*, 144 FERC ¶ 61,219, at PP 26-33 (2013); *Rockies Express Pipeline, LLC*, 116 FERC ¶ 61,272 at PP 74-78.

[182] *Tennessee Gas Pipeline Co L.L.C.*, 144 FERC ¶ 61,219 at P 32.

[183] Atlantic has also afforded Anchor Shippers, in Exhibit A of their precedent agreements, the ability to participate in the first expansion once a Foundation Shipper initiates such a request; however an Anchor Shipper cannot trigger the timing of such expansion. Atlantic Initial Application at 27-28.

the date of a Commission order concerning the expansion that creates the capacity to transport the Optional Quantities and during the primary term of its Service Agreement. Atlantic states that at such time as the Foundation Shipper requests a second expansion, Atlantic shall determine the scope, design, and estimated costs and rates (calculated pursuant to the cost-of-service methodology described in Exhibit C) of the second expansion project.

125. The NCUC states that it is not clear whether Atlantic will roll-in the costs of subsequent inexpensive expansions for purposes of calculating recourse rates and requests that the Commission clarify that nothing in Atlantic's application exempts Atlantic from complying with Commission policy requiring roll-in of inexpensive expansion capacity for purposes of calculating recourse rates.[184]

126. Atlantic states that the NCUC's request that the Commission rule now that Atlantic must roll in the costs of potential future expansions is premature. Atlantic states that it does not propose to be exempt from any Commission policy for pricing service utilizing inexpensive expansion capacity.[185] Atlantic concludes that there is no basis to determine now how recourse rates should be calculated in the event that additional capacity is added at an unknown future date.[186]

127. The Commission has found that giving project sponsors certain priority rights to future expansion capacity is a permissible material deviation from the *pro forma* service agreement because such provision reflects the unique circumstances of the initial project.[187] As the Commission discussed in *Transcontinental Gas Pipeline Co., LLC*, "where a subsequent expansion is envisioned that will be less costly due to the anchor shipper's subscription, such capacity priority is reasonable when an anchor shipper is committing to both projects and the provision was offered to all potential shippers in the open season."[188] We find Atlantic's provision to offer optional capacity to Foundation and Anchor Shippers, via an expansion, to be a contractual incentive for obtaining each shipper's binding commitments to the project. We find these rights are permissible because Atlantic offered all Anchor and Foundation shippers the expansion rights in its open season, and the expansion rights do not present a risk of undue discrimination, do

[184] NCUC Protest at 8-9.

[185] Atlantic Answer at 27.

[186] Atlantic Answer at 28.

[187] *Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192 at P 104.

[188] *Transcontinental Gas Pipeline Co., LLC*, 145 FERC ¶ 61,152, at P 34 (2013).

not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.

128. Further, we find that the negotiated rate calculation methodologies for the first and second expansions outlined in Exhibits B and C are permissible as they apply only to Atlantic's Foundation and Anchor shippers. Without knowing the size and costs associated with any future expansion, the Commission cannot determine if those costs should be rolled in to Atlantic's system rates in a future section 4 rate case.

d. <u>No-Notice Service</u>

129. Atlantic proposes to provide its Foundation and Anchor shippers a no-notice service via a "pack account," which enables a select group of shippers to, on any gas day, tender gas quantities into an account within its MDTQ, for later delivery, as early as the next gas day, on a no-notice basis. Atlantic states that the no-notice service allows Atlantic to provide "cold start" capability to electric generation in Virginia and North Carolina. Atlantic asserts that because there are no storage capabilities on its system, to offer this service Atlantic will draw upon a substantial share of its line pack. Atlantic contends that the no-notice service ensured the viability of the project by incentivizing Anchor and Foundation shippers to commit to supporting the pipeline.

130. Under the NGA and the Commission's regulations,[189] we have consistently rejected pipeline proposals that present a significant potential for undue discrimination among similarly situated shippers.[190] Here, Atlantic proposes to offer a special no-notice service only to a select group of shippers and acknowledges that by offering this service, it is not capable of offering any park and loan service on its system to any other shipper.[191] Thus, similarly situated firm shippers are foreclosed from receiving the same level of service as Foundation and Anchor shippers on Atlantic's system. Because Atlantic's proposed no-notice service presents a significant potential for undue discrimination, we find it to be an impermissible material deviation and will require Atlantic to remove the provision from the non-conforming service agreements. If Atlantic wishes to offer this no-notice service, or a similar park and loan service, it must do so on a non-discriminatory basis through a new rate schedule.

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[189] 15 U.S.C. § 717(c) (2012); 18 C.F.R. §§ 284.7(b), 284.9(b) (2017).

[190] *See Rockies Express Pipeline LLC*, 119 FERC ¶ 61,069, at P 54 (2007) (rejecting a provision that allowed the pipeline to provide a different quality of firm service to original shippers at the potential expense of future shippers).

[191] Atlantic June 2, 2017 Data Response at 3-4.

2. DETI

131. DETI states that there are several provisions in its precedent agreement with Atlantic, its Anchor shipper, which do not conform to the *pro forma* Form of Service Agreement set forth in DETI's tariff, and DETI requests pre-approval by the Commission that the provisions are permissible material deviations.[192] Specifically, DETI's precedent agreement with Atlantic includes three non-conforming provisions: (1) contract extension and reduction rights; (2) delivery obligations; and (3) secondary access. DETI asserts that these terms of service reflect the unique circumstances involved with securing financial commitments necessary to support the development and construction of the project and were offered to all potential shippers through the non-discriminatory, open season bidding process for the project.

a. Extension and Reduction Rights

132. The firm transportation agreement with Atlantic includes a provision addressing extension rights, and if extended, MDTQ reduction rights that DETI states mirror the rights Atlantic provided to its own Foundation and Anchor Shippers. DETI states that these provisions were agreed upon to reflect Atlantic's use of the Supply Header capacity. Specifically, the provision provides Atlantic the right to extend the initial 20-year primary term of its agreement by additional 5-year extension periods, which may be exercised up to 4 times. Further, if Atlantic elects to extend the initial primary term, Atlantic would have the option to reduce its prospective MDTQ, with no subsequent unilateral right to increase its MDTQ.

133. The Commission has approved non-conforming provisions that reflect the unique circumstance involved with the construction of new infrastructure and provide the needed security to ensure that the project gets built.[193] Here, DETI states that these provisions were necessary to ensure contractual commitments without which the project could not go forward. Additionally, we find that the contract extension rights provision is not unduly discriminatory because it conforms to DETI's tariff, which permits DETI and a customer to mutually agree to an extension of the term of a service agreement. Therefore, we find these rights are permissible because they do not present a risk of

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[192] DETI filed a copy of the proposed Firm Transportation Service Agreement (FT Agreement) with Atlantic identifying three non-conforming provisions.

[193] *See, e.g.*, *Tennessee Gas Pipeline Co.*, 144 FERC ¶ 61,219 at PP 26-33; *Rockies Express Pipeline, LLC*, 116 FERC ¶ 61,272 at PP 74-78.

undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[194]

b. Delivery Obligations

134. The firm transportation agreement also includes provisions addressing delivery obligations, including measurement, at the new Marts Junction Interconnect and the nearby Kincheloe Metering and Regulating Station.[195] Specifically, the provisions state that the measurement at the primary delivery point (i.e., the Marts Junction Interconnect) be at the nearby Kincheloe M&R Station because the Marts Junction Interconnect is located on unsuitable terrain for the installation of measurement facilities, and DETI and Atlantic will also interconnect at the Kincheloe M&R Station. Further, the provisions provide that DETI, at its operating discretion, may deliver volumes into Atlantic at either the Marts Junction Interconnect or at the Kincheloe Interconnect and all volumes delivered by DETI to Atlantic at either of these interconnects will be treated contractually as delivered at the Marts Junction Interconnect. We find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.

c. Secondary Access

135. Section 6.1C of Rate Schedule FT of DETI's *pro forma* Form of Service Agreement provides for secondary access to the Applicable Market Center Point[196] on both the Access Segment[197] and Delivery Segment.[198] DETI's precedent agreement with Atlantic includes a provision where secondary access to the Applicable Market Center Point applies on only the Access Segment. DETI asserts that secondary access on the

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[194] *Tennessee Gas Pipeline Co.*, 144 FERC ¶ 61,219 at P 32.

[195] The Kincheloe M&R Station is approximately 7.6 miles downstream from the Marts Junction Interconnect.

[196] Where a Customer's Primary Receipt Point entitlement is designated as upstream of Valley Gate Junction, the Applicable Market Center Point is South Point. *See* GT&C Section 11A.4.G of DETI's Tariff.

[197] The Access Segment is from the Customer's Receipt Point to the Applicable Market Center Point. *See* GT&C Section 11A.4.G of DETI's Tariff.

[198] The Delivery Segment is from the Applicable Market Center Point to the Customer's Delivery Point. *See* GT&C Section 11A.4.G of DETI's Tariff.

Delivery Segment is not necessary because DETI has the capability to provide primary access on the Delivery Segment. We find these rights are permissible because they do not present a risk of undue discrimination, do not affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[199]

F. Atlantic's *Pro Forma* Tariff

1. North American Energy Standards Board (NAESB)

136. Atlantic states that it intends to include tariff provisions in GT&C section 12, Nomination and Confirmation, and GT&C section 17, Incorporation of NAESB Standards, implementing the NAESB Wholesale Gas Quadrant's (WGQ) revised business practice standards that the Commission incorporated by reference in its regulations. Atlantic is directed to file tariff records, 30 to 60 days prior to its in-service date, implementing the latest version of the business practice standards adopted by the NAESB WGQ applicable to interstate natural gas pipelines.[200]

2. GT&C Section 5 – Billing and Payments

137. GT&C section 5.5 of Atlantic's tariff outlines the procedure for handling a customer's failure to make a full payment of any portion of any bill for services received. Specifically, GT&C section 5.5.B states, in part, "[i]f after 15 days Customer has not yet paid Pipeline or has not provided written assurances as required by GT&C Section 6.5, then Pipeline shall be authorized to suspend service."

138. The Commission has not permitted pipelines to impose reservation charges when a pipeline elects to suspend service and it is not providing the service required under the

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[199] Exhibit A to the FTS Agreement provides in relevant part that "[f]or purposes of Section 11.A.4.G [of DETI's GT&C] … access to the Applicable Market Center Point for the Access Segment (as those terms are defined in [DETI's GT&C] for all Points of Receipt shall be South Point on a Secondary basis only." However, it appears that the referenced section is stated erroneously, missing a parenthetical placement. DETI is directed to correct the parenthetical placement, and identify all non-conforming provisions in redline format in section C3 of Exhibit A to the FTS Agreement, as appropriate.

[200] The NAESB WGQ Version 3.0 Standards were promulgated in *Standards for Business Practices of Interstate Natural Gas Pipelines; Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 587-W, FERC Stats. & Regs. ¶ 31,373 (2015), *order on reh'g*, 154 FERC ¶ 61,207 (2016).

contract during suspension. Thus, Commission policy for suspension of service provides that when pipelines elect to suspend service they are making an election of remedies; i.e., they are determining that the risks of continued service outweigh the potential collection of reservation or other charges during the time of the suspension.[201]

139. We approve the above-quoted language in GT&C section 5.5.B of Atlantic's tariff subject to revision because it does not make clear that Atlantic may not impose reservation charges during any such period of suspension. Therefore, we direct Atlantic to include additional language specifying that Atlantic will not impose reservation charges during the period of suspension, consistent with the Commission's policy noted above.

3. <u>GT&C Section 9 – Force Majeure</u>

140. Atlantic's proposed definition of force majeure events in GT&C section 9.2 includes "arrests and priority limitation or restraining orders of any kind of the government of the United States or a State or of any civil or military entity." The Commission has found that outages necessitated by compliance with government standards concerning the regular, periodic maintenance activities a pipeline must perform in the ordinary course of business to ensure the safe operation of the pipeline, including the Pipeline and Hazardous Materials Safety Administration's integrity management regulations, are non-force majeure events requiring full reservation charge credits.[202] Conversely, outages resulting from one-time, non-recurring government requirements, including special, one-time testing requirements after a pipeline failure, are force majeure events requiring only partial crediting.[203] Atlantic's proposed tariff language conflicts with these Commission policies because it can be interpreted to include regular, periodic maintenance activities required to comply with government actions as force majeure events.

141. In addition, Atlantic's proposed definition of force majeure events in GT&C section 9.2 includes "any other causes, whether of the kind herein enumerated or otherwise, *not reasonably within the control* of the party claiming suspension, which by

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[201] *Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, 111 FERC ¶ 61,412, at P 24 (2005).

[202] *Kinder Morgan Louisiana Pipeline LLC*, 154 FERC ¶ 61,145, at P 30 (2016); *TransColorado Gas Transmission Co., LLC* , 144 FERC ¶ 61,175, at PP 35-43 (2013); and *Gulf South Pipeline Co., LP*, 141 FERC ¶ 61,224, at PP 28-47 (2012), *order on reh'g*, 144 FERC ¶ 61,215, at PP 31-34 (2013).

[203] *See Algonquin Gas Transmission, LLC*, 153 FERC ¶ 61,038, at P 104 (2015).

due diligence such party is unable to overcome."[204] The Commission has defined force majeure outages as events that are both "unexpected and uncontrollable."[205] Therefore, we direct Atlantic to revise GT&C section 9 to comply with the Commission Policies, as described above.

4. GT&C Section 10 – Curtailment and Interruption

142. Atlantic's GT&C section 10.2 outlines when and how reductions of service due to curtailments and interruption will be handled and how those reductions of service will be performed. GT&C section 10.2.A outlines the order in which service interruptions, based on scheduled nominations, shall occur. Specifically, section 10.2.A states:

> In cases where Pipeline's ability to Receive, transport, or Deliver is affected, Pipeline shall first order interruption or, where sufficient transportation supplies are available, allocation of transportation quantities to customers based upon scheduled nominations, in the following order:
>
> 1. Scheduled service pursuant to GT&C Section 13.3.G
> 2. Scheduled service pursuant to GT&C Section 13.3.F
> 3. Schedule service under all Firm Transportation Service Agreements pursuant to GT&C Sections 13.3.A through E

GT&C Section 13.3 outlines the order in which customer's nominations will be scheduled, through each point of receipt and delivery, after accounting for any adjustments to a customer's nominations based upon service priorities on segments.

143. The NCUC states that Atlantic's reduction of service provisions in GT&C section 10.2.A.3 appear to apply the same reduction of service priority between primary point and secondary point services. The NCUC suggests that Atlantic's tariff should conform to Commission policy in Order Nos. 636 and 636-A.[206] In Order No. 636-A, the Commission found that existing shippers retained their primary priorities "at designated receipt and delivery points and may not be bumped, preempted, or curtailed under the

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[204] Emphasis Added.

[205] *North Baja Pipeline, LLC v. FERC*, 483 F.3d 819, 823 (D.C. Cir. 2007), *aff'g, North Baja Pipeline, LLC*, 109 FERC ¶ 61,159 (2004), *order on reh'g*, 111 FERC ¶ 61,101 (2005). *See* also, *e.g.*, *Kinder Morgan Louisiana Pipeline LLC*, 154 FERC ¶ 61,145 at P 29; *Algonquin Gas Transmission, LLC*, 153 FERC ¶ 61,038 at P 103.

[206] NCUC Protest at 11.

flexible receipt and delivery point policy."[207] Order No. 636 and Order No. 636-A also recognized that alternate/flexible points are inferior to primary firm points.[208]

144. In its answer, Atlantic states that the NCUC misinterprets its provision in GT&C section 10.2.A.3 and clarifies that the section was intended to reflect a similar ordering of priorities among firm services when allocating capacity as outlined in GT&C sections 13.3.A through E. Atlantic explains that section 13.3 provides the ordering of nomination priorities, starting with primary point services. Atlantic suggests that to clarify its provision in section 10.2.A.3, it proposes to add the phrase, "in the reverse order of priority provided in that section for scheduling."[209]

145. Atlantic's proposed revision to GT&C section 10.2.A.3 of its tariff, as discussed above, provides that reductions in service will be in the reverse order of the scheduling priorities outlined in GT&C section 13.3. Generally, the scheduling priorities for firm service are based on whether a customer's nomination is at primary points, secondary points within the capacity path, or at secondary points outside the capacity path. We find this approach to be inconsistent with our policy that once scheduled, all firm service is assigned the same priority for curtailment purposes, irrespective of whether capacity is utilized on a primary or secondary basis.[210] Accordingly, we direct Atlantic to revise its tariff to be consistent with Commission policy.

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[207] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs. ¶ 30,939, *order on reh'g*, Order No. 636-A, FERC Stats. & Regs. ¶ 30,950, at 30,583, *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *order on reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom. United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

[208] Order No. 636, FERC Stats. & Regs. ¶ 30,939 at 30,429; Order 636-A, FERC Stats. & Regs. ¶ 30,950 at 30,583.

[209] Atlantic Answer at 29.

[210] *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062, at 62,013 (2000), *aff'd in part and remanded in part sub nom*. *Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *aff'd sub nom. American Gas Ass'n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005).

5. GT&C Section 11 – Requesting and Contracting for Service

146. GT&C section 11.3 states:

> A Customer request to add a new Primary Point or change an existing Primary Point under a firm Service Agreement may not affect the priority of existing customers using such point as a Primary Point. Pipeline shall be entitled to reasonably reserve point capacity associated with unsold segment capacity. Pipeline shall not be obligated to add a new Primary Point or change an existing Primary Point if such point is associated with unsold segment capacity. A Customer may add or change a Primary Point only if the requested point is within Customer's Capacity Path Entitlements.

147. The NCUC argues that Atlantic's proposed GT&C section 11.3 appears to be inconsistent with the Commission's flexible point policies.[211] The NCUC believes Atlantic is proposing to limit shippers' ability to use capacity outside of their "Capacity Path" entitlements even though shippers pay for capacity on the entire pipeline via postage stamp rates.[212]

148. In its answer, Atlantic states that GT&C section 11.3 is intended to promote Atlantic's ability to market its small amount of unsubscribed capacity. Atlantic asserts that this limited restriction to their flexibility is reasonable and notes that the provision was accepted by all of its customers.[213]

149. In Atlantic's September 20, 2016 data response, Atlantic clarified that GT&C section 11.3 does not limit a customer's ability to nominate to points outside of its capacity path entitlements on a non-permanent basis.[214] Atlantic noted that in Order No. 637-A, the Commission recognized the need to balance the flexible receipt and delivery point policy with a pipeline's interest in marketing unsubscribed capacity, stating "[e]ven if the pipeline is not fully subscribed, it could protect its ability to sell

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[211] 18 C.F.R. §§ 284.221(g) and (h) (2017) (providing pipelines the authority to permit flexible receipt points for receipts of gas volumes into their systems and gives pipelines the authority to permit flexible delivery points for deliveries of gas volumes from their systems).

[212] NCUC Protest at 10.

[213] Atlantic Answer at 29.

[214] Atlantic September 20, 2016 Data Response at 1.

available mainline capacity by reserving an appropriate percentage of the receipt or delivery point capacity to be associated with the unsubscribed mainline capacity."[215]

150. In *Northern Border Pipeline Co.*, the Commission stated that it has required that pipelines permit shippers to move the primary points listed in their contracts to another point that is outside their contractual path on a permanent basis, subject to the availability of capacity.[216] Further, the Commission rejected language proposed by Northern Border similar to the language contained in Atlantic's GT&C section 11.3.[217] Northern Border's tariff language would have permitted it to reserve primary point capacity for the purpose of selling associated unsubscribed capacity. The Commission has found such reservation of point capacity to be unnecessary on a system where the Commission has allowed a pipeline to limit primary point capacity to mainline contract demand.[218] We therefore reject Atlantic's proposal to reserve unsold segment capacity for unsubscribed mainline capacity. Further, Atlantic is directed to clarify its tariff language so that shippers are permitted to permanently change a primary point, subject to available capacity and payment of the appropriate additional incremental rate to cover the cost of additional capacity reserved, as directed in *Northern Border*.

6. GT&C Section 13 – Scheduling and Scheduling Priorities

151. GT&C section 13 outlines the processes and priorities for scheduling a customer's nominated gas on Atlantic's system. As previously discussed, GT&C section 13.3 outlines the order in which an Atlantic customer's point nominations will be scheduled.

152. In GT&C section 13.3.C and 13.3.D, Atlantic proposes to schedule those customers nominating receipts or deliveries within their contract MDTQ at a primary point for the purpose of resolving imbalances under FT service agreements before scheduling those customers nominating firm service at points outside of their capacity path entitlements. The Commission has stated that imbalance quantities for makeup or payback should not be given a higher scheduling priority than any firm service quantities, stating that firm service with secondary scheduling rights is still firm service, and

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[215] *Id.* at 2 (citing Order 637-A, FERC Stats. & Regs. ¶ 31,099 at 31,594 n.121).

[216] *Northern Border Pipeline Co.*, 103 FERC ¶ 61,134, at PP 36-37 (2003) (*Northern Border*).

[217] *Id.*

[218] *Id.* (citing *ANR Pipeline Co.*, 103 FERC ¶ 61,022, at P 44 (2003)).

therefore, should have a scheduling priority directly following primary firm service.[219] Atlantic's proposal in GT&C section 13.3.C and 13.3.D contradict this Commission Policy, as imbalances under 13.3.C would have scheduling priority over firm nominations in 13.3.D. Therefore, Atlantic must revise its scheduling point priorities by moving the scheduling priority of firm primary point imbalances (GT&C section 13.3.C) after the scheduling priority for those customers nominating firm service at points outside of their capacity path entitlements (GT&C section 13.3.D).

7. GT&C Section 25 – Right of First Refusal

153. Atlantic's GT&C section 25 outlines the provisions within a qualifying customer's service agreement that enables it to continue service under a right of first refusal (ROFR) pursuant to its existing rate schedule and service rights. GT&C section 25.2.C provides that a customer may "elect[] to exercise the ROFR as to only a portion of its capacity." GT&C section 25.2.F.4 provides, in part, that "Pipeline shall notify Customer and the winning bidder in writing of the best bid(s), within five business days after the close of the bid period. The notice to Customer shall include an executable copy of a Service Agreement in the Form of Service Agreement set forth in this Tariff and containing the matching terms" and "[i]f a competing bidder or bidders submits a bid for only a portion of Customer's capacity subject to the ROFR, Customer must match that bid to retain the amount of capacity to which the bid applies." In addition, GT&C section 25.2.F.6 provides, in part, that if no competing bidder submits an applicable bid, "Customer may exercise its ROFR for all or a part of the capacity by notifying Pipeline."

154. We find that although GT&C section 25.2 provides that a customer may elect to retain only a portion of its capacity, GT&C section 25.2 does not expressly indicate when, in the ROFR bid matching process, the customer can make such election. The Commission's long-standing policy is that such election is not required until the service provider has notified the existing shipper of the best bid(s) received from third parties for all or a portion of the expiring capacity.[220] Therefore, Atlantic is directed to clarify GT&C section 25.2 to provide that a shipper is not required to elect how much capacity it will seek to retain through the ROFR process until after receiving notification from Atlantic as to the best offer(s) for its expiring capacity, and may then notify Atlantic of its intent to match the best offer(s) for all or a volumetric portion of its capacity.

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[219] *Colorado Interstate Gas Company*, 111 FERC ¶ 61,216, at P 19 (2005); *Panhandle Eastern Pipe Line Company*, 78 FERC ¶ 61,202, at 61,872 (1997).

[220] *See, e.g., Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192, at P 77 (2014); *Transcontinental Gas Pipe Line Corp.*, 101 FERC ¶ 61,267, at P 26 (2002).

155. GT&C section 25.F.4 provides, in part:

> *To retain capacity, Customer must match the competing bids up to the recourse rate applicable to the service currently being provided under the subject Service Agreement, for the term bid by the best bidder.* In determining whether the existing Customer's bid matches the best third party bid, Pipeline shall use the evaluation criteria specified in its posted notice pursuant to GT&C Section 26.2, as applied to the quantity of service that Customer elects to retain.[221]

156. The emphasized language quoted above contradicts the sentence that follows it. Pursuant to GT&C section 26.2, the pipeline will include in its notice the criteria by which the pipeline will evaluate bids. GT&C section 26.4.D.1 provides one of the evaluation criteria as "[t]he highest net present value (NPV) of the reservation charges or other source of guaranteed revenue to be received by Pipeline over the term of service." The Commission has found that "[u]nder an NPV bid evaluation method, shippers may bid whichever combination of rate and term best represents the value they place on the capacity."[222] Thus, an existing shipper is not required to match the rate or term bid by a third party when the pipeline has posted in the notice that NPV will be the bid evaluation criteria. Therefore, we direct Atlantic to delete the emphasized language quoted above from GT&C section 25.F.4.

8. <u>GT&C Section 29 – Off System Capacity</u>

157. Atlantic's proposed section 29.1 provides as follows:

> From time to time, Pipeline may enter into transportation and/or storage agreements with other interstate or intrastate pipeline companies. If Pipeline acquires capacity on an off-system pipeline, Pipeline will only render service to Customers on the acquired capacity pursuant to Pipeline's FERC Gas Tariff and subject to approved and/or negotiated rates, as such tariff and rates may charge from time to time. For transactions entered into under this Section 29, such capacity shall be referred to as "Off System Capacity", and further, the "shipper must have title" requirement is waived.

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[221] Emphasis Added.

[222] *Transcontinental Gas Pipe Line Corp.*, 105 FERC ¶ 61,365, at P 20 (2003).

158. We find that this language is consistent with the Commission's *Texas Eastern* policy concerning the acquisition of upstream capacity by interstate pipelines.[223] Under that policy a pipeline can acquire off-system capacity without preapproval if it makes a tariff filing that includes a statement that it will only transport gas for others on the acquired capacity pursuant to its open access tariff and subject to its Commission-approved rates. Upon the pipeline filing an appropriate tariff provision, we will grant a generic waiver of the "shipper must hold title" policy for any such transportation that the pipeline subsequently provides.

159. Atlantic states that it will utilize capacity on the DETI Supply Header Project to serve its customers in a seamless, integrated fashion, treating natural gas received through the DETI Supply Header Project as if it is a receipt onto its own system.[224] Atlantic's GT&C section 29.2 outlines the terms and conditions for its primary firm transportation customers that have rights on DETI as outlined in their service agreements. Atlantic states that all of its customers desired the option to have access to DETI capacity corresponding to their full MDTQs.[225]

160. The NCUC filed comments suggesting that the language contained in GT&C section 29.1 appears to be inconsistent with the discussion regarding Atlantic's DETI capacity in its transmittal letter. Specifically, the NCUC states that Atlantic indicated in its application that a shipper on its system may use any point on the DETI system on a secondary basis "in accordance with the terms of D[E]TI's FERC Gas Tariff" while GT&C section 29.1 states in part that the "Pipeline will only render service to Customers on the acquired capacity pursuant to Pipeline's FERC Gas Tariff."[226]

161. In its answer, Atlantic states that in addition to GT&C section 29.1, section 29.2 provides that customer's "rights shall not exceed the rights of Pipeline under its firm transportation service agreement with D[E]TI or D[E]TI's FERC Gas Tariff." Atlantic explains that the statement in its initial application was a short-hand reference to its tariff provision and that the tariff provision should resolve any perceived inconsistencies.[227]

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[223] *Texas Eastern Transmission Corp.*, 93 FERC ¶ 61,273 (2000), *reh'g denied,* 94 FERC ¶ 61,139 (2001) (*Texas Eastern*).

[224] Atlantic Initial Application at 19.

[225] *Id*.

[226] NCUC Protest at 11.

[227] Atlantic Answer at 30.

162. GT&C section 29.2.D states that "[c]ustomer may utilize any points of receipt or delivery on the D[E]TI system, provided however, Customer's rights shall not exceed the rights of Pipeline under its firm transportation service agreement with D[E]TI or D[E]TI's FERC Gas Tariff … ." We find the language contained in GT&C section 29 to be acceptable.

9. GT&C Section 37 – Overruns and Penalties

163. GT&C section 37 of Atlantic's tariff outlines the provisions for overruns and penalties for both authorized and unauthorized overruns applicable to each shipper's MDTQ.

164. The NCUC states that the penalties contained in GT&C section 37 are cumulative and that the Commission has held that pipelines are prohibited from applying multiple penalties for the same infraction.[228] The NCUC further states that section 37 appears to contradict the alternative point rights set out in Rate Schedule FT section 5.3 and is inconsistent with the Commission's flexible point policies as it assesses an overrun penalty if a shipper uses its capacity at an alternative point and exceeds its Maximum Daily Receipt Obligation (MDRO) or Maximum Daily Delivery Obligation (MDDO) at that point even if the shipper is within its overall daily contract quantity. The NCUC also argues that GT&C section 37.4 provides no basis for charging shippers for Operational Balancing Agreement (OBA) costs if shippers are in perfect balance every day within a given month.[229]

165. Atlantic, in its answer, states that a shipper would not incur multiple penalties on any single dekatherm delivered; rather, a shipper could incur different penalties on different quantities within the same day. Atlantic further explains that a shipper could incur scheduling penalties, as outlined in GT&C section 37.3, for certain quantities and then incur overrun penalties, as outlined in GT&C section 37.2, for different quantities within the same day. For example, Atlantic states that "[if] a shipper schedules 80% of its MDTQ and then takes 105% of its MDTQ: that shipper would incur scheduling penalties for quantities between 80% and 102% of the MDTQ and overrun penalties on the quantities in excess of 102%."[230] Atlantic concludes that a shipper could not incur multiple penalties on any single dekatherm delivered, but in its example, would incur two different penalties on the different quantities on the same day. Atlantic also notes that penalties associated with Operational Flow Orders, as provided in GT&C section

[228] NCUC Protest at 11.

[229] *Id*. at 12.

[230] Atlantic Answer at 30.

18.5.C, are in lieu of any penalties assessed pursuant to sections 37.2 and 37.3. Atlantic concludes that its terms and conditions for assessing penalties are reasonable and consistent with Commission policy.[231]

166. In response to the NCUC's concerns regarding alternative point rights and overrun penalties, Atlantic states that the NCUC misconstrues the provision in GT&C section 37.2. Atlantic states that shippers only have applicable MDDOs and MDROs at the primary points along their contract paths; therefore, a shipper could not exceed a maximum contractual point right and incur an overrun charge when delivering or receiving gas at an alternative point.[232]

167. Lastly, in response to the NCUC's concern that a shipper would be assessed OBA costs even if they were in perfect balance every day of the month, Atlantic suggests the NCUC overlooked a relevant portion of the language contained in GT&C section 37.4, emphasized below:[233]

> Customer shall be responsible for any charges that are incurred by Pipeline pursuant to the operational balancing agreements (OBA) between Pipeline and the upstream and downstream interconnecting pipelines to the extent such charges are not recovered or offset through any other sources. Upon determination that certain OBA charges are not recoverable from such sources and *to the extent such charge incurred by Pipeline is caused by Customer(s),* Pipeline shall promptly bill such Customers(s) in the next billing invoice for such charges pro rata based on the Customers' scheduled quantities for the applicable month. Upon request of the Customer, Pipeline shall provide documentation in support of any charges billed pursuant to this Section.

168. We find that Atlantic's proposed overrun and penalty provisions are in compliance with Order No. 637, relying on penalties when necessary to protect system integrity.[234]

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[231] *Id*.

[232] *Id.* at 28.

[233] *Id*. at 31.

[234] *See* Order No. 637-A, FERC Stats. & Regs. ¶ 31,099 at 31,598.

Commission policy prohibits multiple penalties for the same infraction.[235] Atlantic has satisfactorily clarified the concerns raised by the NCUC; therefore, we find the language contained in GT&C section 37 acceptable and consistent with Commission precedent and policy, as discussed further below.

169. Atlantic's GT&C section 37.5 provides for the crediting of unauthorized overrun and penalty revenues to its customers. GT&C sections 30.2 and 30.3 outline Atlantic's ability to confiscate unauthorized gas volumes; however, section 37.5 does not provide for a mechanism to credit such confiscated gas volumes to existing customers. The Commission has found that a pipeline's confiscation of gas left on its system is an operationally justified deterrent to shipper behavior that could threaten the system or degrade service to firm shippers.[236] However, the Commission has found that the value of such confiscated gas must be credited to existing customers. Atlantic has not provided such a mechanism in its tariff. Therefore, we direct Atlantic to revise section 37.5 of its tariff to credit the value of any confiscated gas, net of costs, to non-offending shippers.

10. <u>GT&C Section 37.3 – Scheduling Penalty</u>

170. GT&C Section 37.3 of Atlantic's initial application provides as follows:

> If Deliveries by a Customer to a Point of Delivery on any Gas Day deviate from the scheduled quantity by more than 5%, then Customer shall be subject to a scheduling penalty. The scheduling penalty shall equal the rate published on Tariff Record No. 10.30 for each Dt of deficiency below 95% of scheduled quantities and each Dt of excess above 105% of scheduled quantities. Customer shall pay the Scheduling Penalty in addition to any other applicable charges and penalties. However, for purposes of determining the Scheduling Penalty applicable to Customer, any available Section 41 Pack Account Balance shall be used to reduce the deficiency, and any available Customer's Section 41 MPQ. shall be used to reduce the excess before a Scheduling Penalty is calculated.

171. On October 23, 2015, Atlantic filed to modify section 37.3 of its tariff to include the following sentence at the end of the proposed language in section 37.3: "For firm customers that do not hold a Section 41 Pack Account, the 5% threshold shall be based on 5% of Customer's MDTQ in lieu of scheduled quantities." Atlantic believes this

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[235] *Crossroads Pipeline Co.*, 71 FERC ¶ 61,076, at 61,265 (1995) and 100 FERC ¶ 61,025, at P 51 (2002); *East Tennessee Natural Gas Co.*, 98 FERC ¶ 61,060, at P 107 (2002); *Columbia Gas Transmission Corp.*, 100 FERC ¶ 61,084, at P 201 (2002).

[236] *AES Sparrows Point LNG, LLC*, 126 FERC ¶ 61,019, at P 42 (2009); *Colorado Interstate Gas Co.*, 122 FERC ¶ 61,256, at P 102 (2008).

additional language will provide an adequate incentive for its customers to schedule accurately without impacting the service of other customers on its system.

172. As discussed above, we find that the special no-notice service via a "pack account" is not a permissible material deviation and directed Atlantic to remove the provision from the non-conforming service agreement. Therefore, we reject Atlantic's modified section 37.3, as it relates to firm customers that do not hold a "pack account."

173. The Commission has found with regard to the tolerance level for daily scheduling penalties during non-critical periods, that pipelines must have penalty provisions in place which are at a sufficient level to prevent impairment of reliable service.[237] Determining the penalty tolerance levels necessary to deter certain conduct is an exercise of reasonable judgment.[238] Therefore, when Atlantic submits its proposed tariff 30 to 60 days prior to its in-service date, Atlantic may submit the GT&C section 37.3[239] as proposed in its initial application[240] or the modified GT&C section 37.3. However, whichever language Atlantic chooses must afford all shippers the same rights.

11. GT&C Section 38 – Interruptible Services Revenue Crediting

174. The Commission's policy regarding new interruptible services requires the pipeline either to credit 100 percent of the interruptible revenues, net of variable costs, to maximum rate firm and interruptible customers, or to allocate costs and volumes to these services.[241] Atlantic chose the interruptible revenue crediting option.

175. Atlantic proposes to credit 100 percent of its interruptible revenue credits accrued during the calendar year to customers paying recourse rates or negotiated reservation rates under long-term contracts of one year or more and to interruptible customers and short-term customers pursuant to GT&C section 38.3 of its *pro forma* tariff. Atlantic

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[237] *MoGas Pipeline LLC,* 151 FERC ¶ 61,201, at P 10 (2015).

[238] *Id.*

[239] As discussed below, Atlantic is directed to remove all references of the "pack account" from its tariff and *pro forma* service agreements.

[240] As proposed in Atlantic's initial application, GT&C section 37.3 is consistent with Commission Policy. *Columbia Gas Transmission Corp.,* 133 FERC ¶ 61,217, at P 56 (2010)

[241] *See, e.g., Creole Trail LNG, L.P.*, 115 FERC ¶ 61,331, at P 27 (2006); *Entrega Gas Pipeline Inc.*, 112 FERC ¶ 61,177, at P 51 (2005).

states that the revenue credits will be allocated based on each respective customer's actual base reservation revenue contribution as a percentage of the total base reservation contribution of all eligible customers during the annual revenue crediting period.

176. Atlantic's GT&C section 38.3 states that shippers eligible for interruptible revenue credits may include negotiated rate shippers. We agree that Atlantic is permitted to share interruptible revenues with its negotiated rate shippers;[242] however, we note that maximum rate customers, as a group, must receive a proportionate share of 100 percent of interruptible revenues collected (less administrative costs to provide the interruptible service).[243] Interruptible revenues due to maximum rate shippers cannot be reduced to reflect revenues for negotiated rate agreements. Further, the provisions of a negotiated rate are specific to actual negotiated rate filings and are required to be reported in a tariff record that identifies the negotiated rate provisions.[244] However, in general, the Commission has found that it is not appropriate to place language on negotiated rate terms in various sections of the GT&C of the tariff. Therefore, we accept the provisions in section 38 subject to Atlantic to removing references to negotiated rates in this section.[245]

177. The NCUC states that GT&C section 38.4 provides that Atlantic will only pay interest on overrun funds collected from January through March when a revenue credit is to be provided, however, no interest will be paid for the period during the year in which the credit is accruing.[246] In Atlantic's August 19, 2016 data response, Atlantic clarified language contained in GT&C section 38.4, which intended to state that Atlantic will accrue interest on revenue credits from interruptible transportation service rendered from January 1 to December 31 of any given year and continuing through the month prior to when the customer will be invoiced. In the August 19, 2016 data response, Atlantic also proposes to revise GT&C section 38.4 to state "[r]evenue credits shall be paid to Customers via a credit on the invoices sent to Customers *in April*…" in order to clarify

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[242] *Cheyenne Plains Gas Pipeline Co., L.L.C.*, 108 FERC ¶ 61,052, at PP 12-13 (2004); *Wyoming Interstate Co. Ltd.*, 121 FERC ¶ 61,135, at P 11 (2007).

[243] *Wyoming Interstate Co. Ltd.*, 121 FERC ¶ 61,135, at P 11 (2007).

[244] Alternative Rate Policy Statement, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *order on reh'g and clarification*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066, *reh'g dismissed*, 75 FERC ¶ 61,291 (1996), *petition denied sub nom. Burlington Res. Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998).

[245] *Florida Southeast Connection, LLC*, 154 FERC ¶ 61,080 at P 131.

[246] NCUC Protest at P 12.

when customer invoices will be sent. Atlantic proposes an additional clarification to section 38.4, which states “pipeline shall accrue interest through March of the year in which Customer invoices are credited.”[247] Atlantic proposes to make the modifications to GT&C section 38.4 when actual tariff records are submitted 30 to 60 days prior to the in-service date. Atlantic's proposed modifications to GT&C section 38.4 of its tariff satisfactorily clarify the confusion surrounding the interest to be paid to customers, as raised by the NCUC.

12. GT&C Section 39 – Reservation Charge Adjustment

178. GT&C section 39.2.A states that “Pipeline shall not be obligated to provide reservation charge credits on any Day for quantities not delivered to Customer under the following circumstances … [d]ue to the conduct of the upstream point operator at the firm Primary Receipt Point or the downstream point operator of the facilities at the firm Primary Delivery point, not controlled by the Pipeline … .” The NCUC suggests that it is not clear whether DETI, an affiliate and upstream operator, potentially having the inability to supply gas to Atlantic should be considered a force majeure event on Atlantic’s system after 10 days.[248]

179. In its response, Atlantic states that its tariff exception to not provide reservation charge credits to its customers in the event deliveries are interrupted due to an upstream or downstream operator, as provided in section 39.2.A.3, is fully consistent with Commission policy. Atlantic states that the exception is applicable because it does not control the actions of its interconnecting point operator, and the fact that an affiliate happens to be the upstream interconnecting pipeline is immaterial.[249]

180. The Commission permits pipelines to include tariff exemptions from providing reservation charge credits in situations such as those proposed by Atlantic in section 39.2.A.3.[250] Further, the Commission has required pipelines to clarify that such exemptions are only applicable when the pipeline’s failure to perform is caused solely by the conduct of others not controllable by the pipeline (i.e., operating conditions on

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[247] Atlantic August 19, 2016 Data Response at Question No. 4.

[248] NCUC Protest at 12.

[249] Atlantic Answer at 31-32.

[250] *See, e.g. Enable Gas Transmission, LLC*, 152 FERC ¶ 61,052, at PP 133-134 (2015); *Dominion Transmission, Inc.*, 142 FERC ¶ 61,154, at PP 51-52 (2013).

upstream or downstream facilities).[251] As Atlantic notes, whether the upstream or downstream interconnecting pipeline is affiliated is irrelevant. Therefore, we will accept the proposed tariff language.

13. GT&C Section 41 – Foundation/Anchor Shipper Pack Account

181. GT&C section 41 provides Foundation and Anchor shippers a no-notice service via a "pack account." As discussed above, we rejected Atlantic's proposed no-notice service as unduly discriminatory. Therefore, Atlantic is required to remove section 41, including all references to such section within the tariff and *pro forma* service agreements.

14. GT&C Section 42– Imbalance Resolution Procedures

182. GT&C section 42 of Atlantic's tariff outlines the procedures for resolving system imbalances and requires that each customer eliminate its end-of-month imbalances under each transportation service agreement per the timeline of this section. GT&C section 42.5 states that "[a] customer may correct such net imbalance within seventeen (17) business days after Customer receives such notification of the month-end imbalance from Pipeline."

183. The NCUC states that GT&C section 42.5 provides that if a shipper does not correct its net imbalance within 17 business days after it receives notice of its month-end imbalance, Atlantic has the right to correct the imbalance by immediately suspending deliveries to or receipts from the shipper. The NCUC suggests that this type of discretion appears to be "draconian" because it could be applied to imbalances of any size without regard to whether there is an adverse system impact.[252]

184. In its answer, Atlantic states shippers have multiple opportunities and ways to correct their imbalance over the 17-day time period in accordance with Atlantic's tariff and the applicable NAESB rules. Atlantic further suggests that the need for the right to take decisive action for imbalances that remain uncorrected after the 17-day period arises from Atlantic's lack of storage, limited line pack, and no cash-out provisions for

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[251] *See, e.g.*, *Gulf South Pipeline Co., LP*, 141 FERC ¶ 61,224 at P 84; *Iroquois Gas Transmission Sys., L.P.*, 145 FERC ¶ 61,233, at PP 43-44 (2013); *Gas Transmission Northwest LLC*, 141 FERC ¶ 61,101, at P 42 (2012); *Paiute Pipeline Co.*, 139 FERC ¶ 61,089, at P 31 (2012).

[252] NCUC Protest at 13.

imbalances. Atlantic suggests its tariff language and actions taken in such circumstances are reasonable.

185. The Commission's regulations provide that a pipeline with imbalance penalty provisions in its tariff must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of shippers to manage transportation imbalances, as well as the opportunity to obtain similar imbalance management services from other providers without undue discrimination or preference.[253] In Order No. 637, the Commission stated that "pipelines will be required to provide imbalance management services, like park-and-loan service, and greater information about the imbalance status of shippers and the system, to make it easier for shippers to remain in balance in the first instance."[254] In *Gulf Crossing*, the Commission stated in limited circumstances, where the pipeline lacked storage facilities that can be used for imbalance management and where the pipeline had limited ability to use line pack for such purposes, the Commission has not required the pipeline to provide park and loan services.[255] The Commission has historically urged pipelines to establish services, such as park and loan services, and to propose that they be implemented whenever they are operationally feasible, to reduce reliance on penalties to resolve imbalances.[256]

186. Atlantic has provided two justifications for not offering a park and loan service on its system: (1) a lack of storage on its system and (2) a limited capability to use line pack. Because we have denied Atlantic's no-notice service for Foundation and Anchor shippers, it is not clear that Atlantic is unable to offer a park and loan service on its system. Therefore, we direct Atlantic to either file to implement park and loan services or to fully explain and document why it is operationally infeasible to do so.

G. <u>Accounting</u>

187. For the period March 2015 through August 2016, Atlantic's proposed Allowance for Funds Used During Construction (AFUDC) rate is in excess of its proposed overall

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[253] 18 C.F.R. § 284.12(b)(2)(iii) (2017).

[254] Order No. 637, FERC Stats. & Regs. ¶ 31,091 at 31,309.

[255] *Gulf Crossing Pipeline Company LLC*, 124 FERC ¶ 61,282, at P 7 (2008) (*Gulf Crossing*).

[256] *See, e.g.*, *High Island Offshore System, L.L.C.*, 97 FERC ¶ 61,156, at 61,690 (2001).

rate of return underlying its recourse rates, resulting in an over accrual of AFUDC.[257] AFUDC is a component part of the cost of constructing a project. Gas Plant Instruction 3(17) prescribes a formula for determining the maximum amount of AFUDC that may be capitalized as a component of construction cost.[258] That formula, however, uses prior-year book balances and actual costs of borrowed and other capital. In cases of newly created entities, such as Atlantic, prior-year book balances do not exist; therefore, using the formula contained in Gas Plant Instruction 3(17) is not feasible for initial construction projects. Thus, to ensure that appropriate amounts of AFUDC are capitalized for this project, we will require Atlantic to capitalize the actual costs of borrowed and other funds for construction purposes, not to exceed the amount of debt and equity AFUDC that would be capitalized based on the overall rate of return underlying its recourse rates.[259]

188. In similar cases, the Commission has limited the maximum amount of AFUDC that the pipeline could capitalize by limiting the AFUDC rate to a rate no higher than the overall rate of return underlying its recourse rates (i.e., the rate that it could earn on operating assets).[260] Consistent with this precedent, we will therefore require Atlantic to revise its AFUDC methodology to ensure that its maximum AFUDC rate for the entire construction period is no higher than the overall rate of return underlying its approved recourse rates. Further, Atlantic must use its actual cost of debt (short-term and long-term) in the determination of its AFUDC rate, if it results in an AFUDC rate lower than the overall rate of return underlying its recourse rates.[261]

189. Last, Atlantic proposes to lease up to 100,000 Dth/d of available capacity on Piedmont's system. We will require Atlantic to treat the capacity lease with Piedmont[262]

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[257] To calculate its AFUDC rate of 14 percent, Atlantic used a 100 percent equity for the period March 2015 through August 2016.

[258] 18 C.F.R. pt. 201 (2017).

[259] *See, e.g.*, *Creole Trail LNG L.P.*, 115 FERC ¶ 61,331; *Port Arthur LNG, L.P.*, 115 FERC ¶ 61,344 (2006); *Golden Pass LNG Terminal LP*, 112 FERC ¶ 61,041 (2005).

[260] *See Gulfstream Natural Gas System, L.L.C.*, 91 FERC ¶ 61,119 (2000); *Buccaneer Gas Pipeline Company L.L.C.*, 91 FERC ¶ 61,117 (2000).

[261] *See Weaver Cove Energy, LLC*, 112 FERC ¶ 61,070 (2005); *Pacific Connector Gas Pipeline, LP*, 129 FERC ¶ 61,234 (2009).

[262] Piedmont seeks only a limited-jurisdiction certificate under section 7(c) of the NGA authorizing it to make the leased capacity available for transportation of natural gas

as an operating lease and record the monthly lease payments in Account 858, Transmission and Compression of Gas by Others, consistent with similar capacity lease agreements approved by the Commission.[263]

H. <u>Environmental Analysis</u>

1. <u>Pre-filing Review</u>

190. On November 13, 2014, Commission staff granted Atlantic's and DETI's requests to use the pre-filing environmental review process in Docket Nos. PF15-6-000 and PF15-5-000, respectively. As part of the pre-filing review, on February 27, 2015, the Commission issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Supply Header Project and Atlantic Coast Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meetings* (NOI). The NOI was published in the *Federal Register* on March 6, 2015,[264] and mailed to 6,613 entities, including federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Indian Tribes and Native Americans; potentially affected landowners; other interested individuals and entities; and local libraries and newspapers. The NOI briefly described the projects and the Commission's environmental review process, provided a preliminary list of issues identified by Commission staff, invited written comments on the environmental issues that should be addressed in the draft environmental impact statement (EIS), listed the date and location of 10 public scoping meetings[265] to be held in the project area, and

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in interstate commerce; as such, Piedmont is not required to submit proposed accounting entries recording the capacity lease receipts from Atlantic.

[263] *See, e.g., Midwestern Gas Transmission Company*, 73 FERC ¶ 61,320 (1995); *TriState Pipeline LLC*, 88 FERC ¶ 61,328 (1999); *Gulf Crossing Pipeline Company LLC*, 123 FERC ¶ 61,100 (2008); *Columbia Gas Transmission, LLC*, 145 FERC ¶ 61,028 (2013); and *Constitution Pipeline Co.*, 149 FERC ¶ 61,199.

[264] 80 Fed. Reg. 12,163 (2015).

[265] Commission staff held the public scoping meetings between March 10 and 24, 2015, in Fayetteville, Wilson, and Roanoke Rapids, North Carolina; Chesapeake, Dinwiddie, Farmville, Lovingston, and Stuarts Draft, Virginia; and Elkins and Bridgeport, West Virginia.

established April 28, 2015, as the deadline for comments. A total of 330 people presented oral comments at the pre-filing public scoping meetings.[266]

191. On August 5, 2015, the Commission issued a *Supplemental Notice of Intent to Prepare an Environmental Impact Statement for the Planned Atlantic Coast Pipeline Project, and Request for Comments on Environmental Issues Related to New Alternatives Under Consideration* that described three route alternatives for the ACP Project in Virginia. The supplemental NOI was published in the Federal Register on August 11, 2015,[267] and sent to 618 entities, including federal, state, and local agencies; elected officials; environmental and public interest groups; Indian Tribes and Native Americans; potentially affected landowners; local libraries and newspapers; and other stakeholders who had indicated an interest in the area of the potential alternatives. Issuance of the supplemental NOI opened a 30-day formal supplemental scoping period for filing written comments on the alternatives under consideration.

192. In total, we received approximately 5,600 written comment letters[268] during the pre-filing process, formal scoping and supplemental scoping periods, and throughout preparation of the draft EIS.[269]

2. <u>Application Review</u>

193. As stated above, on September 18, 2015, Atlantic and DETI filed formal applications with the Commission in Docket Nos. CP15-554-000 and CP15-555-000 for the ACP Project and Supply Header Project, respectively. On the same day, Atlantic and Piedmont also filed a joint application in Docket No. CP15-556-000 for the Capacity Lease.

194. On March 14, 2016, Atlantic filed an amendment to its initial application with the Commission in Docket No. CP15-554-001. Atlantic's amended application identified various route modifications to its initially proposed route in West Virginia, Virginia, and North Carolina. As a result, on May 3, 2016, the Commission issued a *Supplemental*

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[266] Transcripts of the scoping meetings were placed into the Commission's public record for this proceeding.

[267] 80 Fed. Reg. 48,093 (2015).

[268] Over half the written comment letters were form letters expressing either opposition or support for the projects.

[269] Table 1.3-1 of the final EIS provided a list of environmental issues raised during scoping.

Notice of Intent to Prepare an Environmental Impact Statement and Proposed Land and Resource Plan Amendment(s) for the Proposed Atlantic Coast Pipeline, Request for Comments on Environmental Issues Related to New Route and Facility Modifications, and Notice of Public Scoping Meetings that described the route modifications identified in Atlantic's amended application and announced two additional public scoping sessions in Marlinton, West Virginia, and Hot Springs, Virginia, on May 20 and 21, 2016. The second supplemental NOI was published in the Federal Register on May 9, 2016,[270] and sent to 9,694 entities, including federal, state, and local agencies; elected officials; environmental and public interest groups; Indian Tribes and Native Americans; potentially affected landowners; local libraries and newspapers; and other stakeholders who had indicated an interest in the area of the proposed route modifications. Issuance of the second supplemental NOI also opened a 30-day formal scoping and comment period for filing written comments on the alternatives under consideration, which concluded on June 2, 2016. A total of 147 attendees provided oral comments at the meetings.[271]

195. On May 11, 2016, July 6, 2016, and August 29, 2016, Commission staff mailed letters to potentially affected landowners along certain modified and adjusted portions of the ACP Project route in West Virginia and Virginia, and requested comments from the affected landowners.

196. To satisfy the requirements of the National Environmental Policy Act (NEPA),[272] Commission staff evaluated the potential environmental impacts associated with the construction and operation of the ACP Project and Supply Header Project in an EIS. The U.S. Department of Agriculture, Forest Service (Forest Service); U.S. Army Corps of Engineers; U.S. Environmental Protection Agency (EPA); U.S. Fish and Wildlife Service (FWS) West Virginia, Virginia, North Carolina Field Offices and Great Dismal Swamp National Wildlife Refuge; West Virginia Department of Environmental Protection; and the West Virginia Department of Natural Resources participated as cooperating agencies in the preparation of the EIS.

197. Commission staff issued the draft EIS on December 30, 2016, addressing the issues raised during the initial and supplemental scoping periods and up to the point of publication. The *Notice of Availability* for the draft EIS was filed with the EPA and

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[270] 81 Fed. Reg. 28,060 (2016).

[271] Transcripts of the public meetings were placed into the Commission's public record for this proceeding.

[272] 42 U.S.C. §§ 4321 *et seq.* (2012). *See also* 18 C.F.R. pt. 380 (2017) (Commission's regulations implementing NEPA).

published in the Federal Register,[273] and established a 90-day comment period[274] ending on April 6, 2017. The draft EIS was sent to 9,805 entities on the environmental mailing list for the projects, including additional interested entities that were added since issuance of the NOIs. Commission staff held 10 public sessions between February 13 and March 2, 2017, in the project areas[275] to take comments on the draft EIS. In total, 620 people provided oral comments at those sessions.[276] Between the issuance of the draft EIS on December 30, 2016, and the end of the comment period on April 6, 2017, the Commission received 1,675 written or electronically filed letters.

198. Commission staff issued the final EIS on July 21, 2017, and the *Notice of Availability* was published in the Federal Register on July 28, 2017.[277] The final EIS addressed timely comments received on the draft EIS.[278] The final EIS was mailed to the same entities as the draft EIS, as well as to newly identified landowners and any additional entities that commented on the draft EIS.[279]

3. Major Environmental Issues and Comments on the Final EIS

199. The final EIS concludes that most environmental impacts resulting from construction and operation of the ACP Project and Supply Header Project would be

[273] 82 Fed. Reg. 2,348 (2017).

[274] The Forest Service, as a cooperating agency, is using the Commission's EIS for the purpose of amending the Forest Service Land and Resource Management Plans. Accordingly, the Commission adopted a 90-day comment period for the final EIS to accommodate Forest Service regulations pertaining to public notification and scoping for proposed Forest Service Plan amendments.

[275] Commission staff held the public comment sessions in Fayetteville, Wilson, and Roanoke Rapids, North Carolina; Suffolk, Farmville, Lovingston, Staunton, and Monterey, Virginia; and Elkins and Marlinton, West Virginia.

[276] Transcripts of the draft EIS comment sessions were placed into the public record for the proceedings.

[277] 82 Fed. Reg. 35,192 (2017).

[278] Appendix Z of the final EIS includes copies of letters in response to the draft EIS received through the close of the comment period, along with Commission staff responses.

[279] The distribution list is provided in Appendix A of the final EIS.

temporary or short-term, but that some impacts would be adverse and significant.[280] This determination was based on a review of the information provided by Atlantic and DETI in their applications and supplemental filings, including responses to staff data requests; field investigations; scoping; literature research; alternatives analyses; consultations with federal, state, and local agencies, as well as Indian Tribes; and additional information filed by members of the public. As discussed in more detail below, Commission staff considered specified impacts to be short-term to permanent, and forest fragmentation impacts to be significant.[281] Commission staff concludes that constructing the pipelines in steep terrain or high landslide incidence areas could increase landslide potential, and, where waterbodies are adjacent to steep terrain, slope instability could have long-term and adverse impacts on water quality and stream channel geometry, and, therefore, downstream aquatic biota.[282] Additionally, constructing the ACP Project facilities could significantly impact cave invertebrates and other subterranean species that occur in only a few known locations, and result in population-level effects on these species.[283] For most other resources, impacts would be reduced to less than significant levels with the implementation of mitigation measures proposed by the applicants and other mitigation measures recommended by Commission staff and included as environmental conditions in the appendix to this order. Major environmental issues of concern addressed in the EIS are discussed below and include: geological resources such as landslides, earthquakes, and karst terrain; water resources, including wells, streams, and wetlands; forested habitat; wildlife and threatened, endangered, and other special status species; land use, recreational areas, and visual resources; socioeconomic issues such as property values, environmental justice, tourism, and housing; cultural resources; air quality; noise; safety; cumulative impacts; and alternatives.

a. <u>Requests to Supplement Draft EIS</u>

200. Several commenters and interveners argue that the draft EIS was insufficient and the Commission should issue a supplemental draft EIS. They assert that, since issuance of the draft EIS, Atlantic and DETI filed extensive, additional information on which commenters should have an opportunity to comment.[284]

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[280] Final EIS at ES-16.

[281] *Id.* at ES-10.

[282] *Id.* at ES-4 and 12.

[283] *Id.* at ES-14.

[284] Commenters cite 40 C.F.R. § 1502.9(c)(1)(ii) (2017).

201. A purpose of a draft EIS is to elicit suggestions for change.[285] The Council on Environmental Quality (CEQ) regulation that the commenters rely upon calls for a supplemental draft or final EIS if the agency "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."[286] The Supreme Court, in *Marsh v. Oregon Natural Resources Council*, stated that under the "rule of reason," "an agency need not supplement an [EIS] every time new information comes to light after the EIS is finalized."[287] Further, NEPA only requires agencies to employ proper procedures to ensure that environmental consequences are fully evaluated, not that a complete plan be presented at the outset of environmental review.[288] In *National Committee for New River v. FERC*,[289] the court held that "if every aspect of the project were to be finalized before any part of the project could move forward, it would be difficult, if not impossible, to construct the project."[290]

202. As shown in the final EIS, the additional information submitted by the applicants between the issuance of the draft EIS and final EIS did not cause the Commission to make "substantial changes in the proposed action," nor did it present "significant new circumstances or information relevant to environmental concerns." The final EIS analyzed the relevant environmental information and recommended environmental conditions, which we are imposing in this order, that must be satisfied before the applicants may proceed with their projects.

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[285] *See City of Grapevine, Tex. v. DOT*, 17 F.3d 1502, 1507 (D.C. Cir. 1994) ("[t]he very purpose of a [draft EIS] is to elicit suggestions for change.").

[286] 40 C.F.R. § 1502.9(c)(1) (2017).

[287] *Marsh v. Oregon Natural Resources Council*, 490 U.S. 360, 373 (1989).

[288] *See Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 352 (1989).

[289] *National Committee for the New River v. FERC*, 373 F.3d 1323, 1329 (D.C. Cir. 2004) (*New River*).

[290] *Id.* (citing *East Tennessee Natural Gas Co.*, 102 FERC ¶ 61,225, at 61,659 (2003)).

b. Geological Resources

i. Steep Slopes and Landslides

203. About 84 miles of the ACP Project pipeline route and 24 miles of the Supply Header Project pipeline route will cross topography with slopes greater than 20 percent grade.[291] In West Virginia, 73 percent of the AP-1 mainline will cross areas with a high incidence of, and a high susceptibility to, landslides. In Virginia, approximately 28 percent of the AP-1 mainline route will cross similar areas. The entire Supply Header Project pipeline route will also cross these types of areas. Atlantic and DETI have committed to implementing a *Best in Class Steep Slope Management Program* and to use specialized techniques when constructing on steep slopes. Atlantic and DETI will also implement their *Slip Avoidance, Identification, Prevention, and Remediation - Policy and Procedure* to avoid, minimize, and mitigate potential landslide issues in slip prone areas prior to, during, and after construction.

204. Specifically, as part of the *Steep Slope Management Program*, Atlantic and DETI would implement mitigation measures for susceptible slopes or hillsides depending on the length and inclination of the slope. Some of these measures include: (1) implanting drainage improvement, such as providing subsurface drainage at seep locations through granular fill and outlet pipes, incorporating drainage into trench breakers using granular fill, and/or intercepting groundwater seeps and diverting them from the right-of-way; (2) buttressing slopes with concrete trench breakers; (3) changing slope geometry to make the slope shallower; (4) benching and re-grading with controlled backfill; (5) using alternative backfill; (6) using chemical stabilization of backfill (e.g., cement, lime); (7) implementing Geogrid reinforced slope that consists of benching existing slope, installing subsurface drains, and incorporating Geogrid reinforcement into compacted backfill; and/or (8) using retaining structures.[292] The final EIS concluded that these measures were generally acceptable. However, because the Phase 2 analysis of slopes was still ongoing, the final EIS recommended, and we will require in Environmental Condition 51, that the final outcomes and designs developed as a result of the Phase 2 analysis be filed with the Commission prior to project construction.

ii. Karst Terrain

205. Karst features, such as sinkholes and caves, form as a result of the long-term action of groundwater on subsurface soluble carbonate rocks (e.g., limestone and dolostone). These features could present a hazard to the pipeline due to cave or sinkhole

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[291] *See* Final EIS at 4-28.

[292] *Id.* at 4-29.

collapse. Commenters expressed concerns regarding subsidence and sinkholes affecting the construction and integrity of the pipeline in areas of karst terrain, and regarding potential impacts on and contamination of karst-related groundwater. The ACP Project will cross 71.3 miles of karst terrain in West Virginia and Virginia, specifically between AP-1 mileposts 59 and 154.[293] Desktop and field surveys conducted by Atlantic identified hundreds of sinkholes and depressions within and adjacent to the ACP Project workspaces. Cave systems and sinking streams also cross beneath and adjacent to the pipeline route.

206. Atlantic and DETI developed a *Karst Mitigation Plan* to minimize and respond to karst activity during construction and operation of the proposed facilities. In addition to the plan, we are requiring further measures to identify and minimize impacts on karst features. Environmental Condition 26 in the appendix to this order requires Atlantic to utilize subsurface analysis, LiDAR data,[294] and existing dye tracing studies[295] to further identify and characterize karst features along the project route. Environmental Conditions 28, 29, and 62 through 64 require Atlantic to complete further studies and to minimize impacts on site-specific karst features. Environmental Condition 29 requires Atlantic to revise its *Karst Mitigation Plan* to include post-construction monitoring using LiDAR data. We concur with the Virginia Department of Conservation and Recreation's comments on the final EIS that strict adherence to the *Karst Mitigation Plan* is essential to minimizing impacts on sensitive karst areas. We also believe that, with appropriate implementation of the *Karst Mitigation Plan*, the proposed AP-1 pipeline route does not require modification. As stated in the final EIS, the Virginia Department of Conservation and Recreation Division of Natural Heritage and the Virginia Cave Board have endorsed the *Karst Mitigation Plan* as comprehensive and indicate that the measures included would reduce the potential risk posed by the ACP Project to karst resources.[296]

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[293] *Id.* at 4-8.

[294] Light Imaging, Detection, And Ranging, or LiDAR, is a remote sensing method used to examine the surface of the Earth, often used to develop 3-dimensionsal images or maps of Earth features.

[295] Dye tracing studies encompass a wide variety of techniques that can be used to track or model groundwater flow, either quantitatively or qualitatively. In groundwater karst systems, it can be effective in determining connectivity of underground systems or pathways of groundwater flow.

[296] Final EIS at 4-177.

iii. Acid-Producing Rock

207. EPA recommends that, prior to construction, Atlantic complete surveys (beyond desktop analysis) where the AP-1 mainline crosses reclaimed coal surface strip mines, and identify measures to be implemented in the event acid-producing rock is encountered; and that these measures be included in any project approval, or in an appropriate construction and mitigation plan. The final EIS summarizes Atlantic's and DETI's consultation with geologic experts to identify geologic formations crossed by the projects that are known to contain acid-producing minerals, and presents mitigation measures committed to by Atlantic and DETI. Such measures include surveys for acid rock drainage, limiting the duration of stockpiled materials to less than 30 days to minimize potential for acid rock drainage, and applying lime or replacing topsoil with acid-free topsoil.[297] We find these measures to be sufficient.

iv. Mining Operations

208. After the issuance of the final EIS, Western Pocahontas Properties (WPP) filed comments regarding ongoing and future plans for coal mining on its properties. In sum, WPP states that the ACP Project route, as proposed, would interfere with several locations in which WPP plans to actively mine coal resources. WPP states that the pipeline as currently routed would prohibit WPP's mining activities, given restrictions on blasting by Atlantic, and would pose safety concerns to the pipeline and the mine. To address these concerns, WPP requests that the Commission adopt an alternative route that WPP now submits for consideration.

209. Section 4.1.4.5 and Appendix Z of the final EIS discusses concerns related to active mineral mining, which includes comments filed by WPP on the draft EIS. The final EIS noted that based upon consultations by Atlantic and DETI with mine owners and operators of active mines in the project area, it appears that those mines are of a design that locates shafts hundreds of feet below the ground surface. Thus, the final EIS concluded that the project would neither conflict with mining activities nor pose a public safety concern.[298] WPP's comments do not provide sufficient information about the depth or specific design of its mining operations for us to definitively conclude whether the ACP Project would conflict with WPP's mining operations. However, depending on the specific mine type and design, we do acknowledge that the project could impact WPP's ability to extract some of the coal resources on its properties. We note that the specific alternative submitted by WPP would result in impacting additional landowners and merely shift the projects impacts to a new group of landowners who have not had the opportunity to participate in the Commission's environmental review process or provide

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[297] *Id*. at 4-32 through 4-34.

[298] *Id.* at 4-35.

comments. Further, while we believe it may be possible to develop a more modest route deviation that would avoid impacts on the locations from which WPP plans to extract mineral resources, we are unable to do so at this time due to the illegibility and insufficient level of detail of the mapping provided by WPP.

210. Accordingly, while we are not approving WPP's requested alternative, we believe WPP's concerns can be addressed through ongoing consultations between Atlantic and WPP, and that minor alignment shifts and mitigation measures specific to construction in areas of active mining can be developed. Therefore, we have added Environmental Condition 73 that requires Atlantic to develop a Mining Area Construction Plan and provide documentation of ongoing consultation with WPP regarding minor alignment shifts to avoid planned mining efforts.

c. Water Resources

i. Groundwater

211. Bedrock aquifers predominate in the project areas, with minor surficial alluvial aquifers occurring along streams. The pipeline trench will rarely exceed 10 feet in depth, but could encounter shallow groundwater. In those situations, the trench will be dewatered through filters into adjacent vegetated uplands so that there will be some recharge to shallow aquifers.

212. The ACP Project pipeline route will also cross four wellhead protection areas[299] in West Virginia and two in Virginia.[300] No groundwater source protection areas were identified in the vicinity of the Supply Header Project.

213. Current survey information has identified 4 public and 236 private water supply wells near the ACP Project, and 18 private wells near Supply Header Project.[301] One of the public wells and 12 of the private wells are within the ACP Project workspace, and one is within the Supply Header Project workspace. A total of 124 springs were identified near the ACP Project, and 4 springs were identified near Supply Header Project.[302] The Virginia Department of Health's Office of Environmental Health Services provided comments related to existing wells and water supplies. Specifically,

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[299] A wellhead protection area encompasses the area around a drinking water well where contaminants could enter and pollute the well. Final EIS at 4-78.

[300] *Id.* at 4-79.

[301] *Id.* at 4-80.

[302] *Id.*

the Office of Environmental Health Services recommended that surveys for wells and springs be completed prior to construction. Due to lack of landowner permission and survey access, Environmental Condition 52 in the appendix to this order requires Atlantic and DETI to complete and file the remaining survey results for wells and springs after this order is issued. The Office of Environmental Health Services also recommended that Atlantic conduct a sanitary survey for sewage systems near the pipeline's final path. Atlantic committed to route around onsite sewage systems if possible, and to work with property owners to relocate onsite sewage systems that cannot be avoided. If previously unidentified sewage systems are encountered, we believe that Atlantic's commitment to relocate any system would resolve any issues, or that reroutes would be accommodated under Environmental Condition 5.

214. Commenters noted the degree of groundwater interconnectivity in areas of karst terrain. Commenters also stated that many landowners depend on wells or springs sourced from karst-generated groundwater for their domestic drinking water supplies, livestock watering, and irrigation of agricultural lands. Because karst features provide a direct connection to groundwater, there is a potential for pipeline construction to increase turbidity in groundwater, due to runoff of sediment into karst features or to contaminate groundwater resources by inadvertent spills of fuel or oil from construction equipment. To minimize impacts on wells, springs, and karst-related groundwater from construction-associated sedimentation and runoff, Atlantic and DETI have committed to implement the erosion control measures outlined in their *Karst Mitigation Plan* as well as the measures in the Commission's *Upland Erosion Control, Revegetation, and Maintenance Plan* (FERC Plan). Further, to minimize the potential for hazardous materials to contaminate groundwater, Atlantic and DETI will implement the measures outlined in their *Stormwater Pollution Prevention Plan*; *Spill Prevention, Control, and Countermeasures Plan*; *Contaminated Media Plan*; and *Blasting Plan*.

215. Atlantic and DETI have begun and will continue to conduct pre-construction water quality evaluations on water wells and springs within 150 feet of the construction workspace (500 feet in karst terrain), and will complete post-construction testing for damage claims during and after construction. Environmental Condition 68 requires Atlantic and DETI to offer post-construction testing of water supplies to all landowners within 150 feet of the construction workspace (500 feet in karst terrain). EPA suggested that the applicants develop a "communication plan" for conveying the information related to well testing with landowners. We believe that providing this information is important to landowners, but we find it unduly burdensome to require the development of an additional plan here. Atlantic and DETI have committed to providing information regarding well testing to landowners, and they are required to do so by this order. Additionally, Environmental Condition 9 requires Atlantic and DETI to develop a complaint resolution procedure, which would provide landowners recourse to secure copies of the reports if they are not provided or solicit the aid of Commission staff. In situations where project-related construction damages the quantity or quality of water

supplies, the applicants have committed to compensate the landowner for damages, repair or replace the water systems to pre-construction conditions, and provide temporary sources of water.

ii. Surface Waters and Fisheries

216. The ACP Project will require 1,536 crossings of surface waterbodies, 587 of which are perennial and 18 of which are defined by the Commission as major waterbodies (more than 100 feet wide).[303] The ACP Project pipeline route will cross 17 waterbodies listed on the Nationwide Rivers Inventory maintained by the National Park Service of rivers with outstanding qualities that may qualify for wild, scenic, or recreational designation; 12 federal navigable waters; as well as numerous state-designated waterbodies.[304] Atlantic will cross waterbodies using a variety of methods, including the wet open-cut, dry open-cut (flumed, dam-and-pump, or cofferdam), horizontal directional drill (HDD), and bore methods. All navigable water crossings will be completed via HDD or the cofferdam method.

217. The Supply Header Project will require 133 crossings of intermediate and minor surface waterbodies, of which 115 are perennial.[305] DETI will cross waterbodies using either dry open-cut or bore crossing methods.

218. Nine public surface water intakes are within 3 miles downstream of the ACP Project route, and one is within 3 miles downstream of the Supply Header Project route.[306] Six source water protection watersheds will be crossed in North Carolina.[307] Atlantic and DETI will use dry and trenchless crossing methods at these crossings.

219. Trout, anadromous fish, or federal or state/commonwealth protected species are present in several waterbodies that will be crossed by the ACP and Supply Header projects. Atlantic and DETI will minimize aquatic resource impacts by using the various trenchless or dry crossing methods, extra workspace restrictions, and restoration procedures. Atlantic will implement mussel relocation in West Virginia, Virginia, and North Carolina, and will implement relocation plans for certain non-mussel species in Virginia and North Carolina. Atlantic and DETI will also implement measures outlined

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[303] *Id.* at 4-100 through 4-103.

[304] *Id.* at 4-112 through 4-113.

[305] *Id.* at 4-100 through 4-103.

[306] *Id.* at 4-110 through 4-112.

[307] *Id.*

in their construction and restoration plans, such as restoring stream beds and banks to preconstruction conditions and implementing measures to minimize erosion and sediment loads. Where in-stream blasting may occur, Atlantic and DETI will implement blasting plans that provide measures for minimizing fishery impacts. Atlantic and DETI agreed to adhere to in-water work windows established by state resource agencies for crossing streams that contain or may contain sensitive species or special designations. However, given the number of waterbodies crossed, the final EIS concluded, and we agree, that certain designated water resources should be crossed with prescribed time of year restrictions to further avoid impacts on these resources. Therefore, Environmental Condition 20 in the appendix to this order requires Atlantic and DETI to adhere to additional in-water work windows, as detailed in appendix K of the final EIS.

220. EPA recommended that the Neuse River crossing be completed via the HDD method, pending a hydrofracture study that indicates low risk of inadvertent release, or to use the direct pipe method if the risk is not shown to be low. Environmental Condition 35 requires Atlantic to file a hydrofracture potential analysis for the Neuse River (located at MP 98.5 on AP-2), and to utilize the HDD method at this crossing if the potential for hydrofracture is low. If the HDD method is not feasible, Environmental Condition 35 requires Atlantic to consult with the U.S. Fish and Wildlife Service and North Carolina Wildlife Resources Commission to identify additional conservation measures that Atlantic will implement at this crossing to mitigate for the potential impacts on Endangered Species Act-listed, proposed, and/or under review species.

221. In its comments on the final EIS, the Virginia Marine Resource Commission provided recommendations for measures to be implemented at two waterbody crossings, Quaker Swamp and Cohoon Creek, including erosion and sediment control measures outlined in an April 13, 2017 memorandum from Environmental Resources Management to DETI, as well as timing restrictions related to predicted rainfall events. In a letter dated April 13, 2017, from Atlantic to the Virginia Department of Environmental Quality, that included the Environmental Resources Management memorandum as an attachment,[308] Atlantic committed that, if weather forecasts indicate that heavy rainfall is predicted, trenching would not occur until the threat of rain has passed. Further, Atlantic agreed in its letter to improve erosion and sediment control measures, as outlined in the memorandum.

222. Atlantic and DETI will require a total of approximately 86.6 million gallons of water for hydrostatic testing (82.9 million gallons for the ACP Project and 3.7 million gallons for the Supply Header Project).[309] Of this volume, 46.9 and 39.7 million gallons

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[308] Atlantic's April 13, 2017 Letter to the Virginia Department of Environmental Quality (filed May 5, 2017).

[309] Final EIS at 4-121.

will be required from municipal sources and surface water sources, respectively. Water for hydrostatic testing will be withdrawn and discharged in accordance with the Commission's *Wetland and Waterbody Construction and Mitigation Procedures* (FERC Procedures), state/commonwealth regulations, and required permits. Atlantic and DETI will construct temporary cylindrical water impoundment structures adjacent to several of the water withdrawal points to allow a slower withdrawal rate. As recommended by staff in the final EIS and adopted here, Environmental Condition 61 requires Atlantic and DETI to limit water withdrawal to not exceed 10 percent of instantaneous flow at waterbodies that contain federally protected species.[310] Environmental Condition 17 requires Atlantic and DETI to identify proposed or potential sources of water used for dust control, anticipated quantities of water to be appropriated from each source, and the measures they will implement to ensure water sources and any related aquatic biota are not adversely affected by the appropriation activity.

223. We received comments regarding potential effects on surface waterbodies during construction and operation of the projects due to sedimentation or spills or leaks of hazardous materials. We also received comments after the issuance of the final EIS claiming that open-cut waterbody crossings would prevent navigation or migration of aquatic species and cause excessive upstream flooding. Studies show that dry open-cut waterbody crossings result in temporary (less than 4 days) and localized (for a distance of only a few hundred feet of the crossing) increases in turbidity downstream of construction. The magnitude of this increase is small in comparison to increased turbidity associated with natural runoff and precipitation events.[311] Once construction is complete, streambeds and banks will be restored. The FERC Procedures (at section V.C.1.) stipulate the use of clean gravel or native cobbles for the upper one foot of trench backfill in all waterbodies that are classified as coldwater fisheries. The FERC Procedures also stipulate that downstream flows must be maintained (for aquatic resources) and that crossings are designed to meet the maximum flows of the water body. Furthermore, these crossings would be subject to ongoing monitoring while flows are diverted to prevent any undue damming of waterbodies. Atlantic and DETI will minimize impacts on riparian vegetation at the edge of waterbodies by narrowing the width of the standard construction rights-of-way at waterbody crossings to 75 feet and by siting most temporary workspaces at least 50 feet away from stream banks. Atlantic and DETI will minimize impacts on surface waterbodies by implementation of the construction practices outlined in their project-specific construction plans, the FERC Plan and Procedures, and by adhering to state and federal construction, restoration, and

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[310] The VA Department of Game and Inland Fisheries noted it was unable to confirm whether this was required in the final EIS, and we confirm here that Atlantic will be required to adhere to this measure.

[311] See Final EIS at 4-229.

operational requirements. To avoid or minimize the potential impacts of fuel or oil or other hazardous materials spilled from construction equipment, Atlantic and DETI will follow the procedures outlined in their *Spill Prevention, Control, and Countermeasures Plan*, which includes both preventative and mitigation measures such as personnel training, equipment inspection, refueling procedures, and spill cleanup and containment. Additionally, Atlantic and DETI will employ onsite environmental inspectors who will ensure that the applicants follow their construction plans and adhere to the environmental conditions described in this order.

224. In addition to the measures we require here, the U.S. Army Corps of Engineers as well as the Pennsylvania Department of Environmental Protection, West Virginia Department of Environmental Protection, Virginia Department of Environmental Quality, and North Carolina Department of Environmental Quality, have the opportunity to impose conditions to protect water quality pursuant to section 401 and 404 of the Clean Water Act. We expect strict compliance by the applicants with any such conditions.

iii. Wetlands

225. Construction of the ACP and Supply Header projects will impact a total of 798.2 acres of wetlands, including 91 acres of emergent wetlands, 97.4 acres of scrub-shrub wetlands, and 604.1 acres of forested wetlands.[312] Construction of the projects' aboveground facilities will result in the loss of 7.4 acres of wetlands.[313] To ensure this loss of wetlands is appropriately mitigated, Environmental Condition 53 in the appendix to this order requires Atlantic and DETI to file a copy of their final wetland mitigation plans and documentation of U.S. Army Corps of Engineers approval of the plans prior to construction. The remainder of wetlands will be restored after pipeline installation. However, in some cases there will be conversions of wetland types and functions.

226. EPA recommended continued efforts, including route modifications, to avoid and minimize impacts on cypress gum swamps, riparian habitats, and other special aquatic habitats. As stated in the final EIS in response to EPA's comments on the draft EIS,[314] impacts on these and other sensitive wetlands would be avoided, minimized, and/or mitigated through the U.S. Army Corps of Engineers' section 404 and 401 review and permit process. The final wetland mitigation plan, and U.S. Army Corps of Engineers' approval, would include appropriate mitigation for impacts on forested and high quality wetland resources.

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[312] Final EIS at 4-135.

[313] *Id.* at 4-139.

[314] *Id.* at Attachment Z, page 53.

227. Within the 10-foot-wide corridor centered on the pipelines that is mowed on a regular basis in accordance with the FERC Procedures, there will be a permanent conversion of forested and shrub wetlands to herbaceous wetlands. Impacts on emergent and scrub-shrub wetlands within temporary workspaces will be short-term. After construction, those areas will be restored, with emergent and scrub-shrub wetlands returning to their original condition and function within a few years. Forested wetlands within temporary workspaces will be subject to long-term impacts. While trees could regenerate in those areas, it will take decades for them to mature and return the forested wetlands to their original condition and function.

228. In general, construction and operation-related impacts on wetlands may also be mitigated by the applicants' compliance with the conditions of the Clean Water Act sections 404 and 401 permits. For unavoidable wetland impacts, Atlantic and DETI commit to purchase wetland and stream credits from approved mitigation banks in the respective states. In-lieu fee state programs may also be considered.[315] Proof of compensatory mitigation credit purchase will be provided by the applicants to the U.S. Army Corps of Engineers prior to construction. With implementation of the acceptable avoidance and minimization measures, as well as the environmental conditions of this order, we agree with the final EIS's conclusion that the ACP and Supply Header projects would not significantly impact wetlands.[316]

d. <u>Vegetation, Forested Land, and Wildlife</u>

229. Construction of the ACP Project will affect 5,522 acres of forest, 379 acres of shrublands, and 226 acres of grasslands.[317] Operation of the ACP Project will affect about 2,455 acres of forest, 172 acres of shrublands, and 101 acres of grasslands.[318] About 532 acres of forest will be permanently converted to industrial land use at aboveground facilities and permanent access roads for the ACP Project.

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[315] In-lieu-fee programs may be used pursuant to an agreement between a regulatory agency or agencies in which an external mitigation sponsor collects funds from permittees (applicant) in lieu of the permitees providing their own permittee-responsible compensatory mitigation that would be required for their U.S. Army Corps of Engineers permit. The external sponsor can then use those collected funds from multiple applicants or permittees to create one or more mitigation sites.

[316] Final EIS at 4-140.

[317] *Id.* at 4-155 through 4-156.

[318] *Id.*

230. Construction of the Supply Header Project will affect a total of about 614 acres of forest, 6 acres of shrublands, and 226 acres of grasslands.[319] Operation of the Supply Header Project will affect about 290 acres of forest, 175 acres of shrublands, and 101 acres of grasslands.[320] About 97 acres of forest and 2 acres of shrublands will be permanently converted to industrial land use at aboveground facilities and permanent access roads for the Supply Header Project.

231. The ACP Project will pass through several managed or vegetation communities of special concern, including the James River and Horsepen Wildlife Management Areas; the Kumbrabow and Seneca State Forests; the Monongahela National Forest and George Washington National Forest; late seral forests; 16 Natural Heritage Conservation Sites in Virginia; and 12 natural heritage natural areas and 9 natural communities in North Carolina. The Supply Header Project will pass through the Lewis Wetzel Wildlife Management Area in West Virginia. Since the issuance of the final EIS, the Virginia Department of Conservation and Recreation has identified three new stream conservation units (Spruce Creek, Matthews Creek, and Kingsale Swamp) and two new conservation sites (Duncan Knob Access Road and Wilson Mountain) that would be crossed by the AP-1 mainline. Atlantic will be required to implement the agency-recommended time of year restrictions and crossing measures, and comply with the restoration requirements, that were developed in consultation with resources agencies and contained in the FERC Plan and Procedures when crossing the newly identified stream conservation units.

232. The Virginia Department of Conservation and Recreation reiterated its previous comments that a hydrologic study of the Emporia Powerline Bog and Handsom-Gum Powerline Conservation Sites is essential to determine appropriate construction and restoration measures within these conservation sites. Atlantic has committed to completing hydrologic surveys of these sites, but does not propose to do so until the second quarter of 2018. To ensure that construction and restoration measures can be developed in coordination with the Virginia Department of Conservation and Recreation, Environmental Condition 60 requires Atlantic to complete the hydrologic studies of these sites prior to any construction within these conservation sites, and to file the results of the studies, along with construction and restoration measures developed in consultation with the Virginia Department of Conservation and Recreation, for Commission staff review.

233. The 50-foot-wide operational pipeline easements in uplands will be kept clear of trees, resulting in the permanent conversion of forest to grasslands/shrub land use. The remainder of the temporary construction workspace along the pipeline routes in forested uplands will be allowed to regenerate; although it will take many years for trees to mature. This will be a long-term impact affecting about 2,772 acres of forest, but the

[319] *Id.*

[320] *Id.*

resource will eventually recover. The removal of interior forest in order to create the necessary pipeline rights-of-way will result in the conversion of forest area to a different vegetation type. This will contribute to forest fragmentation and the creation of forest edges, which will remove habitat for interior species.

234. The ACP Project pipeline route will cross seven EPA Level III ecoregions: the Western Allegheny Plateau, Central Appalachians, Ridge and Valley, Blue Ridge Mountains, the Piedmont, Southeastern Plains, and Middle Atlantic Coastal Plain. All components for the Supply Header Project will be within the Western Allegheny Plateau ecoregion. Combined, these ecoregions make up a total area of more than 200 million acres, of which more than 120 million acres is forested. In considering the total acres of forest affected by the projects, the quality and use of forest for wildlife habitat, and the time required for full restoration in temporary workspaces, we agree with the final EIS's conclusion that the projects will have significant impacts on forest.[321]

235. EPA recommended that in forested areas, the permanently-maintained right-of-way be kept to the narrowest width possible. As described in the final EIS, Atlantic would generally maintain a permanent corridor of 50 feet, and a narrower corridor in sensitive areas such as wetlands. Atlantic's permanent right-of-way will be reduced significantly from the construction right-of-way, which typically measures 125 feet in width. A maintained corridor is important to facilitate routine and thorough inspections of the pipeline by its operator. These inspections are required by federal law to ensure safe operation of the pipeline and ensure an adequate degree of public health and safety. Given these considerations and because the width of the right-of-way has been reduced to the minimum necessary, we do not find it reasonable or practical in this instance to require further reductions in the width of the right-of-way.

236. To minimize forest fragmentation and edge effects, Atlantic has collocated about 9 percent and DETI 31 percent of the pipeline routes with existing linear corridors. Atlantic and DETI will seed and install temporary and permanent erosion control measures according to their *Restoration and Rehabilitation Plan*, the FERC Plan and Procedures, and the *Construction, Operation, and Maintenance Plan*, which is being developed by the applicants in coordination with the Forest Service. Atlantic and DETI have also developed an *Invasive Species Management Plan*. Environmental Condition 18 in the appendix to this order requires Atlantic and DETI to revise their *Restoration and Rehabilitation Plan* and *Invasive Species Management Plan* to minimize and/or restrict herbicide, pesticide, and insecticide applications.

237. The Virginia Forest Conservation Partnership recommended that an additional forest fragmentation analysis be completed using Virginia Forest Conservation Partnership methodologies, and that mitigation, including compensatory mitigation, be

[321] *Id.* at 4-170.

provided for direct and indirect impacts on forests. The final EIS assesses the fragmentation and edge effect impacts that would result from construction and operation of the pipeline using similar methodologies recommended by the Virginia Forest Conservation Partnership, and presents measures committed to by Atlantic and DETI that would be implemented to minimize or avoid fragmentation impacts.[322] Specifically, the final EIS concluded that the ACP Project would result in the loss of interior forest habitat, creation of new forest edges, fragmentation of forest cores, and reduction in the size of forest cores.[323] Atlantic has committed to incorporating mitigation measures including: (1) using regionally-specific flowering plant seed mixes to provide food and habitat for pollinators and local wildlife species; (2) mitigating for impacts on sensitive environmental resources including listed species habitats and migratory birds; (3) restricting maintenance mowing to occur outside of the bird nesting season for migratory birds; (4) identifying conservation easements or sites where forested areas could be restored; and (5) acquiring a 400-acre conservation site adjacent to the Monongahela National Forest to provide offsite mitigation.[324] The Commission does not require or encourage applicants to participate in compensatory mitigation to groups, governments, or agencies. The mitigation measures proposed or recommended in the final EIS's analysis target specific natural resources. The final EIS concludes, and we agree, that despite the mitigation measures that would be implemented in Atlantic's and DETI's construction and restoration plans and conditions of this order, forested areas would experience long-term to permanent significant impacts as a result of fragmentation.[325]

238. EPA, Virginia Department of Conservation and Recreation, and Virginia Department of Game and Inland Fisheries recommended that an expanded list of invasive and noxious plant species be included in the *Invasive Plant Species Management Plan*. The nine species of noxious weeds identified in Atlantic's *Invasive Plant Species Management Plan* are consistent with the Virginia Administrative Code and with those species identified during correspondence with the program manager for the Virginia Department of Agriculture and Consumer Services. Although the *Invasive Plant Species Management Plan* does not include an expanded list of non-regulated invasive and noxious weeds, many of the measures included in Atlantic's plan will aid in minimizing the spread of non-regulated species in addition to the regulated species. Additionally, restoration measures outlined in the FERC Plan and Procedures require that the restored

[322] *Id*. at 4-187 through 4-202.

[323] *Id*. at 4-200.

[324] *Id*. at 4-202.

[325] *Id*. at 5-14.

right-of-way must have a similar density and cover of non-nuisance vegetation as compared to adjacent undisturbed areas. We find these measures sufficient.

239. In its comments on the final EIS, the Virginia Department of Game and Inland Fisheries reiterated its comments on the draft EIS[326] regarding identification of invasive aquatic plant species of concern that may occur in the ACP Project corridor, and recommended measures to be included in an invasive species plan. The final EIS acknowledges the comments of the Virginia Department of Game and Inland Fisheries in the discussion of invasive aquatic species.[327] Further, the final EIS notes that Atlantic and DETI would control the potential transport of invasive aquatic species through adherence to federal and state-specific regulations for preventing the land transport of such species by primarily utilizing municipal sources of water for HDDs, hydrostatic testing, and dust control, and, where sourced from surface waters, by discharging hydrostatic test waters into well-vegetated upland areas.[328] We also will require Atlantic and DETI to include with their Implementation Plans measures to control the spread of invasive aquatic species and procedures for notifying federal and state agencies should invasive aquatic species be identified during construction.

240. A variety of wildlife species occupy the ecoregions and habitats to be crossed by Atlantic's and DETI's pipelines. Construction of the projects may result in limited mortality for less mobile animals, such as small rodents, reptiles, amphibians, and invertebrates, that are unable to escape equipment. More mobile animals will likely be displaced to adjacent similar habitats during construction. Once the right-of-way is revegetated, it will be reoccupied by the displaced wildlife.

241. The ACP Project could have significant adverse impacts on karst, cave, and other subterranean habitat, as well as on the species associated with such habitat. Subterranean species are often located in only a few locations and are vulnerable to changes in hydrological pattern or water quality. Impacts associated with construction activities could have population-level impacts on these species (such as cave-adapted amphipods).

242. Additionally, constructing the projects could disrupt bird courting, breeding, or nesting behaviors. Migratory birds, including Birds of Conservation Concern, are associated with the habitats that will be affected by the projects. Three Bird Conservation Regions will be crossed by the ACP Project: Bird Conservation Regions

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[326] These comments were addressed by Atlantic and DETI. *See* Final EIS at Attachment Z, page 248.

[327] *Id*. at 4-238.

[328] *Id*. at 4-239.

27 (Southern Coastal Plain), 28 (Appalachian Mountains),[329] and 29 (Piedmont). In addition, 10 Important Bird Areas will be crossed by the projects. Atlantic and DETI developed a *Migratory Bird Plan* to minimize impacts on bird species, and have agreed to conduct tree clearing outside of state-specific migratory bird nesting seasons. Our Environmental Condition 19 requires Atlantic and DETI to revise their *Migratory Bird Plan* and address potential impacts on active rookeries. Additionally, on August 29, 2017, the Forest Service provided supplemental comments on the *Migratory Bird Plan*, offering minor textual revisions and improvements. We recognize these additions may have some benefits; therefore, we have modified Environmental Condition 19 to include the Forest Service in any of Atlantic and DETI's ongoing consultations with state wildlife agencies.

e. Threatened, Endangered, and Other Special Status Species

243. Commission staff identified 36 federally listed threatened or endangered species (or federal candidate species or federal species of concern) that could be present in the vicinity of the projects.[330] However, four of these species do not occur in the specific project area. Of the remaining 32 species, the final EIS concludes that the ACP Project would have no effect on 11 species, would not be likely to adversely affect 14 species, and would be likely to adversely affect 7 species (Indiana bat, northern long-eared bat, Roanoke logperch, Madison Cave isopod, clubshell mussel, small whorled pogonia, and running buffalo clover).[331] The final EIS further evaluated designated critical habitats[332] for the Indiana bat and Atlantic Sturgeon and concluded that construction and operation of the ACP Project would have no effect on U.S. Fish and Wildlife designated critical habitat for the Indiana bat and would not adversely modify U.S. Fish and Wildlife designated critical habitat for the Atlantic sturgeon.[333] The final EIS concludes that the Supply Header Project would not likely adversely affect two mussels, but would likely

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[329] Bird Conservation Region 28 (Appalachian Mountains) will also be crossed by the Supply Header Project.

[330] Final EIS at 4-247 through 4-250.

[331] *Id.* at ES-7.

[332] Not all threatened or endangered species have U.S. Fish and Wildlife Service designated critical habitats. However, for species that do have designated critical habitats, the action agency must evaluate a project's effects on designated habitat(s) in addition to the effects on the species itself.

[333] *Id.* at 4-269 and 4-286.

adversely affect the Indiana bat and northern long-eared bat.[334] The conclusions by Commission staff in the final EIS were based in part upon Atlantic's and DETI's commitments for implementing certain species-specific avoidance and minimization measures. Commission staff has submitted a Biological Assessment to the U.S. Fish and Wildlife Service that includes a detailed assessment regarding the effects of the projects on federally listed species, initiating formal consultation with the U.S. Fish and Wildlife Service regarding species that will likely be adversely affected by either the ACP or Supply Header project. Environmental Condition 54 in the appendix to this order stipulates that construction cannot begin until after staff completes the process of complying with the Endangered Species Act.

244. We clarify that the final EIS requires that electric resistivity studies and/or air track drilling surveys of karst features identified within the construction workspace and within 5 miles of known or survey-identified bat hibernacula be completed for all project areas, not just for those areas that have been or would be surveyed in 2017. Accordingly, Environmental Condition 64 of this order has been revised to clarify this requirement.

245. The projects will also affect, to varying degrees, over one hundred species that are state-listed as threatened, endangered, or were noted by the applicable state agencies as being of special concern (in addition to those species already counted as federally listed). The final EIS concludes that that for species with high site fidelity and/or limited mobility (such as isopods), construction activities could impact and alter their habitat or cause localized population declines or local extirpations.[335] Atlantic and DETI will implement various construction plans to minimize impacts on these species.[336] Additional species-specific conservation measures that would be implemented by Atlantic and DETI are described in Appendix S of the final EIS.[337]

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[334] *Id.* at 4-269 and 4-277.

[335] *Id.* at 4-342.

[336] The following plans all have measures that will help minimize impacts: the FERC Plan and Procedures; the *Restoration and Rehabilitation Plan*; the *HDD Plan*; the *Karst Mitigation Plan*; the *Spill Prevention, Control, and Countermeasures Plan*; the *Timber Removal Plan*; the *Invasive Plant Species Management Plan*; the *Blasting Plan*; the *Migratory Bird Plan*; the *Protected Snake Conservation Plan*; the *Fire Plan*; the *Fugitive Dust Control and Mitigation Plan*; and the *Construction, Operations, and Maintenance Plan* (on National Forest lands).

[337] *Id.* at Appendix S.

f. Land Use, Recreation, and Visual Resources

246. The ACP Project pipeline route will mostly cross forest (56.1 percent), followed by agricultural land (27.7 percent), and wetlands (8.6 percent).[338] The Supply Header Project pipeline route will mostly cross forest (88.4 percent), followed by agricultural land (7.1 percent), and developed lands (3.6 percent).[339]

247. Combined, both projects will affect about 3,453 acres of agricultural lands.[340] Impacts on agricultural lands will be short-term, lasting during the period of construction and restoration and returning to pre-construction conditions within a few years. The applicants have committed to compensate farmers for the loss of agricultural production during the construction and restoration period. Following pipeline installation, the right-of-way will be restored to near pre-construction conditions and use, and agricultural practices could resume. Except for orchards, crops and pasture can be planted directly over the entire right-of-way. Mitigation measures typically implemented in agricultural lands (as specified in the FERC Plan) include topsoil segregation, rock removal, soil decompaction, and repair/replacement of irrigation and drainage structures damaged by construction. Environmental Condition 40 in the appendix to this order requires Atlantic to develop site-specific *Organic Farm Protection Plans* that outline measures to be implemented when crossing organic farms.

248. Atlantic identified 77 residences and DETI identified 5 residences within 50 feet of their respective proposed construction rights-of-way.[341] Site-specific residential mitigation plans are included as appendix J1 of the final EIS. The final EIS concludes that with implementation of Atlantic's and DETI's mitigation measures, including the construction methods in residential areas, and Landowner Complaint Resolution Procedures, impacts on residences would be minimized or mitigated.[342] We agree.

249. Federally owned or managed recreational and special use areas that will be crossed by the ACP Project pipeline route include the Appalachian National Scenic Trail, Blue Ridge Parkway, Monongahela National Forest, and George Washington National Forest. The Blue Ridge Parkway, managed by the National Park Service, and the Appalachian National Scenic Trail, managed by the Forest Service, will be crossed under with an

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[338] *See id*. at 4-344 through 4-349.

[339] *See id*.

[340] *Id.* at 4-349.

[341] *See id*. at 4-374 through 4-375.

[342] *Id.* at 4-377.

HDD, eliminating any surface impacts on either the Blue Ridge Parkway or the Appalachian National Scenic Trail. Construction and operation of the pipeline under the Appalachian National Scenic Trail and Blue Ridge Parkway will also not have a significant visual impact. Additionally, the final EIS discussed contingency planning for the HDD crossing of the resources, as well as an analysis of alternate crossing locations of the Blue Ridge Parkway and Appalachian National Scenic Trail.

250. The ACP Project pipeline route will pass through the Monongahela National Forest and George Washington National Forest for a total of 5.2 miles and 16.0 miles, respectively. As listed on table 2.2-2 of the final EIS, the ACP Project will affect about 112 acres in the Monongahela National Forest and 318 acres in the George Washington National Forest during construction.[343] The Monongahela National Forest and George Washington National Forest operate under Land and Resource Management Plans. The Forest Service analyzed amending its Management Plans to allow for the project within the Monongahela National Forest and George Washington National Forest, and on June 21, 2017, issued a draft record of decision to authorize the use and occupancy of National Forest System lands for the ACP Project. The draft record of decision was available for public objections until September 5, 2017. After resolving objections, the Forest Service will issue a final decision on the respective authorizations before it. Impacts on National Forest resources will be minimized by Atlantic following the measures outlined in its *Construction, Operation, and Maintenance Plan*.

g. <u>Socioeconomics</u>

i. <u>Property Values, Mortgages, and Insurance</u>

251. Several commenters expressed concerns regarding the potential effect of the projects on property values, mortgages, and homeowner's insurance. The final EIS identifies ten studies that conclude that the presence of a pipeline or compressor station either has no effect or an insignificant effect on property values.[344] Commenters cite a study performed by Key-Log Economics LLC,[345] which they assert demonstrates that property values will decrease as result of the proposed project. As stated in the final EIS, the Key-Log Study provides anecdotal evidence regarding sale value of properties, but does not present sources for the data presented with regard to loss of property value due

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[343] *Id.* at 2-18.

[344] However, the final EIS acknowledges that specific valuation predictions cannot be made on a property-by-property basis. *Id.* at 4-504 through 4-506.

[345] Key-Log Economics LLC, *Economic Costs of the Atlantic Coast Pipeline* (Feb. 2016) (filed Feb. 16, 2016) (Key-Log Study).

to proximity to a pipeline.[346] Accordingly, we conclude here, as we have in other cases, that the proposed project is not likely to significantly impact property values in the project area.[347]

252. With regard to concerns regarding to homeowner's insurance, our staff has researched this extensively and has found no evidence of any practices by mortgage companies to re-categorize properties, nor are we aware of federally insured mortgages being revoked, based on proximity to pipelines.[348] Accordingly, the final EIS concludes, and we agree, that homeowners' insurance rates are unlikely to change due to construction and operation of the proposed projects.[349]

ii. <u>Environmental Justice</u>

253. Executive Order 12898 requires that specified federal agencies make achieving environmental justice part of their missions by identifying and addressing, as appropriate, disproportionately high and adverse human or environmental health effects of their programs, policies, and activities on minorities and low income populations.[350] The Commission is not one of the specified agencies and the provisions of Executive Order 12898 are not binding on this Commission. Nonetheless, in accordance with our usual practice, the final EIS addresses this issue.[351]

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[346] For example, the Key-Log Study uses opinion surveys of realtors in Wisconsin to support its claims. However, these surveys are strictly personal opinion and do not carry with them the rigors of statistically developed and controlled studies. Final EIS at 4-504.

[347] *See, e.g., Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 at P 106; *Central New York Oil & Gas Co., LLC*, 116 FERC ¶ 61,277, at P 44 (2006).

[348] Final EIS at 4-506. *See also Transcontinental Gas Pipe Line Company, LLC,* 158 FERC ¶ 61,125 at PP 107-108.

[349] Final EIS at 4-506.

[350] Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, Executive Order 12,898 (Feb. 11, 1994), reprinted at 59 Fed. Reg. 7629.

[351] Final EIS at 4-511 through 4-515.

254. In accordance with EPA guidance,[352] the final EIS followed a three step approach for environmental justice reviews: (1) determine the existence of minority and low-income populations in the project area; (2) determine if the resource impacts are *high and adverse*; and (3) determine if any identified high and adverse impacts fall disproportionately on environmental justice populations. If the federal agency finds that any of these conditions are not present, the agency may then conclude its review and determine the action is not sited in a discriminatory manner on low-income or minority communities.

255. The construction and operation of the proposed facilities would affect a mix of racial/ethnic and socioeconomic areas in the ACP and Supply Header project area.[353] However, not all impacts identified in the final EIS would affect minority or low-income populations. The primary adverse impacts on the environmental justice communities associated with the construction of projects would be the temporary increases in dust, noise, and traffic from project construction.[354] These impacts would occur along the entire pipeline route and in areas with a variety of socioeconomic background. We also received numerous comments expressing concern about minority and low income communities near the proposed Compressor Station 2 in Buckingham County, Virginia. Based on the methodology used in the final EIS, of the three census tracts within one mile of Compressor Station 2, one is a designated low-income community, and *none* of the tracts were designated as minority environmental justice populations.[355]

256. Atlantic and DETI would implement a series of measures that would minimize potential impacts on the communities, including environmental justice communities, near project facilities. For example, Atlantic and DETI propose to employ proven construction-related practices to control fugitive dust, such as application of water or other commercially available dust control agents on unpaved areas subject to frequent vehicle traffic. Similarly, Atlantic and DETI will implement noise control measures during construction and operation of the projects.

257. In response to comments regarding specific environmental health concerns of minority communities, including African American populations, the final EIS considered in greater detail the potential risks of impacts falling on these communities, and what

[352] EPA, *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses* (April 1998).

[353] *Id.* at 4-512 through 4-513.

[354] *Id.* at 4-513.

[355] *Id.* at 4-513.

those effects would be. Due to construction dust and compressor station emissions, African American populations[356] near ACP and Supply Header projects could experience disproportionate health impacts due to higher rates of asthma within the overall African American community.[357] However, health impacts from construction dust would be temporary, localized, and minor. Health impacts from compressor station emissions would be moderate because, while they would be permanent facilities, air emissions would not exceed regulatory permittable levels. While the final EIS discusses the potential for the risk of impacts to fall disproportionately on minority communities, it further notes that, in relation to comments received regarding Compressor Station 2's effects on African Americans, the census tracts around the station are not designated as minority environmental justice populations. Therefore, by following the methodology outlined above, the final EIS concludes, and we agree, that the projects will not result in disproportionately high and adverse impacts on environmental justice populations as a result of air quality impacts, including impacts associated with the proposed Compressor Station 2.[358] Further, no disproportionately high and adverse impacts on environmental justice populations as a result of other resources impacts will be expected as a result of the projects.[359]

iii. Housing, Business, and Tourism

258. About 50 percent of the projects' workforce (5,815 workers) will be non-local, resulting in demand for local temporary housing in the projects' areas.[360] The final EIS estimates that there are at least 52,875 rooms/sites available in the project area, and there are sufficient accommodations to meet the increase in demand caused by the influx of the non-local construction workforce.[361] While some construction activity will be conducted during the peak tourism season, sufficient temporary housing is still likely to be available

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[356] As stated above, although minorities, including African Americans, do reside in the three census tracts within one mile of Compressor Station 2, none of the tracts were designated as minority environmental justice populations.

[357] *Id.* at 4-514 (citing U.S. Dep't of Health and Human Services, Centers for Disease Control and Prevention, *Asthma Facts – CDC's National Asthma Control Program Grantees* (July 2013)).

[358] *Id.*

[359] *Id.* at 4-515.

[360] *Id.* at 4-492.

[361] *Id*.

for tourists, however, it may be more difficult to find (particularly on short notice) or more expensive to secure. The final EIS concludes, and we agree, that the increase in demand for short-term housing from non-local construction workers during the construction of the projects would be temporary and minor.[362]

259. The projects will have economic benefits to local communities through expenditures on goods and services, including spending on hotels and restaurants, and tax revenues.[363] However, the final EIS acknowledges that some local businesses may be directly and indirectly impacted by the projects.[364]

260. The Commission received comments that the ACP Project would cause a delay or potentially prevent two large projects from being developed in the Rockfish Valley area. The first is the development of a self-described luxury hotel at Wintergreen Resort. Based on information provided by Wintergreen Property Owners Association Inc. and Wintergreen Resort Inc., the hotel would be located over one mile east of the ACP Project near AP-1 MPs 159.0 to 160.0. Wintergreen Pacific LLC and Pacific Group Resorts, the developers of the project, claim that they "would be forced to discontinue development of [the] hotel, or substantially delay its development" if the ACP Project is constructed. Commenters expressed concern regarding blocking access along Beech Grove Road leading to the resort area and hindering future development and sale of lots. Commenters also speculated that if the hotel at Wintergreen Resort was not developed, the value of the existing resort would diminish, impacting the future viability of the resort. Wintergreen Resort is cited as the largest employer in Nelson County, and commenters claimed that any diminishing value or opportunities for the resort could cause negative economic impacts for the entire Rockfish Valley area and the county, including the loss of property values if Wintergreen Resort went out of business.

261. The second development is the Spruce Creek Resort and Market, a proposed resort, hotel, restaurant, and public market on 100 acres of mature woodland along Virginia State Route 151 and bisected by Spruce Creek. Based on information provided by the developer, the AP-1 mainline would cross the resort between approximate MPs 162.4 and 162.7 in Nelson County, Virginia. The developer is concerned that ACP Project would cross the middle of the property, eliminating the attractiveness of the resort area and, thus, development of the resort would be stopped.

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[362] *Id*. at 4-492.

[363] *Id*. at 4-510.

[364] *Id.* at 4-510.

262. The final EIS concluded, and we agree, that construction of ACP Project and development of the hotel at Wintergreen Resort and the development of Spruce Creek Resort and Market could still be accomplished such that the overall socioeconomic impacts associated with the ACP Project are reduced or mitigated, while maintaining the appeal of the area, as demonstrated by other residential and commercial developments in the area of similar projects throughout the country.[365]

263. However, the final EIS acknowledges that the Spruce Creek Resort and Market could be impacted by the proposed projects.[366] Because of these impacts, Commission staff assessed other alternatives, primarily the "Spruce Creek Alternative," to avoid the proposed development. As further described in the final EIS, these other alternatives would result in similar but different impacts on a different set of landowners.[367] These included a privately-owned airstrip and various other local businesses or commercial endeavors, including Blue Heron Farms, High View Farm, Blue Toad Hard Cider, and a bed and breakfast. Commission staff concluded that the Spruce Creek Alternative did not offer a significant environmental advantage, and thus, did not recommend its adoption.

264. Commenters also indicated that construction and operation the projects could adversely impact local tourism. The final EIS found no evidence that short-term effects of pipeline construction have long-term significant impacts on the tourism industry in areas where pipeline construction has occurred. The final EIS concludes, and we agree, that recreational uses and tourism activities in the project area would not be affected by operation of the project.[368]

h. <u>Cultural Resources</u>

265. Atlantic identified 198 archaeological and historic sites within the area of potential effect for the ACP Project that are listed in the National Register of Historic Places (National Register), eligible for listing, are unevaluated, or would otherwise require treatment during construction (e.g., cemetery avoidance plans for cemeteries that are not eligible for listing).[369] State Historic Preservation Office (SHPO) concurrence with

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[365] *Id*. at 4-510.

[366] Specifically, the developer asserts in its comments that the development could lose up to 30 percent of its accommodations and its spa complex.

[367] Final EIS at 3-44.

[368] *Id*. at 4-497 through 4-500.

[369] *See id*. at 4-516 through 4-530.

Atlantic's recommendations of eligibility is pending on most of these sites. Atlantic will avoid impacts on eligible or unevaluated cultural sites by project design, or will conduct additional studies to further assess National Register eligibility.

266. DETI identified two cultural resources sites that are recommended as eligible and will be avoided or mitigated during construction: one historic farmstead that is recommended as eligible, but will not be affected by the Supply Header Project; and three historic cemeteries that are recommended not eligible, but will be avoided during construction.[370]

267. The ACP Project pipeline route crosses two Historic Districts: Warminster Rural Historic District and South Rockfish Rural Historic District. Atlantic will assess potential effects on these historic districts, consult with the Virginia Department of Historic Resources and other interested parties as needed, and make recommendations for further evaluation or mitigation of adverse effects. Two access roads along the AP-3 pipeline will cross the Sunray Agricultural Historic District. Atlantic asserts that use of these roads will not affect the historic district. After the issuance of the final EIS, Roberta Koontz, co-owner of "The Wilderness," filed comments taking issue with Atlantic's survey of the property and Atlantic's recommendations regarding eligibility for listing in the National Register. The Virginia Department of Historic Resources commented that the property was determined eligible for listing on the National Register, and the Virginia Department of Historic Resources review board approved the nomination of "The Wilderness" for listing on the Virginia Landmarks Registry and the National Register. While discrepancies in the absolute boundaries of the parcel and exact location of structures are apparent, we clarify here, as did the final EIS, that the historic farmstead "The Wilderness" does meet the criteria for listing on the National Register and includes a residence, numerous outbuildings, and agricultural fields. Thus, the property will continue to be considered as part of staff's ongoing consultations under the National Historic Preservation Act. An assessment of effects and proposed mitigation for the historic property is required to be completed before project construction.

268. Atlantic and DETI consulted with 15 federally recognized Indian tribes to provide them an opportunity to comment on the projects. Several tribes and organizations requested additional information, and we have responded to tribes that commented on the projects. Atlantic and DETI have prepared plans to be used in the event any unanticipated archaeological sites or human remains are encountered during construction. The plans provide for work stoppage and the notification of interested parties, including Indian tribes, in the event of discovery.

269. Commission staff has not finished consultations with the SHPOs. In addition, Atlantic and DETI are still conducting investigations at sites where access was previously

[370] *See id*. at 4-530 through 4-535.

denied. If, in the future, Commission staff determines that any historic properties will be adversely affected, staff will notify the Advisory Council on Historic Preservation, and consult with appropriate consulting parties regarding the production of an agreement document to resolve adverse effects, in accordance with 36 C.F.R. § 800.6. The process of compliance with section 106 of the National Historic Preservation Act has not yet been completed for ACP and Supply Header projects. Therefore, Environmental Condition 56 in the appendix to this order precludes construction until after any additional required surveys and evaluations are completed, survey and evaluation reports have been reviewed by the appropriate consulting parties, the Advisory Council on Historic Preservation has had an opportunity to comment, and the Director of OEP provides written notification to proceed.

i. Air Quality and Noise Impacts

i. Air Quality

270. Air quality impacts associated with construction of the projects will include emissions from construction equipment and fugitive dust. The final EIS concludes that such air quality impacts will generally be temporary, localized, and not have a significant impact on air quality or contribute to a violation of applicable air quality standards.[371] We agree.

271. Operational emissions will be mainly generated by the three new compressor stations for the ACP Project and the modification of four compressor stations for the Supply Header Project. Atlantic's proposed new Compressor Stations 1, 2, and 3 will be subject to a Prevention of Significant Deterioration (PSD) major source threshold of 250 tons per year. Potential operational emissions from the Crayne and JB Tonkin Compressor Stations after proposed modifications will remain below PSD major source thresholds; therefore, these stations will not be subject to PSD regulations. While emissions from the Mockingbird Hill Compressor Station will be minor, the net emissions increase of particulate matter, particulate matter with an aerodynamic diameter less than or equal to 10 microns, particulate matter with an aerodynamic diameter less than or equal to 2.5 microns, and greenhouse gasses (GHGs) will still exceed the major modification thresholds, representing a significant net emissions increase and requiring a Best Available Control Technology analysis. The Mockingbird Hill and JB Tonkin Compressor Stations are currently subject to Clean Air Act Title V regulations and will remain Title V facilities after construction. The Crayne Compressor Station, authorized under a state operating permit, is a minor source under Title V and will remain so after construction of the Supply Header Project. The final EIS concludes, and we agree, that

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[371] *Id*. at 5-32.

emissions resulting from operation of the compressor stations will not cause or contribute to a violation of national air quality standards.[372]

ii. Noise Impacts

272. Noise levels are quantified according to decibels (dB), which are units of sound pressure. The A-weighted sound level, expressed as dBA, is used to quantify noise impacts on people. Sound level increases during pipeline construction will be intermittent and will generally occur during daylight hours, with the possible exception of some HDD activities. Construction equipment noise levels will typically be around 85 dBA at a distance of 50 feet. Blasting may be necessary to trench through shallow bedrock. Blasting noise levels have been documented at about 94 dBA at a distance of 50 feet. Noise impacts during construction will be transient as pipe installation progresses from one location to the next. HDD operations at the entry and exit locations will result in high noise levels at the source location. Typically, noise from HDD operations is estimated to be about 90 dBA at 50 feet.

273. As stated in the final EIS, the applicants modeled noise levels at noise sensitive areas (NSA) near each compressor station during operation. Increases over existing ambient noise levels will be barely noticeable, ranging from 0.1 dBA to 8.5 dBA. "Worst case" modeled noise levels at each NSA due to typical compressor station operation will be below the Commission staff's noise limit of 55 dBA, with the exception of the JB Tonkin Compressor Station.[373] At the existing JB Tonkin Compressor Station, four NSAs currently experience total noise levels above the Commission staff guideline. However, after the proposed modifications, these NSAs will experience an overall *decrease* in noise ranging from 1.1 dBA to 3.9 dBA. Environmental Conditions 69, 70, and 72 in the appendix to this order require that the applicants file the results of noise surveys during operation of the compressor stations, and if noise exceeds the day-night sound level of 55 dBA at any NSA (or is above existing sound levels in the case of the existing NSAs at the JB Tonkin Compressor Station), the applicants must install additional noise controls and refile noise survey results a year later.

274. Therefore, the final EIS concludes, and we agree, that construction and operation the projects would not result in significant noise impacts on residents, and the surrounding communities.[374]

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[372] *Id.* at 4-561 and 4-563.

[373] *Id.* at 4-571 through 4-575.

[374] *Id*. at 4-576.

j. **Safety**

275. Numerous commenters questioned the safety of the projects. The final EIS notes that the project facilities must be designed, constructed, operated, and maintained to meet or exceed the U.S. Department of Transportation's (DOT) Minimum Federal Safety Standards[375] and other applicable federal and state regulations. These regulations include specifications for material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

276. Data reviewed by Commission staff and discussed in section 4.12 of the EIS support the conclusion that Commission-jurisdictional pipelines are a safe, reliable means of transporting natural gas. The rate of total fatalities for the nationwide natural gas transmission lines in service is approximately 0.01 per year per 1,000 miles of pipeline.[376] Using this rate, the 642.0-mile-long ACP and Supply Header projects' pipelines might result in a fatality (either an industry employee or a member of the public) on the pipeline every 156 years. Therefore, the final EIS concludes, and we agree, that the projects would represent only a slight increase in risk to the nearby public.[377]

277. We received comments during scoping and on the draft EIS from residents and emergency response representatives of Wintergreen Resort; Bath County, Virginia; and several community members and landowners regarding single-point access roads and the ability to evacuate in event of an emergency. Atlantic stated its intention is to work with local emergency responders to ensure they are comfortable with their ability to respond to a natural gas emergency, including evacuation, and by holding annual meetings and setting up table-top drills to work through the action items necessary to resolve a natural gas emergency scenario. Atlantic would also prepare *Operational Emergency Response Plans* in coordination with local emergency response providers. *The Operational Emergency Response Plans* would address incident evacuation requirements. Therefore, the final EIS concluded, and we agree, that operation of the project would represent only a slight increase in risk to the nearby public.[378]

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[375] *See* 49 C.F.R. pt. 192 (2017).

[376] Final EIS at 4-590.

[377] *Id*.

[378] *Id*. at 4-584; *see also EarthReports, Inc. v. FERC*, 828 F.3d 949, 959 (D.C. Cir. 2016) (the "opinions and standards of – and [the LNG operator's] future coordination with – federal and local authorities" were a reasonable component of the Commission's public safety evaluation).

278. We also received comments expressing concern that the ACP Project may become a target for a future act of terrorism. The likelihood of future acts of terrorism or sabotage occurring along the ACP or Supply Header Projects' pipelines or at any of the myriad natural gas pipeline or energy facilities throughout the United States is unpredictable given the disparate motives and abilities of terrorist groups. Further, the Commission, in cooperation with other federal agencies, including the U.S. Department of Homeland Security, industry trade groups, and interstate natural gas companies, is working to improve pipeline security practices, strengthen communications within the industry, and extend public outreach in an ongoing effort to secure pipeline infrastructure. In accordance with the DOT surveillance requirements, the applicants will incorporate air and ground inspection of its proposed facilities into its inspection and maintenance program. Security measures at the new aboveground facilities will include secure fencing.

k. <u>Programmatic Environmental Impact Statement</u>

279. Several interveners and commenters contend that the Commission should prepare a programmatic EIS for natural gas infrastructure projects in the Marcellus and Utica Shale formations. Commenters argue that the CEQ recommends the use of a programmatic EIS in circumstances like those surrounding the ACP Project where "several energy development programs proposed in the same region of the country have similar proposed methods of implementation and similar best practices and mitigation measures that can be analyzed in the same document." Commenters argue that reviewing individual applications in isolation masks regional impacts. They note that other agencies, including the U.S. Department of Energy and the U.S. Bureau of Land Management, have used a programmatic EIS to address energy development issues on a regional basis.

280. CEQ regulations do not require broad or "programmatic" NEPA reviews. CEQ's guidance provides that such a review may be appropriate where an agency is: (1) adopting official policy; (2) adopting a formal plan; (3) adopting an agency program; or (4) proceeding with multiple projects that are temporally and spatially connected.[379] The Supreme Court has held that a NEPA review covering an entire region (that is, a programmatic review) is required only if there has been a report or recommendation on a

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[379] Memorandum from CEQ to Heads of Federal Departments and Agencies, *Effective Use of Programmatic NEPA Reviews* 13-15 (Dec. 24, 2014) (citing 40 C.F.R. § 1508.18(b)), https://www.whitehouse.gov/sites/default/files/docs/effective_use_of_programmatic_nepa_reviews_18dec2014.pdf. We refer to the memorandum as 2014 Programmatic Guidance.

proposal for major federal action with respect to the region.[380] Moreover, there is no requirement for a programmatic EIS where the agency cannot identify projects that may be sited within a region because individual permit applications will be filed later.[381]

281. We have explained that there is no Commission plan, policy, or program for the development of natural gas infrastructure.[382] Rather, the Commission acts on individual applications filed by entities proposing to construct interstate natural gas pipelines. Under NGA section 7, the Commission is obligated to authorize a project if it finds that the construction and operation of the proposed facilities "is or will be required by the present or future public convenience and necessity."[383] What is required by NEPA, and what the Commission provides, is a thorough examination of the potential impacts of specific projects. As to projects that have a clear physical, functional, and temporal nexus such that they are connected or cumulative actions,[384] the Commission will prepare a multiple-project environmental document.[385] Such is not the case here.

282. The Commission is not engaged in regional planning. Rather, the Commission processes individual pipeline applications in carrying out its statutory responsibilities under the NGA. That there currently are a number of planned, proposed, or approved infrastructure projects to increase infrastructure capacity to transport natural gas from the

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[380] *Kleppe v. Sierra Club*, 427 U.S. 390 (1976) (*Kleppe*) (holding that a broad-based environmental document is not required regarding decisions by federal agencies to allow future private activity within a region).

[381] *See Piedmont Environmental Council v. FERC*, 558 F.3d 304, 316-17 (4th Cir. 2009) (*Piedmont Environmental Council*).

[382] *See, e.g., National Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 at PP 82-88; *National Fuel Gas Supply Corp.*, 154 FERC ¶ 61,180, at P 13 (2016); *Texas Eastern Transmission, LP*, 149 FERC ¶ 61,259, at PP 38-47 (2014); *Columbia Gas Transmission, LLC*, 149 FERC ¶ 61,255 (2014).

[383] 15 U.S.C. § 717f(e) (2012).

[384] 40 C.F.R. § 1508.25(a)(1)-(2) (2017) (defining connected and cumulative actions).

[385] *See, e.g.*, EA for the Monroe to Cornwell Project and the Utica Access Project, Docket Nos. CP15-7-000 & CP15-87-000 (filed Aug. 19, 2015); Final Multi-Project Environmental Impact Statement for Hydropower Licenses: Susquehanna River Hydroelectric Projects, Project Nos. 1888-030, 2355-018, and 405-106 (filed Mar. 11, 2015).

Marcellus and Utica Shale does not establish that the Commission is engaged in regional development or planning.[386] Instead, this confirms that pipeline projects to transport Marcellus and Utica Shale gas are initiated solely by a number of different companies in private industry. As we have noted previously, a programmatic EIS is not required to evaluate the regional development of a resource by private industry if the development is not part of, or responsive to, a federal plan or program in that region.[387]

283. The Commission's siting decisions regarding pending and future natural gas pipeline facilities respond to proposals by private industry, and the Commission has no way to accurately predict the scale, timing, and location of projects, much less the kind of facilities that will be proposed.[388] Any broad, regional environmental analysis would "be little more than a study . . . containing estimates of potential development and attendant environmental consequences,"[389] and could not present "a credible forward look" that would be "a useful tool for basic program planning."[390] In these circumstances, the Commission's longstanding practice to conduct an environmental review for each proposed project, or a number of proposed projects that are interdependent or otherwise interrelated or connected, "facilitate[s], not impede[s], adequate environmental

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[386] *See, e.g.*, *Sierra Club v. FERC*, 827 F.3d 36, 50 (D.C. Cir. 2016) (Freeport LNG) (rejecting claim that NEPA requires FERC to undertake a nationwide analysis of all applications for liquefied natural gas export facilities); *cf. Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1326-27 (D.C. Cir. 2015) (*Myersville*) (upholding FERC determination that, although a Dominion Transmission Inc.-owned pipeline project's excess capacity may be used to move gas to the Cove Point terminal for export, the projects are "unrelated" for purposes of NEPA).

[387] *See Kleppe*, 427 U.S. at 401-02 (holding that a regional EIS is not required where there is no overall plan for regional development).

[388] Lack of jurisdiction over an action does not necessarily preclude an agency from considering the potential impacts. As explained in the indirect and cumulative impact sections of this order, however, it reinforces our finding that because states, and not the Commission, have jurisdiction over natural gas production and associated development (including siting and permitting), the location, scale, timing, and potential impacts from such development are even more speculative.

[389] *Kleppe*, 427 U.S. at 402.

[390] *Piedmont Environmental Council*, 558 F.3d at 316.

assessment."[391] Thus, the Commission's environmental review of the ACP and Supply Header projects together in a single EIS is appropriate under NEPA.

284. In sum, CEQ states that a programmatic EIS can "add value and efficiency to the decision-making process when they inform the scope of decisions," "facilitate decisions on agency actions that precede site- or project-specific decisions and actions," or "provide information and analyses that can be incorporated by reference in future NEPA reviews."[392] The Commission does not believe these benefits can be realized by a programmatic review of natural gas infrastructure projects because the projects subject to our jurisdiction do not share sufficient elements in common to narrow future alternatives or expedite the current detailed assessment of each particular project. Thus we find a programmatic EIS is neither required nor useful under the circumstances here.

l. Indirect Impacts of Upstream and Downstream Activities

285. Interveners and commenters broadly argue that the EIS must consider the project's indirect effects, particularly regarding impacts of induced upstream production of natural gas from the Marcellus and Utica Shale. In addition they assert that the Commission must consider as indirect impacts the downstream end-use, of natural gas on greenhouse gases and climate change.

286. CEQ's regulations direct federal agencies to examine the direct, indirect, and cumulative impacts of proposed actions.[393] Indirect impacts are defined as those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[394] Further, indirect effects "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems."[395] Accordingly, to determine whether an impact should be studied as an indirect impact, the Commission must determine whether it is both (1) caused by the proposed action; and (2) reasonably foreseeable.

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[391] *Id*.

[392] 2014 Programmatic Guidance at 13.

[393] 40 C.F.R. § 1508.25(c) (2016).

[394] *Id.* § 1508.8(b).

[395] *Id.* § 1508.8(b).

287. With respect to causation, "NEPA requires 'a reasonably close causal relationship' between the environmental effect and the alleged cause"[396] in order "to make an agency responsible for a particular effect under NEPA."[397] As the Supreme Court explained, "a 'but for' causal relationship is insufficient [to establish cause for purposes of NEPA]."[398] Thus, "[s]ome effects that are 'caused by' a change in the physical environment in the sense of 'but for' causation," will not fall within NEPA if the causal chain is too attenuated.[399] Further, the Court has stated that "where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect."[400]

288. An effect is "reasonably foreseeable" if it is "sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision."[401] NEPA requires "reasonable forecasting," but 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."[402]

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[396] *U.S. Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, at 767 (2004) (*Pub. Citizen*) (quoting *Metropolitan Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, at 774 (1983) (*Metro Edison Co.*).

[397] *Id.*

[398] *Id.*; *see also* Freeport LNG, 827 F.3d at 46 (FERC need not examine everything that could conceivably be a but-for cause of the project at issue); *Sierra Club v. FERC*, 827 F.3d 59, 68 (D.C. Cir. 2016) (Sabine Pass LNG) (FERC order authorizing construction of liquefied natural gas export facilities is not the legally relevant cause of increased production of natural gas).

[399] *Metro. Edison Co.*, 460 U.S. at 774.

[400] *Pub. Citizen*, 541 U.S. at 770; *see also* Freeport LNG, 827 F.3d at 49 (affirming that *Public Citizen* is explicit that FERC, in authorizing liquefied natural gas facilities, need not consider effects, including induced production, that could only occur after intervening action by the DOE); Sabine Pass LNG, 827 F.3d at 68 (same); *EarthReports, Inc. v. FERC*, 828 F.3d at 955-56 (same).

[401] *Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992). *See also City of Shoreacres v. Waterworth*, 420 F.3d 440, 453 (5th Cir. 2005).

[402] *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1078 (9th Cir. 2011).

i. **Impacts from Upstream Natural Gas Production**

289. With respect to the argument that the Commission must analyze the environmental impacts associated with the upstream production of natural gas that may be induced by the approval of ACP and Supply Header projects, as we have previously concluded, 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 CEQ regulations.[403] A causal relationship sufficient to warrant Commission analysis of the non-pipeline activity as an indirect impact would only exist if the proposed pipeline would transport new production from a specified production area and that production would not occur in the absence of the proposed pipeline (i.e., there will be no other way to move the gas).[404] To date, the Commission has not been presented with a proposed pipeline project that the record shows will cause the predictable development of gas reserves. In fact, 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.

290. Even accepting, *arguendo*, that a specific pipeline project will cause natural gas production, we have found that the potential environmental impacts resulting from such production are not reasonably foreseeable. As we have explained, the Commission generally does not have sufficient information to determine the origin of the gas that will be transported on a pipeline. It is the states, rather than the Commission, that have jurisdiction over the production of natural gas and thus would be most likely to have the information necessary to reasonably foresee future production. There are no forecasts in the record which would enable the Commission to meaningfully predict production-related impacts, many of which are highly localized. Thus, even if the Commission

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[403] *See, e.g., Central New York Oil and Gas Co., LLC*, 137 FERC ¶ 61,121, at PP 81-101 (2011), *order on reh'g*, 138 FERC ¶ 61,104, at PP 33-49 (2012), *petition for review dismissed sub nom. Coal. for Responsible Growth v. FERC*, 485 F. Appx., 472, 474-75 (2nd. Cir. 2012) (unpublished opinion).

[404] *See cf. Sylvester v. U.S. Army Corps of Engineers*, 884 F.2d 394, 400 (9th Cir. 1989) (upholding the environmental review of a golf course that excluded the impacts of an adjoining resort complex project). *See also Morongo Band of Mission Indians v. FAA*, 161 F.3d 569, 580 (9th Cir. 1998) (concluding that increased air traffic resulting from airport plan was not an indirect, "growth-inducing" impact); *City of Carmel-by-the-Sea v. U.S. Dep't of Transportation.*, 123 F.3d 1142, 1162 (9th Cir. 1997) (acknowledging that existing development led to planned freeway, rather than the reverse, notwithstanding the project's potential to induce additional development).

knows the general source area of gas likely to be transported on a given pipeline, a meaningful analysis of production impacts would require more detailed information regarding the number, location, and timing of wells, roads, gathering lines, and other appurtenant facilities, as well as details about production methods, which can vary per producer and depending on the applicable regulations in the various states. Accordingly, the impacts of natural gas production are not reasonably foreseeable because they are "so nebulous" that we "cannot forecast [their] likely effects" in the context of an environmental analysis of the impacts related to a proposed interstate natural gas pipeline.[405]

291. Nonetheless, we note that the Department of Energy has examined the potential environmental impacts generally associated with unconventional natural gas production activities.[406] The DOE Addendum concludes that such production, when conforming to regulatory requirements, implementing best management practices, and administering pollution prevention concepts, may have temporary, minor impacts to water resources.[407]

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[405] *Habitat Education Center v. U.S. Forest Service*, 609 F.3d 897, 902 (7th Cir. 2010) (finding that impacts that cannot be described with enough specificity to make their consideration meaningful need not be included in the environmental analysis). *See also Sierra Club v. DOE*, 867 F.3d 189, 198-199 (D.C. Cir. 2017) (accepting DOE's "reasoned explanation" as to why the indirect effects pertaining to induced natural gas production were not reasonably foreseeable where DOE noted the difficulty of predicting the incremental quantity of natural gas that might be produced, where at the local level such production might occur, and that an economic model estimating localized impacts would be far too speculative to be useful).

[406] U.S. Department of Energy, *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States*, 79 Fed. Reg. 48,132 (Aug. 15, 2014) (DOE Addendum), available at http://energy.gov/sites/prod/files/2014/08/f18/Addendum.pdf (analyzing air quality, water resource, GHG emissions, induced seismicity, and land use impacts from unconventional natural gas production activities in the lower 48 states). The U.S. Court of Appeals for the D.C. Circuit has upheld DOE's reliance on the DOE Addendum to supplement its environmental review of the proposed export of LNG. *See Sierra Club v. DOE*, 867 F.3d at 195, 201.

[407] DOE Addendum at 19; *see also Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands*, 80 Fed. Reg. 16,128, 16,130 (Mar. 26, 2015) (Bureau of Land Management promulgated regulations for hydraulic fracturing on federal and Indian lands to "provide significant benefits to all Americans by avoiding potential damages to water quality, the environment, and public health").

With respect to air quality, the Department of Energy found that natural gas development leads to both short- and long-term increases in local and regional air emissions.[408] It also found that such emissions may contribute to climate change.[409] But to the extent that natural gas production replaces the use of other carbon-based energy sources, the U.S. Department of Energy found that there may be a net positive impact in terms of climate change.[410] We find the information provided in the DOE Addendum to be helpful to generally inform the public regarding potential impacts of increased natural gas production and therefore consider the DOE Addendum to be supplemental material to our environmental review.

292. While the DOE Addendum provides a nation-wide impacts analysis, Commission staff estimated the impacts on land use and water consumption associated with the production wells that would be required to provide 100 percent of the volume of natural gas which could be transported by the ACP and Supply Header projects over the life of the projects[411] from the Marcellus and Utica Shale basin. Each natural gas well pad and associated infrastructure (road infrastructure, water impoundments, and pipelines) requires about 1.48 acres of land.[412] Based on the projects' volume and the expected estimated ultimate recovery of Marcellus/Utica Shale wells,[413] our Commission staff estimates that between 2,149 and 4,212 wells would be required to provide the gas over the estimated 30-year project lifespan. Therefore, on a normalized basis,[414] drilling wells

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[408] DOE Addendum at 32.

[409] *Id*. at 44.

[410] *Id*.

[411] Our environmental staff assumed a 30 year life of the project.

[412] Life Cycle Analysis of Natural Gas Extraction and Power Generation, Dept. of Energy and Nat'l Energy Tech. Laboratory DOE/NETL-2015/1714; page 22, Table 3-6, (August 30, 2016).

[413] Energy Information Assoc. http://www.eia.gov/conference/2015/pdf/presentations/staub.pdf, and Environmental Impacts of Unconventional Natural Gas Development and Production, DOE/NETL-2014/1651 (May 29, 2014).

[414] 30 year impacts averaged on a per year basis.

may affect between 106 and 208 acres a year.[415] Previous research[416] indicates that, within the Marcellus and Utica Shale areas, about 72.3 percent of the land affected by natural gas production is forest, about 22.4 percent is agricultural, and about 5.3 percent is grass or open lands.

293. Recent estimates[417] show that drilling and developing an average Marcellus Shale well requires between 3.88 and 5.69 million gallons of water, depending on whether the producer uses a recycling process. Therefore, producing wells required to supply the project could require the normalized consumptive use of as much as 278 to 798 million gallons of water per year over the 30-year project life. In addition, staff conservatively estimated the upstream GHG emissions from extraction as 1.2 million metric tpy CO_{2e}, and from processing as 2.4 million metric tpy CO_{2e}.[418]

294. The record in this proceeding does not demonstrate the requisite reasonably close causal relationship between the impacts of future natural gas production and the proposed projects that would necessitate the specific local-level impacts analysis that commenters

[415] Dept. of Energy and Nat'l Energy Tech. Laboratory, *Life Cycle Analysis of Natural Gas Extraction and Power Generation*, DOE/NETL-2015/1714, page 22, table 3-6 (August 30, 2016) .

[416] *Id.* at DOE/NETL-2015/1714, pg 24, table 3-8.

[417] Environmental Impacts of Unconventional Natural Gas Development and Production May 29, 2014 DOE/NETL-2014/1651; page 76, exhibit 4-1.

[418] The upstream GHG emissions were estimated using the May 29, 2014 Life Cycle Analysis of Natural Gas Extraction and Power Generation May 29, 2014 DOE/NETL-2014/1646. Generally, Commission staff used the average leak and emission rates identified in the NETL analysis for each segment of extraction, processing, and transport. The method is outlined in Section 2 of the NETL report, and the background data used for the model is outlined in Section 3.1. Staff used the results identified in Tables 4.3, 4.4, and 4.5 to look at each segment and grossly estimate GHG emission. To be conservative, staff did not account for the New Source Performance Standards Oil & Gas rule changes, or other GHG mitigation. Additionally, staff made a conservative estimate of the length of non-jurisdictional pipeline prior to the gas reaching Project components, as well as the length of downstream pipeline to the delivery point. *See Sierra Club v. DOE*, 867 F.3d at 201-202 (finding sufficient DOE's estimate of potential GHG emissions from producing, transporting and exporting LNG reported in a 2014 Life Cycle Report on Exporting LNG).

seek.[419] The fact that natural gas production and transportation facilities are all components of the general supply chain required to bring domestic natural gas to market is not in dispute. We have acknowledged that the pipeline projects are designed to move gas supplies from the Appalachian Basin to markets in Virginia and North Carolina. This does not mean, however, that approving these particular projects will induce further shale gas production. Rather, as we have explained in other proceedings, a number of factors, such as domestic natural gas prices and production costs drive new drilling.[420] If the proposed projects were not constructed, it is reasonable to assume that any new production spurred by such factors would reach intended markets through alternate pipelines or other modes of transportation.[421] Again, any such production would take place pursuant to the regulatory authority of state and local governments.[422]

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[419] *See Sierra Club v. DOE*, 867 F.3d at 200 (rejecting contention that DOE must project shale-play level environmental impacts specific to the amount of liquefied natural gas exports it authorized).

[420] *Rockies Express Pipeline LLC*, 150 FERC ¶ 61,161, at P 39 (2015). *See also Sierra Club v. DOE*, 867 F.3d at 198 (accepting DOE's explanation that natural gas production is driven by numerous factors including the price of gas, pace of technological change, and U.S. environmental regulations and that there is fundamental uncertainty about how natural gas production at the local level will respond to price changes at the national level); *Sierra Club v. Clinton*, 746 F. Supp. 2d 1025, 1045 (D. Minn. 2010) (holding that the U.S. Department of State, in its environmental analysis for an oil pipeline permit, properly decided not to assess the transboundary impacts associated with oil production because, among other things, oil production is driven by oil prices, concerns surrounding the global supply of oil, market potential, and cost of production); *Florida Wildlife Fed'n v. Goldschmidt*, 506 F. Supp. 350, 375 (S.D. Fla. 1981) (ruling that an agency properly considered indirect impacts when market demand, not a highway, would induce development).

[421] *Rockies Express Pipeline LLC*, 150 FERC ¶ 61,161 at P 39; *see also Sierra Club v. DOE*, 867 F.3d at 199 (noting that there is an interconnected pipeline system throughout the lower 48 states).

[422] We acknowledge that NEPA may obligate an agency to evaluate the environmental impacts of non-jurisdictional activities. That states, however, not the Commission, have jurisdiction over natural gas production and associated development (including siting and permitting) supports the conclusion that information about the scale, timing, and location of such development and potential environmental impacts are even more speculative. *See Sierra Club v. DOE*, 867 F.3d at 200 (DOE's obligation under NEPA to "drill down into increasingly speculative projections about regional

295. Moreover, even if a causal relationship between our action here and additional production were presumed, the scope of the impacts from any induced production is not reasonably foreseeable. That there may be incentives for producers to locate wells close to pipeline infrastructure does not change the fact that the location, scale, and timing of any additional wells are matters of speculation, particularly regarding their relationship to the proposed projects. As we have previously explained, a broad analysis, based on generalized assumptions rather than reasonably specific information, will not provide meaningful assistance to the Commission in its decision making, e.g., evaluating potential alternatives to a specific proposal.[423]

ii. <u>Impacts from Downstream Combustion of Project-Transported Natural Gas</u>

296. Interveners and commenters also assert that the Commission must consider the impacts on climate change as a result of the end-use consumption of the natural gas transported by the pipeline.

297. With respect to impacts from GHGs, the final EIS discusses the direct GHG impacts from construction and operation of the projects and other projects that were considered in the Cumulative Impacts analysis, the climate change impacts in the region, and the regulatory structure for GHGs under the Clean Air Act. The final EIS also quantifies GHG emissions from the projects' construction (totaling 1,115,374 tons, CO_2-equivalent [CO_{2e}]) and operation (1,347,035 tons per year [tpy] CO_{2e}).[424]

298. In addition, Commission staff used an EPA-developed methodology to estimate the downstream GHG emissions resulting from the ultimate use of the gas transported on the ACP and Supply Header projects.[425] The final EIS includes a conservative estimate

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environmental impacts [of induced natural gas production] is also limited by the fact that it lacks any authority to control the locale or amount of export-induced gas production, much less any of its harmful effects") (citing *Pub. Citizen*, 541 U.S. at 768).

[423] *Rockies Express Pipeline LLC*, 150 FERC ¶ 61,161 at P 40. *See also Sierra Club v DOE*, 867 F.3d at 198 (holding that the dividing line between what is reasonable forecasting and speculation is the "usefulness of any new potential information to the decision-making process").

[424] *See* final EIS at 4-556 through 4-559.

[425] Estimated using EPA's GHG Equivalencies Calculator - Calculations and References *available at* https://www.epa.gov/energy/ghg-equivalencies-calculator-calculations-and-references.

of downstream GHG emissions of 29.96 million tpy CO_{2e} from end-use combustion.[426] We note that this estimate represents an upper bound for the amount of end-use combustion that could result from the gas transported by these projects. This is because some of the gas may displace other fuels, which could actually lower total CO_{2e} emissions. It may also displace gas that otherwise would be transported via different means, resulting in no change in CO_{2e} emissions.

299. Sierra Club argues that because of the recent decision by the D.C. Circuit Court of Appeals in *Sierra Club v. FERC*[427] the Commission should reopen the record in this proceeding and issue a supplemental EIS to address GHG emissions and climate impacts. Sierra Club asserts that, although the final EIS did estimate the GHG emissions from combustion, the final EIS erroneously states that those emissions are not "causally connected" to the projects. To support its claim, Sierra Club cites Sabal Trail, in which the court stated that burning gas transported by pipeline "is not just 'reasonably foreseeable,' it is the project's entire purpose."[428]

300. Sierra Club claims that the final EIS was not only required to quantify the GHG emissions, but also must include a discussion of their significance and any cumulative impacts associated with GHG emissions. Sierra Club argues that the final EIS only provides a cursory analysis of the impact associated with downstream combustion, comparing the emissions to state-wide totals.[429] Sierra Club also states that the final EIS relies on the assertion that the projects would result in the displacement of some coal, but that this approach was rejected by the court in Sabal Trail because the Commission failed to assess whether total emissions would be reduced or increased, or what the degree of reduction or increase would be.[430]

301. Next, Sierra Club asserts that the final EIS should have used the social cost of carbon methodology to determine how the proposed project's incremental contribution to

[426] Total annual emissions of GHG were estimated for ACP and Supply Header projects based on the total capacity of 1.5 billion cubic feet per day for the projects.

[427] *Sierra Club v. FERC*, 867 F.3d 1357 (D.C. Cir. 2017) (Sabal Trail).

[428] Sabal Trail, 867 F.3d at 1372.

[429] Sierra Club states that the final EIS states both "we cannot determine whether the projects' contribution to cumulative impacts on climate change would be significant," and that "we conclude that ACP and SHP would not significantly contribute to GHG cumulative impacts or climate change."

[430] *Sabal Trail*, 867 F.3d at 1374-75.

GHG emissions would translate into physical effects on the global environment. Sierra Club asserts that the court in Sabal Trail held that the Commission must explain why it did not use the methodology to determine project-specific impacts.[431]

302. Last, Sierra Club states that the final EIS's statement that "the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change that produces the impacts previously described" does not adequately address the cumulative impacts of the projects. Sierra Club avers that the final EIS incorrectly downplays the cumulative climate impacts associated with the natural gas infrastructure build out in Pennsylvania, West Virginia, Virginia, North Carolina, and surrounding states, and does not quantify the project's GHG emissions in combination with these past, present, and reasonably foreseeable gas projects.

303. Sierra Club concludes that as a result of the final EIS's failure to address these concerns, the Commission did not conduct an informed public process and failed to provide information necessary to assess potential alternatives and mitigation measures.

304. The court in Sabal Trail held that where it is known that the natural gas transported by a project will be used for end-use combustion, the Commission should "estimate[] the amount of power-plant carbon emissions that the pipelines will make possible."[432] As Sierra Club acknowledges, the final EIS did just that. The fact that the final EIS stated that the emissions were not "causally connected" to the project is immaterial because the information was presented in both the draft and final EIS.[433] Thus, the Commission and the public were fully informed of the potential impacts from the project.

305. In an effort to provide some context to the GHG emissions from the ACP and Supply Header projects, the final EIS included the GHG inventory for Pennsylvania, West Virginia, Virginia, and North Carolina.[434] Table 1 compares the GHG emissions from the project to the GHG Inventories for the four-state region and nationwide. Table 1 includes two scenarios: (1) all natural gas transported by the projects is used for

[431] *Id.* at 1375.

[432] *Id*. at 1371.

[433] Final EIS at 4-620; Draft EIS at 4-512 through 4-513.

[434] Final EIS at 4-620.

end-use combustion (full burn) and (2) 79 percent of the natural gas transported by project is used for power generation (estimate of actual consumption).[435]

Table 1		
	Estimate of Actual Consumption Emissions	**Full Burn Emissions**
GHG Volume (Million Metric tons per year)	23.67	29.96
Percentage of Four State Inventory	4.12	5.2
Percentage of National Inventory	0.44	0.56

Thus, we estimate that the downstream use of the natural gas to be transported by the projects would potentially increase the GHG emissions inventory in the four-state region by up to 5.2 percent.

306. Moreover, the final EIS acknowledged that the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change.[436] However, as the final EIS explained, because the project's incremental physical impacts on the environment caused by climate change cannot be determined, it also cannot be determined whether the projects' contribution to cumulative impacts on climate change would be significant.[437]

307. We also disagree with Sierra Club's assertion that the Commission should have used the social cost of carbon methodology to determine how the proposed projects' incremental contribution to GHGs would translate into physical effects on the global environment. While we recognize the availability of the social cost of carbon methodology, it is not appropriate for use in any project-level NEPA review for the following reasons: (1) EPA states that "no consensus exists on the appropriate [discount]

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[435] Atlantic anticipates approximately 79.2 percent of the natural gas transported by project would be used as a fuel to generate electricity for industrial, commercial, and residential uses. *Id*. at 1-3.

[436] *Id*. at 4-620.

[437] *Id*.

rate to use for analyses spanning multiple generations"[438] and consequently, significant variation in output can result;[439] (2) the tool does not measure the actual incremental impacts of a project on the environment; and (3) there are no established criteria identifying the monetized values that are to be considered significant for NEPA reviews. The methodology may be useful for rulemakings or comparing regulatory alternatives using cost-benefit analyses where the same discount rate is consistently applied; however, it is not appropriate for estimating a specific project's impacts or informing our analysis under NEPA. Moreover, Executive Order 13783, Promoting Energy Independence and Economic Growth, has disbanded the Interagency Working Group on Social Cost of Greenhouse Gases and directed the withdrawal of all technical support documents and instructions regarding the methodology, stating that the documents are "no longer representative of governmental policy."[440]

m. Cumulative Impacts

308. A number of commenters raised issues related to the cumulative impacts of the projects. CEQ defines "cumulative impact" as "the impact on the environment which results from the incremental impact of the action [being studied] when added to other past, present, and reasonably foreseeable future actions . . . ."[441] The requirement that an impact must be "reasonably foreseeable" to be considered in a NEPA analysis applies to both indirect and cumulative impacts.

309. The "determination of the extent and effect of [cumulative impacts], and particularly identification of the geographic area within which they may occur, is a task assigned to the special competency of the appropriate agencies."[442] CEQ has explained that "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."[443] Further, a

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[438] *See* Fact Sheet: Social Cost of Carbon issued by EPA in November 2013, http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf.

[439] Depending on the selected discount rate, the tool can project widely different present day cost to avoid future climate change impacts.

[440] Exec. Order No. 13783, 82 Fed. Reg. 16093 (Mar. 28, 2017).

[441] 40 C.F.R. § 1508.7 (2017).

[442] *Kleppe*, 427 U.S. at 413.

[443] CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act* at 8 (January1997) (1997 Cumulative Effects Guidance).

cumulative impact analysis need only include "such information as appears to be reasonably necessary under the circumstances for evaluation of the project rather than to be so all-encompassing in scope that the task of preparing it would become either fruitless or well-nigh impossible."[444] An agency's analysis should be proportional to the magnitude of the environmental impacts of a proposed action; actions that will have no significant direct and indirect impacts usually require only a limited cumulative impacts analysis.[445]

310. In considering cumulative impacts, CEQ advises that an agency first identify the significant cumulative effects issues associated with the proposed action.[446] The agency should then establish the geographic scope for analysis. Next, the agency should establish the time frame for analysis.[447] Finally, the agency should identify other actions that potentially affect the same resources, ecosystems, and human communities that are affected by the proposed action.[448] As noted above, CEQ advises that an agency should relate the scope of its analysis to the magnitude of the environmental impacts of the proposed action.[449]

311. Commission staff defined the geographic scope for its analysis of cumulative impacts on specific environmental resources to include projects/actions within the same construction footprint as the projects for geology, soils, and land use; within the U.S. Geological Survey hydrologic unit code 10 watersheds for water resources, wetlands, vegetation, aquatic resources, wildlife, and reliability and safety; within 0.5 mile of the projects for visual resources, with an additional 5-mile visual radius around each compressor station; at the county level for socioeconomic impacts; within 0.5 mile of the projects for NSAs around compressor stations; within the area of potential effect for cultural resources; within the Air Quality Control Regions for climate change; and for air quality impacts, within 0.5 mile of the project for construction impacts and within the Air Quality Control Regions for operational impacts.

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[444] *Id*.

[445] *See* CEQ, *Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis* at 2-3 (June 24, 2005).

[446] 1997 Cumulative Effects Guidance at 11.

[447] *Id.*

[448] *Id*.

[449] CEQ, *Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis* at 2 (June 24, 2005).

312. The types of other projects, in addition to the ACP and Supply Header projects, evaluated in the final EIS within the same geographic region and appropriate time frame that could potentially contribute to cumulative impacts on a range of environmental resources include other Commission-jurisdictional natural gas interstate transportation projects; non-jurisdictional pipelines and gathering system projects; oil and gas exploration and production activities; mining operations; transportation or road projects; commercial/residential/industrial and other development projects; and other energy projects, including power plants or electric transmission lines.

313. The final EIS concludes that most cumulative impacts would be temporary and minor when considered in combination with past, present, and reasonably foreseeable activities. Long-term but minor cumulative impacts would occur on wetland, upland forested vegetation, and associated wildlife habitats, as well as waterbodies, special status species, and visual quality. Impacts on vernal pools, rocky outcrops, and subterranean features could adversely affect habitat of wildlife species with limited mobility and home ranges. Subterranean obligate species are often endemic to only a few known locations, and are vulnerable to changes in hydrological pattern or water quality;[450] therefore, it is possible that impacts associated with construction activities could have population-level impacts on these species. Short-term cumulative benefits will also be realized through jobs and wages and purchases of goods and materials. There is also the potential that the projects will contribute to a cumulative improvement in regional air quality if a portion of the natural gas associated with the proposed projects displaces the use of other, more polluting fossil fuels.[451]

n. <u>Alternatives</u>

314. The final EIS analyzes alternatives, including the no action alternative, system alternatives, and route alternatives. If the no action alternative is selected, the environmental impacts outlined in the final EIS will not occur. However, if the projects are not authorized, their stated objectives will not be realized, and natural gas will not be transported from production areas in the Appalachian Basin to end-users in Virginia and North Carolina. In response to the no active alternative, shippers may seek other infrastructure to transport natural gas to customers, and construction of those other

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[450] West Virginia Division of Natural Resources, 2015 West Virginia State Wildlife Action Plan (Sep. 1, 2015), http://www.wvdnr.gov/2015%20West%20Virginia%20State%20Wildlife%20Action%20Plan%20Submittal.pdf.

[451] Final EIS at 4-623.

projects may result in environmental impacts that will be similar to or greater than the proposed projects.

315. The final EIS also considers if the contracted volumes of the ACP and Supply Header projects could be transported through the Mountain Valley Project and Equitrans Expansion Project (collectively, the Mountain Valley Project) proposed in Docket Nos. CP16-10-000 and CP16-13-000, respectively. The EIS examines two hypothetical scenarios[452] for this: (1) the merged system alternative, in which the ACP and Supply Header projects' volumes would be transported together with the Mountain Valley Project volumes in a single pipeline along the proposed Mountain Valley Project route; and (2) the collocation alternative, in which the ACP Project pipeline would be relocated along the same route as the Mountain Valley Project, with additional pipeline to meet Atlantic's delivery requirements.

316. With respect to the collocation alternative, as described in the final EIS, there is insufficient space along the narrow ridgelines to accommodate two parallel 42-inch-diameter pipelines, making this alternative technically infeasible.[453] Construction of such pipelines would require side-hill or two-tone construction techniques, with additional acres of disturbance required for additional temporary workspace, given the space needed to safely accommodate equipment and personnel, as well as spoil storage. The final EIS concludes, and we agree, that when the environmental factors, technical feasibility, and ability to meet the purpose and need of the projects are cumulatively considered, the collocation alternative does not offer a significant advantage.[454]

317. With respect to the merged system alternative, if the volumes of both the Mountain Valley Project and ACP Project, totaling about 3.44 billion cubic feet per day, were combined into a single 42-inch-diameater pipeline, the significant additional

[452] We note that no applicant has proposed to construct, and no shipper indicated an interest in utilizing either of the hypothetical alternative pipeline systems.

[453] *See* Final EIS at 3-9. *See also Fuel Safe Washington v. FERC*, 389 F.3d 1313, 1323 (10th Cir. 2004) (The Commission need not analyze "the environmental consequences of alternatives it has in good faith rejected as too remote, speculative, or ... impractical or ineffective.") (quoting *All Indian Pueblo Council v. United States*, 975 F.2d 1437, 1444 (10th Cir.1992) (internal quotation marks omitted)); *see also Nat'l Wildlife Fed'n v. F.E.R.C.*, 912 F.2d 1471, 1485 (D.C. Cir. 1990) (NEPA does not require detailed discussion of the environmental effects of remote and speculative alternatives); *Natural Resources Defense Council, Inc. v. Morton*, 458 F.2d 827, 837–38 (D.C.Cir.1972) (same).

[454] Final EIS at 3-11.

compression needed for such a project would restrict Atlantic's ability to provide operational flexibility for customers' potentially needed flow rate variations and line pack, and may prohibit any future expansion of the pipeline system. Commission staff estimated that the necessary additional compression could triple air quality impacts in comparison to the Mountain Valley Project and ACP Project considered individually. Construction of larger diameter, non-typical 48-inch diameter pipeline would require a wider construction right-of-way.[455] Although, as the final EIS notes, the merged system alternative may hold an environmental advantage,[456] because this alternative may negatively impact shippers by reduced operational flexibility and future expansibility, the Commission finds that this alternative is not preferable.[457]

318. We are mindful, as the D.C. Circuit has acknowledged, that "given the choice, almost no one would want natural gas infrastructure built on their block."[458] But as the court noted:

> [G]iven our nation's increasing demand for natural gas . . . it is an inescapable fact that such facilities must be built somewhere. …. Congress decided to vest the [Commission] with responsibility for overseeing the construction and expansion of interstate natural gas facilities. And in carrying out that charge, sometimes the Commission is faced with tough judgment calls as to where those facilities can and should be sited.[459]

[455] Final EIS at 3-10 (installation of 48-inch pipeline would require 30 feet or more of additional construction right-of-way over entire length of the pipeline route and would displace about 30 percent more soil).

[456] Final EIS at 3-9. We note that since no entity has proposed or engineered this hypothetical alternative, our assessments of potential benefits and impacts is necessarily limited, and based on best available information.

[457] *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 967-68 (D.C. Cir. 2000) (FERC must carefully consider alternatives, but even in the face of a preferable alternative, FERC may reasonably find that the proposed project is in the public convenience and necessity).

[458] *Minisink Residents for Environmental Preservation and Safety v. FERC*, 762 F.3d 97, 100 (D.C. Cir. 2014) (affirming the Commission's decision to approve project where two dissenting commissioners preferred an alternative pipeline project).

[459] *Id.*

319. While "the existence of a more desirable alternative is one of the factors which enters into a determination of whether a particular proposal would serve the public convenience and necessity,"[460] we conclude, based on record evidence, that when considering the environmental factors, technical feasibility, and ability to meet the purpose and need of the projects, including the time frames in which service has been requested by the shippers, these alternatives do not provide an advantage over the ACP and Supply Header projects.[461]

320. The final EIS also considered 26 other major route alternatives, 3 route variations along the ACP Project route, and 1 route variation along the Supply Header Project route. In almost all cases, the alternative routes were found to not provide a significant environmental advantage over the proposed route segments and were not recommended, with the exception of the Butterwood Creek Route Variation, a minor alignment shift that would reduce the number of stream crossings. We agree with the conclusions in the final EIS.

321. A number of commenters suggested that additional crossing locations be considered for the HDD of the Blue Ridge Parkway and Appalachian National Scenic Trail. In response, the final EIS considered several alternatives in the vicinity of the Rockfish Gap that would relocate the Blue Ridge Parkway and Appalachian National Scenic Trail HDD as well as modify the sections of the pipeline project to accommodate the shift in the crossing location. The final EIS concluded, based on a variety of factors, that relocating the HDD to the Rockfish gap could encounter difficulties based on constraints in the area including steep topography, structures, roads, bridges, a railroad tunnel, and limited locations for workspace outside of National Park Service lands and workspace necessary to fabricate the pull-back section of pipe, and ultimately may be infeasible.[462]

322. In addition, the Rockfish Gap alternatives identified by commenters involved collocating with existing roadways. The final EIS analyzed these alternatives and noted that roadways had been carved into the mountainside such that the alternative would involve extreme side-slope construction (i.e., significant grading, large workspaces, and

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[460] *City of Pittsburgh v. FPC*, 237 F.2d 741, 751 n.28 (D.C. Cir. 1956).

[461] The Commission's NEPA obligation requires that it "'identify the reasonable alternatives to the contemplated action' and 'look hard at the environmental effects of [its] decision[ ].'" *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 967 (D.C. Cir. 2000) (quoting *Corridor H Alternatives, Inc. v. Slater*, 166 F.3d 368, 374 (D.C.Cir.1999)) (alterations in original).

[462] Final EIS at 3-30.

large spoil staging areas). Furthermore, residential and commercial development along highways in the area would prevent the installation of a 42-inch-diameter pipeline in many areas. Therefore, the alternative routes would have to be modified in many areas to avoid construction constraints, which reduces the collocation advantages that this route could offer. Therefore, the final EIS concluded and we agree that the Rockfish Gap Alternatives did not offer a significant environmental advantage and not requiring their adoption into the project.[463]

4. Environmental Analysis Conclusion

323. We have reviewed the information and analysis contained in the final EIS regarding potential environmental effects of the ACP Project, Supply Header Project, and the Capacity Lease, as well as the other information in the record. We are accepting the environmental recommendations in the final EIS as modified herein, and are including them as conditions in Appendix A to this order.

324. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this order. The Commission encourages cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[464]

325. Based on our consideration of this information and the discussion above, we agree with the conclusions presented in the final EIS and find that the projects, if constructed and operated as described in the final EIS, are environmentally acceptable actions. Therefore, for the reasons discuss above, we find that the projects are in the public convenience and necessity.

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[463] *Id.*

[464] *See* 15 U.S.C. § 717r(d) (state or federal agency's failure to act on a permit considered to be inconsistent with Federal law); *see also Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 310 (1988) (state regulation that interferes with FERC's regulatory authority over the transportation of natural gas is preempted) and *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 245 (D.C. Cir. 2013) (noting that state and local regulation is preempted by the NGA to the extent it conflicts with federal regulation, or would delay the construction and operation of facilities approved by the Commission).

326. The Commission on its own motion received and made a part of the record in this proceeding all evidence, including the applications, and exhibits thereto, and all comments and upon consideration of the record,

The Commission orders:

(A) A certificate of public convenience and necessity is issued authorizing Atlantic to construct and operate the Atlantic Coast Pipeline Project, as described in this order and in the applications in Docket Nos. CP15-554-000 and CP15-554-001.

(B) A certificate of public convenience and necessity is issued authorizing DETI to construct and operate the Supply Header Project, as described in this order and in the application in Docket No. CP15-555-000.

(C) A blanket transportation certificate is issued to Atlantic under Subpart G of Part 284 of the Commission's regulations.

(D) A blanket construction certificate is issued to Atlantic under Subpart F of Part 157 of the Commission's regulations.

(E) The certificate authority issued in Ordering Paragraph (A) and (B) shall be conditioned on the following:

> (1) Applicants' completion of the authorized construction of the proposed facilities and making them available for service within three years from the date of this order, pursuant to section 157.20(b) of the Commission's regulations;
>
> (2) Applicants' compliance with all applicable Commission regulations under the NGA including, but not limited to, Parts 154 and 284, and paragraphs (a), (c), (e), and (f) of section 157.20 of the regulations;
>
> (3) Applicants' compliance with the environmental conditions listed in Appendix A to this order.

(F) A certificate of public convenience and necessity is issued to Atlantic authorizing it to lease the subject capacity from Piedmont as described herein.

(G) A limited-jurisdiction certificate of public convenience and necessity is issued to Piedmont to operate 100,000 Dth per day of capacity on its North Carolina intrastate pipeline system for Atlantic.

(H) Atlantic shall notify the Commission within 10 days of the date of the acquisition of the capacity leased from Piedmont.

(I) DETI is authorized to abandon Compressor Units 1 and 2 at the Hastings Compressor Station in Wetzel County, West Virginia.

(J) DETI shall notify the Commission within 10 days of the date of the abandonment of the compressor units.

(K) Atlantic and DETI shall file a written statement affirming that they have executed firm contracts for the capacity levels and terms of service represented in signed precedent agreements, prior to commencing construction.

(L) Atlantic's initial rates and tariff are approved, as conditioned and modified above.

(M) Atlantic is required to file actual tariff records reflecting the initial rates and tariff language that comply with the requirements contained in the body of this order not less than 30 days and not more than 60 days prior to the commencement of interstate service consistent with Part 154 of the Commission's regulations.

(N) Atlantic and DETI must file not less than 60 days before the in-service date of the proposed facilities an executed copy of the non-conforming agreements reflecting the non-conforming language and a tariff record identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations.

(O) No later than three months after the end of its first three years of actual operation, as discussed herein, Atlantic must make a filing to justify its existing cost-based firm and interruptible recourse rates. Atlantic's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Atlantic is advised to include as part of the eFiling description, a reference to Docket No. CP15-554-000 and the cost and revenue study.

(P) DETI's request for authority to charge an incremental reservation rate for the Supply Header Project is approved.

(Q) DETI shall file actual tariff records setting forth its incremental rates at least 30 days, but no more than 60 days, prior to the date the project facilities go into service. That filing should be made as an eTariff compliance filing using type of filing code 580, and will be assigned an RP docket. It will be processed separately from the instant certificate proceeding in Docket No. CP15-555-000.

(R) DETI's request to use its system-wide fuel retention percentage as well as its EPCA and TCRA surcharges is approved.

(S) DETI shall keep separate books and accounting of costs and revenues attributable to the Supply Header Project, as more fully described above.

(T) Atlantic shall adhere to the accounting requirements discussed in the body of this order.

(U) Atlantic and DETI shall notify the Commission's environmental staff by telephone or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Atlantic or DETI. The Applicants shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(V) The requests for a trial-type hearing are denied.

By the Commission. Commissioner LaFleur is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A
Environmental Conditions

As recommended in the final environmental impact statement (EIS) and otherwise amended herein, this authorization includes the following conditions. The section number in parentheses at the end of a condition corresponds to the section number in which the measure and related resource impact analysis appears in the final EIS.

These measures will further mitigate the environmental impact associated with construction and operation of the projects. We have included several conditions that require the applicants to file additional information **with their Implementation Plan** or **prior to construction**. Other conditions require actions **during operations**. Some are standard conditions typically attached to Commission Orders. There are conditions that apply to both applicants, and other conditions are specific to either Atlantic Coast Pipeline, LLC (Atlantic) or Dominion Energy Transmission, Inc. (DETI).

Conditions 1 through 12 are standard conditions that apply to both Atlantic and DETI.

1. Atlantic and DETI shall follow the construction procedures and mitigation measures described in their applications and supplements (including responses to staff data requests) and as identified in the EIS, unless modified by the Order. Atlantic and DETI must:

   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);

   b. justify each modification relative to site-specific conditions;

   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

   d. receive approval in writing from the Director of the Office of Energy Projects (OEP) **before using that modification.**

2. The Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the order, and take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the projects. This authority shall allow:

   a. The modification of conditions of this order;

b. stop work authority; and

c. the imposition of additional measures deemed necessary to assure continued compliance with the intent of the conditions of the order as well as the avoidance or mitigation of unforeseen adverse environmental impacts resulting from project construction and operation.

3. **Prior to any construction**, Atlantic and DETI shall file affirmative statements with the Secretary, certified by senior company officials, that all company personnel, Environmental Inspectors (EIs), and contractor personnel would be informed of the EIs' authority and have been or would be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the EIS, as supplemented by filed alignment sheets, and shall include the staff's recommended Butterwood Creek Route Variation and workspace modifications identified in the EIS. **As soon as they are available, and before the start of construction**, Atlantic and DETI shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

   Atlantic's and DETI's exercise of eminent domain authority granted under the Natural Gas Act (NGA) section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Atlantic's and DETI's rights of eminent domain granted under NGA section 7(h) do not authorize them to increase the size of their natural gas facilities to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas

5. Atlantic and DETI shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations; staging areas; pipe storage yards; new access roads; and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified

on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area.**

This requirement does not apply to extra workspace allowed by the FERC *Upland Erosion Control, Revegetation and Maintenance Plan* (Plan) and/or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or special concern species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **At least 45 days prior to construction**, Atlantic and DETI shall file their respective Implementation Plans with the Secretary, for review and written approval by the Director of OEP. Atlantic and DETI must file revisions to their plans as schedules change. The plans shall identify:

a. how Atlantic and DETI would implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EIS, and required by the Order;

b. how Atlantic and DETI would incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to on-site construction and inspection personnel;

c. the number of EIs assigned per spread and how the company would ensure that sufficient personnel are available to implement the environmental mitigation;

d. the number of company personnel, including EIs and contractors, who would receive copies of the appropriate material;

e. the location and dates of the environmental compliance training and instructions Atlantic and DETI would give to all personnel involved with construction and restoration (initial and refresher training as the projects progress and personnel change), with the opportunity for OEP staff to participate in the training session(s);

f. the company personnel (if known) and specific portion of Atlantic's and DETI's organizations having responsibility for compliance;

g. the procedures (including use of contract penalties) Atlantic and DETI would follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram) and dates for:

i. the completion of all required surveys and reports;

ii. the environmental compliance training of on-site personnel;

iii. the start of construction; and

iv. the start and completion of restoration.

7. Atlantic and DETI shall employ a team of EIs (i.e., two or more or as may be established by the Director of OEP) per construction spread. The EI(s) shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 6 above) and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;

d. a full-time position, separate from all other activity inspectors;

e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

f. responsible for maintaining status reports.

8. **Beginning with the filing of the Implementation Plans**, Atlantic and DETI shall each file updated status reports with the Secretary on a weekly basis until all construction and restoration activities are complete. On request, these status reports would also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. an update on Atlantic's and DETI's efforts to obtain the necessary federal authorizations;

b. the construction status of each spread, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;

c. a listing of all problems encountered and each instance of noncompliance observed by the EIs during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

d. a description of the corrective actions implemented in response to all instances of noncompliance, and their cost;

e. the effectiveness of all corrective actions implemented;

f. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and

g. copies of any correspondence received by Atlantic and DETI from other federal, state, or local permitting agencies concerning instances of noncompliance, and Atlantic's and DETI's responses.

9. Atlantic and DETI shall develop and implement an environmental complaint resolution procedure. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the ACP and Supply Header projects and restoration of the right-of-way. **Prior to construction**, Atlantic and DETI shall each mail the complaint procedures to each landowner whose property would be crossed by the ACP Project and Supply Header Project.

a. In its letter to affected landowners, Atlantic and DETI shall:

i. provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

ii. instruct the landowners that if they are not satisfied with the response, they should call Atlantic's and DETI's Hotline; the letter should indicate how soon to expect a response; and

iii. instruct the landowners that if they are still not satisfied with the response from Atlantic's and DETI's Hotline, they should contact the Commission's Landowner Helpline at 877-337-2237 or at LandownerHelp@ferc.gov.

b. In addition, Atlantic and DETI shall include in their respective weekly status report a copy of a table that contains the following information for each problem/concern:

i. the identity of the caller and date of the call;

ii. the location by milepost and identification number from the authorized alignment sheet(s) of the affected property;

iii. a description of the problem/concern; and

iv. an explanation of how and when the problem was resolved, would be resolved, or why it has not been resolved.

10. Atlantic and DETI must receive written authorization from the Director of OEP **before commencing construction of any project facilities**. To obtain such authorization, Atlantic and DETI must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof). The Director of OEP will not issue a notice to proceed with construction of the Atlantic or DETI project facilities independently.

11. Atlantic and DETI must receive written authorization from the Director of OEP **before placing their respective projects into service**. Such authorization would only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the ACP and Supply Header projects are proceeding satisfactorily.

12. **Within 30 days of placing the authorized facilities in service**, Atlantic and DETI shall file affirmative statements with the Secretary, certified by a senior company official:

    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities would be consistent with all applicable conditions; or

    b. identifying which of the Certificate conditions the applicant has complied with or would comply with. This statement shall also identify any areas affected by their respective projects where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

Condition 13 applies to Atlantic and shall be implemented upon issuance of this Order and during operation of the facilities.

13. Atlantic shall not exercise eminent domain authority granted under section 7(h) of the NGA to acquire a permanent pipeline right-of-way exceeding 50 feet in width. In addition, where Atlantic has obtained a larger permanent right-of-way width through landowner negotiations, routine vegetation mowing and clearing over the permanent right-of-way shall not exceed 50 feet in width. *(Section 2.2.1.1)*

Conditions 14 through 25 apply to both Atlantic and DETI, and shall be addressed as part of Atlantic's and DETI's Implementation Plan

14. Atlantic and DETI shall design all workspaces that are not identified in table 2.3.1-2 of the EIS to comply with the FERC Procedures. Any additional modifications to the FERC Procedures must be requested and justified in **Atlantic's and DETI's Implementation Plans**. *(Section 2.3.1.1)*

15. **As part of Atlantic's and DETI's Implementation Plans and prior to receiving written authorization from the Director of the OEP to commence construction of any project facilities**, Atlantic and DETI shall file with the Secretary environmental constraints maps illustrating the avoidance and conservation measures required by the resource agencies and committed to by Atlantic and DETI along the ACP Project and Supply Header Project routes. The environmental constraints maps can be provided in the form of alignment sheets with a separate environmental constraints band. *(Section 2.4)*

16. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, a *Plan for Discovery of Unanticipated Paleontological Resources* that describes how Atlantic

and DETI will recognize and manage significant fossils encountered during construction. This plan shall also describe the notification procedures to the appropriate authorities in each state crossed by the ACP and Supply Header projects. *(Section 4.1.5)*

17. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, proposed or potential sources of water used for dust control, anticipated quantities of water to be appropriated from each source, and the measures it will implement to ensure water sources and any related aquatic biota are not adversely affected by the appropriation activity. *(Section 4.3.2.7)*

18. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary and appropriate federal and state agencies an updated *Restoration and Rehabilitation Plan* and *Invasive Species Management Plan*, for review and written approval by the Director of OEP, that includes the following measures:

    a. aerial spraying will not be utilized for invasive species control along the right-of-way;

    b. no herbicides will be applied within 25 feet of Endangered Species Act (ESA)-listed plant species;

    c. no use of herbicides or pesticides within 100 feet of a waterbody or wetland, except where allowed by state or federal agencies;

    d. no spraying of insecticides or herbicides will be allowed within the 300-foot karst feature buffer, except where allowed by state or federal agencies; and

    e. includes the results of the West Virginia and Virginia Natural Heritage Program recommendations for herbicide treatment adjacent to sensitive features. *(Section 4.4.4)*

19. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, a revised *Migratory Bird Plan* that incorporates the results of consultation with the West Virginia Department of Natural Resources, Virginia Department of Game and Inland Fisheries (VDGIF), North Carolina Wildlife Resources Commission (NCWRC), and the Forest Service, and verify that no additional conservation measures will be required to minimize impacts on active rookeries. In addition, table A-1 of the revised plan shall incorporate the NCWRC's recommended updates to the North Carolina Birds of Conservation Concern list. The revised plan shall also include the Virginia Piedmont Forest

Block Complex, Allegheny Mountains Forest Block Complex, and the Southern Allegheny Plateau Forest Block Complex Important Bird Areas that would be crossed by the ACP and Supply Header projects in Virginia and West Virginia. *(Section 4.5.3.5)*

20. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, revised Master Waterbody Crossing tables for the ACP and Supply Header projects that address the recommended conditions in the identified column of appendix K of the EIS, and that include all National Rivers Inventory segments crossed. The revised table or accompanying filing shall document correspondence and input from the appropriate federal and state agencies regarding the updated information and any additional mitigation measures Atlantic and DETI will incorporate for each waterbody. *(Section 4.6.1)*

21. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, revised *Virginia Fish Relocation Plan, Freshwater Mussel Relocation Protocol for ACP in North Carolina*, and *North Carolina Revised Fish and Other Aquatic Taxa Collection and Relocation Protocol for Instream Activities*. These revised plans and protocols shall include notification to the appropriate federal and/or state agencies should an invasive aquatic species be observed or collected during relocation efforts; and, in consultation with the appropriate federal and/or state agency, identify the mitigation measures that Atlantic and DETI will implement at the crossing location if invasive aquatic species are observed. *(Section 4.6.4)*

22. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, an aquatic invasive species protocol for West Virginia mussel relocation efforts on both the ACP and Supply Header projects. *(Section 4.6.4)*

23. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, a final *Timber Removal Plan* that:

    a. incorporates the recommendations included in the Virginia Department of Environmental Quality's (VDEQ) letter dated April 6, 2017 (Accession No. 20170406-5489);

    b. updates the construction schedule discussion; and

    c. updates all time of year restrictions (TOYR) related to migratory birds and special status species for tree clearing. *(Section 4.8.1.1)*

24. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, finalized site-specific *Timber Extraction Plans*. *(Section 4.8.1.1)*

25. **As part of their Implementation Plans**, Atlantic and DETI shall file with the Secretary, for review and written approval by the Director of OEP, final site-specific *Residential Construction Plans* for all residences within 50 feet of the construction work areas identified after issuance of the draft EIS (including the residence at AP-1 milepost [MP] 169.4). *(Section 4.8.3)*

Conditions 26 through 50 apply only to Atlantic and shall be addressed <u>as part of Atlantic's Implementation Plan</u>. Condition No. 37 also includes a condition that shall be addressed <u>during construction.</u>

26. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, the results of the fracture trace/lineament analysis utilizing remote sensing platforms (aerial photography and LiDAR), along with the results of existing dye trace studies. Atlantic shall provide the results of this analysis on a composite map(s), illustrating surficial karst features with the potential for intersecting shallow interconnected karst voids and cave systems over a wide area; specifically, between the pipeline and nearby water receptors (i.e., public water supply wells, municipal water supplies, private wells, springs, caves systems, and surface waters receiving discharge). *(Section 4.1.2.3)*

27. **As part of its Implementation Plan,** Atlantic shall consult with the Virginia Department of Conservation and Recreation (VDCR) to determine if the route alignment and construction activities will impact the Burnsville Cove Cave Conservation Site. Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, the results of its consultations, along with any proposed construction modifications or alignment shifts to avoid impacts on this site. *(Section 4.1.2.3)*

28. **As part of its Implementation Plan,** Atlantic shall conduct a data review and field survey of potential karst features in Augusta County, Virginia between AP-1 MPs 106.8 and 110, and file this information with the Secretary, along with any mitigation measures, for review and written approval by the Director of OEP. *(Section 4.1.2.3)*

29. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Karst Terrain Assessment Construction, Monitoring, and Mitigation Plan* that includes

monitoring of all potential karst areas for subsidence and collapse using LiDAR monitoring methods during years 1, 2, and 5 following construction. *(Section 4.1.2.3)*

30. **As part of its Implementation Plan,** Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, updated site-specific crossing plans for major waterbody crossings. The plans shall include, as necessary, the location of temporary bridges and bridge type, appropriate cofferdam locations, water discharge structure locations, pump locations, and agency-imposed TOYR and construction and restoration requirements. *(Section 4.3.2.2)*

31. **As part of its Implementation Plan,** Atlantic shall file with the Secretary, for review and written approval by the Director of the OEP, site-specific plans to minimize and mitigate impacts on the waterbodies that will be impacted at the Blue Ridge Parkway (BRP)/Appalachian National Scenic Trail (ANST) horizontal directional drill (HDD) entry and exit workspaces. Final plans shall be developed in consultation the U.S. Army Corps of Engineers and/or appropriate state agency(s). *(Section 4.3.2.6)*

32. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a site-specific plan for the water impoundment structure at Jennings Branch (AP-1 MP 129.1), or identify an alternative location for the structure. *(Section 4.3.2.7)*

33. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Restoration and Rehabilitation Plan* that incorporates recommended mitigation measures and seed mixes for Seneca State Forest based on consultation with the West Virginia Division of Forestry. *(Section 4.4.2.1)*

34. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, and the Forest Service for review and concurrence, detailed mapping of the existing conditions and proposed improvements to access road 36-016.AR1, including digital data, a description of the construction and operation impacts, including impacts on the adjacent vegetation communities, potential pond crossings identified in appendix K of the EIS, George Washington National Forest (GWNF) locally rare species located downslope, and identify the conservation measures that will be implemented to mitigate potential impacts. *(Section 4.4.7)*

35. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a hydrofracture potential analysis for the Neuse River (AP-2 MP 98.5). If the potential for hydrofracture is

low, Atlantic shall utilize the HDD method at this crossing to reduce potential impacts on ESA-listed, proposed, and/or under review species. If the HDD method is not feasible, Atlantic shall consult with the U.S. Fish and Wildlife Service (FWS) and NCWRC to identify additional conservation measures that Atlantic will implement at this crossing to mitigate for the potential impacts on ESA-listed, proposed, and or under review species. *(Section 4.7.1.8)*

36. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a hydrofracture potential analysis for the Nottoway River (AP-1 MP 260.7). If the hydrofracture potential is low, Atlantic shall utilize the HDD method at this crossing to reduce potential impacts on ESA-listed, proposed, and/or under review species. If the HDD method is not feasible, Atlantic shall consult with the FWS and VDGIF to identify additional conservation measures that Atlantic will implement at this crossing to mitigate for the potential impacts on ESA-listed, proposed, and/or under review species. *(Section 4.7.1.10)*

37. **As part of its Implementation Plan,** Atlantic shall file revised Carolina madtom habitat assessments based on 2017 surveys and consultations with the FWS North Carolina Field Office. This information shall also be incorporated into the ACP Master Waterbody Crossing table. **During construction**, Atlantic shall assume presence of the Carolina madtom where there is suitable habitat and implement the *North Carolina Revised Fish and Other Aquatic Taxa Collection and Relocation Protocol for Instream Construction Activities*, as well as the FWS' enhanced conservation measures for ESA sensitive waterbodies as defined in section 4.7.1 of the EIS. *(Section 4.7.1.11)*

38. **As part of its Implementation Plan**, Atlantic shall file with the Secretary the results of consultation with the VDGIF regarding in-stream construction activities proposed during the Roanoke logperch VDGIF TOYR at Waqua Creek and Sturgeon Creek. Documentation shall include any additional conservation measures required by VDGIF, which shall also be incorporated into the final ACP Master Waterbody Crossing table for each waterbody. *(Section 4.7.4.2)*

39. **As part of its Implementation Plan**, Atlantic shall file with the Secretary the results of consultation with the VDGIF regarding in-stream construction activities proposed during the VDGIF TOYR for green floater in waterbodies where presence has been assumed for this species (see appendix K of the EIS), in addition to in-stream construction activities proposed at Sturgeon Creek during the VDGIF TOYR for Atlantic pigtoe and dwarf wedgemussel. Documentation shall include any additional conservation measures required by the VDGIF, which shall also be incorporated into the final ACP Master Waterbody Crossing table for each waterbody. *(Section 4.7.4.2)*

40. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a site-specific *Organic Farm Protection Plan* for the certified organic farms affected by the ACP Project, including (but not limited to) the milk and corn farm crossed between AP-1 MPs 141.8 and 142.4; the certified organic hog farm crossed between AP-2 MPs 118.8 and 118.9; and any additional certified organic farms not previously identified prior to construction. *(Section 4.8.1.1)*

41. **As part of its Implementation Plan**, Atlantic shall file a final copy of its *Haul Plan*, which will address transportation of equipment, materials, and personnel along narrow public roads in steep terrain. *(Section 4.8.1.4)*

42. **As part of its Implementation Plan**, Atlantic shall identify by milepost the locations where it will adopt a narrowed right-of-way to reduce impacts on forest land within the Seneca State Forest, and identify the locations of corresponding additional temporary workspace (ATWS). Atlantic shall also provide updated and reduced construction impacts information for all applicable resources (land use, wetlands, soils, vegetation, cultural resources, etc.) affected by the changes to construction right-of-way and ATWS. *(Section 4.8.5.1)*

43. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a finalized *Contaminated Media Plan* that considers the recommendations included in the VDEQ's letter dated April 6, 2017 (Accession No. 20170406-5489). As appropriate, provide evidence of consultations with the VDEQ regarding its comments on the *Contaminated Media Plan. (Section 4.8.7)*

44. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, site-specific visual mitigation measures for each scenic byway developed in consultation with the DOT, Federal Highway Administration, West Virginia Department of Transportation, Virginia Department of Transportation, VDCR, and North Carolina Department of Transportation. Atlantic shall also provide documentation of agency consultation. *(Section 4.8.8.2)*

45. **As part of its Implementation Plan**, Atlantic shall identify mitigation measures, for review and written approval by the Director of OEP, to reduce the impacts on the Fenton Inn at approximately AP-1 MP 158.7 resulting from lighting equipment needed to support the HDD of the BRP and the ANST. *(Section 4.8.8.2)*

46. **As part of its Implementation Plan**, Atlantic shall file with the Secretary the locations where it will adopt a narrowed right-of-way to reduce impacts on forest

land and ecologically sensitive areas within the Monongahela (MNF) and GWNF, along with the locations of corresponding ATWS. *(Section 4.8.9.1)*

47. **As part of its Implementation Plan**, Atlantic shall file with the Secretary a revised trail, road, and railroad crossing table that lists the final crossing method that it will implement at each trail, road, and railroad. The crossing method at trails and roads on the GWNF shall be developed in consultation with GWNF staff. *(Section 4.8.9.1)*

48. **As part of its Implementation Plan**, Atlantic shall, if a bore or HDD crossing is not feasible, file with the Secretary, for review and written approval by the Director of OEP, site-specific crossing plans that identify the location(s) of a detour, public notification, signage, and consideration of avoiding days of peak usage for each trail and road affected by the ACP Project on the GWNF. The crossing plans shall be developed in consultation with GWNF staff. *(Section 4.8.9.1)*

49. **As part of its Implementation Plan**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, a final site-specific HDD crossing plan and an alternative direct pipe crossing plan for the BRP. Provide documentation that Atlantic has consulted with the National Park Service (NPS) regarding both of these plans and adopted or addressed any substantive comments from the NPS into these plans. *(Section 4.8.9.1)*

50. **As part of its Implementation Plan**, Atlantic shall file with the Secretary aerial photographs depicting the entry and exit sites for the proposed Interstate 79 and Route 58 HDDs. The aerials shall identify any noise-sensitive areas (NSAs) within 0.5 mile of the entry/exit sites for each HDD or clearly demonstrate that there are no NSAs within 0.5 mile of the entry/exit sites. *(Section 4.11.2.2).*

Conditions 51 through 56 apply to both Atlantic and DETI and shall be addressed <u>before construction is allowed to commence.</u>

51. **Prior to construction**, Atlantic and DETI shall file with the Secretary:

    a. all outstanding geotechnical studies for sites SL024, SS018, SL235, and SL239; geohazard analysis field reconnaissance of the 25 sites on the AP-1 mainline and 5 sites on the TL-635 loopline (as well as any additional geotechnical studies proposed following completion of site reconnaissance of these sites); and any mitigations proposed following the geotechnical studies and geohazard analysis field reconnaissance; and

b. status of the Best in Class Steep Slope Management Program analysis related to the ACP and Supply Header projects. *(Section 4.1.4.2)*

52. **Prior to construction**, Atlantic and DETI shall complete the remaining field surveys for wells and springs within 150 feet of the construction workspace, and within 500 feet of the construction workspace in karst terrain, and file the results, including type and location, with the Secretary. *(Section 4.3.1.5)*

53. **Prior to construction**, Atlantic and DETI shall file with the Secretary a copy of its final wetland mitigation plans and documentation of U.S. Army Corps of Engineers approval of the plans. *(Section 4.3.3.8)*

54. Atlantic and DETI **shall not begin construction of the proposed facilities until:**

a. all outstanding biological surveys are completed;

b. the FERC staff complete any necessary section 7 consultation with the FWS; and

c. Atlantic and DETI have received written notification from the Director of OEP that construction and/or use of mitigation (including implementation of conservation measures) may begin. *(Section 4.7.1)*

55. **Prior to construction and upon completion of 2017 surveys**, Atlantic and DETI shall file with the Secretary and FWS the total acreages of:

a. northern long-eared bat occupied habitat that will be impacted by the ACP and Supply Header projects; and

b. northern long-eared bat suitable habitat that will be impacted by the ACP and Supply Header projects. *(Section 4.7.1.4)*

56. Atlantic and DETI shall **not begin** construction of the ACP and Supply Header projects facilities or use of contractor yards, ATWS, or new or to-be-improved access roads **until:**

a. Atlantic files with the Secretary documentation of communications with the Lumbee Indian Nation, Coharie Tribal Council, Haliwa-Saponi Tribe, and the Meherrin Tribe regarding traditional tribal sites, including natural resources gathering locations in the project area;

b. Atlantic and DETI file with the Secretary:

i. all survey reports, evaluation reports, reports assessing project effects, and site treatment plans, and cemetery avoidance treatment plans;

ii. comments on all reports and plans from the Pennsylvania, West Virginia, Virginia, and North Carolina SHPOs, the MNF, GWNF, and NPS, as well as any comments from federally recognized Indian tribes, and other consulting parties, as applicable; and

iii. revised *Unanticipated Discovery Plans* that include tribal contact information for those tribes that request notification following post-review discovery of archaeological sites, including human remains, during project activities;

c. the ACHP is afforded an opportunity to comment if historic properties will be adversely affected; and

d. the FERC staff reviews and the Director of OEP approves the cultural resources reports and plans, and notifies Atlantic and DETI in writing that treatment plans/mitigation measures (including archaeological data recovery) may be implemented and/or construction may proceed.

All material filed with the Commission that contains **location, character, and ownership** information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering "**CUI//PRIV – DO NOT RELEASE**." *(Section 4.10.7)*

Condition 57 applies only to DETI and shall be addressed <u>before construction is allowed to commence.</u>

57. **Prior to construction**, DETI shall continue to consult with the Westmoreland Conservancy regarding a route variation to minimize impacts on conservation easements, and shall file with the Secretary documentation regarding the results of its consultations and any proposed route modifications. *(Section 3.4.2)*

Conditions 58 through 60 apply only to Atlantic and shall be addressed <u>before construction is allowed to commence.</u>

58. Atlantic shall incorporate the Butterwood Creek Route Variation into its final route for the ACP Project. **Prior to construction**, Atlantic shall file with the Secretary the results of all environmental surveys, an updated 7.5-minute U.S. Geological Survey topographic quadrangle map, and a large-scale alignment sheet that illustrates this route change. *(Section 3.4.4)*

59. **Prior to construction**, Atlantic shall file with the Secretary documentation of concurrence from the VDEQ that the ACP Project is consistent with the Coastal Zone Management Act. *(Section 4.8.6)*

60. **Prior to construction within the Emporia Powerline Bog and Handsom-Gum Powerline Conservation Sites,** Atlantic shall:

    a. complete hydrologic studies using methodologies developed in conjunction with the Virginia Department of Conservation and Recreation; and

    b. develop in conjunction with the Virginia Department of Conservation and Recreation construction and restoration measures to avoid or minimize hydrology impacts on the sites for review and written approval by the Director of OEP.

Condition 61 applies to both Atlantic and DETI and shall be addressed <u>during construction.</u>

61. **During construction**, to minimize potential impacts of water withdrawals on ESA-listed, proposed, and under review species, Atlantic and DETI shall limit water withdrawal to not exceed 10 percent of instantaneous flow at ESA sensitive waterbodies identified in appendix K of the EIS. *(Section 4.7.1)*

Conditions 62 through 67 apply only to Atlantic and shall be addressed <u>during construction</u>, or <u>before specific construction activities are allowed to commence.</u>

62. **Prior to construction, but following tree clearing**, Atlantic shall file with the Secretary, for review and written approval by the Director of OEP, the results of the electrical resistivity imaging (ERI) studies along with any proposed construction modifications or alignment shifts to avoid impacts on Mingo Run and the Simmons-Mingo cave system. *(Section 4.1.2.3)*

63. **Prior to completing any geotechnical boring in karst terrain**, Atlantic shall file with the Secretary verification that it consulted with VDCR karst protection personnel regarding each geotechnical boring and shall follow the Virginia Cave Board's "Karst Assessment Standard Practice" for land development when completing the borings. *(Section 4.1.2.3)*

64. **Prior to construction, but following tree clearing**, Atlantic shall:

a. conduct ERI and/or air track drilling surveys of karst features identified within the construction workspace that are located within 5 miles of known or survey-identified bat hibernacula;

b. file a report(s) documenting these surveys with the Secretary and the appropriate federal and state agencies; and

c. if data suggests that construction activities have the potential to impact subsurface karst features that are connected to downstream bat hibernacula and/or the Madison Cave isopod suitable habitat (based on the ERI and/or air track drilling surveys), Atlantic shall consult with the FERC staff, FWS, and VDCR, and other appropriate federal and/or state agencies to develop the appropriate site-specific mitigation measures to avoid potential impacts on these species and their habitat. *(Section 4.7.1)*

65. **If the candy darter is proposed or listed during the life of the ACP Project**, Atlantic shall assume presence of the candy darter within Knapp Creek, Clover Creek, Glade Run, Thomas Creek, and the Greenbrier River, and apply the FWS' enhanced conservation measures for aquatic species outlined in section 4.7.1 of the EIS to these waterbodies, and any perennial tributaries within 1 mile of these crossing locations to minimize impacts on this species (see appendix K of the EIS). *(Section 4.7.1.12)*

66. **Prior to construction, but following tree clearing**, Atlantic shall:

a. conduct ERI and/or air track drilling surveys of the karst features identified during 2017 karst surveys that are within the construction workspace within the Madison Cave isopod priority area, including along proposed access roads;

b. file a report(s) documenting these surveys with the Secretary, and the appropriate federal and state agencies; and

c. if data suggests that construction activities have the potential to impact subsurface karst features that are connected to downstream Madison Cave isopod suitable habitat (based on the ERI and/or air track drilling surveys), Atlantic shall consult with the FERC staff, FWS, and VDCR, and other appropriate federal and/or state agencies to develop the appropriate site-specific mitigation measures to avoid potential impacts on this species and its habitat. *(Section 4.7.1.13)*

67. Atlantic shall file in the **weekly construction status reports** the following for NSA S9, the Gatehouse, and the office building near BRP; the Route 17 HDD entry and exit sites; and NSAs S11, S13, and S14 near the Swift Creek entry site:

a. the noise measurements from these NSAs, obtained at the start of drilling operations;

b. the noise mitigation that Atlantic implemented at the start of drilling operations; and

c. any additional mitigation measures that Atlantic will implement if the initial noise measurements exceeded an L_{dn} of 55 decibels on the A-weighted scale (dBA) at the nearest NSA and/or increased noise is greater than 10 dBA over ambient conditions. *(Section 4.11.2.2)*

Condition 68 applies to both Atlantic and DETI, and shall be addressed <u>after construction.</u>

68. Atlantic and DETI shall offer to conduct, with the landowner's permission, **post-construction** water quality tests, using the same parameters used in the preconstruction tests, for all water supply wells and springs within 150 feet of the construction workspace and within 500 feet of the construction workspace in karst terrain. *(Section 4.3.1.7)*

Conditions 69 and 70 apply to only DETI and shall be addressed <u>after construction</u> or <u>during operation of the facilities.</u>

69. DETI shall file a noise survey with the Secretary **no later than 60 days** after placing the JB Tonkin Compressor Station in service. If a full load condition noise survey of the entire station is not possible, DETI shall instead file an interim survey at the maximum possible horsepower load and file the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the JB Tonkin Compressor Station under interim or full horsepower load conditions exceeds existing levels at NSAs S10, S11, S12, and S14 or 55 dBA L_{dn} at any other nearby NSAs, DETI shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. DETI shall confirm compliance with the above requirements by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(Section 4.11.2.2)*

70. DETI shall file a noise survey with the Secretary **no later than 60 days** after placing each of the Crayne and Mockingbird Hill Compressor Stations in service. If a full load condition noise survey of the entire station is not possible, DETI shall instead file an interim survey at the maximum possible horsepower load and file

the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the Crayne and Mockingbird Hill Compressor Stations under interim or full horsepower load conditions exceeds 55 dBA L_{dn} at any nearby NSAs, DETI shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. DETI shall confirm compliance with the 55 dBA L_{dn} requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(Section 4.11.2.2)*

Conditions 71 and 72 apply to only Atlantic and shall be addressed <u>after construction</u> or <u>during operation of the facilities.</u>

71. **Following construction**, Atlantic shall replant long-leaf pine within the ATWS and the temporary construction workspace along the ACP Project route, and outside the 50-foot-wide permanent right-of-way, where it was cleared for construction. Based on Atlantic's May 1, 2017 supplemental filing, long-leaf pine-wire grass communities occur between AP-2 MPs 156.5 and 156.9. *(Section 4.7.1.5)*

72. Atlantic shall file a noise survey with the Secretary **no later than 60 days** after placing each of the ACP Project compressor stations in service. If a full load condition noise survey is not possible, Atlantic shall instead file an interim survey at the maximum possible horsepower load and file the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at any station under interim or full horsepower load exceeds 55 dBA, L_{dn} at any nearby NSA, Atlantic shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. Atlantic shall confirm compliance with the 55 dBA L_{dn} requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(Section 4.11.2.2)*

Condition 73 was developed after issuance of the final EIS, applies only to Atlantic, and shall be addressed <u>as part of Atlantic's Implementation Plan.</u>

73. **As part of its Implementation Plan and prior to construction**, Atlantic shall file with the Secretary, for review and written approval of the Director of OEP, a Mining Area Construction Plan that includes specific mitigation measures that it will use in areas of active or planned mining and that addresses issues related to mine subsidence and safe construction. Atlantic's Mining Area Construction Plan shall include documentation of its consultation with Western Pocahontas Properties (WPP) **including site-specific route deviations, as appropriate,** to resolve the concerns of WPP.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic Coast Pipeline, LLC	Docket Nos.	CP15-554-000 CP15-554-001
Dominion Transmission, Inc.		CP15-555-000
Atlantic Coast Pipeline, LLC Piedmont Natural Gas Company, Inc.		CP15-556-000

(Issued October 13, 2017)

LaFLEUR, Commissioner *dissenting*:

With the increasing abundance of domestic natural gas, the Commission plays a key role in considering applications for the construction of natural gas infrastructure to support the delivery of this important fuel source. Under the Certificate Policy Statement, which sets forth the Commission's approach to evaluating proposed projects under Section 7 of the Natural Gas Act, the Commission evaluates in each case whether the benefits of the project as proposed by the applicant outweigh adverse effects on existing shippers, other pipelines and their captive customers, landowners, and surrounding communities.[1] For each pipeline I have considered during my time at the Commission, I have tried to carefully apply this standard, evaluating the facts in the record to determine whether, on balance, each individual project is in the public interest.[2] Today, the Commission is issuing orders that authorize the development of the Mountain Valley Pipeline Project/Equitrans Expansion Project (MVP) and the Atlantic Coast Pipeline Project (ACP). For the reasons set forth herein, I cannot conclude that either of these projects as proposed is in the public interest, and thus, I respectfully dissent.

Deciding whether a project is in the public interest requires a careful balancing of the need for the project and its environmental impacts. In the case of the ACP and MVP

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[1] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999) (Certificate Policy Statement), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000); 15 U.S.C. 717h (Section 7(c) of the Natural Gas Act provides that no natural gas company shall transport natural gas or construct any facilities for such transportation without a certificate of public convenience and necessity.).

[2] *See Millenium Pipeline Company*, *L.L.C.*, 140 FERC ¶ 61,045 (2012) (LaFleur, Comm'r, *dissenting*).

projects, my balancing determination was heavily influenced by similarities in their respective routes, impact, and timing. ACP and MVP are proposed to be built in the same region with certain segments located in close geographic proximity. Collectively, they represent approximately 900 miles of new gas pipeline infrastructure through West Virginia, Virginia and North Carolina, and will deliver 3.44 Bcf/d of natural gas to the Southeast. The record demonstrates that these two large projects will have similar, and significant, environmental impacts on the region. Both the ACP and MVP cross hundreds of miles of karst terrain, thousands of waterbodies, and many agricultural, residential, and commercial areas. Furthermore, the projects traverse many important cultural, historic, and natural resources, including the Appalachian National Scenic Trail and the Blue Ridge Parkway. Both projects appear to be receiving gas from the same location, and both deliver gas that can reach some common destination markets. Moreover, these projects are being developed under similar development schedules, as further evidenced by the Commission acting on them concurrently today.[3] Given these similarities and overlapping issues, I believe it is appropriate to balance the collective environmental impacts of these projects on the Appalachian region against the economic need for the projects. In so doing, I am not persuaded that both of these projects as proposed are in the public interest.

I am particularly troubled by the approval of these projects because I believe that the records demonstrate that there may be alternative approaches that could provide significant environmental advantages over their construction as proposed. As part of its alternatives analysis, Commission staff requested that ACP evaluate an MVP Merged Systems Alternative that would serve the capacity of both projects.[4] This alternative would largely follow the MVP route to deliver the capacity of both ACP and MVP in a single large diameter pipeline. Commission staff identifies significant environmental advantages of utilizing this alternative. For example, the MVP Merged Systems Alternative would be 173 miles shorter than the cumulative mileage of both projects individually. This alternative would also increase collocation with existing utility rights-of-way, avoid the Monongahela National Forest and the George Washington National Forest, reduce the number of crossings of the Appalachian National Scenic Trail and Blue Ridge Parkway, and reduce the amount of construction in karst topography. Commission staff eliminated this alternative from further consideration because it failed to meet the project's objectives, in particular that it would "result in a significant delay to the delivery of the 3.44 Bcf/d of natural gas to the proposed customers of both ACP and

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[3] ACP and MVP filed their applications for approval pursuant to section7(c) of the Natural Gas Act on September 18, 2015 and October 23, 2015, respectively.

[4] ACP Final Environmental Impact Statement (FEIS) at 3-6 – 3-9.

MVP"[5] due to the significant time for the planning and design that would be necessary to develop a revised project proposal.[6]

Similarly, in the MVP FEIS, Commission staff evaluated a single pipeline alternative to the MVP project that would utilize the proposed ACP to serve MVP's capacity needs.[7] While this alternative was found to have certain environmental disadvantages, such as the need for additional compression to deliver the additional gas, the EIS acknowledges that this alternative would "essentially eliminate all environmental impacts on resources along the currently proposed MVP route."[8]

I recognize that the two alternatives described above were eliminated from further consideration because they were deemed not to meet each project's specific stated goals. However, I believe that these alternatives demonstrate that the regional needs that these pipelines address may be met through alternative approaches that have significantly fewer environmental impacts.

While my dissents rest on my concerns regarding the aggregate environmental impacts of the proposed projects, particularly given the potential availability of environmentally-superior alternatives, I believe that the needs determinations for these projects highlight another issue worthy of further discussion.

The Commission's policy regarding evaluation of need, and the standard applied in these cases, is that precedent agreements generally are the best evidence for determining market need. When applying this precedent here, I believe there is an important distinction between the needs determinations for ACP and MVP. Both projects provide evidence of precedent agreements to demonstrate that these pipelines will be fully subscribed. ACP also provides specific evidence regarding the end use of the gas to be delivered on its pipeline. ACP estimates that 79.2 percent of the gas will be transported to supply natural gas electric generation facilities, 9.1 percent will serve residential purposes, 8.9 percent will serve industrial purposes, and 2.8 percent will serve

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[5] *Id.* at 3-9.

[6] Staff also found that this alternative would likely limit the ability to provide additional gas to the projects' customers, another of the stated goals for the original proposal. *Id*.

[7] MVP FEIS at 3-14.

[8] *Id*.

other purposes such as vehicle fuel.[9] In contrast, "[w]hile Mountain Valley has entered into precedent agreements with two end users … for approximately 13% of the MVP project capacity, the ultimate destination for the remaining gas will be determined by price differentials in the Northeast, Mid-Atlantic, and Southeast markets, and thus, is unknown."[10]

In my view, it is appropriate for the Commission to consider as a policy matter whether evidence other than precedent agreements should play a larger role in our evaluation regarding the economic need for a proposed pipeline project. I believe that evidence of the specific end use of the delivered gas within the context of regional needs is relevant evidence that should be considered as part of our overall needs determination. Indeed, the Certificate Policy Statement established a policy for determining economic need that allowed the applicant to demonstrate need relying on a variety of factors, including "environmental advantages of gas over other fuels, lower fuel costs, access to new supply sources or the connection of new supply to the interstate grid, the elimination of pipeline facility constraints, better service from access to competitive transportation options, and the need for an adequate pipeline infrastructure."[11] However, the Commission's implementation of the Certificate Policy Statement has focused more narrowly on the existence of precedent agreements.

I believe that careful consideration of a fuller record could help the Commission better balance environmental issues, including downstream impacts, with the project need and its benefits.[12] I fully realize that a broader consideration of need would be a change in our existing practice, and I would support a generic proceeding to get input from the

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[9] ACP FEIS at 1-3.

[10] *Mountain Valley Pipeline, LLC, Equitrans, L.P.*, 161 FERC ¶ 61,043 at FN 286 (October 13, 2017).

[11] *Certificate Policy Statement*, 88 FERC ¶ 61,227 at 61,744.

[12] I note that this approach would not necessarily lead to the rejection of more pipeline applications. Rather, it would provide all parties, including certificate applicants, the opportunity to more broadly debate and consider the need for a proposed project. This could, for example, support development of new infrastructure in constrained regions where there may be demand for new capacity, but barriers to the execution of precedent agreements that are so critical under the Commission's current approach. In such situations, evidence of economic need other than precedent agreements might be offered as justification for the pipeline.

regulated community, and those impacted by pipelines, on how the Commission evaluates need.[13]

I recognize that the Commission's actions today are the culmination of years of work in the pre-filing, application, and review processes, and I take seriously my decision to dissent. I acknowledge that if the applicants were to adopt an alternative solution, it would require considerable additional work and time. However, the decision before the Commission is simply whether to approve or reject these projects, which will be in place for decades. Given the environmental impacts and possible superior alternatives, approving these two pipeline projects on this record is not a decision I can support.

For these reasons, I respectfully dissent.

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Cheryl A. LaFleur
Commissioner

[13] *See also*, *National Fuel Gas Supply Corporation, Empire Pipeline, Inc.*, 158 FERC ¶ 61,145 (Bay, Comm'r, *Separate Statement*).

People's Dossier: FERC's Abuses of Power and Law → Undermining Federal Authority

Federal Authority Undermined Attachment 4, Order Issuing Certificates and Granting Abandonment Authority, Docket Nos. CP16-10-000 and CP16-13-000, October 13, 2017.

161 FERC ¶ 61,043
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

Mountain Valley Pipeline, LLC	Docket Nos. CP16-10-000
Equitrans, L.P.	CP16-13-000

ORDER ISSUING CERTIFICATES AND GRANTING ABANDONMENT AUTHORITY

(Issued October 13, 2017)

1. On October 23, 2015, Mountain Valley Pipeline, LLC (Mountain Valley) filed an application in Docket No. CP16-10-000, pursuant to section 7(c) of the Natural Gas Act (NGA)[1] and Part 157 of the Commission's regulations,[2] for authorization to construct and operate its proposed Mountain Valley Pipeline Project in West Virginia and Virginia (MVP Project). The project is designed to provide up to 2,000,000 dekatherms (Dth) per day of firm transportation service from Wetzel County, West Virginia to Transcontinental Pipe Line Company, LLC's (Transco) Compressor Station 165 in Pittsylvania County, Virginia. Mountain Valley also requests a blanket certificate under Part 157, Subpart F of the Commission's regulations to perform certain routine construction activities and operations and a blanket certificate under Part 284, Subpart G of the Commission's regulations to provide open-access transportation services.

2. On October 27, 2015, Equitrans, L.P. (Equitrans) filed an application in Docket No. CP16-13-000, pursuant to section 7(c) of the NGA and Part 157 of the Commission's regulations, for authorization to construct and operate the system modifications necessary to enable Equitrans to provide an additional 600,000 Dth per day of north-to-south firm transportation service from western Pennsylvania to an interconnect with the MVP

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[1] 15 U.S.C. § 717f(c) (2012).

[2] 18 C.F.R. pt. 157 (2017).

Project in Wetzel County, West Virginia (Equitrans Expansion Project). As part of the project, Equitrans also proposes to abandon, pursuant to section 7(b) of the NGA,[3] its existing 4,800-horsepower (hp) Pratt Compressor Station in Greene County, Pennsylvania.

3. For the reasons discussed in this order, the Commission grants the requested certificate authorizations, subject to conditions.

I. <u>Background</u>

4. Mountain Valley,[4] a Delaware limited liability company, does not currently own or operate any interstate pipeline facilities and does not provide any services subject to the Commission's jurisdiction. Upon commencement of operations proposed in its application, Mountain Valley will become a natural gas company within the meaning of section 2(6) of the NGA,[5] and, as such, will be subject to the jurisdiction of the Commission.

5. Equitrans,[6] a Pennsylvania limited partnership, is a natural gas company, engaged in the transportation and storage of natural gas in interstate commerce subject to the Commission's jurisdiction. Equitrans' interstate natural gas system is located in northern West Virginia and southwestern Pennsylvania.

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[3] 15 U.S.C. § 717f(b) (2012).

[4] Five companies own Mountain Valley: (1) MVP Holdco, LLC, a subsidiary of EQT Corporation; (2) US Marcellus Gas Infrastructure, LLC, a subsidiary of NextEra Energy Capital Holdings, Inc.; (3) WGL Midstream, Inc., a subsidiary of WGL Holdings, Inc.; (4) RGC Midstream, LLC, a subsidiary of RGC Resources, Inc.; and (5) Con Edison Gas Midstream, LLC, a subsidiary of Consolidated Edison, Inc. *See* Exhibit A to the Joinder Agreement filed on January 27, 2016; *see also* Appalachian Mountain Advocates' December 22, 2016 Comment on the Draft EIS at 12-13 (stating that Vega Energy Partners, Ltd., an original owner of Mountain Valley, sold its shares to WGL Midstream, Inc. in late October 2016).

[5] 15 U.S.C. § 717(a)(6) (2012).

[6] Two subsidiaries of EQT Midstream Partners, LLC (Equitrans Investments, LLC and Equitrans Services, LLC) own Equitrans. EQT Midstream Partners, LLC is a subsidiary of EQT Corporation.

II. Proposals

A. Mountain Valley Pipeline Project

6. Mountain Valley proposes to construct and operate its project to provide up to 2,000,000 Dth per day of firm transportation service from Wetzel County, West Virginia to Transco's Compressor Station 165 in Pittsylvania, Virginia, enabling its shippers to access markets in the Northeast, Mid-Atlantic, and Southeast regions.

7. Specifically, Mountain Valley proposes to construct the following facilities:

- A 303.5-mile-long, 42-inch-diameter greenfield natural gas pipeline (the Mountain Valley pipeline) with a maximum allowable operating pressure (MAOP) of 1,480 pounds per square inch gauge (psig), extending from Equitrans' existing H-302 pipeline near MarkWest Liberty Midstream & Resources, L.L.C.'s (MarkWest) Mobley processing facility in Wetzel County, West Virginia at milepost (MP) 0.0, to an interconnection with Columbia Gas Transmission, LLC's (Columbia) WB System in Braxton County, West Virginia, at MP 77.6, and then to an interconnection with Transco's mainline system near Transco's existing Zone 5 Compressor Station 165 at MP 303.5 in Pittsylvania County, Virginia;[7]

- Three new compressor stations in West Virginia, totaling 171,600 nominal hp of compression:[8]

  - Bradshaw Compressor Station, located at MP 2.7 in Wetzel County, comprising four gas-driven turbine units totaling 89,600 hp;

  - Harris Compressor Station, located at MP 77.4 in Braxton County, comprising two gas-driven turbine units totaling 41,000 hp; and

  - Stallworth Compressor Station, located at MP 154.5 in Fayette County, comprising two gas-driven turbine units totaling 41,000 hp;

- Four new interconnections:

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[7] *See* Mountain Valley's October 14, 2016 Filing (revised pipeline route).

[8] Mountain Valley also proposes to install ancillary facilities at each compressor station, such as a storage/maintenance building, gas and utility piping, separators, and safety equipment.

  - Mobley Interconnect, located at MP 0.0 in Wetzel County, West Virginia, receiving natural gas from Equitrans' existing H-302 pipeline via Equitrans' proposed H-316 pipeline;[9]

  - Sherwood Interconnect, located at MP 23.6 in Harrison County, West Virginia, receiving natural gas from MarkWest's existing upstream non-jurisdictional system at the discharge side of the Sherwood Gas Processing Plant;

  - WB Interconnect, located at MP 77.6 in Braxton County, West Virginia, delivering gas from the MVP Project into Columbia's system; and

  - Transco Interconnect, located at MP 303.5 in Pittsylvania County, Virginia, delivering natural gas from the MVP Project to Transco pipeline system at Transco's Compressor Station 165;

- Four new meter and regulating stations, one at each of the new interconnects;

- Three new taps:

  - Webster Tap at Equitrans' Webster Interconnect at MP 0.8 on the Mountain Valley pipeline in Wetzel County, West Virginia;

  - Lafayette Tap at Roanoke Gas Company's (Roanoke Gas) Lafayette Interconnect at MP 235.7 on the Mountain Valley pipeline in Montgomery County, Virginia; and

  - Franklin Tap at Roanoke Gas' Franklin Interconnect at MP 261.4 on the Mountain Valley pipeline in Franklin County, Virginia; and

- Related appurtenant facilities, such as eight pig launchers and receivers; 36 mainline block valves, cathodic protection, and communication towers.

8. EQT Midstream Partners, LP, a subsidiary of EQT Corporation and a parent of Mountain Valley, will operate the project.

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[9] The MVP Project will receive gas from Equitrans at two points: Mountain Valley's proposed Mobley Interconnect and Equitrans' proposed Webster Interconnect in Wetzel County, West Virginia.

9. Mountain Valley conducted a non-binding open season for firm transportation service from June 12, 2014 through July 10, 2014 and a binding open season from September 2, 2014 through October 21, 2014, resulting in the execution of binding precedent agreements on October 21, 2014 with EQT Energy, LLC (EQT Energy) and USG Properties Marcellus Holdings, LLC (USG) for 1,790,000 Dth per day of firm transportation on the project. Later, Mountain Valley executed binding precedent agreements with WGL Midstream, Inc. (WGL Midstream) on March 10, 2015, and Roanoke Gas Company on October 1, 2015, for the remaining capacity available on the system. Accordingly, the project is fully subscribed.

10. On January 27, 2016, Consolidated Edison of New York, Inc. (ConEd) executed a binding precedent agreement for 250,000 Dth per day of transportation service made available by USG reducing its firm transportation capacity commitment from 500,000 Dth per day to 250,000 Dth per day.[10] In addition, Con Edison Gas Midstream, LLC, the parent company of ConEd, has become a part owner of Mountain Valley.[11] Currently, the project has five shippers for the contracted volumes below:

Shipper	**Contracted Volumes**
EQT Energy, LLC[12]	1.29 million Dth per day
Roanoke Gas Company[13]	10,000 Dth per day

[10] *See* Mountain Valley's January 27, 2016 Supplemental Information at 1.

[11] *See id.* at 1-2.

[12] EQT Energy, LLC is a gas marketing subsidiary of EQT Corporation (an indirect owner of Mountain Valley), providing optimization of capacity and storage assets, natural gas liquids sales and natural gas sales to commercial and industrial customers.

[13] Roanoke Gas Company, a subsidiary of RGC Resources, Inc. (as is Mountain Valley owner, RGC Midstream, LLC), is a utility that provides local natural gas distribution services in Virginia.

USG Properties Marcellus Holdings, LLC[14]	250,000 Dth per day
WGL Midstream, Inc.[15]	200,000 Dth per day
Consolidated Edison of New York, Inc.[16]	250,000 Dth per day

The precedent agreements require the project shippers to execute 20-year term firm transportation service agreements.

11. Mountain Valley also conducted a non-binding open season from September 17, 2015 to October 1, 2015, for short-term firm transportation service between various receipt points in the Appalachian Basin area to the new WB Interconnect in Braxton County, West Virginia, during the interim period between when the WB Interconnect with Columbia is placed into service and when the Transco Interconnect is placed into service. No precedent agreements have yet been executed for the offered short-term firm service.

12. Mountain Valley estimates that the MVP Project will cost approximately $3.7 billion. The project shippers each agreed to pay negotiated rates.

13. Mountain Valley also requests approval of its proposed *pro forma* tariff. Mountain Valley proposes initial maximum and minimum recourse reservation and usage rates set forth under Rate Schedules FTS (Firm Transportation Service), ITS (Interruptible Transportation Service), and ILPS (Interruptible Lending and Parking Service). Mountain Valley also proposes an Interim Service Period, during which it will provide firm and IT service to the WB Interconnect prior to the completion of the entire project.

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[14] USG Properties Marcellus Holdings, LLC, a subsidiary of NextEra Energy, Inc., and affiliate of Mountain Valley-owner US Marcellus Gas Infrastructure, LLC, is a natural gas production and distribution company.

[15] WGL Midstream, Inc., which is also an owner of Mountain Valley, engages in developing, acquiring, investing in, managing and optimizing natural gas storage and transportation assets.

[16] ConEd, an affiliate of Mountain Valley-owner Con Edison Gas Midstream, LLC, is a public utility that provides electric and natural gas distribution services.

14. Mountain Valley requests a Part 284, Subpart G blanket certificate of public convenience and necessity pursuant to section 284.221 of the Commission's regulations authorizing it to provide transportation service to customers requesting and qualifying for transportation service under its proposed FERC Gas Tariff, with pre-granted abandonment authority.[17]

15. Mountain Valley also requests a blanket certificate of public convenience and necessity pursuant to section 157.204 of the Commission's regulations authorizing future facility construction, operation, and abandonment as set forth in Part 157, Subpart F of the Commission's regulations.[18]

B. Equitrans Expansion Project

16. Equitrans proposes to construct and operate its Equitrans Expansion Project to provide up to 600,000 Dth per day of firm transportation service from southern Pennsylvania and northern West Virginia to proposed interconnections with the MVP Project in West Virginia.

17. Specifically, Equitrans proposes to construct the following facilities:

- Six new segments of natural gas pipelines, totaling about 7.87 miles, on Equitrans' existing mainline system:
  - H-318, a new 3.8-mile-long, 20-inch-diameter pipeline with an MAOP of 1,200 psig in Allegheny and Washington Counties, Pennsylvania, which will transport natural gas from EQT Gathering, LLC's[19] Applegate Gathering System to Equitrans' existing H-148 pipeline;
  - H-316, a new 3.0-mile long, 20-inch-diameter pipeline with an MAOP of 1,200 psig in Greene County, Pennsylvania, extending from the new Redhook Compressor Station to Equitrans' existing H-302 pipeline;
  - H-305, a new 550-foot-long, 24-inch-diameter pipeline with an MAOP of 1,200 psig in Greene County, Pennsylvania, extending from the new Redhook Compressor Station to Equitran's existing

[17] 18 C.F.R. § 284.221 (2017).

[18] *Id.* § 157.204.

[19] EQT Gathering, LLC is a gathering subsidiary of EQT Corporation.

Braden Run Interconnect with Texas Eastern Transmission, L.P. (Texas Eastern);

- o H-319, a new 200-foot-long, 16-inch-diameter pipeline with an MAOP of 1,200 psig in Wetzel County, West Virginia, extending from Equitrans' existing H-306 pipeline to its new Webster Interconnect;

- o An 0.2-mile extension of Equitrans' existing 1.38-mile-long, 6-inch-diameter M-80 pipeline with an MAOP of 1,000 psig in Greene County, Pennsylvania, to the new Redhook Compressor Station; and

- o An 0.2-mile extension of Equitrans' existing 1.42-mile-long, 12-inch-diameter H-158 pipeline with an MAOP of 1,000 psig in Greene County, Pennsylvania, to the new Redhook Compressor Station;

- The new Redhook Compressor Station, located at MP 0.0 in Greene County, Pennsylvania, which is comprised of two gas-fired reciprocating engines and two gas-fired turbine engines totaling 31,300 hp;

- Four new taps:

  - o Mobley Tap at MP 0.6 on H-302 in Wetzel County, West Virginia, connecting with the Mountain Valley pipeline;

  - o H-302 Tap at MP 3.0 on H-316 in Greene County, Pennsylvania;

  - o H-306 Tap at MP 0.0 on H-319 in Wetzel County, West Virginia; and

  - o H-148 Tap at MP 3.8 on H-318 in Washington County, Pennsylvania;

- The new Webster Interconnect, located around MP 0.1 in Wetzel County, West Virginia, which would deliver gas from Equitrans' H-306 to the new H-319 to the Mountain Valley pipeline;

- Six new tie-ins; and

- Related appurtenant facilities, such as three pig launchers and receivers, cathodic protection, and communication towers.

18. Additionally, Equitrans also requests authorization to abandon its existing 4,800-hp Pratt Compressor Station in Greene County, Pennsylvania, which will no longer be needed to provide service after construction of the new Redhook Compressor Station. Equitrans will use the abandoned site of the Pratt Compressor Station as a storage yard during operation of the Expansion Project. Specifically, Equitrans proposes to abandon two 1,080-hp compressor units, three 880-hp compressor units, the station building, coolers, storage tanks, auxiliary equipment and related piping, and a small portion of Equitrans' M-80 and H-158 pipelines.

19. Equitrans conducted a non-binding open season for firm transportation capacity from March 5, 2015, through March 20, 2015, for potential deliveries to existing and future interconnects, including interconnects with Texas Eastern, Dominion Transmission, Inc., and the MVP Project. As a result of the open season, Equitrans executed a precedent agreement with EQT Energy for 400,000 Dth of firm transportation service on the Expansion Project. Equitrans also conducted a reverse open season but did not receive any offers to turn back capacity. Equitrans states that it will enter into a 20-year firm transportation service agreement under Equitrans' existing Rate Schedule FTS for the subscribed capacity prior to the in-service date of its project.

20. Equitrans estimates the total cost of the project is approximately $172 million. Equitrans proposes to use its existing mainline system rates as the initial recourse rates for firm transportation service. Equitrans and EQT Energy have entered into a negotiated rate agreement for firm transportation service on the Expansion Project.

III. Procedural

A. Notice, Interventions, Protests, and Comments

21. Notice of Mountain Valley's and Equitrans' applications was published in the *Federal Register* on November 13, 2015 (80 Fed. Reg. 70,196), with interventions, comments, and protests due by November 27, 2015.[20] The parties listed in Appendix A filed timely, unopposed motions to intervene, which were granted by operation of Rules 214(a)(2) and 214(c) of the Commission's Rules of Practice and Procedure.[21] Late

[20] The Commission's Rules of Practice and Procedure provide that, if a filing deadline falls on a Saturday, Sunday, holiday, or other day when the Commission is not open for business, the filing deadline does not end until the close of business on the next business day. 18 C.F.R. § 385.2007(a)(2) (2017). The filing deadline fell on November 26, 2015, which was Thanksgiving Day. Thus, the filing deadline was the close of business on Friday, November 27, 2015.

[21] *Id.* §§ 385.214(a)(2) and 385.214(c).

interventions were granted by notice issued on June 9, 2017, and this order, and are listed in Appendix B of this order.[22] ICG Eastern, LLC (ICG Eastern) filed a late, opposed motion to intervene, which we grant, as discuss below.

22. ICG Eastern, the owner of coal mines that may be affected by the MVP Project, filed a late motion to intervene in the MVP Project proceeding on July 20, 2017. Mountain Valley filed a motion to oppose the late intervention on August 11, 2017, arguing that ICG Eastern was notified of the application on October 25, 2015, but sat on its right to intervene. To date, the Commission's practice in certificate proceedings has generally been to grant motions to intervene filed prior to issuance of the Commission's order on the merits.[23] While ICG Eastern's motion pushes this practice, we find that ICG Eastern has demonstrated a sufficient interest in the proceeding and under the circumstances here, we will grant its late motion to intervene.

23. Numerous entities and individuals filed comments and protests regarding various issues, including project purpose and need; project alternatives; geological hazards; water resources; wetlands; forested habitat; wildlife and threatened, endangered, and other special status species; land use, recreational areas, and visual resources; cultural resources; air quality and noise impacts; and safety. These concerns are addressed in the final Environmental Impact Statement (EIS) and/or below.

B. <u>Answers</u>

24. Mountain Valley; Coronado Coal, LLC (Coronado Coal); Roanoke County, Virginia; ConEd, NextEra Energy Resources, LLC (NextEra), WGL Midstream, Newport Rural Historic District Committee (Greater Newport); Louisa Gay; Four Corners Farm; and Appalachian Mountain Advocates filed answers. Some submitted multiple answers in response to other's answers.

25. Separately, in Docket No. CP16-13-000, Equitrans filed an answer to Peoples Natural Gas Company LLC's (Peoples) protest of Equitrans' application, which led Peoples to file a responsive answer. Peoples subsequently withdrew its protest.

26. Although the Commission's Rules of Practice and Procedure do not permit answers to protests or answers to answers, we find good cause to waive our rules and

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[22] *See id.* § 385.214(d).

[23] *See Dominion Transmission, Inc.*, 155 FERC ¶ 61,106, at P 9 (2016) (finding that granting the untimely motions to intervene filed prior to the issuance of the certificate order generally does not delay, disrupt, or unfairly prejudice other parties to the proceeding).

accept the answers because they provide information that has assisted in our decision making process.[24]

C. Requests for a Formal Hearing

27. Several entities, including the Blue Ridge Environmental Defense League (Blue Ridge); jointly, the Shenandoah Valley Network, Highlanders for Responsible Development, Virginia Wilderness Committee, Shenandoah Valley Battlefields Foundation, and Natural Resources Defense Council (collectively Shenandoah Valley Network); Preserve Giles County; and Greater Newport request a formal hearing for both projects.

28. Although our regulations provide for a hearing, neither section 7 of the NGA nor our regulations require that such hearing be a formal, trial-type evidentiary hearing.[25] When, as is usually the case, the written record provides a sufficient basis for resolving the relevant issues, it is our practice to provide for a hearing based on the written record.[26] That is the case here. We have reviewed the requests for an evidentiary hearing and conclude that all issues of material fact relating to Mountain Valley's and Equitrans' proposals are capable of being resolved on the basis of the written record. Accordingly, we will deny the requests for a formal hearing.

IV. Discussion

29. Since the proposed facilities will be used to transport natural gas in interstate commerce and the facilities to be abandoned have been used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the proposed

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[24] *See* 18 C.F.R. § 385.213(a)(2) (2017).

[25] *See Minisink Residents for Environmental Preservation and Safety v. FERC*, 762 F.3d 97, 114 (D.C. Cir. 2014) (*Minisink Residents*) (stating "FERC's choice whether to hold an evidentiary hearing is generally discretionary.").

[26] *See NE Hub Partners, L.P.*, 83 FERC ¶ 61,043, at 61,192 (1998), *reh'g denied*, 90 FERC ¶ 61,142 (2000); *Pine Needle LNG Co., LLC*, 77 FERC ¶ 61,229, at 61,916 (1996). Moreover, courts have recognized that even where there are disputed issues, the Commission need not conduct an evidentiary hearing if the disputed issues "may be adequately resolved on the written record." *Minisink Residents*, 762 F.3d at 114 (quoting *Cajun Elec. Power Coop., Inc. v. FERC*, 28 F.3d 173, 177 (D.C. Cir. 1994)).

abandonment, construction, and operation of the facilities are subject to subsections (b), (c), and (e) of section 7 of the NGA.[27]

A. Certificate Policy Statement

30. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new construction.[28] The Certificate Policy Statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains, that in deciding whether to authorize the construction of major new natural gas facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

31. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, or landowners and communities affected by the construction. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis where other interests are considered.

1. Mountain Valley Pipeline Project

a. Subsidization and Impacts on Existing Customers

32. As stated, the threshold requirement is that the applicant must be prepared to financially support the project without relying on subsidization from its existing customers. Mountain Valley is a new pipeline entrant with no existing customers. Thus,

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[27] 15 U.S.C. §§ 717f(b), 717f(c), and 717f(e) (2012).

[28] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

there is no potential for subsidization on Mountain Valley's system or degradation of service to existing customers.

b. Need for the Project

33. Several parties and commenters challenged the need for the proposed MVP Project on several grounds, including: (1) the availability of existing infrastructure to serve demand for natural gas in Virginia, North Carolina, and South Carolina; (2) compliance with the Clean Power Plan or a shift in power generation could render the project's capacity unnecessary; (3) need for heightened scrutiny of precedent agreements with Mountain Valley affiliates; (4) potential of shifting of costs to captive ratepayers; (5) unreliability of Mountain Valley's market demand study; and (6) Mountain Valley's open seasons were not legitimate.

i. Ability of Existing Infrastructure to Meet Demand

34. Several commenters, such as Shenandoah Valley Network, argue that the MVP Project, Atlantic Coast Project,[29] Transco's Appalachian Connector,[30] and Columbia's WB Xpress Project,[31] are redundant because they all are designed to deliver gas from the Marcellus and Utica production area[32] to Transco's mainline system. They argue that

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[29] The Atlantic Coast Pipeline Project is designed to increase firm transportation service by 1.5 billion Dth per day in West Virginia, Virginia, and North Carolina. The project is currently pending before the Commission in Docket Nos. CP15-554, CP15-555, and CP15-556.

[30] Transco has not filed an application, nor has it initiated a pre-filing process, with the Commission for its Appalachian Connector Project.

[31] Columbia's proposed WB Xpress Project is designed to provide up to an additional 1.3 million Dth per day of bi-directional firm transportation service on Columbia's system. The WB Xpress Project is currently pending before the Commission in Docket No. CP16-38-000.

[32] The Marcellus shale formation extends deep underground from Ohio and West Virginia, northeast through Pennsylvania and southern New York. The Utica shale formation lies a few thousand feet below Marcellus shale formation in primarily the same, but slightly larger area as the Marcellus shale formation. *See Beardslee v. Inflection Energy, LLC*, 761 F.3d 221, 224 (2d Cir. 2014).

Transco's Atlantic Sunrise Project[33] and utilization of unused capacity on existing interstate natural gas transmission systems would accommodate the growth in market demand in the Mid-Atlantic and Southeast, specifically Virginia and the Carolinas.[34] For that reason, they contend approving the MVP Project would result in the overbuilding of natural gas infrastructure.

35. Commenters, such as Shenandoah Valley Network, also argue that a state's compliance with the Environmental Protection Agency's Clean Power Plan[35] or potential switch to renewable fuel for power generation may render the capacity on the Mountain Valley system unnecessary. They argue that this potential should be considered in assessing project need.

36. In support of their positions, commenters rely on several studies. First, they cite a U.S. Department of Energy (DOE) study for the proposition that increasing utilization

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[33] The Atlantic Sunrise Project will enable Transco to flow gas bidirectionally on its mainline system in order to provide up to 1.7 million Dth per day of firm transportation service from northern Pennsylvania to Alabama. The Commission issued a certificate for the fully-subscribed project on February 3, 2017. *Transcontinental Gas Pipe Line Company, LLC*, 158 FERC ¶ 61,125 (2017) (*Transo*).

[34] In addition to this argument, in its November 25, 2015 Motion to Intervene, Blue Ridge also asserts that the U.S. Department of Energy's estimates of recoverable shale gas supply is overly optimistic and has created a "bubble" for the commodity, which will ultimately harm the economy. Blue Ridge's argument is beyond the scope of this order because the Commission has no jurisdiction to regulate the production or gathering of natural gas. *See* 15 U.S.C. § 717(b) (2012). States, not the Commission, regulate production activities and are most likely to have the information necessary to foresee future production. The Commission can only act on the application before us.

[35] *See* EPA, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 80 Fed. Reg. 64,662 (2015). *See also West Virginia v. Environmental Protection Agency*, 136 S.Ct. 1000 (2016) (staying the final rule).

rates of existing interstate gas pipelines, re-routing gas flows, and expanding existing pipeline capacity are potentially lower-cost alternatives to building new infrastructure.[36]

37. Commenters also cite to a study by Synapse Energy Economics, Inc. (Synapse) that Southern Environmental Law Center and Appalachian Mountain Advocates commissioned, which asserts that existing gas pipeline capacity, existing storage in Virginia and the Carolinas, and the future operation of Transco's Atlantic Sunrise Project and Columbia's WB Xpress Project can satisfy the growing peak demand in that region.[37] The study concludes that the natural gas infrastructure capacity of the Virginia and the Carolinas region is more than sufficient to meet expected future peak demand.[38]

38. Appalachian Mountain Advocates and others also cite to a study by the Institute for Energy Economics and Financial Analysis (IEEFA), which argues, in part, that interstate pipeline infrastructure to ship natural gas from the Marcellus and Utica region is overbuilt.[39]

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[36] *See* Shenandoah Valley Network's November 27, 2015 Motion to Intervene and Protest at 12-13 (quoting U.S. DEP'T OF ENERGY, *NATURAL GAS INFRASTRUCTURE IMPLICATIONS OF INCREASED DEMAND FROM THE ELECTRIC POWER SECTOR* at 31 http://energy.gov/epsa/downloads/report-natural-gas-infrastructure-implications-increased-demand-electric-power-sector (DOE Study)).

[37] SYNAPSE ENERGY ECONOMICS, INC., ARE THE ATLANTIC COAST PIPELINE AND THE MOUNTAIN VALLEY PIPELINE NECESSARY? (2016) (filed as Exhibit B of Appalachian Mountain Advocates' December 22, 2016 Comment on the Draft Environmental Impact Study) (Synapse Study).

[38] Specifically, the Synapse Study analyzes the winter peak hour gas usage under various scenarios, and finds that even under the highest gas usage scenario modeled, natural gas supply exceeds demand by approximately 100 million cubic feet per day (which is equivalent to about 100,000,000 Dth per day) through 2030. Synapse Study at Figure ES-2.

[39] INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS, RISKS ASSOCIATED WITH NATURAL GAS EXPANSION IN APPALACHIA (April 2016) (attached to Friends of Nelson's December 9, 2016 Comment on the Draft EIS) (IEEFA Study).

39. In response to commenters, Mountain Valley filed its own market demand study.[40] The Wood Mackenzie Study estimates that demand growth for natural gas capacity in the Southeast will reach 8.3 billion cubic feet (Bcf) per day[41] by 2030.[42] Much of the gas needed to meet this demand would be from the Marcellus and Utica shale regions, which would require additional pipeline capacity.[43] Mountain Valley points out the other new projects, which the commenters argue make its project unnecessary, are being constructed to serve different, specific customers/markets and are themselves nearly fully subscribed. In turn, Appalachian Mountain Advocates and other commenters counter that the Wood Mackenzie Study is unreliable because it relies on data from an unusually cold winter and assumes gas will be flexible to meet the variable needs of generators.

40. The Certificate Policy Statement established a policy under which the Commission would allow an applicant to rely on a variety of relevant factors to demonstrate need, rather than continuing to require that a percentage of the proposed capacity be subscribed under long-term precedent or service agreements.[44] These factors might include, but are not limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[45] The Commission stated that it would consider all such evidence submitted by the applicant regarding project need. However, although the Certificate Policy Statement broadened the types of evidence certificate applicants may present to show the public benefits of a project, it did not compel an additional showing. The policy

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[40] WOOD MACKENZIE, INC., SOUTHEAST U.S. NATURAL GAS MARKET DEMAND IN SUPPORT OF THE MOUNTAIN VALLEY PIPELINE PROJECT (Jan. 2016) (filed as Exhibit A of Mountain Valley's January 27, 2016 Answer) (Wood Mackenzie Study).

[41] A volumetric capacity of 8.3 Bcf per day is equivalent to 8,300,000,000 Dth per day.

[42] Wood Mackenzie Study at 6.

[43] *See id.* at 20-21.

[44] Certificate Policy Statement, 88 FERC at 61,747. Prior to the Certificate Policy Statement, the Commission required a new pipeline project to have contractual commitments for at least 25 percent of the proposed project's capacity. *See id.* at 61,743. The fully subscribed MVP Project and the two-thirds subscribed Equitrans Expansion Project would both have satisfied this prior, more stringent, requirement.

[45] Certificate Policy Statement, 88 FERC at 61,747.

statement made clear that, although precedent agreements are no longer required to be submitted, they are still significant evidence of project need or demand.[46]

41. Mountain Valley has entered into long-term, firm precedent agreements with five shippers for 2,000,000 Dth per day of firm transportation service – the project's full design capacity. Equitrans has entered into a precedent agreement for 66 percent of the design capacity of its project. Further, Ordering Paragraph (C)(4) of this order requires that Mountain Valley and Equitrans file a written statement affirming that they have executed final contracts for service at the levels provided for in their precedent agreements prior to commencing construction. The shippers on the MVP and Equitrans Expansion Projects will supply gas to a variety of end users and those shippers have determined that there is a market for their gas and the MVP and Equitrans Expansion Projects are the preferred means of delivering or receiving that gas. We find that the contracts entered into by the shippers are the best evidence that additional gas will be needed in the markets that the MVP and Equitrans Expansion Projects are intended to serve.[47] We find that Mountain Valley has sufficiently demonstrated that there is market demand for its project. We also find that end users will generally benefit from the projects because they will develop gas infrastructure that will serve to ensure future

[46] *Id.* at 61,748.

[47] While, as discussed above, we have relied on the existence of precedent agreements to find there is a need for the proposed projects, we will note that the findings of the studies may have been somewhat over stated by their filers. For example, rather than demonstrating that the current pipeline network is overbuilt, the DOE Study explains that the reason far less pipeline capacity is projected to be added between 2015 and 2030 (34 to 38 Bcf per day) than in the past (127 Bcf per day between 1998 and 2013) [*See* DOE Study at 20-21, 31] is that natural gas production and natural gas demand are now geographically dispersed; instead of pipelines stretching over a thousand miles, e.g., from the Rockies to the East Coast, the Marcellus shale supply is located much closer to the East Coast markets. [*See* DOE Study at 2-3.] Similarly, while the study notes that natural gas companies are increasingly using underutilized capacity on existing pipelines, re-routing natural gas flows, and expanding existing pipeline capacity, it does not contend that this supplants the need to build new infrastructure. [*See* DOE Study at n.51 (acknowledging that in some cases unsubscribed capacity is not available on existing pipelines and expanding existing pipeline capacity is not a viable option)]. The Synapse Study makes an unlikely assumption that all gas is flowed by primary customers along their contracted paths, failing to take into consideration the use of regional pipeline capacity by shippers outside of Virginia and the Carolinas by means of interruptible service or capacity release.

domestic energy supplies and enhance the pipeline grid by connecting sources of natural gas to markets in the Northeast, Mid-Atlantic, and Southeast regions.[48]

42. We disagree with commenters' assertion that the Commission should examine the need for pipeline infrastructure on a region-wide basis. Commission policy is to examine the merits of individual projects and each project must demonstrate a specific need.[49] While the Certificate Policy Statement permits the applicant to show need in a variety of ways, it does not suggest that the Commission should examine a group of projects together and pick which projects best serve an estimated future regional demand. In fact, projections regarding future demand often change and are influenced by a variety of factors including economic growth, the cost of natural gas, environmental regulations, and legislative and regulatory decisions by the federal government and individual states. Given this uncertainty associated with long-term demand projections, such as those in the various studies noted by the applicants and commenters above, where an applicant has precedent agreements for long-term firm service, the Commission deems the precedent agreements to be the better evidence of demand. Thus, the Commission primarily relies – as it does here – on evaluating individual projects based on demonstrated need from specific shippers in the form of precedent agreements. We also note that neither any existing or proposed pipeline nor any pipeline customers have suggested that the MVP Project would have negative impacts on them, as one would expect them to do if they anticipated being burdened with the cost of unused capacity.

43. The final EIS considers the availability of capacity on other pipelines to serve as alternatives to the MVP and Equitrans Expansion Projects and determines that sufficient capacity to and from the necessary receipt and delivery points was not available.[50] Similarly, the final EIS concludes that renewable energy is not a comparable replacement for the transportation of natural gas to be provided by the projects.[51] It is speculative and outside of the scope of this proceeding to consider whether a state would comply with the EPA's Clean Power Plan regulations (which regulations are subject to a judicial stay and

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[48] *See ETC Tiger Pipeline, LLC*, 131 FERC ¶ 61,010, at P 20 (2010).

[49] With respect to comments requesting the Commission assess the market demand for gas to be transported by other proposed interstate pipeline projects, we note that the Commission will evaluate the proposals in those proceedings in accordance with the criteria established in the policy statement.

[50] *See* Final EIS at 3-1 to 3-4.

[51] *Id*. at 3-1.

a notice of proposed rulemaking to repeal[52]) and how a state would manage its electric-power fuel source for the next 20 years.

ii. Precedent Agreements with Affiliate Shippers

44. Commenters, such as Appalachian Mountain Advocates, argue that because shippers are affiliated with Mountain Valley, we should exercise heightened scrutiny in reviewing whether there is actual market demand for the project.[53] They also rely on former Commission Chairman Bay's statement that the Commission should look behind precedent agreements and reevaluate its test for need[54] to argue that the Commission's approval of affiliate-backed projects have resulted in the overbuilding of interstate gas infrastructure.

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[52] EPA, Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Oct. 10, 2017), https://www.epa.gov/sites/production/files/2017-10/documents/frn_cpp_repeal_2060-at55_proposal_20171010disclaimer.pdf.

[53] Appalachian Mountain Advocates and other commenters cite to *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277, at P 58 (2002) (*Milennium*), as an example of when the Commission exercised a heightened standard of review to prevent affiliate abuse of our regulation of interstate gas pipelines. However, the Commission did not exercise any heightened standard of review in the cited proceeding. Rather, in the referenced discussion, the Commission explained that it can exercise control over a non-jurisdictional affiliate of a pipeline when there is evidence that that affiliate is acting in concert with its pipeline in connection with interstate transport of natural gas in a manner that frustrates the Commission's effective regulation of the interstate pipeline. *See id.* (citing *Arkla Gathering Services Co.*, 67 FERC ¶ 61,257 (1994)). However, in *Millennium*, as here, the Commission stated that we do not distinguish between pipelines' precedent agreements with affiliates or independent marketers in establishing the market need for a proposed project. *Id.* at P 57.

[54] *National Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) (*National Fuel*).

45. We disagree. The fact that the project shippers are affiliated with Mountain Valley does not require the Commission to look behind the precedent agreements to evaluate project need.[55] As the court affirmed in *Minisink Residents for Environmental Preservation & Safety v. FERC,* the Commission may reasonably accept the market need reflected by the applicant's existing contracts with shippers.[56] An affiliated shipper's need for new capacity and its obligation to pay for such service under a binding contract are not lessened just because it is affiliated with the project sponsor.[57] When considering applications for new certificates, the Commission's primary concern regarding affiliates of the pipeline as shippers is whether there may have been undue discrimination against a non-affiliate shipper.[58] Here, no such allegations have been made, nor have we found that the project sponsors have engaged in any anticompetitive behavior. As discussed above, Mountain Valley and Equitrans held both non-binding and binding open seasons for capacity on their projects and all potential shippers had the opportunity to contract for service.

46. Former Chairman Bay's separate statement in *National Fuel* summarizes recent arguments that appear in our natural gas certificate proceedings. In particular, Chairman Bay encouraged the Commission to not focus exclusively on precedent agreements but to also take into account all the public benefit considerations listed in the Certificate Policy

[55] *Millennium*, 100 FERC ¶ 61,277 at P 57 ("as long as the precedent agreements are long-term and binding, we do not distinguish between pipelines' precedent agreements with affiliates or independent marketers in establishing the market need for a proposed project"). *See also* Certificate Policy Statement, 88 FERC at 61,748 (explaining that the Commission's policy is less focused on whether the contracts are with affiliated or unaffiliated shippers and more focused on whether existing ratepayers would subsidize the project); *see also id.* at 61,744 (the Commission does not look behind precedent agreements to question the individual shippers' business decisions to enter into contracts) (citing *Transcontinental Gas Pipe Line Corp*., 82 FERC ¶ 61,084, at 61,316 (1998)).

[56] *Minisink Residents*, 762 F.3d at 110 n.10; *see also Sierra Club v. FERC*, 867 F.3d 1357, 1379 (D.C. Cir. 2017) (Sabal Trail) (finding that pipeline project proponent satisfied Commission's "market need" where 93 percent of the pipeline project's capacity has already been contracted for).

[57] *See, e.g., Greenbrier Pipeline Company, LLC,* 101 FERC ¶ 61,122, at P 59 (2002), *reh'g denied*, 103 FERC ¶ 61,024 (2003).

[58] *See* 18 C.F.R. § 284.7(b) (2017) (requiring transportation service to be provided on a non-discriminatory basis).

Statement. Indeed, on a case-by-case basis, the Commission examines all evidence of public benefits and weighs them against adverse project impacts.

47. Appalachian Mountain Advocates also argue that we should treat ConEd as an "overnight" affiliate shipper because it was formed months after Mountain Valley filed its application.[59] Citing *Independence Pipeline Company*,[60] it argues that we should be dubious of the demand created by an overnight affiliate of an owner.

48. *Independence* is distinguishable from the facts here. *Independence* was a pre-Certificate Policy Statement proceeding. Thus, as discussed above,[61] under the then-applicable policy the pipeline was required to demonstrate contractual commitments for at least 25 percent of the proposed project's capacity. However, Independence had provided no contractual evidence of market support when it filed its application. After repeated statements by Independence that eleven shippers had expressed interest in the project, followed by its failure to provide precedent agreements to support those statements, Commission staff informed Independence that it would dismiss Independence's application by September 24, 1997, if the precedent agreements were not submitted.[62] On the eve of the deadline, Independence created an affiliate marketer with whom it signed a precedent agreement.[63] The Commission rejected the precedent agreement as evidence of market support for the project finding Independence had created an affiliate "virtually overnight" to falsely evidence market need for the project.[64]

49. Here, Mountain Valley's binding open season conducted in 2014 resulted in commitments from USG and EQT. By the time Mountain Valley filed its application in October 2015, it had signed binding precedent agreements with two additional shippers. Three months after it filed its application, ConEd both became an affiliate of Mountain Valley and a shipper on the project, taking, as described above, capacity previously subscribed by USG, another Mountain Valley affiliate. However, while a new affiliate of

[59] *See* Appalachian Mountain Advocates' December 22, 2016 Comments on the Draft EIS at 12-13.

[60] 89 FERC ¶ 61,283 (1999) (*Independence*).

[61] See *supra* note 44.

[62] *See* 89 FERC at 61,820.

[63] *See id.* at 61,840.

[64] *See id.*

Mountain Valley, ConEd is a longstanding company, created many years prior to the filing date of Mountain Valley's application.[65]

iii. Shifting Costs to Captive Ratepayers

50. Appalachian Mountain Advocates and other commenters argue that two project shippers, Roanoke Gas and ConEd, will pass the cost of the firm transportation service on the MVP Project through to their captive ratepayers through annual gas adjustment mechanisms. Appalachian Mountain Advocates also argue that because neither the Virginia nor New York public utility regulators have approved the precedent agreements, it is important for the Commission to scrutinize the proposal to determine whether the project is needed. Similarly, they argue that because USG and WGL Midstream, both owners of Mountain Valley, signed precedent agreements with Mountain Valley, they are able to bypass state public utility commission regulatory review when they pass the cost of the project through to their affiliate utility companies (i.e., Florida Power & Light Company (FPL) and Washington Gas Light Company (WGL)). Because state regulatory review of the precedent agreements have been lacking, customers of the affiliate utilities do not have a forum to contest rates.

51. In response to Appalachian Mountain Advocates' comment, ConEd states that it filed its precedent agreement with the New York State Public Service Commission and has been transparent with the New York regulators about its subscription to capacity on the MVP Project. It asks that the Commission not substitute its judgment for the judgement of New York regulators.

52. NextEra and WGL Midstream also filed an answer to Appalachian Mountain Advocates' comment, in which they deny the allegation that USG and WGL Midstream are attempting to avoid state regulatory oversight. They assert that both FPL and WGL contract for gas transportation on their own behalf and operate largely independently from their affiliates; thus neither USG nor WGL Midstream can pass along their costs from the MVP Project through to FPL or WGL. NextEra and WGL Midstream also contend that in the event either FPL or WGL enter into gas supply arrangements with any MVP Project shipper, or become project shippers themselves, those actions would be subject to state regulatory prudence review.

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[65] In its December 22, 2016 Comment on the Draft EIS, Appalachian Mountain Advocates specifically identifies Con Edison Gas Midstream, LLC as an "overnight affiliate," but Appalachian Mountain Advocates' argument is misdirected. Its argument is centered on alleged false demand created by an "overnight" affiliate shipper. In this case, ConEd is the affiliate shipper, not Con Edison Gas Midstream, LLC, and has been an active corporation in the state of New York since 1884.

53. We find Appalachian Mountain Advocates' arguments unavailing. State utility regulators must approve any expenditures by state-regulated utilities. We disagree with commenters who suggest that once the Commission has made a determination in this proceeding, state regulators cannot effectively review the expenditures of utilities that they regulate. In fact, any attempt by the Commission to look behind the precedent agreements in this proceeding might infringe upon the role of state regulators in determining the prudence of expenditures by the utilities that they regulate. The Commission's policy of not looking beyond precedent agreements includes not limiting our reliance on such agreements to those which have been previously approved by a state public service commission. Further, Appalachian Mountain Advocates' reliance on *Guardian Pipeline, L.L.C.*[66] is misplaced. In that order, we stated that it is the Commission's "preference not to second guess the business decisions of end users or challenge the business decisions of an end user on whether it is economic to undertake direct service from a pipeline supplier, particularly when that decision has been approved by the appropriate regulatory body."[67] *Guardian* follows a long line of orders in which we have stated that we are reluctant to second guess the business decisions of pipeline shippers.[68] Issues related to a utility's ability to recover costs associated with its decision to subscribe for service on the MVP and Equitrans Expansion Projects involve matters to be determined by the relevant state utility commissions; those concerns are beyond the Commission's jurisdiction.

iv. <u>Mountain Valley's Open Seasons</u>

54. Appalachian Mountain Advocates and other commenters argue that the precedent agreements are not a result of the open season process. They contend that Mountain Valley had to extend its binding open seasons five times because no shipper subscribed to service in the prior open seasons. They assert that these extensions—along with the fact that the project is subscribed by only affiliates—suggest that the market does not support the project. Our open season policy for new interstate pipeline construction only requires that a pipeline applicant conduct a fair and transparent open season, prior to filing its application, for potential shippers to seek and obtain firm capacity rights.[69] One purpose of an open season is to provide the project sponsor with valuable information about

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[66] 91 FERC ¶ 61,285 (2000) (*Guardian*).

[67] *Id.* at 61,966-67.

[68] *See, e.g., Southern Natural Gas Co.*, 76 FERC ¶ 61,122, at 61,635 (1996); *Williams Natural Gas Co.*, 70 FERC ¶ 61,306, at 61,924 (1995); *Tennessee Gas Pipeline Co.*, 69 FERC ¶ 61,239, at 61,901 (1994).

[69] *See Pine Prairie Energy Center, LLC*, 135 FERC ¶ 61,168, at P 30 (2011).

market interest that it can utilize to properly design and size its project.[70] Our policy does not limit the number of open seasons a project sponsor can hold. The significant fact is that the project is fully subscribed, not how long it took this to occur. The fact that no project was proposed before the Commission until market participants had indicated, by signing precedent agreements, that the ultimate proposal would indeed meet their needs, is indicative of the validity of the Commission's process and policy.

55. In conclusion, we find that the MVP Project will make reliable natural gas service available to end use customers and the market. Precedent agreements signed by multiple shippers for 100 percent of the project's capacity adequately demonstrate that the project is needed.

c. Existing Pipelines and Their Customers

56. The MVP Project is designed to transport domestically-sourced natural gas from the Marcellus and Utica supply areas to markets in the Northeast, Mid-Atlantic, and Southeast regions. No transportation service provider or captive customer has protested this project. Therefore, we find that the MVP Project will have no adverse impact on existing pipelines or their captive customers.

d. Landowners and Communities

57. Regarding impacts on landowners and communities along the project route, Mountain Valley proposes to locate its pipeline within or parallel to existing rights-of-way, where feasible. Approximately 30 percent of the MVP Project's rights-of-way will be collocated or adjacent to existing pipeline, roadway, railway, or utility rights-of-way.[71] The new compressor stations will be constructed on land owned by Mountain Valley. Mountain Valley participated in the Commission's pre-filing process[72] and has been working to address landowner and community concerns and input. Specifically, in order to address landowner requests, avoid sensitive environmental resources, such as archaeological sites and wetlands, and avoid steep terrain or side slopes, Mountain Valley incorporated over 11 route variations and 571 minor route variations (during pre-filing), and another 2 route variations and 130 additional minor variations (post-application filing) into its proposal.[73] Additionally, Mountain Valley has stated that it will make

[70] *Id.*

[71] Final EIS at 2-10.

[72] Docket No. PF15-3-000.

[73] Final EIS at ES-3 and 3-17.

good faith efforts to negotiate with landowners for any needed rights, and will resort only when necessary to the use of the eminent domain. Accordingly, while we are mindful that Mountain Valley has been unable to reach easement agreements with many landowners, for purposes of our consideration under the Certificate Policy Statement, we find that Mountain Valley has generally taken sufficient steps to minimize adverse impacts on landowners and surrounding communities.

58. Several commenters argue that the use of eminent domain in connection to the project would be unconstitutional because the project would only benefit private entities, not the public.[74] Several landowners, many of whom are intervenors in this proceeding, filed a complaint and petition for injunctive relief in U.S. District Court for the Western District of Virginia (Berkley Complaint) arguing that the Commission's issuance of a certificate to Mountain Valley, which effectuates eminent domain authority under NGA section 7(h), would result in the unlawful and unconstitutional takings of the plaintiffs' property.[75] Similarly, Bold Alliance, Bold Education Fund, Friends of Nelson, and individual landowners (collectively, Bold Alliance) filed a petition for declaratory order and injunctive relief in Federal District Court for the District of Columbia.[76] Bold Alliance alleges that the eminent domain provisions of the NGA and the Commission's Certificate Policy Statement do not further a public use, and therefore, violate the Due Process Clause and Takings Clause of the Fifth Amendment.

59. The Commission itself does not confer eminent domain powers. Under NGA section 7, the Commission has jurisdiction to determine if the construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination and issues a natural gas company a certificate of public convenience and necessity, it is NGA section 7(h) that authorizes that certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[77]

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[74] *See, e.g.,* David and Judith Rauchle's November 25, 2015 Comment at 1; Helena Teekell's July 4, 2016 Comment at 1; and Anthony Novitzki's December 13, 2016 Comment at 1.

[75] *See Orus Ashby Berkley v. Mountain Valley Pipeline, LLC*, No. 7:17-cv-00357, Plaintiffs' Complaint and Memorandum of Law in Support of Plaintiffs' Motion for a Preliminary Injunction (July 27, 2017).

[76] The petition was filed with the Commission on September 6, 2017.

[77] 15 U.S.C. § 717f(h) (2012).

60. While this matter is currently before the court, we note that both the Berkley Complaint's and Bold Alliance's legal theory is unfounded. Both sets of plaintiffs generally argue that the Commission's certification process falls short of the standard required by the Constitution for a taking: that the exercise of eminent domain is for a "public use." As noted above, Congress provided in NGA section 7(h) that a certificate holder was entitled to use eminent domain. Congress did not suggest that there was a further test, beyond the Commission's determination under NGA section 7(c)(e),[78] that a proposed pipeline was required by the public convenience and necessity, such that certain certificated pipelines furthered a public use, and thus were entitled to use eminent domain, while others did not. The Commission has interpreted the section 7(c)(e) public convenience and necessity determination as requiring the Commission to weigh the public benefit of the proposed project against the project's adverse effects.[79] We undertake this balancing through our application of the Certificate Policy Statement criteria, under which we balance the public benefits of a project against the residual adverse effects.[80] Thus, through this balancing process we make findings that support our ultimate conclusion that the public interest is served by the construction of the proposed project.[81] Accordingly, once a natural gas company obtains a certificate of

[78] 15 U.S.C. § 717f(e) (2012).

[79] As the agency that administers the Natural Gas Act, and in particular as the agency with expertise in addressing the public convenience and necessity standard in the Act, the Commission's interpretation and implementation of that standard is accorded deference. *See Chevron, USA, Inc. v. Natural. Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984); *Delaware Riverkeeper Network v. FERC*, 857 F.3d 388, 392 (D.C. Cir. 2017); *Office of Consumers' Counsel v. FERC*, 655 F.2d 1132, 1141 (D.C. Cir. 1980); *See Total Gas & Power N. Am., Inc. v. FERC*, No. 4:16-1250, 2016 WL 3855865, at *21 (S.D. Tex. July 15, 2016), *aff'd*, 859 F.3d 325 (5th Cir. 2017); *see also MetroPCS Cal., LLC v. FCC*, 644 F.3d 410, 412 (D.C. Cir. 2011) (under Chevron, the Court "giv[es] effect to clear statutory text and defer[s] to an agency's reasonable interpretation of any ambiguity").

[80] Certificate Policy Statement, 88 FERC at 61,747-49.

[81] *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000) (because the Commission declared that the subject pipeline would serve the public convenience and necessity, the takings complained of did serve a public purpose); *see also Guardian Pipeline, L.L.C. v. 529.42 Acres of Land*, 210 F. Supp. 2d 971, 974 (N.D. Ill. 2002) (no evidence of public necessity other than the Commission's determination is required).

public convenience and necessity, it may exercise the right of eminent domain in a U.S. District Court or a state court.

61. The Commission, having determined that the MVP Project is in the public convenience and necessity, need not make a separate finding that the project serves a "public use" to allow the certificate holder to exercise eminent domain. In short, the Commission's public convenience and necessity finding is equivalent to a "public use" determination.[82] In enacting the NGA, Congress clearly articulated that the transportation and sales of natural gas in interstate commerce for ultimate distribution to the public is in the public interest.[83] This congressional recognition that natural gas transportation furthers the public interest is consistent with the Supreme Court's emphasis on legislative declarations of public purpose in upholding the power of eminent domain.[84]

62. Bold Alliance erroneously cites to *Transco*,[85] where the Commission, after evaluating record evidence of need for the project at issue, found that there was a need

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[82] *See Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d at 973; *see also Troy Ltd. v. Renna*, 727 F.2d 287, 301 (3rd Cir. 1984) ("authoriz[ing] an occupation of private property by a common carrier . . . engaged in a classic public utility function" is an "exemplar of a public use"); *E. Tenn. Natural Gas Co. v. Sage*, 361 F.3d 808 (4th Cir. 2004) ("Congress may, as it did in the [Natural Gas Act], grant condemnation power to 'private corporations . . . execut[ing] works in which the public is interested.'") (quoting *Miss. & Rum River Boom Co. v. Patterson*, 98 U.S. 403, 406 (1878)).

[83] 15 U.S.C. § 717(a) (2012) (declaring that the "business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest"). *See also Thatcher v. Tennessee Gas Transmission Co.*, 180 F.2d 644, 647 (5th Cir. 1950) (*Thatcher*), *cert. denied*, 340 U.S. 829 (1950) (explaining that Congress, in enacting the NGA, recognized that "vast reserves of natural gas are located in States of our nation distant from other States which have no similar supply, but do have a vital need of the product; and that the only way this natural gas can be feasibly transported from one State to another is by means of a pipe line.").

[84] *Kelo v. City of New London, Conn.*, 545 U.S. 469, 479-80 (2005) (upholding a state statute that authorized the use of eminent domain to promote economic development); *see also id.* at 480 (noting that without exception the Court has defined the concept of "public purpose" broadly, reflecting the Court's longstanding policy of deference to the legislative judgments in this field).

[85] *Transcontinental Gas Pipe Line Co., LLC*, 158 FERC ¶ 61,125 (2017).

for the project for purposes of section 7(c) of the NGA[86] and that the project served a public purpose sufficient to satisfy the Takings Clause.[87] We have done the same here. The proposed projects in this proceeding, are designed to primarily serve natural gas demand in the Northeast, Mid-Atlantic, and Southeast regions. Through the transportation of natural gas from the projects, the public at large will benefit from increased reliability of natural gas supplies. Furthermore, upstream natural gas producers will benefit from the project by being able to access additional markets for their product. Therefore, we conclude that the proposed project is required by the public convenience and necessity.

63. Notwithstanding the fact that we addressed a takings argument raised in *Transco* and here, such a question is beyond our jurisdiction: only the courts can determine whether Congress' action in passing section 7(h) of the NGA conflicts with the Constitution. We note, however, that courts have found eminent domain authority in section 7(h) of the NGA to be constitutional.[88]

e. <u>Conclusion</u>

64. We find that the benefits that the MVP Project will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and landowners or surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and NGA section 7(e), and subject to the environmental discussion below, we find that the public convenience and necessity requires approval of Mountain Valley's proposal, as conditioned in this order.

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[86] *Id.* PP 20-33.

[87] *Id.* PP 66-67.

[88] *See Thatcher*, 180 F.2d at 647. In addition, the eminent domain authority in many federal statutes mirror the authority in section 7(h) of the NGA. For instance, section 21 of the Federal Power Act (FPA), 16 U.S.C. § 814 (2012), provides that when a licensee cannot acquire by contract lands or property necessary to construct, maintain, or operate a licensed hydropower project, it may acquire the same by the exercise of the right of eminent domain in a U.S. District Court or a state court. The U.S. Supreme Court has not questioned the constitutionality of section 21 of the FPA. *See FPC v. Tuscarora Indian Nation*, 362 U.S. 99, 123-24 (1960). Similarly, Congress included the same eminent domain authority for permit holders for electric transmission facilities when it enacted the Energy Policy Act of 2005. 16 U.S.C. § 824p(e)(1) (2012).

2. Equitrans Expansion Project

65. As stated, the threshold requirement for pipelines proposing new projects is that the applicant must be prepared to financially support the project without relying on subsidization from its existing customers. The Commission has determined, in general, that where a pipeline proposes to charge incremental rates for new construction that are higher than the company's existing system rates, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers.[89] Here, Equitrans calculated the incremental firm transportation base reservation rate, which was lower than its existing system-wide rate. Equitrans therefore proposes to charge its existing mainline system rates as the initial recourse rates, which will recover the costs of the project. Accordingly, we find that the Equitrans Expansion Project will not be subsidized by existing customers and satisfies the threshold no-subsidy requirement under the Certificate Policy Statement.

66. Peoples, a shipper on Equitrans' existing system, protested Equitrans' application because it was concerned that the proposed change of gas-flow direction on Equitrans' system (i.e., from south-to-north to north-to-south) could disrupt service to Peoples in the northern portion of Equitrans' existing system. Subsequently, Equitrans negotiated with Peoples to address Peoples' concerns and conducted additional modeling and flow analysis, resulting in an agreed upon statement concerning how operation of the proposed project would not negatively impact Peoples' existing service.[90] Later, Peoples withdrew its protest, conditioned on the Commission's acceptance and incorporation of specific language agreed to by the parties explaining how Equitrans would operate its system to ensure that Peoples' service was not affected.[91]

67. Commission staff's review of the engineering data submitted in the proceeding confirms that the Equitrans Expansion Project would not adversely affect Equitrans'

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[89] *See Transcontinental Gas Pipe Line Corp.*, 98 FERC ¶ 61,155, at 61,552 (2002) (noting that the Commission has previously determined that where a pipeline proposes to charge an incremental rate for new construction, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers) (citations omitted); *see also Dominion Transmission, Inc.*, 155 FERC ¶ 61,106 (2016) (same).

[90] *See* Equitrans' February 24, 2017 Data Request Response at 1; Peoples' April 18, 2017 Notice of Withdrawal of Protest at 2.

[91] Peoples' April 18, 2017 Notice of Withdrawal of Protest at n.3 (Equitrans and Peoples agreed that if the MVP Project shippers nominate natural gas flows less than levels assumed in Equitrans' flow models, then flows to Mountain Valley and the use of the Redhook Compressor Station will be reduced accordingly in order to transport gas to Peoples' delivery points "in the same manner as it is today").

ability to meet its firm contractual obligations to Peoples and other existing customers. We appreciate that the parties have negotiated an understanding that reinforces Equitrans' certificate obligation to operate its system in a manner that will meet all of its contractual obligations. However, based on Commission staff's finding that operation of the Equitrans Expansion Project would not adversely affect Peoples' service on Equitrans' existing system, we find that the inclusion of the requested language in this order is unnecessary and therefore, we decline to include it. In the unanticipated event service on the Equitrans Expansion Project causes service disruptions to Peoples under its firm transportation service contract, Peoples may file a complaint with the Commission, seek reservation charge credits, or seek damages under its contract in court. Thus, we find that the proposal will not adversely affect Equitrans' existing customers because there will be no degradation of existing service. In addition, other pipelines and their captive customers will not be adversely impacted because the proposal is not intended to replace service on other pipelines. Rather, the project would allow Equitrans to provide additional transportation services to EQT Energy on its system. Further, no pipeline or their captive customers have protested the application.

68. We also find that the Equitrans Expansion Project will have minimal adverse impacts on landowners and communities. Approximately 32 percent of the right-of-way for the proposed project will be collocated or adjacent to existing pipeline, roadway, railway, or utility rights-of-way.[92] Additionally, the Redhook Compressor Station will be located on land owned by Equitrans.

69. We find that Equitrans' proposed abandonment of facilities is permitted by the present or future public convenience or necessity.[93] Once construction is complete, the Redhook Compressor Station will replace the Pratt Compressor Station. In addition, small portions of Equitrans' existing M-80 and H-158 pipelines, which currently connect to the Pratt Compressor Station, will be rerouted from the Pratt Compressor Station to the Redhook Compressor Station in order to continue service. Thus, the proposed abandonment of the Pratt Compressor Station, its appurtenant facilities, and portions of the M-80 and H-158 pipelines will not affect existing customers on Equitrans' system. Last, no shipper affected by the proposed abandonment has filed comments in opposition to Equitrans' proposal.

70. We find that the benefits that the Equitrans Expansion Project will provide to the market outweigh any adverse effects on existing shippers, other pipelines and their captive customers, and on landowners and surrounding communities. Consistent with the criteria discussed in the Certificate Policy Statement and subject to the environmental

[92] Final EIS at ES-7.

[93] 15 U.S.C. § 717f(b) (2012).

discussion below, we find that the public convenience and necessity requires approval of Equitrans' proposal, as conditioned in this order.

B. Blanket Certificates

71. Mountain Valley requests a Part 284, Subpart G blanket certificate in order to provide open-access transportation services. Under a Part 284 blanket certificate, Mountain Valley will not require individual authorizations to provide transportation services to particular customers. Mountain Valley filed a *pro forma* Part 284 tariff to provide open-access transportation services. Since a Part 284 blanket certificate is required for Mountain Valley to offer these services, we will grant Mountain Valley a Part 284 blanket certificate, subject to the conditions imposed herein.

72. Mountain Valley also requests a Part 157, Subpart F blanket certificate. A Part 157 blanket certificate gives an interstate pipeline NGA section 7 authority to automatically, or after prior notice, perform certain activities related to the construction, acquisition, abandonment, and replacement and operation of pipeline facilities.

73. Roanoke County, Virginia (Roanoke County) objects to Mountain Valley's request for pre-granted abandonment or acquisition authority under a Part 157 blanket certificate. Roanoke County contends that the Commission must determine the public convenience and necessity of Mountain Valley's request at the time of any proposal to abandon or acquire facilities.

74. Roanoke County presents no arguments why Mountain Valley's specific request for a blanket certificate should be denied; rather it seems to take general issue with the Commission's blanket certificate program. Part 157, Subpart F of the Commission's regulations authorizes a certificate holder to engage in a limited number of routine activities under a blanket certificate, subject to certain reporting, notice, and protest requirements.[94] The blanket certificate procedures are intended to increase flexibility and reduce regulatory and administrative burdens. Because the eligible activities permitted under a blanket certificate regulations can satisfy our environmental requirements and meet the blanket certificate cost limits, they will have minimal impacts, such that the close scrutiny involved in considering applications for case-specific certificate authorization is not necessary to ensure compatibility with the public convenience and necessity. For almost all eligible activities, a certificate holder seeking to engage in such activities must notify landowners prior to commencing the activity.[95] For activities that require prior notice, an opportunity to protest is afforded once notice of the certificate

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[94] *See* 18 C.F.R. § 157.203 (2017).

[95] *See id.* § 157.203(d).

holder's request is issued to the public.[96] If a protest cannot be resolved, then the certificate holder may not perform the requested activity under a blanket certificate.[97] Thus, because Mountain Valley will be operating a jurisdictional pipeline facility for which this order grants certificate authorization, we will also grant the requested Part 157, Subpart F blanket construction certificate authorizing Mountain Valley's performance of certain routine activities in conjunction with its operation of the pipeline.

C. Rates

1. Mountain Valley Pipeline Project

a. Mountain Valley's Initial Recourse Transportation Rates

75. Under the proposed *pro forma* tariff, Mountain Valley proposes to provide firm transportation service under its Rate Schedule FTS, interruptible transportation service under its Rate Schedule ITS, and interruptible lending and parking service under its Rate Schedule ILPS, all pursuant to Part 284 of the Commission's regulations. Instead of paying cost-based recourse rates, the project shippers have elected to pay negotiated rates for transportation service on the project.[98] Mountain Valley states that it will file the negotiated rate agreements, as specified by the Commission's regulations.

76. To derive its firm recourse transportation charges, Mountain Valley states that it utilized a straight-fixed variable rate design methodology and designed its rates on a postage-stamp basis. For firm transportation service under Rate Schedule FTS, Mountain Valley proposes a monthly reservation recourse charge of $29.5967 per Dth and a commodity charge of $0.0035 per Dth based on annual reservation determinants of 730,000,000 Dth and an annual cost of service of $712,903,260.[99] Mountain Valley proposes to charge a maximum daily IT recourse rate of $0.9766 per Dth, based on the maximum daily FTS reservation charge plus the FTS commodity charge. Mountain

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[96] *See id.* § 157.205.

[97] *See id.* § 157.205(f).

[98] Details of the negotiated rate authority are contained in Mountain Valley's General Terms & Conditions (GT&C) section 6.27.

[99] Exhibit P, Schedule 1, Page 2 of Mountain Valley's Application. Mountain Valley breaks down the annual cost of service into $710,320,684 for fixed costs and $2,582,576 for variable costs.

Valley also proposes to charge a maximum rate of $0.9755 per Dth for lending and parking under its Rate Schedule ILPS.

77. In addition, Mountain Valley proposes to offer Interim Period Service, from Wetzel County to the WB Interconnect, prior to the in-service date of the entire project.[100] Mountain Valley's proposed Interim Period Service rates under Rate Schedule FTS consist of a $15.9014 per Dth monthly reservation recourse charge and a $0.0032 per Dth commodity charge based on annual reservation determinants of 377,651,265 Dth and an annual cost of service of $198,628,658.[101] The Interim Period Service IT recourse rate of $0.5260 per Dth is based on the maximum daily FTS reservation rate plus the FTS commodity charge.

78. The Commission has reviewed Mountain Valley's proposed cost of service and initial rates and finds that they generally reflect current Commission policy, except for Mountain Valley's proposed return on equity (ROE), which we discuss below. The Commission accepts Mountain Valley's proposed recourse rates as the initial rates for service on its project, subject to the revisions discussed below.

b. Return on Equity and Capital Structure

79. Mountain Valley developed its proposed initial rates based on a capital structure of 40 percent debt and 60 percent equity, with a debt cost of 6 percent and a ROE of 14 percent. Mountain Valley states that its expected capital structure is reflective of the large capital expenditure necessary to construct the project, which it alleges will result in a large non-recourse placement of debt in the debt markets. Mountain Valley's weighted average cost of capital under its proposed capital structure is 10.8 percent.

80. Mountain Valley's combined return on equity and capital structure proposal does not reflect current Commission policy. For new pipelines, the Commission has approved an ROE of 14 percent, but only where the equity component of the capitalization is no

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[100] *See* Mountain Valley's Application, Exhibit P, Part II – Pro Forma Tariff, Mountain Valley Pipeline, LLC, FERC Gas Tariff, Volume No. 1, Section 4.1 Statement of Rates – FTS.

[101] Exhibit P, Schedule 2, Page 2 of Mountain Valley's Application. Mountain Valley breaks down the annual cost of service into $197,431,290 for fixed costs and $1,197,368 for variable costs.

more than 50 percent.[102] In *Florida Southeast Connection, LLC*, the Commission approved a greenfield pipeline's proposed 14 percent ROE but rejected its capital structure of 60-percent equity and 40-percent debt. The Commission found that imputing a capitalization containing such a large equity ratio is more costly to ratepayers, because equity financing is typically more costly than debt financing and the interest incurred on debt is tax deductible.[103] Consequently, the Commission required that the greenfield pipeline design its cost-based rates on a capital structure that included at least 50-percent debt.[104]

81. Appalachian Mountain Advocates argue that Mountain Valley's requested 14-percent ROE is higher than the ROE in other utility sectors. It also contends that the high ROE motivates the project shippers to become owners of Mountain Valley because the shipper/owner can then recover the "generous" return on equity.[105]

82. The Commission's policy of approving equity returns of up to 14 percent with an equity capitalization of no more than 50 percent provides an appropriate incentive for new pipeline companies to enter the market and reflects the fact that greenfield pipelines undertaken by a new entrant in the market face higher business risks than existing pipelines proposing incremental expansion projects.[106] Thus, approving Mountain Valley's requested 14-percent return on equity in this instance is in response to the risk Mountain Valley faces as a new market entrant, constructing a new greenfield pipeline system. Moreover, the returns approved for other utilities, such as electric utilities and LDCs are not relevant because there is no showing that these companies face the same level of risk as faced by greenfield projects proposed by a new natural gas pipeline

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[102] *Florida Southeast Connection, LLC,* 154 FERC ¶ 61,080, *order on reh'g,* 156 FERC ¶ 61,160 (2016), *vacated and remanded sub nom. Sabal Trail*, 867 F.3d 1357 (affirming the Commission's approval of a 14-percent ROE based on a 50-50 debt-equity capital structure); *MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165 (2008).

[103] *See Florida Southeast Connection*, 154 FERC ¶ 61,080 at P 117.

[104] *See id.*

[105] Appalachian Mountain Advocates' Dec. 22, 2016 Comments on Draft EIS at 11, 17-18.

[106] *See, e.g., Rate Regulation of Certain Natural Gas Storage Facilities,* Order No. 678, FERC Stats & Regs. 31,220, at P 127 (2006) (explaining that existing pipelines who need only acquire financing for incremental expansions face less risk than "a greenfield project undertaken by a new entrant in the market").

company.[107] Appalachian Mountain Advocates' second argument is inapposite where, as here, the bulk of the shippers are producers or marketers who will be competing against other producers/marketers in the interstate market for the sale of their gas. These parties have no guarantee that they will recover the costs of their capacity commitment and are fully at risk for the cost of that capacity.

83. Further, as explained below, we are requiring Mountain Valley to file a cost and revenue study at the end of its first three years of actual operation to justify its existing cost-based rates. The three-year report will provide an opportunity for the Commission and the public to review Mountain Valley's original estimates, upon which its initial rates are based, to determine whether Mountain Valley is over-recovering its cost of service with its approved initial rates, and whether the Commission should exercise its authority under section 5 of the NGA to establish just and reasonable rates. Alternatively, Mountain Valley may elect to make a NGA section 4 filing to revise its initial rates. In such section 4 proceeding, the public would have an opportunity to review Mountain Valley's proposed return on equity and other cost of service components at that time and would have an opportunity to raise issues relating to the rate of return, as well as all other cost components. Accordingly, we find that Mountain Valley's proposed rates will "ensure that the consuming public may be protected" until just and reasonable rates can be determined through the more thorough and time-consuming ratemaking sections of the NGA.[108]

84. For the foregoing reasons we approve Mountain Valley's proposed 14 percent ROE as reflective of current Commission policy for a new pipeline entity. However, Mountain Valley must design its cost-based rates on a capital structure that includes at least 50 percent debt. Mountain Valley is directed to recalculate its recourse rates in its compliance filing.

c. Fuel Charge

85. Mountain Valley states that it will implement a retainage factor to track and recover actual experienced fuel and lost and unaccounted for gas. Mountain Valley states that the initial posted retainage factor will be 1.36 percent based on the fuel study submitted as Exhibit Z-3 of its application. The Commission finds the fuel study

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[107] The Commission has previously concluded that distribution companies are less risky than a pipeline company. *See, e.g., Trailblazer Pipeline Co.*, 106 FERC ¶ 63,005, at P 94 (2004) (rejecting inclusion of local distribution companies in a proxy group because they face less risk than a pipeline company).

[108] *Id.* at 392.

acceptable and approves the proposed 1.36 percent retainage factor as Mountain Valley's initial retainage rate.

86. As previously mentioned, Mountain Valley will enter into negotiated rate agreements with the project shippers on its system. Such agreements include provisions regarding fuel retention. The Commission prohibits a pipeline from shifting costs associated with negotiated rate shippers to recourse rate shippers.[109] Consistent with this policy, the Commission has held that when a pipeline negotiates fuel retainage percentage factors with a negotiated rate shipper, the pipeline must bear the risk of under-recovery of its fuel costs and cannot shift unrecovered fuel costs to its recourse rate shippers.[110] Accordingly, in any fuel proceeding, Mountain Valley will have the burden of showing that its proposal does not shift any unrecovered fuel costs from negotiated rate shippers to recourse rate shippers.

d. <u>Three-Year Filing Requirement</u>

87. Consistent with Commission precedent, Mountain Valley is required to file a cost and revenue study at the end of its first three years of actual operation to justify its existing cost-based firm and interruptible recourse rates.[111] In its filing, the projected units of service should be no lower than those upon which Mountain Valley's approved initial rates are based. The filing must include a cost and revenue study in the form specified in section 154.313 of the Commission's regulations to update cost of service data.[112] Mountain Valley's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Mountain Valley is advised to include as part of the eFiling description, a reference to Docket No. CP16-10-000 and the cost and revenue study.[113] After reviewing the data, the Commission will determine whether to exercise its authority under NGA section 5 to investigate whether the rates remain just and reasonable. In the alternative, in lieu of this filing, Mountain Valley may make a NGA general section 4 rate filing to propose alternative rates to be effective no later than three years after the in-service date for its proposed facilities.

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[109] *See Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224, at P 62 (2009).

[110] *Id*.

[111] *Rover Pipeline LLC*, 158 FERC ¶ 61,109, at P 82 (2017); *Bison Pipeline LLC*, 131 FERC ¶ 61,013, at P 29 (2010); *Ruby Pipeline*, 128 FERC ¶ 61,224 at P 57.

[112] 18 C.F.R. § 154.313 (2017).

[113] *Electronic Tariff Filings*, 130 FERC ¶ 61,047, at P 17 (2010).

2. Equitrans Expansion Project

a. Equitrans' Initial Recourse Transportation Rate

88. Equitrans proposes to use its existing mainline system rates as the initial recourse rates for firm transportation service on the Expansion Project. Equitrans calculated an illustrative monthly incremental reservation charge for the project of $4.2408 per Dth.[114] This illustrative charge is lower than Equitrans' currently effective reservation charge for Rate Schedule FTS of $6.1206 per Dth for Winter (November 1 to March 31) and $7.5189 per Dth for Non-Winter (April 1 to October 31).[115] In addition, Equitrans' illustrative incremental commodity charge is lower than its currently-effective commodity charge.[116] Commission policy requires that when an incremental rate is lower than the system rate, the system rate is used as the initial recourse rate for providing service on the expansion project.[117] Therefore, we will approve the use of Equitrans' existing system rates as the initial recourse rates for services utilizing the new capacity created by the expansion facilities.

b. Fuel

89. Equitrans states that the expected fuel usage for the new project facilities is approximately 0.98 percent per Dth, which is less than its Mainline System Retainage Factor of 2.72 percent. Therefore, it maintains that existing customers will not subsidize the project. In addition to the lower fuel percentage, Equitrans has a fixed fuel rate set forth in its Commission-approved tariff. Thus, in the event service under the project causes Equitrans to use more fuel than it recovered from its project shipper, Equitrans will bear the risk of any under recovery of fuel as its fuel rates are fixed and it is unable

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[114] Exhibit N, page 2 of Equitrans' Application. $30,522,569 (Cost of Service) ÷ 219,000,000 (annual billing determinants [600,000 x 365]) = $0.1394 per Dth. $0.1394 x 365 ÷ 12 = $4.2408 per Dth per month.

[115] Equitrans, L.P., FERC NGA Gas Tariff, Equitrans Tariff, Section 4.1, Transportation Rates NOFT, FTS, STS-1 & FTSS, 15.1.0.

[116] Equitrans calculates a commodity rate of $0.0071, compared to the mainline commodity rate of $0.1481 for winter, and $0.1466 for base, based on total first-year operation and maintenance expense of $1,562,448.

[117] *See, e.g.*, *Tennessee Gas Pipeline Company, L.L.C.*, 157 FERC ¶ 61,208, at P 19 (2016); *Eastern Shore Natural Gas Company*, 156 FERC ¶ 61,054, at P 21 (2016) (*Eastern Shore*).

to pass through any underrecovery of fuel costs.[118] Therefore, existing customers will not subsidize the fuel recovery of the project.

c. **<u>Predetermination of Rolled-in Rate Treatment</u>**

90. Equitrans requests a predetermination that it may roll the costs associated with the project into its system-wide rates in a future NGA section 4 rate case. In considering a request for a predetermination that a pipeline may roll the costs of a project into its system-wide rates in its next NGA general section 4 rate proceeding, a pipeline must demonstrate that rolling in the costs associated with the construction and operation of new facilities will not result in existing customers subsidizing the expansion.[119] In general, this means that a pipeline must show that the revenues to be generated by an expansion project will exceed the cost of the project. For purposes of making such a determination, we compare the cost of the project to the revenues generated utilizing actual contract volumes and the maximum recourse rate (or the actual negotiated rate if the negotiated rate is lower than the recourse rate).[120]

91. Here, EQT Energy has elected to pay a negotiated rate that is less than the system rate. We find that the projected revenues from actual contract volumes are greater than the expected cost of service. Equitrans' Exhibit N estimates a total cost of service of $30,533,569 for the first year of service, $29,447,151 for the second year, and $28,200,111 for the third year, and revenues of $45,397,640 for each year.[121] The revenues are derived from multiplying the contract quantity by Equitrans' maximum rate for the appropriate season. Therefore, we will grant a predetermination of rolled-in rate treatment for the costs associated with the project in its next NGA general section 4 rate proceeding, barring a significant change in circumstances.

3. **<u>Negotiated Rates</u>**

92. Mountain Valley and Equitrans propose to provide service to their project shippers under negotiated rate agreements. Mountain Valley and Equitrans must file their negotiated rate agreements or tariff records setting forth the essential elements of the agreements in accordance with the Commission's Alternative Rate Policy Statement and the Commission's negotiated rate policy. Consistent with Commission policy, Mountain Valley and Equitrans must either file the negotiated rate agreements or a tariff record

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[118] *See, e.g.*, *Gulf Crossing Pipeline Company LLC*, 139 FERC ¶ 61,082 (2012).

[119] *See* Certificate Policy Statement, 88 FERC at 61,746.

[120] *See Eastern Shore*, 156 FERC ¶ 61,219 at P 24.

[121] Exhibit N of Equitrans' Application.

setting forth the essential terms of these agreements at least 30 days, but not more than 60 days, before the proposed effective date for such rates.

D. Non-Conforming Contract Provisions

93. Mountain Valley and Equitrans entered into precedent agreements that contained certain contractual rights not available to other customers, which they state may be viewed as material deviations, but are necessary incentives to secure the level of contractual commitments to develop the projects. Mountain Valley and Equitrans request that the Commission approve these non-conforming contract provisions.

1. Mountain Valley

94. Mountain Valley states that the service agreements will grant the project shippers certain contractual rights not available to other customers, which could be viewed as material deviations, but were necessary to obtain the capacity commitments to advance the project and are provided in recognition of the shippers' financial commitments to the project. Mountain Valley states that all prospective customers were given the opportunity to become an initial shipper through the open season process and requests that the Commission approve its service provisions as permissible deviations.

95. In its April 28, 2016 data response, Mountain Valley provided unexecuted firm transportation agreements and identified the following three non-conforming provisions:

- Most Favored Nations (MFN) clause. The agreement with EQT Energy includes an MFN clause.

- Reservation Charge Crediting. The agreement with EQT Energy includes a provision stating that Mountain Valley will provide full reservation charge credits after the first 30 days of an outage. The agreements with USG, WGL Midstream, and Roanoke Gas provide that the customer is not entitled to reservation charge credits in the event of an outage.

- Credit Agreement. Mountain Valley states the Credit Agreement attached as Exhibit 2 to each of the Precedent Agreements will be incorporated by reference in the firm transportation service agreements.

96. In addition to the these three provisions, we identified two additional nonconforming provisions:

- Contractual Right of First Refusal (ROFR).[122] The agreements with EGT Energy, USG, WGL Midstream, and Roanoke Gas provide the customer with a ROFR at

[122] *See* Mountain Valley's April 28, 2016 Response to Data Request.

the expiration of the Primary Term, for a renewal term of no less than five years, in accordance with Mountain Valley's tariff.

- Meter Rights. The agreement with EQT Energy provides the customer with in-path meter capacity of at least 1.5 times the Contract MDQ.[123]

97. In *Columbia Gas Transmission Corporation*, the Commission clarified that a material deviation is any provision in a service agreement that: (a) goes beyond filling in the blank spaces with the appropriate information allowed by the tariff; and (b) affects the substantive rights of the parties.[124] The Commission prohibits negotiated terms and conditions of service that result in a shipper receiving a different quality of service than that offered other shippers under the pipeline's generally applicable tariff or that affect the quality of service received by others.[125] However, not all material deviations are impermissible. As the Commission explained in *Columbia Gas*, provisions that materially deviate from the corresponding *pro forma* agreement fall into two general categories: (a) provisions the Commission must prohibit because they present a significant potential for undue discrimination among shippers; and (b) provisions the Commission can permit without a substantial risk of undue discrimination.[126] In other proceedings, we have also found that non-conforming provisions may be necessary to reflect the unique circumstances involved with constructing new infrastructure and to provide the needed security to ensure the viability of a project.[127]

98. We find that the above described non-conforming provisions constitute material deviations from Mountain Valley's *pro forma* service agreement for Rate Schedule FTS. However, with the exception of the contractual ROFR provision, these non-conforming provisions are permissible because they do not present a risk of undue discrimination, do not adversely affect the operational conditions of providing service to other shippers, and do not result in any shipper receiving a different quality of service.

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[123] Mountain Valley's January 6, 2017 Response to Data Request.

[124] *See Columbia Gas Transmission Corp.*, 97 FERC ¶ 61,221, at 62,002 (2001) (*Columbia Gas*).

[125] *Monroe Gas Storage Co., LLC*, 130 FERC ¶ 61,113, at P 28 (2010).

[126] *Columbia Gas*, 97 FERC at 62,003-04.

[127] *Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089, at P 82 (2008); *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 78 (2006).

99. With regard to the contractual ROFR provision, the provision states that the shipper may apply for a renewal term of "no less than five years." In contrast, Mountain Valley's tariff has no term requirement for executing a ROFR. While the negotiation of a contractual ROFR with a shipper is permissible, Commission policy states that it is not permissible for a negotiated contractual ROFR to "supersede" the provisions of the pipeline's ROFR as stated in its tariff.[128] A contractual ROFR is equivalent to the tariff ROFR and is subject to the ROFR process set forth in the tariff.[129] For this reason, we find Mountain Valley's contractual ROFR provision an impermissible non-conforming provision that violates the Commission's policy. Therefore, any revised contractual ROFR provision that Mountain Valley files in compliance with this order must in all respects conform to the ROFR open season provisions in revised General Terms and Conditions (GT&C) section 6.21.

100. Mountain Valley is required to file its non-conforming service agreements associated with this project with the Commission at least 30 days, but not more than 60 days, before the proposed effective date for such agreements.[130] Pipelines are required to file any service agreement containing non-conforming provisions and to disclose and identify any transportation term or agreement in a precedent agreement that survives the execution of the service agreement.

2. <u>Equitrans</u>

101. Equitrans states that EQT Energy, its anchor shipper, has been granted certain contractual rights as an anchor shipper not available to other customers. Equitrans states it offered these incentives to obtain the capacity commitments required to advance the project and to recognize the shipper's financial commitments to the project. Equitrans requests that the Commission approve the following non-conforming service provisions as permissible pursuant to these standards:

- The firm transportation agreement includes a MFN clause.

[128] *Kinder Morgan Interstate Gas Transmission LLC*, 119 FERC ¶ 61,225, at P 8 (2007).

[129] *Id*.

[130] Our determination of non-conforming provisions in this certificate proceeding does not waive our right to review such provisions in the future, when the executed copies of the non-conforming agreements and a tariff record identifying the agreements as non-conforming are filed with the Commission, consistent with section 154.112 of the Commission's regulations. *See Tennessee Gas Pipeline Co., L.L.C.*, 150 FERC ¶ 61,160, at P 44, n.33 (2015).

- Reservation Charge Crediting. The firm transportation agreement includes a provision stating that Equitrans will provide full reservation charge credits after the first 30 days of an outage.

- Credit Agreement. Equitrans states the Credit Agreement attached as Exhibit 2 to the Precedent Agreement will be incorporated by reference in the Firm Transportation Service Agreement.

102. In addition to the three provisions described by Equitrans above, Commission review of the nonconforming provisions identified an additional provision:

- Contractual ROFR.[131] The firm transportation agreement provides the customer with a ROFR at the expiration of the Primary Term, for a renewal term of no less than five years, in accordance with Equitrans' tariff.

103. Following the Commission's policy in *Columbia Gas*,[132] as discussed above,[133] we find that the above described non-conforming provisions constitute material deviations from Equitrans' *pro forma* service agreement for Rate Schedule FTS. However, we find that, with the exception of the contractual ROFR provision, these non-conforming provisions are permissible because they do not present a risk of undue discrimination, do not adversely affect the operational conditions of providing service to other shippers, and do not result in any shipper receiving a different quality of service.[134]

104. Equitrans' contractual ROFR provision states that it will apply for a renewal term of "no less than five years." Equitrans' tariff, however, has no term requirement for executing a ROFR. As discussed above, while a contractual ROFR is permissible, Commission policy states it is not permissible for a negotiated contractual ROFR to "supersede" the provisions of the pipeline's ROFR as stated in its tariff. A contractual ROFR must be equivalent to the tariff ROFR and is subject to the ROFR process set forth in the tariff.[135] For this reason, Equitrans' contractual ROFR provision is an impermissible non-conforming provision.

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[131] Equitrans identified this provision in its initial application.

[132] *Columbia Gas*, 97 FERC at 62,002.

[133] *See supra* P 97.

[134] *See, e.g.*, *Tennessee Gas Pipeline Co. L.L.C.*, 156 FERC ¶ 61,156 (2016).

[135] *Wyoming Interstate Co. L.L.C.*, 145 FERC ¶ 61,289, at P 6 (2013).

105. Equitrans is required to file any non-conforming service agreements associated with this project with the Commission at least 30 days, but not more than 60 days, before the proposed effective date for such agreements.[136] Pipelines are required to file any service agreement containing non-conforming provisions and to disclose and identify any transportation term or agreement in a precedent agreement that survives the execution of the service agreement.

E. Mountain Valley's *Pro Forma* Tariff

106. As part of its application, Mountain Valley has included a *pro forma* FERC gas tariff. We approve the *pro forma* tariff subject to the revisions discussed below. Mountain Valley is directed to file tariff records 30 to 60 days prior to its in-service date that incorporate the Commission directed revisions

1. Section 6.8(1)(f) – Curtailment

107. Section 6.8(1)(f) of the GT&C of Mountain Valley's *pro forma* tariff states: "To the extent that the desired delivery point is an electricity generation facility, Customer *must* also separately provide the hourly quantity profile for each day's nomination."[137] In its November 2, 2016 data response, Mountain Valley explained that obtaining hourly quantity profiles for gas-fired electric generation facilities will assist it in planning system flows throughout the day. However, if the hourly quantity is not provided, Mountain Valley states that it will assume that gas will flow at a uniform hourly rate consistent with Daily Rates of Flow detailed in Rate Schedules FTS of its tariff.

108. While the Commission acknowledges the need for pipelines and generators to cooperate and share information, we are concerned about the tariff's requirement that a customer nominating a delivery point to serve an electric generation facility "must" provide the hourly quantity profile. A marketer might not have direct access to hourly quantity profile information when making a nomination to the delivery point and could thus potentially be unduly discriminated against by Mountain Valley. Therefore,

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[136] Our determination of non-conforming provisions in this certificate proceeding does not waive our right to review such provisions in the future, when the executed copy of the non-conforming agreement and a tariff record identifying the agreement as non-conforming are filed with the Commission, consistent with section 154.112 of the Commission's regulations. *See, e.g., Tennessee Gas Pipeline Co., L.L.C.*, 150 FERC ¶ 61,160 at P 44, n.33.

[137] Section 6.8(1)(f) of Exhibit P, Part II, of Mountain Valley's Application (emphasis added).

Mountain Valley is directed to revise its tariff such that the required information is provided on a "best efforts" or "maximum extent practicable" basis.

2. Section 6.9(3) – Curtailment of Service

109. Section 6.9(3) of the GT&C states that Mountain Valley may request information from a customer in order to implement any curtailment of services. The information requested may include the customer's monthly requirement by priority service categories, including information for individual industrial customers served by Mountain Valley's customer. In its November 2, 2016 data response, Mountain Valley states that it does not anticipate utilizing the customer's monthly requirements by priority service category in a curtailment situation and proposes to eliminate this requirement in its compliance filing. Mountain Valley is directed to revise its tariff accordingly.

3. Section 6.12(9)(a)(i) – Determination of Deliveries and Imbalances

110. Section 6.12(9)(a)(i) of the GT&C sets forth the procedure for calculating the Monthly Index Price for monthly imbalance cashouts. In its November 2, 2016 data response, Mountain Valley notes that it will use the "Columbia Gas, Appalachia" price as published in *Gas Daily* for deliveries to Columbia's WB System and the "Transco, Zone 5 Delivered" price as published in *Gas Daily* for deliveries to Roanoke Gas and Transco Compressor Station 165.

111. Commission policy requires that pipelines provide supporting liquidity documentation for each price index location to ensure that price index locations are sufficiently liquid.[138] While Mountain Valley has clarified the indices it will use for the points on its system, it has not provided sufficient supporting documentation regarding the liquidity of the price index locations as required by the Commission's Price Index Policy Statement. Therefore, Mountain Valley is directed to provide this information in its compliance filing.

4. Section 6.21 – Right of First Refusal

112. GT&C section 6.21 provides a regulatory right of first refusal (ROFR) to shippers whose contracts meet the requirements provided in section 284.221(d)(2) of the Commission's regulations, and a contractual ROFR to shippers whose contracts do not

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[138] *Policy Statement on Natural Gas and Electric Price Indices*, 104 FERC ¶ 61,121, at P 41 (2003), *Order on Clarification of Policy Statement on Natural Gas and Electric Price Indices*, 105 FERC ¶ 61,282, *Order Further Clarifying Policy Statement on Natural Gas and Electric Price Indices*, 112 FERC ¶ 61,040 (2005) (Price Index Policy Statement).

otherwise qualify for the regulatory ROFR. We will require Mountain Valley to revise the following aspects of GT&C section 6.21 to be consistent with Commission policy and precedent.

113. GT&C section 6.21(2)(b) states that a "Customer shall be permitted to designate a quantity of gas less than its existing [Maximum Daily Quantity (MDQ)] which Customer wishes to retain under the Right of First Refusal." While this language is permissible, we note that Commission policy entitles the ROFR shipper to decide how much capacity it wishes to retain,[139] and that the decision to retain only a volumetric portion of its capacity does not have to be made until after the pipeline presents the ROFR shipper with the best bid for the purpose of matching.[140] Although GT&C section 6.21(2)(b) provides that a customer may elect to retain only a portion of its capacity at the start of ROFR process, it does not provide the customer that option after the bids have been received. Therefore, Mountain Valley is directed to clarify GT&C section 6.21 to provide that a shipper is not required to elect how much capacity it will seek to retain through the ROFR process until after receiving notification from Mountain Valley as to the best offer(s) for its expiring capacity, and may then notify Mountain Valley of its intent to match the best offer(s) for all or a volumetric portion of its capacity.

114. GT&C section 6.21(2)(e) states:

> If, during the Posting Period, [Mountain Valley] receives an acceptable offer for all or a portion of the service rights under Customer's Long-Term Agreement, [Mountain Valley] shall notify Customer in writing of the offer having the greatest economic value; provided, that *for purposes of value comparisons under this section the rate utilized shall be limited to the maximum rate that can be charged to the existing Customer*. If Customer elects to match the offer, Customer shall notify [Mountain Valley] of such election in writing within 30 days after receiving notice from [Mountain Valley] and shall execute a new Service Agreement matching the offer within 30 days after [Mountain Valley] has tendered the Service Agreement. If Customer elects not to match the offer or does not execute the Service Agreement within 30 days, [Mountain

[139] *See Dominion Transmission, Inc.*, 111 FERC ¶ 61,135, at PP 18-22 (2005).

[140] *See Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192, at P 78 (2014); *Transcontinental Gas Pipe Line Corp.*, 101 FERC ¶ 61,267, at P 26 (2002).

> Valley] will tender a Service Agreement to the prospective Customer submitting *the offer having the greatest economic value*.[141]

115. The phrase "the offer having the greatest economic value" in GT&C section 6.21(2)(e) does not clearly describe the methodology to be used. The tariff should clearly state the methodology that the pipeline will use to determine the best third-party bids in a ROFR open season.[142] Mountain Valley is directed to revise this language in its compliance filing to articulate how it intends to evaluate bids in a ROFR open season.

5. Section 6.22(3)(f) – Capacity Release

116. Section 6.22(3)(f) of the GT&C states that a releasing customer may "release capacity on a firm or interruptible basis." In its November 2, 2016 data response, Mountain Valley proposes to eliminate the "or interruptible" reference from its tariff. Mountain Valley is directed to make the proposed revision in its tariff compliance filing.

6. Section 6.27 – Negotiated Rates

117. Section 6.27 of the GT&C permits Mountain Valley to charge a negotiated rate for service under any Rate Schedule and addresses certain aspects of its negotiated rate transactions, including the types of rates that may be negotiated, how negotiated rate capacity is treated for purposes of capacity release, and the right to seek discount-type adjustments for negotiated rate transactions in future general rate proceedings.

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[141] Section 6.21(2)(e) of Exhibit P, Part II, of Mountain Valley's Application (emphasis added).

[142] *See, e.g.*, Transcontinental Gas Pipe Line Company, LLC, FERC NGA Gas Tariff, Fifth Revised Volume No. 1, Section 48, Right of First Refusal Procedures, 0.0.0. Commission policy also requires that the same methodology should be used to determine the best bid and whether the ROFR shipper has matched the bid. *See Transcontinental Gas Pipe Line Corp.*, 105 FERC ¶ 61,365, at P 19 (2003).

118. We find that section 6.27 lacks key provisions required by the Alternative Rate Policy Statement[143] and the Commission's negotiated rate policy.[144] Commission policy requires pipelines to file with the Commission all negotiated rate service agreements or a tariff record stating the name of the shipper, the rate schedule, the receipt and delivery points, the contract quantity, and, where applicable, the exact formula underlying a negotiated rate.[145] Pipelines with negotiated rate authority are also required to maintain separate records for all revenues associated with negotiated rate agreements and maintain and provide separately identified and totaled volume, billing determinant, rate or surcharge component, and revenue accounting information for their negotiated rate arrangements in any general or limited rate change filing that it makes.[146] Therefore, Mountain Valley is directed to revise section 6.27 to be consistent with the Commission's negotiated rate policy and include these provisions in its tariff.

7. Section 6.28 – Transportation Retainage

119. Mountain Valley is proposing to recover its actual fuel gas, and lost and unaccounted for gas in-kind from shippers pursuant to section 6.28 of its GT&C. Section 6.28(2) describes how Mountain Valley proposes to determine its retainage factor. This section simply states that "[Mountain Valley] shall adjust the Retainage Factor on a quarterly basis to more accurately reflect actual experienced fuel and lost and unaccounted for gas" and, further, "[Mountain Valley] may file to adjust the Retainage Factor to reflect a material change in the actual experienced fuel and unaccounted for gas." Section 6.28(3) describes how Mountain Valley proposes to reconcile its actual fuel and lost and unaccounted for volumes versus the volumes actually retained. To

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[143] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines; Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *order on reh'g and clarification*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066, *reh'g dismissed*, 75 FERC ¶ 61,291 (1996), *petition denied sub nom. Burlington Res. Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998).

[144] *Natural Gas Pipelines Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 (2003), *order on reh'g and clarification*, 114 FERC ¶ 61,042, *dismissing reh'g and denying clarification*, 114 FERC ¶ 61,304 (2006).

[145] *Natural Gas Pipelines Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 at PP 31-34.

[146] *Id.*

accomplish the reconciliation, Mountain Valley proposes a quarterly true-up to determine for each month of the quarter volumes owed to either Mountain Valley or the shipper.

120. Mountain Valley's proposed retainage mechanism fails to comply with the notice and filing requirements of, respectively, sections 154.207[147] and 154.403[148] of the Commission's regulations. Pipelines are not permitted to impose fuel charges on shippers without making a tariff filing and providing notice and the opportunity to participate in the proceedings.[149] As proposed, Mountain Valley's fuel retainage mechanism would allow Mountain Valley to revise its retainage factor without any review or comment by its shippers and without prior Commission approval. Therefore, when Mountain Valley files actual tariff records in accordance with the ordering paragraphs herein, it is required to revise GT&C section 6.28 to conform to the notice and filing requirements of sections 154.207 and 154.403 of the Commission's regulations.

8. Section 6.31 - North American Energy Standards Board (NAESB)

121. GT&C section 6.31 states that Mountain Valley has adopted Version 3.0 of the Business Practices and Electronic Communications Standards adopted by NAESB Wholesale Gas Quadrant (WGQ), which are required by section 284.12(a) of the Commission's regulations.[150] Mountain Valley's *pro forma* tariff generally complies with Version 3.0, but Mountain Valley is directed to make the following ten revisions:

a. Change the reference from standard 1.3.2(i-v) to 1.3.2(i-vi) in the section titled "Standards not Incorporated by Reference and their Location in Tariff" in GT&C section 6.31;

b. Remove standard 1.3.2(vi) from the section titled "Standards Incorporated by Reference" in GT&C section 6.31;

c. Remove standards 0.3.19, 1.3.47, 1.3.49, 1.3.50, 1.3.54, 1.3.57, 1.3.59, 1.3.60, 1.3.61, 1.3.63, 2.3.33, 2.3.34, 2.3.35, 3.3.1, 4.3.5, 4.3.29, 4.3.51, 4.3.56, 4.3.59, 4.3.73, 4.3.74, and 4.3.76 from the section titled "Standards Incorporated by Reference" in GT&C section 6.31;

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[147] 18 C.F.R. § 154.207 (2017).

[148] *Id.* § 154.403.

[149] *See MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165 at P 31.

[150] 18 C.F.R. § 284.12(a) (2017).

d. Remove standard 5.3.73 from the section titled "Standard Incorporated by Reference," because the text of the standard is included in GT&C section 6.22.11;

e. Indicate the adoption of standards revised by Minor Corrections MC15003, MC15004, MC15005, MC15009 and MC15012 all marked with an asterisk [*];

f. Add an asterisk [*] to standards 0.4.2, 1.3.8, 1.3.9, 1.4.1, 1.4.2, 1.4.3, 1.4.4, 1.4.5, 1.4.6, 1.4.7, 2.4.1, 2.4.3, 2.4.4, 2.4.5, 3.4.1, 5.3.56, 5.4.16, 5.4.20, 5.4.21, 5.4.22, 5.4.24, and 5.4.26;

g. List standards 0.4.1 and 0.4.4 in the section titled "Standards Incorporated by Reference;"

h. Either list standards 1.3.81, 4.3.104, and 4.3.105 in the section titled "Standards Incorporated by Reference" or include the text of the standards;

i. Revise the text of the section titled "Timely Nomination Cycle" in GT&C section 6.8, Scheduling of Services, to provide that scheduled quantities should be effective at the start of the next Gas Day; and

j. Revise the text regarding recall notifications in GT&C section 6.22, Capacity Release, to conform to revised standard 5.3.44.

F. Environmental Analysis

1. Pre-filing Review

122. On October 31, 2014, Commission staff granted Mountain Valley's request to use the pre-filing process in Docket No. PF15-3-000. As part of the pre-filing review, on April 17, 2015, the Commission issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Mountain Valley Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meetings* (Mountain Valley NOI). The Mountain Valley NOI was published in the *Federal Register* on April 28, 2015,[151] and mailed to 2,846 entities, including federal, state, and local government representatives and agencies; elected officials; regional environmental groups and non-governmental organizations; Indian Tribes and Native Americans; affected property owners; other interested entities; and local libraries and newspapers. The Mountain Valley NOI briefly described the project and the Commission's environmental review process, provided a preliminary list of issues identified by Commission staff, invited

[151] 80 Fed. Reg. 23,535 (2015).

written comments on the environmental issues that should be addressed in the draft EIS, listed the date and location of six public scoping meetings[152] to be held in the project area, and established June 16, 2015, as the deadline for comments.

123. A total of 169 people presented oral comments at the pre-filing public scoping meetings. Transcripts of the scoping meeting were placed into the Commission's public record for this proceeding. In addition, during the official scoping period, between April 17 and June 16, 2015, we received well over 1,000 written or electronically filed comment letters.[153]

124. On April 9, 2015, Commission staff granted Equitrans' request to use the pre-filing process in Docket No. PF15-22-000. On August 11, 2015, the Commission issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Equitrans Expansion Project, and Request for Comments on Environmental Issues* (Equitrans NOI). The Equitrans NOI stated that because the Equitrans Expansion Project would interconnect to the MVP Project, it was the intent of the Commission staff to conduct an environmental analysis of both projects combined in a single comprehensive EIS. The Equitrans NOI was sent to 575 entities, and published in the *Federal Register* on August 17, 2015.[154] The comment period closed on September 14, 2015. During that scoping period, we received a total of five comment letters. Because of the low response to the Equitrans NOI, Commission staff did not hold separate public scoping meetings in the Equitrans Expansion Project area.

2. <u>Application Review</u>

125. The pre-filing review period ended when Mountain Valley filed its project application on October 23, 2015 and Equitrans filed its project application on October 27, 2015.

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[152] Commission staff held the public scoping meetings between May 4 and 13, 2015, in Pine Grove, Weston, Summersville, and Lindside, West Virginia, and Ellison and Chatham, Virginia.

[153] Table 1.4-1 of the draft and final EIS provides a list of environmental issues raised during scoping.

[154] 80 Fed. Reg. 49,217 (2015).

126. To satisfy the requirements of the National Environmental Policy Act of 1969 (NEPA),[155] Commission staff evaluated the potential environmental impacts associated with the construction and operation of the MVP and Equitrans Expansion Projects in an EIS. The U.S. Department of Agriculture, Forest Service (Forest Service); U.S. Army Corps of Engineers (Army Corps); U.S. Environmental Protection Agency (EPA); U.S. Department of the Interior, Bureau of Land Management (BLM) and Fish and Wildlife Service (FWS); U.S. Department of Transportation (DOT); West Virginia Department of Environmental Protection (WVDEP), and West Virginia Department of Natural Resources (WVDNR) participated as cooperating agencies.

127. Commission staff issued the draft EIS for the projects on September 16, 2016, addressing the issues raised during the scoping period and up to the point of publication. Notice of the draft EIS was published in the *Federal Register* on September 27, 2016,[156] setting a 90-day comment period ending on December 22, 2016. The draft EIS was mailed to the environmental mailing list for the projects, including additional interested entities that were added since issuance of the NOIs. Commission staff held seven public comment sessions between November 2 and 9, 2016, in the areas of the projects[157] to take comments on the draft EIS. Over 260 speakers provided oral comments at these sessions. Transcripts of the draft EIS comment sessions were placed into the public record for the proceedings.[158] Between the issuance of the draft EIS on September 16 and the end of the comment period on December 22, 2016, we received 1,237 written or electronically filed letters.[159]

128. In October 2016, after the issuance of the draft EIS, Mountain Valley filed a number of minor route modifications to address recommendations in the draft EIS, avoid sensitive environmental areas, accommodate landowner requests, or for engineering

[155] 42 U.S.C. §§ 4321 *et seq.* (2012). *See also* 18 C.F.R. pt. 380 (2017) (Commission's regulations implementing NEPA).

[156] 81 Fed. Reg. 66,268 (2016).

[157] Commission staff held public comment sessions in Weston, Summersville, and Peterstown, West Virginia, Roanoke, Rocky Mount, and Chatham, Virginia, and Coal Center, Pennsylvania.

[158] Copies of the transcripts were filed in the Commission's eLibrary system on November 3, 2016 (accession number 20161103-4005) and November 16, 2016 (accession number 20161116-4001).

[159] Table 1.4-2 of the final EIS lists the range of issues raised in comments on the draft EIS.

design reasons. On January 17, 2017, Commission staff mailed letters to 45 newly-affected landowners, requesting comments on the route modifications during a supplemental comment period that ended February 21, 2017. In response, three landowners filed letters in the Commission's public record.

129. Commission staff issued the final EIS on June 23, 2017, notice of which was published in the *Federal Register* on June 29, 2017.[160] The final EIS addressed timely comments received on the draft EIS.[161] The final EIS was mailed to the same entities as the draft EIS, as well as to newly-identified landowners and any additional entities that commented on the draft EIS.[162] The final EIS addresses geological hazards such as landslides, earthquakes, and karst terrain; water resources including wells, streams, and wetlands; forested habitat; wildlife and threatened, endangered, and other special status species; land use, recreational areas, and visual resources; socioeconomic issues such as property values, environmental justice, tourism, and housing; cultural resources; air quality and noise impacts; safety; cumulative impacts; and alternatives.

130. The final EIS concludes that construction and operation of the MVP and Equitrans Expansion Projects may result in some adverse environmental impacts on specific resources. The final EIS concludes that impacts on most environmental resources would be temporary or short-term. However, in the case of the clearing of forest, the final EIS concludes that impacts will be long-term and significant. For the other resources, impacts will be reduced to less-than-significant levels with the implementation of mitigation measures proposed by the applicants and other mitigation measures recommended by Commission staff and included as environmental conditions in this order.

131. Between the issuance of the final EIS on June 23, 2017 and September 11, 2017, the Commission received numerous written individual letters or electronic filings commenting on the final EIS or about the projects. These comments letters raise concerns regarding impacts on drinking water sources, surface water, karst, steep slopes, cultural resources, threatened and endangered species, forests, erosion, invasive species, visual resources, and health and safety.

[160] 82 Fed. Reg. 29,539 (2017).

[161] Appendix AA of the final EIS includes copies of letters about the draft EIS received through the close of the comment period on December 22, 2016, along with Commission staff responses.

[162] The distribution list is provided in Appendix A of the final EIS.

3. **Major Environmental Issues**

a. **Requests to Supplement or Revise Draft EIS**

132. Several commenters, including Allegheny Defense Project and James Workman, argue that the draft EIS was insufficient and the Commission should revise it or issue a supplemental draft EIS. They assert that the draft EIS lacks a discussion of project need under section 7(c) of the NGA and inappropriately postpones submittal of certain information to the end of the draft EIS comment period or before commencement of construction. Commenters argue that they should have an opportunity to comment on this new information.

133. A purpose of a draft EIS is to elicit suggestions for change.[163] The Council of Environmental Quality (CEQ) regulation that the commenters reply upon calls for a supplemental draft EIS if the agency "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."[164] The Supreme Court, in *Marsh v. Oregon Natural Resources Council*, stated that under the "rule of reason," "an agency need not supplement an [EIS] every time new information comes to light after the EIS is finalized."[165] Further, NEPA only requires agencies to employ proper procedures to ensure that environmental consequences are fully evaluated, not that a complete plan be presented at the outset of environmental review.[166] In *National Committee for New River v. FERC*,[167] the court held that "if every aspect of the project were to be finalized before any part of the project could move forward, it would be difficult, if not impossible, to construct the project."[168]

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[163] *See City of Grapevine v. DOT*, 17 F.3d 1502, 1507 (D.C. Cir. 1994) ("[t]he very purpose of a [draft EIS] is to elicit suggestions for change.").

[164] 40 C.F.R. § 1502.9(c)(1) (2017).

[165] *Marsh v. Oregon Natural Resources Council*, 490 U.S. 360, 373 (1989).

[166] *See Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 352 (1989).

[167] *National Committee for New River v. FERC*, 373 F.3d 1323 (D.C. Cir. 2004) (*New River*).

[168] *New River*, 373 F.3d at 1329 (citing *East Tennessee Natural Gas Co*., 102 FERC ¶ 61,225, at 61,659 (2003)).

134. As shown in the final EIS, the additional information submitted by the applicants between the issuance of the draft EIS and of the final EIS did not cause the Commission to make “substantial changes in the proposed action,” nor did it present “significant new circumstances or information relevant to environmental concerns.” The final EIS analyzed the relevant environmental information and recommended environmental conditions. We adopt most of the recommended environmental conditions in this order. Applicants must satisfy the environmental conditions contained in Appendix C of this order before they may proceed with their projects.

135. Commenters’ argument regarding project need is misplaced. An EIS identifies a project’s purpose and need to define the parameters for the alternatives analysis,[169] not to determine whether the project is in the public interest. It is the Commission, in its order on the certificate application, that evaluates project need under section 7(c) of the NGA.[170]

136. Nan Gray states that the final EIS was deficient because it lacked analyses of avoidance areas, no-build zones,[171] alternatives, cumulative effects, cultural, visual, aquatic, geological, soil, and biological resources. This is not accurate. The final EIS provides an analysis of alternatives (in section 3), geological resources (section 4.1), soils (section 4.2), biological resources (sections 4.5 and 4.7), aquatic resources (section 4.6), visual resources (section 4.8), cultural resources (section 4.10), and cumulative impacts (section 4.13).

b. <u>Programmatic EIS</u>

137. Nan Gray and other commenters request that the Commission prepare a programmatic EIS. CEQ regulations do not require broad or “programmatic” NEPA reviews. CEQ’s guidance provides that such a review may be appropriate where an agency is: (1) adopting official policy; (2) adopting a formal plan; (3) adopting an agency program; or (4) proceeding with multiple projects that are temporally and

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[169] 40 C.F.R. § 1502.13 (2017); *see also National Fuel Gas Supply Corporation*, 158 FERC ¶ 61,145 at P 95 (citing *City of Grapevine, Tex. v. U.S. DOT.*, 17 F.3d at 1506).

[170] *See* section IV.A.1.b. of this order (discussing project need).

[171] Nan Gray and others argue that karst terrain should be considered a “no-build” zone although no law provides such a prohibition. Section 4.1 of the final EIS and section IV.F.3.c. of this order discuss project impacts on karst terrain and mitigation measures.

spatially connected.[172] The Supreme Court has held that a NEPA review covering an entire region (that is, a programmatic review) is required only if there has been a report or recommendation on a proposal for major federal action with respect to the region.[173] Moreover, there is no requirement for a programmatic EIS where the agency cannot identify projects that may be sited within a region because individual permit applications will be filed later.[174]

138. We have explained that there is no Commission plan, policy, or program for the development of natural gas infrastructure.[175] Rather, the Commission acts on individual applications filed by entities proposing to construct interstate natural gas pipelines. Under NGA section 7, the Commission is obligated to authorize a project if it finds that the construction and operation of the proposed facilities "is or will be required by the present or future public convenience and necessity."[176] What is required by NEPA, and what the Commission provides, is a thorough examination of the potential impacts of specific projects. As to projects that have a clear physical, functional, and temporal nexus such that they are connected or cumulative actions,[177] the Commission will prepare

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[172] Memorandum from CEQ to Heads of Federal Departments and Agencies, *Effective Use of Programmatic NEPA Reviews* 13-15 (Dec. 24, 2014) (citing 40 C.F.R. § 1508.18(b)), https://www.whitehouse.gov/sites/default/files/docs/effective_use_of_programmatic_nepa_reviews_18dec2014.pdf. We refer to the memorandum as the 2014 Programmatic Guidance.

[173] *Kleppe v. Sierra Club*, 427 U.S. 390 (1976) (*Kleppe*) (holding that a broad-based environmental document is not required regarding decisions by federal agencies to allow future private activity within a region).

[174] *See Piedmont Environmental Council v. FERC*, 558 F.3d 304, 316-17 (4th Cir. 2009) (*Piedmont Environmental Council*).

[175] *See, e.g., National Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 at PP 82-88; *National Fuel Gas Supply Corp.*, 154 FERC ¶ 61,180, at P 13 (2016); *Texas Eastern Transmission, LP*, 149 FERC ¶ 61,259, at PP 38-47 (2014); *Columbia Gas Transmission, LLC*, 149 FERC ¶ 61,255 (2014).

[176] 15 U.S.C. § 717f(e) (2012).

[177] 40 C.F.R. § 1508.25(a)(1)-(2) (2017) (defining connected and cumulative actions).

a multiple-project environmental document.[178] Other than the relationship between the MVP and Equitrans Expansion Projects, such is not the case here.

139. The Commission is not engaged in regional planning. Rather, the Commission processes individual pipeline applications in carrying out its statutory responsibilities under the NGA. That there currently are a number of planned, proposed, or approved infrastructure projects to increase infrastructure capacity to transport natural gas from the Marcellus and Utica Shale does not establish that the Commission is engaged in regional development or planning.[179] Instead, this confirms that pipeline projects to transport Marcellus and Utica Shale gas are initiated solely by a number of different companies in private industry. As we have noted previously, a programmatic EIS is not required to evaluate the regional development of a resource by private industry if the development is not part of, or responsive to, a federal plan or program in that region.[180]

140. The Commission's siting decisions regarding pending and future natural gas pipeline facilities respond to proposals by private industry, and the Commission has no way to accurately predict the scale, timing, and location of projects, much less the kind of facilities that will be proposed.[181] Any broad, regional environmental analysis would "be little more than a study . . . containing estimates of potential development and attendant

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[178] *See, e.g.*, EA for the Monroe to Cornwell Project and the Utica Access Project, Docket Nos. CP15-7-000 & CP15-87-000 (filed Aug. 19, 2015); Final Multi-Project Environmental Impact Statement for Hydropower Licenses: Susquehanna River Hydroelectric Projects, Project Nos. 1888-030, 2355-018, and 405-106 (filed Mar. 11, 2015).

[179] *See, e.g.*, *Sierra Club v. FERC*, 827 F.3d 36, 50 (D.C. Cir. 2016) (*Freeport LNG*) (rejecting claim that NEPA requires FERC to undertake a nationwide analysis of all applications for liquefied natural gas export facilities); *cf. Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1326-27 (D.C. Cir. 2015) (*Myersville*) (upholding FERC determination that, although a Dominion Transmission Inc.-owned pipeline project's excess capacity may be used to move gas to the Cove Point terminal for export, the projects are "unrelated" for purposes of NEPA).

[180] *See Kleppe*, 427 U.S. at 401-02 (holding that a regional EIS is not required where there is no overall plan for regional development).

[181] Lack of jurisdiction over an action does not necessarily preclude an agency from considering the potential impacts. As explained in the indirect and cumulative impact sections of this order, however, it reinforces our finding that because states, and not the Commission, have jurisdiction over natural gas production and associated development (including siting and permitting), the location, scale, timing, and potential impacts from such development are even more speculative.

environmental consequences,"[182] and could not present "a credible forward look" that would be "a useful tool for basic program planning."[183] In these circumstances, the Commission's longstanding practice to conduct an environmental review for each proposed project, or a number of proposed projects that are interdependent or otherwise interrelated or connected, "facilitate[s], not impede[s], adequate environmental assessment."[184] Thus, the Commission's environmental review of only the MVP and Equitrans Expansion Projects together in a single EIS is appropriate under NEPA.

141. In sum, CEQ states that a programmatic EIS can "add value and efficiency to the decision-making process when they inform the scope of decisions," "facilitate decisions on agency actions that precede site- or project-specific decisions and actions," or "provide information and analyses that can be incorporated by reference in future NEPA reviews."[185] The Commission does not believe these benefits can be realized by a programmatic review of natural gas infrastructure projects because the projects subject to our jurisdiction do not share sufficient elements in common to narrow future alternatives or expedite the current detailed assessment of each particular project. Thus we find a programmatic EIS is neither required nor useful under the circumstances here.

c. Geological Resources

i. Steep Slopes and Landslides

142. Several commenters, including Giles and Roanoke Counties, Virginia (Counties), expressed concern that the projects could contribute to unstable slopes and cause landslides or other slope and soil failures.

143. About 32 percent of the MVP Project and 45 percent of the approximately eight-mile long Equitrans Expansion Project will cross topography with steep (greater than a 15 percent grade) slopes.[186] About 67 percent of the MVP Project and all of the Equitrans Expansion Project will cross areas susceptible to landslides.

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[182] *Kleppe*, 427 U.S. at 402.

[183] *Piedmont Environmental Council*, 558 F.3d at 316.

[184] *Id*.

[185] 2014 Programmatic Guidance at 13.

[186] Final EIS at ES-4.

144. The final EIS acknowledges and addresses the projects' landslide potential.[187] Mountain Valley and Equitrans have committed to use specialized construction techniques on steep slopes, including cut-and-fill and two-tone grading, to minimize adverse effects.[188] Mountain Valley will use thicker Class 2 pipe to mitigate hazards to the pipeline from triggered slope displacement, and will employ geotechnical experts to inspect construction in areas of potential subsidence or landslide concern.

145. To prevent landslides, both Mountain Valley and Equitrans developed Landslide Mitigation Plans, which was revised in March 2017. However, because the Mountain Valley's *Landslide Mitigation Plan* does not adopt some industry best management practices to reduce the potential for landslides in steep slope areas, we require, as Environmental Condition No. 19, that Mountain Valley revise its *Landslide Mitigation Plan* to outline construction measures to be used when crossing steep slopes at angles perpendicular to contours and to include a more robust monitoring program. Moreover, to bolster pipeline integrity and safety in landslide hazard areas, we further require that Mountain Valley revise its *Landslide Mitigation Plan* to expand its post-construction monitoring program to cover all potential landslide areas project-wide. The Commission finds that these additional measures would effectively mitigate potential impacts from the projects' constructions in areas of high susceptibility to landslides.

146. The Virginia Department of Game and Inland Fisheries (Virginia Department of Game) expresses concern that slope failures will cause instream sedimentation. The final EIS discusses the potential for landslides and measures to ensure slope stability and prevent instream sedimentation, including the measures outlined in Mountain Valley's *Landslide Mitigation Plan*, to which, as discussed above, we are requiring enhancements. Mountain Valley also agreed to follow the measures outlined in the Commission's *Upland Erosion Control, Revegetation, and Maintenance Plan* (Commission's Plan) and its *Wetland and Waterbody Construction and Mitigation Procedures*, which include erosion controls to prevent sedimentation into waterbodies. The final EIS concludes that these plans cannot fully prevent sedimentation, but would provide adequate protections by reducing sedimentation into streams and reducing the potential for slope failures.

ii. Seismic Activity and Soil Liquefaction Potential

147. Several commenters note the MVP Project is routed through an area with a history of seismic activity and assert that constructing a gas pipeline in such an area poses a danger to the community.

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[187] Final EIS at 4-52 to 4-58.

[188] Final EIS at 4-55.

148. The MVP Project will be in close proximity to the active Giles County Seismic Zone.[189] An earthquake in this zone would only be expected to cause generally light damage. In areas where seismic hazards exist, Mountain Valley will install pipeline with Class 2 or Class 3 thickness, under DOT's pipeline safety regulations in 49 C.F.R. Part 192, to withstand a seismic event and mitigate for potential soil liquefaction. Additionally, Mountain Valley has committed to a post-construction monitoring program utilizing sequentially-acquired the Light Imaging Detection and Ranging (LiDAR) imagery to detect slope movement in the area where the pipeline traverses through the seismic zone. Due to the use of thicker pipe and a post-construction monitoring program, we find that Mountain Valley will sufficiently manage the safety issues from seismic activity in the MVP Project area.

149. The Equitrans Expansion Project will not cross any Quaternary faults.[190] It is in an area identified to have a low probability of a significant seismic event. Soil liquefaction is a phenomenon often associated with seismic activity in which saturated, non-cohesive soils temporarily lose their strength and liquefy (i.e., behave like viscous liquid) when subjected to forces such as intense and prolonged ground shaking. Due to the low potential for significant ground shaking, we agree with the final EIS's conclusion that soil liquefaction in the area of the Equitrans Expansion Project is unlikely.

iii. Karst Terrain

150. Commenters expressed concerns regarding subsidence and sinkholes affecting the construction and integrity of the pipeline in areas of karst terrain and potential impacts on karst-related groundwater.

151. Karst features, such as sinkholes and caves, form as a result of the long-term action of groundwater on subsurface soluble carbonate rocks (e.g., limestone and dolostone). The Equitrans Expansion Project will not be located at any areas known to contain karst features. Conversely, the MVP Project will cross about 67 miles of karst terrain. The MVP Project will cross minor karst development from about MPs 172 to 174 and significant karst development from about MPs 191 to 239. As stated in the final EIS, Mountain Valley's Karst Hazard Assessment identified 99 karst features in

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[189] The Giles County Seismic Zone is located in the western part of the Valley and Ridge province, south of the Appalachian bend near Roanoke, Virginia. It is considered seismically active, experienced 12 earthquakes that span 4 orders of magnitude and over 2 decades, from 1959 through 1980. *See* Final EIS at 4-23 to 4-24.

[190] A Quaternary fault is a fault that has experienced displacement in the last 2.6 million years and is predicted to most likely demonstrate displacement again. *See* Final EIS at 4-24.

Summers and Monroe Counties, West Virginia, and Giles, Craig, and Montgomery Counties, Virginia.[191] Karst features could present a hazard to the MVP Project due to cave or sinkhole collapse.

(a) Variation 250

152. To mitigate potential impacts, Mountain Valley adopted the Mount Tabor Variation into its proposed route, as recommended in the draft EIS, to reduce project impacts on karst features within the Mount Tabor Sinkhole Plain in Montgomery County, Virginia. Section 3.5.1 of the final EIS concludes that Variation 250 would reduce the environmental impacts on the Slussers Chapel Conservation Site (e.g., the variation is shorter and has less impact on perennial waterbodies, forest, and karst features) compared to the proposed pipeline route. It also avoids waterbodies that are of concern to the VADCR. We agree with this conclusion.[192] Thus, Environmental Condition No. 16 of this order requires Mountain Valley to adopt Variation 250, which modifies the Mount Tabor Variation, between MPs 221.0 and 222.2, to further reduce impacts on karst terrain and the Slussers Chapel Conservation Site, which is located within the Mount Tabor Sinkhole Plain.

153. Mountain Valley also developed a *Karst Mitigation Plan* and a *Karst-specific Erosion and Sediment Control Plan*. Environmental Condition No. 20 of this order requires Mountain Valley to revise its *Karst Mitigation Plan* to include post-construction monitoring using LiDAR data to further ensure safe operation of the pipeline over its lifetime. We agree with the final EIS's conclusions that, with implementation Mountain Valley's mitigation measures and the conditions included in the Appendix C, impacts on karst resources would be adequately minimized.

154. The Virginia Department of Conservation and Recreation (VADCR) encourages the Commission to require that Mountain Valley submit a route that more closely follows the VADCR's Slussers Chapel Conservation Site Avoidance Variation as submitted to Commission on September 9, 2016. The VADCR's Slussers Chapel Conservation Site Avoidance Variation provides both advantages and disadvantages when compared with the proposed route. The VADCR's Slussers Chapel Conservation Site Avoidance Variation would be slightly (0.2-mile) longer than the corresponding segment of the proposed route, but more collocated with existing corridors by about 1.6 miles and it would cross about 0.7 fewer miles on the Slussers Chapel Conservation Site, nine fewer parcels, eight fewer acres of forested land, two fewer perennial waterbodies, and 14 fewer karst features such as sinkholes. However, the corresponding segment of the proposed

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[191] Final EIS 4-37.

[192] The Blue Ridge Land Conservancy states that Variation 250 would result in impacts on the Slusser Chapel Conservation Site.

route would affect about 2.5 miles less of National Forest System lands, 1.1 miles less of side slope, about 25 fewer acres of interior forest, and one mile less of shallow bedrock. In balancing the factors evaluated, the final EIS did not find an overall significant environmental advantage for the VADCR alternative when compared to the proposed route. However, as noted above, we are requiring that Mountain Valley adopt Variation 250 into its proposed route to reduce impacts on the Slussers Chapel Conservation Site.

(b) Dye-Tracing Studies

155. The VADCR requests that Mountain Valley conduct additional dye-tracing studies to determine the underground connectivity and relationships between karst features and sinkholes in the vicinity of the MVP Project. As stated in section 4.1.2.5 of the final EIS, Mountain Valley's *Karst Mitigation Plan* outlines inspection criteria for known karst features identified during construction in proximity to the right-of-way. If a karst feature is identified, Mountain Valley will conduct a weekly inspection and document soil subsidence, rock collapse, sediment filling, swallets, springs, seeps, caves, voids, and morphology. If any changes are identified during the weekly inspection, Mountain Valley will then conduct more in-depth additional inspections. Any required in-depth additional inspections will include visual assessment, geophysical survey, track drill probes, infiltration, or dye tracing. If a feature is found to have a direct connection to a subterranean environment or groundwater flow system, Mountain Valley will work with the karst specialist and appropriate state agencies to develop mitigation measures for the karst feature.

156. Section 4.1.1.5 of the final EIS states that surface water will typically flow overland down slope to recharge features, such as swallets (underground streams). Groundwater will flow vertically through the unsaturated zone along interconnected fractures, and conduits, and along preferential paths downslope until reaching the saturated (phreatic) zone where groundwater will flow from areas of high hydraulic head (recharge locations) to areas of low hydraulic head (discharge locations). Mountain Valley's analysis included evaluating recharge features (swallets, sinkholes, and sinking streams), resurgence features (spring and seeps), topography, bedrock structure (strike and dip) as well as the results of the fracture trace-lineament analysis, and the results of previous dye-trace studies. Using these data, groundwater flow paths can be extrapolated and additional dye testing at these locations would not significantly change the understanding of groundwater flow. Performing a dye-trace analysis of every sinkhole or sink point along the pipeline alignment is not feasible or necessary.

157. We conclude that the impacts to geological resources will be adequately minimized with the implementation of the applicants' best management practices and the implementation of the environmental conditions in Appendix C.

d. **Mining Operations**

158. After issuance of the final EIS, Coronado Coal and Mountain Valley, through multiple filings, disputed whether the project would cross active mines leased by Coronado Coal in Greenbrier and Nicholas Counties, West Virginia (Pocahontas Nos. 6 and 7). Coronado Coal owns and manages Greenbrier Minerals LLC, which owns Matoaka Land Company, LLC (Matoaka). Matoaka leased the mineral rights to the two coal reserves from Coronado, and then leased its mineral rights to MWV Community Development and Land Management, LLC. Highland Mineral Resources LLC and its affiliate Plum Creek Timberlands L.P. lease the surface rights to the land where the coal reserves are located from Weyerhaeuser, the land owner.[193] Coronado Coal contends that the project would cause subsidence and other impacts on its existing and future mining operations, resulting in a depreciation of its mineral rights and an increase of its coal-mining operating costs. Coronado Coal requests that the order be conditioned on requiring Mountain Valley to compensate it for loss of coal value and increased costs, which was initially recommended in the draft EIS but was subsequently removed in the final EIS.

159. Coronado Coal and Mountain Valley debate the degree of activity that would constitute as "active" mining. Coronado Coal states that it has developed plans for completing permitting and mining within the schedule set forth in its mineral lease, drove entry-ways and constructed shafts for workers to access and supply the mines, and obtained a permit from West Virginia to install a station to access Pocahontas No. 7 seam, which it completed.[194] In response, Mountain Valley argues that Coronado Coal is not actively mining Pocahontas Nos. 6 or 7 because it does not have a current permit or a pending application to mine those seams.[195] Mountain Valley contends that Coronado Coal's current permits are for mines located over a mile away from the project.[196]

160. For the purposes of whether the project would depreciate the value of Coronado Coal's mineral rights, the specific level of activity that would constitute "active" mining is irrelevant. The heart of this issue is the value of Coronado Coal's mineral rights,

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[193] *See* Coronado Coal's August 4, 2016 Comment at 2-5.

[194] *See* Coronado Coal's August 23, 2017 Answer at n.25.

[195] *See* Mountain Valley's August 11, 2017 Answer at 10.

[196] *Id.*

which is not a matter for the Commission to adjudicate.[197] Section 7 of the NGA only authorizes the Commission to grant certificates of public convenience and necessity and does not empower us to determine the value of various property interests or to award related damages.[198] Instead appropriate compensation is a matter of negotiation between the property owner and the pipeline and, if an agreement cannot be made, courts are the appropriate venue.[199] Thus, if negotiation fails, Coronado Coal must seek relief from courts in connection to its claim that the MVP Project would result in a loss in value of its coal mines.

161. As for Coronado Coal's concern about the project's potentially disruptive effect on its current and future mining operations, in previous situations where pipeline facilities are proposed to be constructed through active and proposed coal mining areas with known areas of present or potential ground instability resulting from mining operations, the Commission has required a pipeline applicant to establish a site-specific plan addressing specific mining subsidence problems.[200] In other instances, where no active or proposed mining activities are occurring near proposed pipeline construction activities, we have refrained from speculating on the details of vague and uncertain potential coal mining activities, their ambiguous effects, and attempts to mitigate such effects through a construction and operation subsidence plan.[201] We have noted that

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[197] 15 U.S.C. § 717f(h) (2012). *American Energy Corp. v. Rockies Express Pipeline LLC*, 622 F.3d 602, 606 (6th Cir. 2010) (*American Energy Corp.*) (holding that the Commission lacks jurisdiction to adjudicate damages to property, including conversion, caused by a certificated gas project).

[198] *American Energy Corp.*, 622 F.3d at 606; *see* 15 U.S.C. § 717f (2012).

[199] *See* 15 U.S.C. § 717f(h) (2012).

[200] *See Texas Eastern Transmission, LP*, 131 FERC ¶ 61,164, at PP 18-21 (2010) (*Texas Eastern*) (affirming that pipeline must comply with all applicable safety requirements and resolve any subsidence mitigation issues within the purview of the relevant state agency that might come into play at such time as active mining is authorized to proceed under any of its facilities). *See also Rockies Express Pipeline LLC*, 123 FERC ¶ 61,234, *reh'g denied*, 125 FERC ¶ 61,160 (2008), *reh'g granted and denied*, 128 FERC ¶ 61,045 (2009) (requiring the pipeline applicant to develop, and file with the Commission prior to construction, a construction and operation plan for a portion of the project to ensure the integrity of the pipeline and to ensure that the project does not compromise existing or future mining activities).

[201] *See, e.g.*, *Texas Eastern*, 131 FERC ¶ 61,164 at P 19.

pipeline applicants must comply with all applicable safety requirements when they conduct active mining operations in the future.[202]

162. Here, the facts align most closely with *Texas Eastern*. As in *Texas Eastern*, the mining company has not actively mined in the project area and has not yet proposed a plan to mine. In the absence of specific information about the details of how potential mining activities would go forward, what they would involve, and how they would likely be affected by the construction of the project, the pipeline mitigation plans that Coronado Coal would have us require would be based only on speculation. Where coal mining in the vicinity of a proposed pipeline is a reasonably foreseeable future action,[203] the Commission has considered the impacts that mining activities might have on a proposed pipeline as part of our environmental review of the project.[204] Should Coronado Coal at some point in the future engage in long-wall mining beneath the facilities Mountain Valley will construct, Mountain Valley would remain under an obligation to comply with all relevant DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) safety requirements for existing pipelines.[205]

163. We expect Mountain Valley to consult with companies planning to extract coal beneath the approved right-of-way and to follow procedures to maintain its facilities' integrity when mining operations undercut a pipeline. As discussed in the final EIS,[206] the MVP Project is subject to the oversight of PHMSA, and thus must adhere to any measures that PHMSA requires to mitigate risks when mining operations occur in proximity to pipelines, and is also subject to certain state requirements related to the project's construction and operation.

164. Thus, we reject Coronado Coal's request to condition construction of the MVP Project on mitigation of potential impacts from speculative future coal mining operations.

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[202] *Id.* at P 22.

[203] *See* 40 C.F.R. § 1508.7 (2017) (NEPA regulations describing cumulative impacts).

[204] *See e.g.* Final EIS at 4-48 (noting that if subsidence becomes an issue Mountain Valley would supplement its *Mining Area Construction Plan* through consultation with the WVDEP and mine operators with regards to potential hazards).

[205] *See also* Final EIS at 4-48 to 4-49 (addressing future longwall mining).

[206] *Id.* at 1-23 and 4-558.

e. Water Resources

i. Groundwater

165. Commenters argue that the projects would harm groundwater supplies, especially in karst terrain areas.

166. The project areas are primarily comprised of bedrock aquifers with minor surficial aquifers along streams. The pipeline trench will rarely exceed 10 feet in depth, but could encounter shallow groundwater. In those situations, the trench will be dewatered through filters into adjacent vegetated uplands so that there will be some recharge to shallow aquifers.

167. As stated in the final EIS, the MVP Project will cross two groundwater wellhead protection areas[207] located in the Nettie-Leivasy Public Service District in Nicholas County, West Virginia. In addition, the MVP Project will cross surface water protection areas, including 6 Zones of Critical Concern and 14 Zones of Peripheral Concern[208] in West Virginia. The MVP Project will cross the Red Sulphur Public Service District's Zone of Critical Concern and Zone of Peripheral Concern at MP 195.4 in Monroe County, West Virginia. No groundwater source protection areas were identified in the vicinity of the Equitrans Expansion Project.

168. The MVP Project will be within 0.1 mile of two public water supplies: one well in Greenbrier County, West Virginia (the Greenbrier County Public Supply District #2), and the other in Pittsylvania County, Virginia (the Robin Court Subdivision). The MVP Project will also be within 0.3 mile of Rich Creek Spring, located near MP 195.2, which is used as a water supply by the Red Sulphur Public Service District. No public water supply resources were identified within one mile of the Equitrans Expansion Project.

169. To minimize potential impact from construction of the MVP Project on groundwater wellhead protection areas or surface water supply protection areas, Environmental Condition No. 24 requires Mountain Valley to develop a contingency plan with measures to protect, repair, or replace the water supplies of public service districts.

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[207] The 1986 Amendment of the Safe Drinking Water Act required states to develop wellhead protection programs to protect public supply wells from contamination. *See* 42 U.S.C. § 300h-7 (2012).

[208] Zones of Critical Concern and Zones of Peripheral Concern are generally established buffers mapped around all sources that contribute directly to a public water supply intake.

170. Commenters note the degree of groundwater interconnectivity in areas of karst terrain. Commenters also state that many landowners depend on wells or springs sourced from karst-generated groundwater for their domestic drinking water supplies, livestock watering, and irrigation of agricultural lands.

171. Because karst features provide a direct connection to groundwater, there is a potential for pipeline construction to increase turbidity in groundwater due to runoff of sediment into karst features or to contaminate groundwater resources by inadvertent spills of fuel or oil from construction equipment. To minimize potential impacts on karst related groundwater through construction associated sedimentation and runoff, Mountain Valley will implement the erosion control measures outlined in the Commission's Plan and its *Karst-specific Erosion and Sediment Control Plan*. Further, to minimize the potential for hazardous materials leaking from construction equipment to contaminate groundwater, Mountain Valley will implement the measures outlined in its *Stormwater Pollution Prevention Plan* (SWPP Plan)*; Spill Prevention, Control, and Countermeasures Plan* (SPCC Plan)*;* and *Unanticipated Discovery of Contamination Plan for Construction Activities in West Virginia and Virginia*.

172. Because field surveys for both projects have not been completed due to lack of approved access, Mountain Valley and Equitrans have been unable to identify all private wells and springs used for domestic water supplies within 150 feet of the pipelines (500 feet in karst terrain). Therefore, Environmental Condition No. 12 of this order requires the applicants to file an updated list of the locations of water wells, springs, and other drinking water sources within 150 feet (500 feet in karst terrain) of construction work areas and aboveground facilities, prior to construction. In areas where a public or private water supply well or spring is identified within 150 feet of the projects (500 feet in karst terrain), the applicants will flag the wellhead or spring as a precaution and notify the owner or operator of the water resource. The applicants will conduct pre-construction water quality evaluations on water wells. Further, Environmental Condition Nos. 21 and 35 of this order require Mountain Valley and Equitrans to conduct post-construction testing of domestic water supplies evaluated during the pre-construction process. In situations where project-related construction damages the quantity or quality of domestic water supplies, the applicants will compensate the landowner for damages, repair or replace the water systems to near pre-construction conditions, and provide temporary sources of water.

173. On July 31, 2017, Indian Creek Watershed Association filed a report prepared by Thomas Bouldin regarding sedimentation in streams crossed by the MVP Project. Mr. Bouldin states that estimates of sedimentation into waterbodies contained in the final EIS are flawed because they do not account for runoff from construction workspaces. In addition, Mr. Bouldin claims that final EIS ignores points made in the *Hydrologic Analysis of Sedimentation* report prepared by Mountain Valley for the Forest Service.

174. We disagree. Section 4.3 of the final EIS discusses runoff caused by construction[209] and includes a summary of the findings of Mountain Valley's *Hydrologic Analysis of Sedimentation* report. Further, the final EIS states that Mountain Valley will work with the Forest Service and appropriate agencies to develop a stream monitoring plan that it will implement during operation of the MVP Project.

175. Section 4.3.2 of the final EIS provides a discussion of two peer-reviewed scientific studies, including one prepared by the U.S. Geological Survey, regarding sedimentation into waterbodies crossed from dry-ditch methods. The final EIS states that the dry-ditch methods would result in minor, short-term, and localized increases in sedimentation in waterbodies crossed by the MVP Project.[210] Those minor increases in sedimentation at pipeline stream crossings should not significantly affect aquatic resources within the waterbodies.

176. As outlined in the final EIS (section 2.4.1.1), Mountain Valley agreed to adopt the Commission's Plan without modifications and the *Wetland and Waterbody Construction and Mitigation Procedures* with modifications. The Commission's Plan and Procedures provide baseline mitigation measures, including erosion control devices, that would limit sedimentation and runoff from all work areas. Based on Commission staff's experience with pipeline construction, and Mountain Valley's commitment to cross waterbodies via dry-ditch methods, adherence to the measures in the Commission's Plan and Procedures, Mountain Valley's proposal to conduct a stream monitoring plan, and use of the Commission's third-party construction compliance program, we determine that impacts on waterbodies due to sedimentation will be effectively minimized.

177. We conclude that impacts on groundwater will be adequately minimized with the implementation of the applicants' best management practices as appropriate and the implementation of the environmental conditions in Appendix C.

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[209] *See, e.g.*, Final EIS at 4-137 ("The use of heavy equipment for construction could cause compaction of near-surface soils, an effect that could result in increased runoff into surface waters in the immediate vicinity of the proposed construction right-of-way. Increased surface runoff could transport sediment into surface waters, resulting in increased turbidity levels and increased sedimentation rates in the receiving waterbody. Disturbances to stream channels and stream banks could also increase the likelihood of scour after construction.").

[210] Final EIS at 4-217.

ii. Surface Waters and Fisheries

178. Some commenters, including the Appalachian Mountain Advocates, question the adequacy of the final EIS's discussion on the MVP Project's impacts on surface waters.

179. The MVP Project will cross 389 perennial surface waterbodies, 5 of which are defined as major waterbodies (i.e., more than 100-feet-wide). Mountain Valley will cross all waterbodies using dry open-cut (flumed, dam-and-pump, or cofferdam) methods, except for the Pigg River. The MVP Project crosses the Pigg River, a state-designated Scenic River that contains habitat for the federally-endangered Roanoke logperch (freshwater fish), in Pittsylvania County, Virginia. To minimize potential impacts on the Pigg River and the Roanoke logperch, Environmental Condition No. 23 of this order requires Mountain Valley to use a horizontal directional drill (HDD) to cross under the Pigg River.

180. The Equitrans Expansion Project will cross 15 perennial surface waterbodies. Of these, the Monongahela River is a major river more than 100-feet-wide. Equitrans will cross all waterbodies using either dry open-cut or HDD crossing methods. Nine waterbody crossings will be completed by HDD: the Monongahela River, South Fork Tenmile Creek, and seven crossings of unnamed tributaries of the South Fork Tenmile Creek. Because Equitrans has not completed environmental surveys for the New Cline Variation, which is incorporated in Equitrans' proposal, we will require, Environmental Condition No. 36, that Equitrans file the results of all the environmental surveys for the New Cline Variation prior to construction.

181. The MVP Project will cross four waterbodies (i.e., Left Fork Holly River, Elk River, Greenbrier River, and Craig Creek) listed on the National Park Service's (NPS) National Rivers Inventory as rivers with outstanding qualities that may qualify for wild, scenic, or recreational designation. The MVP Project will also cross Greenbrier River, a waterbody protected under the Natural Streams Preservation Act of West Virginia, and two waterbodies (i.e., Blackwater River and the Pigg River) on the Virginia Scenic Rivers List.

182. The MVP Project will cross 23 perennial waterbodies in West Virginia and 10 perennial waterbodies in Virginia that contain freshwater mussels. The Virginia Department of Game defines windows in which construction should not occur in streams that contain freshwater mussels characterized as long-term brooders, such as the yellow lampmussel and green floater. The restricted windows are April 15 through June 15 and August 15 through September 30. Further, construction will be restricted in streams that contain freshwater mussels characterized as short-term brooders, such as the James spinymussel and Atlantic pigtoe, from May 15 through July 31. Mountain Valley has agreed to adhere to these in-water work windows.

183. Mountain Valley estimates that about 58,422,382 gallons of water may be needed for the hydrostatic testing of its pipeline, with about 46,644,831 gallons coming from municipal sources, and about 11,777,551 gallons from surface water sources (i.e., Meadow River and the Greenbrier River). For pipeline segments that will be tested using surface water sources, the withdrawal and discharge of the hydrostatic test water will occur within the same watersheds. About 55,000 gallons per day of water from unidentified surface or groundwater sources may be required for dust control for each spread along the MVP Project. Environmental Condition No. 22 requires Mountain Valley to reveal the sources and quantities of water to be utilized for dust control prior to construction.

184. Commenters, such as the Counties, expressed concerns regarding potential effects on surface waterbodies during construction and operation of the projects due to sedimentation or spills or leaks of hazardous materials.

185. The final EIS concludes that dry open-cut waterbody crossings result in temporary (less than 4 days) and localized (for a distance of only a few hundred feet of the crossing) increases in turbidity downstream of construction, but the magnitude of this increase is minimal compared to increased turbidity associated with natural runoff events. Once construction is complete, Mountain Valley will stabilize and restore streambeds and banks consistent with its *Wetland and Waterbody Construction and Mitigation Procedures*. In addition, Mountain Valley and Equitrans will follow their *Wetland and Waterbody Construction and Mitigation Procedures*, which stipulates the use of clean gravel or native cobbles for the upper one foot of trench backfill in all waterbodies that are classified as coldwater fisheries. Mountain Valley and Equitrans will minimize impacts on riparian vegetation at the edge of waterbodies by narrowing the width of the standard construction rights-of-way at waterbody crossings to 75 feet, and by locating most temporary workspaces at least 50 feet away from stream banks. Outside of the 10-foot-wide corridor over the pipeline maintained clear of trees, Mountain Valley will hand plant shrubs and trees within the temporary workspaces at specific waterbody crossings, up to 100 feet from the stream bank. The applicants will minimize impacts on surface waterbodies by implementation of the construction practices outlined in their project-specific *Erosion and Sediment Control Plans*, the Commission's Plan (for the MVP Project), Equitrans' project-specific *Upland Erosion Control, Revegetation, and Maintenance Plan* (Equitrans Plan), and Equitrans' project-specific *Wetland and Waterbody Construction and Mitigation Procedures* (Equitrans' Procedures). As stated in the final EIS, Commission staff reviewed these plans and procedures and determined that they will provide acceptable protection of surface waterbodies.[211]

186. To avoid or minimize the potential impacts of fuel or oil or other hazardous materials spilled from construction equipment, Mountain Valley will follow the

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[211] Final EIS at 4-149.

procedures outlined in its SPCC Plan and Equitrans will implement its SPCC Plan and/or its *Preparedness, Prevention, and Contingency and Emergency Action Plan* depending on the project location. These plans include both preventative and mitigation measures such as personnel training, equipment inspection, refueling procedures, and spill cleanup and containment.

187. In addition to the measures we require here, the Army Corps, the Pennsylvania Department of Environmental Protection (PADEP), WVDEP, and Virginia Department of Environmental Quality (VADEQ) have the opportunity to impose conditions to protect water quality pursuant to sections 401 and 404 of the Clean Water Act. The applicants must obtain all necessary federal and state permits and authorizations, including the water quality certifications, prior to receiving Commission authorization to commence construction. We expect strict compliance by the applicants with any federal and state-mandated conditions.

iii. <u>Wetlands</u>

188. The final EIS states that construction of the MVP and Equitrans Expansion Projects will impact a total of 32.1 acres of wetlands, including 24.9 acres of emergent wetlands, 2.5 acres of scrub-shrub wetlands, and 4.6 acres of forested wetlands.[212] Because all wetlands will be restored after pipeline installation, there will be no net loss of wetlands. However, in some cases there will be conversions of wetland types and functions.

189. Within the 10-foot-wide corridor centered on the pipeline that will be mowed on a regular basis to comply with DOT's pipeline safety regulations, there will be a permanent conversion of forested and shrub wetlands to herbaceous wetlands. Impacts on emergent and scrub-shrub wetlands within temporary workspaces will be short-term. After construction, those areas are expected to be restored, and emergent and scrub-shrub wetlands return within a few years to their original condition and function. Forested wetlands within temporary workspaces will be subject to long-term impacts. While trees could regenerate in those areas, it will take decades for them to mature and return the forested wetlands to their original condition and function.

190. In general, construction and operation-related impacts on wetlands may also be mitigated by the applicants' compliance with their *Wetland and Waterbody Construction and Mitigation Procedures* and the conditions of the Clean Water Act sections 404 and

[212] Final EIS 4-153.

401 permits.[213] With implementation of the acceptable avoidance and minimization measures, as well as the environmental conditions in this order, we agree with the final EIS's conclusion that impacts on wetland resources will be appropriately mitigated and reduced to less than significant levels.

f. Vegetation, Forested Land, and Wildlife

191. The MVP Project will cross about 235 miles of forest, 2.7 miles of shrublands, and 7.5 miles of grasslands. The Equitrans Expansion Project will cross about 4 miles of forest and less than 0.1 mile of grasslands. Construction of the MVP Project will affect a total of about 4,453 acres of forest, while operation of the project will affect about 1,597 acres of forest. Construction of the Equitrans Expansion Project will affect a total of about 62 acres of forest and operation of the Equitrans Expansion Project will impact a total of about 22 acres of forest.

192. The 50-foot-wide operational pipeline easement in uplands will be kept clear of trees, resulting in the permanent conversion of forest to grasslands/shrub land use. The remainder of the temporary construction workspace along the pipeline routes in forested uplands will be allowed to regenerate, although it would take many years for trees to mature. This long-term impact will affect about 3,164 acres of forest, but the forest is expected to eventually recover.[214] About 174 acres of forest will be permanently converted to industrial land use at the MVP Project's aboveground facilities and permanent access roads. Construction of the Equitrans Expansion Project's aboveground facilities will clear a total of about 5 acres of forest, and operation will permanently remove 4 acres.

193. The removal of interior forest to create the necessary pipeline rights-of-way will result in the conversion of forest area to a different vegetation type. This will contribute to forest fragmentation and the creation of forest edges. The pipeline right-of-way through forest will remove habitat for interior forest wildlife species. The MVP Project will pass through 24 state-listed core forest areas in West Virginia, which will result in temporary impacts from construction on about 2,428 acres of large core forest areas (greater than 500 acres) and permanent impacts from operations on about 872 acres of

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[213] For unavoidable wetland impacts, the applicants commit to purchase wetland and stream credits from approved mitigation banks in the respective states. In-lieu fee state programs may also be considered. Proof of compensatory mitigation credit purchase will be provided by the applicants to the Army Corps prior to construction.

[214] This would include the temporary workspace along the pipeline right-of-way outside of the 50-foot-wide permanent easement, additional temporary workspaces, yards, and temporary access roads.

large core forest areas. In Virginia, the MVP Project will pass through 17 state-listed ecological core areas categorized as Outstanding, Very High, or High. Construction of the MVP Project in Virginia will result in temporary impacts on about 547 acres of ecological core areas categorized as Outstanding to High and permanent impacts on about 209 acres of ecological core areas categorized as Outstanding to High. Construction and operation of the Equitrans Expansion Project's H-318 pipeline in Pennsylvania will affect one tract of interior forest of about 50 acres.

194. The MVP Project will cross five EPA Level III ecoregions:[215] the Western Allegheny Plateau, Central Appalachians, Ridge and Valley, Blue Ridge Mountains, and the Piedmont. All components for the Equitrans Expansion Project will be within the Western Allegheny Plateau ecoregion. Combined, these ecoregions make up a total area of more than 164 million acres, of which more than 100 million acres is forested. However, in considering the total acres of forest affected, the quality and use of forest for wildlife habitat, and the time required for full restoration in temporary workspaces, the final EIS concludes that the MVP Project will have significant impacts on forested land.[216]

195. To minimize forest fragmentation and edge effects, Mountain Valley has collocated about 30 percent of the pipeline route with existing linear corridors. Mountain Valley will revegetate the right-of-way and workspaces with seeds for species recommended by the Wildlife Habitat Council. Mountain Valley will reduce impacts on vegetation with the implementation of the Commission's Plan and Mountain Valley's project-specific *Erosion and Sediment Control Plan*. Mountain Valley also developed an *Exotic and Invasive Species Control Plan* to minimize impacts from invasive species. Equitrans will reduce impacts on vegetation by implementing the measures of its Plan and approved seeding mixes, rates, and dates obtained from the Pennsylvania Erosion and Sediment Control Manuals, and invasive species control measures outlined in Equitrans' invasive species control strategies. Commission staff's review of the applicants' proposed seed mixes revealed a limited number of non-native plant species and recommended, in the final EIS, the development of revised erosion control plans. Environmental Condition No. 13 of this order requires the applicants to revise their erosion control plans to contain seed mixes for only native species.

196. The Roanoke Appalachian Trail Club argues that the final EIS underestimates the impacts caused by the clearing of forest because of forest fragmentation. The final EIS

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[215] Ecoregions are areas where ecosystems are generally similar. They are classified into four levels. *See* EPA, Ecoregions, https://www.epa.gov/eco-research/ecoregions.

[216] Final EIS at 4-191.

appropriately addresses forest habitat impacts, including interior/core forest habitats, in sections 4.4 and 4.5. These sections include mapping, tabular data, impact analyses, and proposed measures to reduce impacts on forest.

197. The Virginia Department of Game expresses concerns about invasive species management. Section 4.4 of the final EIS appropriately discusses Mountain Valley's *Exotic and Invasive Species Control Plan* and determines that the plan is adequate to manage invasive species along the restored right-of-way.[217]

198. Preserve Roanoke expresses concern regarding the use of herbicides along the pipeline route. As stated in the final EIS, Mountain Valley would not use herbicides anywhere on the right-of-way, except where requested by landowners.[218] We agree that Preserve Roanoke's concern is adequately addressed.

199. The Virginia Department of Game comments on the loss of forested habitat, including core/interior forest habitat. The VADCR also expresses concerns about forest fragmentation. The final EIS addresses forest habitat impacts and impact avoidance, minimization, and mitigation in sections 4.4 and 4.5. It concludes that impacts on forest resources would be significant, but have been minimized to the extent practicable. For example, the final EIS states that impacts on forest will be reduced by collocating the MVP Project adjacent to existing rights-of-way for about 30 percent of the project route. Mountain Valley will also reseed construction areas with native vegetation during restoration.[219]

200. Dr. Carl Zipper contends that the final EIS does not adequately address mitigation of adverse effects on forest, and requests a Supplemental EIS. Other people filed comments supporting Dr. Zipper's statements. Dr. Zipper offers his own recommendations for forest mitigation in comments filed on the draft EIS. The final EIS addresses Dr. Zipper's proposed forest mitigation measures in Appendix AA of the final EIS.[220]

201. Further, the final EIS discloses the extent and level of impacts on forest, and outlines measures Mountain Valley proposes to reduce or mitigate those impacts. Dr. Zipper does not offer new information or a change of circumstance since the final EIS was issued. Therefore, a Supplemental EIS is not necessary.

[217] Final EIS at 4-189 to 4-191.

[218] Final EIS at 4-187.

[219] Final EIS at 4-183.

[220] *See* response to comment IND244 in Appendix AA of the final EIS.

202. The final EIS clarifies that during restoration, Mountain Valley will seed temporary workspaces with species recommended by the Wildlife Habitat Council. In forested areas, Mountain Valley will use a woody seed mix composed of native overstory, understory, and shrub oak-hickory forest species. Environmental Condition No. 13 of this order requires that Mountain Valley only use native species in its seed mixes. Mountain Valley will also plant native shrubs and saplings (outside of the 30-foot-corriodor over the pipeline) within forested wetlands and at the crossings of waterbodies known to contain special status species.

203. Dr. Zipper's comments regarding the effectiveness of hand-planting trees as compared to using a woody seed mix are noted. However, the proposed use of a woody seed mix is a reasonable measure to minimize impacts on forests. As stated in the final EIS, Mountain Valley will monitor revegetation efforts following restoration.[221] As stated in the final EIS response to Dr. Zipper's comments on the draft EIS, natural recruitment will allow for the regeneration of more highly variable plant species and trees best suited for local conditions.

204. Dr. Zipper also criticizes Commission staff's approval of Mountain Valley's *Exotic and Invasive Species Control Plan* and recommends handcutting of invasive species. However, as stated in the final EIS, Mountain Valley will adhere to the measures outlined in the Commission's Plan, which provides that "[r]evegetation in non-agricultural areas shall be considered successful if upon visual survey the density and cover of non-nuisance vegetation are similar in density and cover to adjacent undisturbed lands." Based on our staff's experience monitoring revegetation efforts where the spread of invasive species was successfully limited, we conclude that Mountain Valley's *Exotic and Invasive Species Control Plan* would limit the spread of invasive species during revegetation.

205. A variety of wildlife species occupy the ecoregions and habitats crossed by the MVP and Equitrans Expansion Projects. Construction of both projects may result in limited mortality for less mobile animals, such as small rodents, reptiles, amphibians, and invertebrates, that are unable to escape equipment. More mobile animals will likely be displaced to adjacent similar habitats during construction. Once the right-of-way is revegetated, it will be reoccupied by displaced wildlife.

206. Additionally, constructing the projects could disrupt bird courting, breeding, or nesting behaviors. Migratory birds, including Birds of Conservation Concern, are associated with the habitats that will be affected by both projects. Two Important Bird Areas will be crossed: 1) Bird Conservation Region 28 (Appalachian Mountains for both projects) and 2) Bird Conservation Region 29 (Piedmont for the MVP Project). Both Mountain Valley and Equitrans developed *Migratory Bird Habitat Conservation Plans* to

[221] Final EIS at 4-180.

minimize impacts on bird species. In addition, Equitrans has agreed to conduct tree clearing outside of the migratory bird nesting season (generally between April 15 and August). Mountain Valley will potentially conduct tree clearing in select areas during the migratory bird nesting season (during April, May, and August). Environmental Condition No. 27 of this order requires Mountain Valley to finalize its *Migratory Bird Habitat Conservation Plan* and address the comments of resource agencies. As a result, we agree with the final EIS's conclusion that the projects would not result in population-level impacts on migratory bird species.

207. The VADCR points out that Appendix N-15 (Recommended Seed Mixtures and Fertilizer/Mulch for Revegetation Mountain Valley Project – Virginia) in the final EIS lists different seed mixes than those listed in Mountain Valley's *Migratory Bird Conservation Plan* (Appendix D - Restoration and Rehabilitation Plan). We acknowledge that the two seed mix lists are different. Environmental Condition No. 27 of this order requires Mountain Valley to revise its *Migratory Bird Conservation Plan* in order to ensure that the seed mix in the plan matches the seed mix in the final EIS.

208. The Blue Ridge Land Conservancy expresses concerns about scenic views of Brush Mountain, the MVP Project's proximity to the Brush Mountain Wilderness, alternations of wildlife patterns resulting from the MVP Project, and the potential for the introduction of invasive species. Sections 4.4, 4.5, and 4.8 of the final EIS discuss these topics and conclude that the implementation of the measures outlined in the final EIS would minimize adverse effects.[222]

209. In conclusion, the final EIS finds, and we agree, that construction and operation of both projects would not significantly affect wildlife.

g. <u>Threatened, Endangered, and Other Special Status Species</u>

210. The final EIS identifies 23 federally-listed threatened or endangered species (or federal candidate species or federal species of concern) that will be potentially present in the vicinity of the projects.[223] The final EIS concludes that the MVP Project will have no effect on two species; is not likely to adversely affect eight species; will have no adverse

[222] *See also* responses to Comments CO-7 and CO-31 in Appendix AA of the final EIS.

[223] One species, the bog turtle, is not subject to section 7 consultation under the Endangered Species Act.

impacts anticipated for two species of concern;[224] is not likely to contribute to a trend toward federal listing for three species; and is likely to adversely affect seven species (Indiana bat, northern long-eared bat, Roanoke logperch, running buffalo clover, shale barren rock cress, small whorled pogonia, and Virginia spiraea). The likely-to-adversely-affect determination for four of the seven species – the running buffalo clover, shale barren rock cress, small whorled pogonia, and Virginia spiraea – is based on Commission staff's conservative assumption that these species are present in portions of the MVP Project corridor that Mountain Valley was not granted land access to survey. On July 10, 2017, Commission staff issued a Biological Assessment (BA), which was submitted to West Virginia and Virginia Field Offices of the FWS, that included a detailed assessment regarding the effects of the MVP Project on federally-listed species.

211. The final EIS concludes that the Equitrans Expansion Project is not likely to adversely affect the two endangered bats assumed to be present in the vicinity of the project. The conclusion was based in part upon Equitrans implementing avoidance and minimization measures outlined in the FWS-approved Myotid Bat Conservation Plan.

212. In response to our BA, the FWS stated, in a letter to the Commission dated August 4, 2017, that based on new information provided by Mountain Valley, it determined that the MVP Project is not likely to adversely affect shale barren rock cress and running buffalo clover. Commission staff agrees with the findings of the FWS for these two species.

213. However, because consultation with the FWS is not yet complete, Environmental Condition No. 28 of this order prohibits construction of the MVP Project until Commission staff completes the process of complying with the Endangered Species Act.

214. The projects could also affect 20 additional species that are state-listed as threatened, endangered, or were noted by the applicable state agencies as being of special concern. Based on implementation of the applicants' proposed mitigation and the environmental conditions in the appendix of the order, we agree with the final EIS's conclusion that impacts on special-status species will be adequately avoided or minimized.[225]

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[224] "Species of concern" is an informal term used by FWS to refer to species that have been identified as important to monitor, but do not have endangered, threatened or candidate status and thus receive no legal protection.

[225] Final EIS at 4-250.

h. Land Use, Recreation, and Visual Resources

i. Land Use

215. Construction of the MVP Project would impact forest land (76.6 percent), agricultural land (14.6 percent), and open land, commercial, open water, and residential (approximately 8.7 percent). Construction of the Equitrans Expansion Project would primarily impact the following land use types: agricultural (46.3 percent), forest (37.6 percent), and open land (12.5 percent). Both projects combined would affect about 1,023 acres of agricultural lands. Impacts on agricultural lands will be short-term, lasting during the period of construction and restoration and a few years later.

216. The applicants will compensate farmers for loss of agricultural production during the construction and restoration period. Following pipeline installation, the right-of-way will be restored to near pre-construction conditions and use, and agricultural practices could resume. Except for orchards, crops and pasture can be planted directly over the entire right-of-way. Mitigation measures typically implemented in agricultural lands (as specified in the Commission's Plan) include topsoil segregation, rock removal, soil decompaction, and repair/replacement of irrigation and drainage structures damaged by construction. Mountain Valley developed an *Organic Farm Protection Plan* that outlined measures that it will implement when crossing organic farms to reduce impacts.

217. Mountain Valley identified 118 residences within 50 feet of its proposed construction right-of-way. Site-specific residential mitigation plans for all residences within 50 feet of the construction right-of-way are included as Appendix H of the final EIS, as required by our regulations.[226] Environmental Condition No. 30 of this order requires Mountain Valley to file landowner concurrence with the plans for all residences that will be within 10 feet of the construction work area. In addition, because the final EIS identified an additional residence within 20 feet from MP 216.6 since the issuance of the draft EIS, we also include as part of Environmental Condition No. 30 the requirement that Mountain Valley file a site-specific residential plan within 50 feet of this newly-identified residence.

218. The VADCR indicates that the final EIS incorrectly states that incorporation of the Canoe Cave Variation into the proposed route would avoid the Canoe Cave Conservation Site in Giles County, Virginia. We acknowledge the error and note that the proposed pipeline route will only cross the edges of the Canoe Cave Conservation Site. Further, as table 4.1.1-14 of the final EIS indicates, the pipeline centerline will be about 902 feet away from Canoe Cave.

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[226] *See* 18 C.F.R. § 380.12(j)(10) (2017).

219. The Virginia Outdoors Foundation, which manages land on behalf of Virginia, states that it initially identified the Wimmer Easement (tract MON-VOF-1871 at MP 234.2 in Montgomery County, Virginia) as land that it manages.[227] Virginia Outdoors Foundation now clarifies that the MVP Project will not cross the Wimmer Easement. Therefore, we clarify that the MVP Project will not affect the Wimmer Easement.

220. The final EIS included a recommended condition, which would have required Mountain Valley provide documentation that WVDNR reviewed a crossing plan for the Burnsville Lake Wildlife Management Area. In a communication with Mountain Valley that was forwarded to Commission staff on August 22, 2017, a representative of the WVDNR who reviewed the final EIS clarified that the MVP Project will not cross any portion of the Burnsville Lake Wildlife Management Area that is owned or managed by the state of West Virginia. Instead, the only lands within the boundaries of the Burnsville Lake Wildlife Management Area that will be crossed by the pipeline are owned and managed by the Army Corps (i.e., Weston and Gauley Bridge Turnpike Trail). The BLM will cover Army Corps-owned lands in its future right-of-way grant to Mountain Valley. Therefore, we do not adopt recommended Environmental Condition No. 30 from section 5.2 of the final EIS.

ii. Recreation

221. Federally owned or managed recreational and special use areas that will be crossed by the MVP Project include the Weston and Gauley Bridge Turnpike Trail, the Blue Ridge Parkway, and the Jefferson National Forest. The Weston and Gauley Bridge Turnpike Trail is owned by the Army Corps, and will be crossed with a bore to avoid all surface impacts on the trail. The Blue Ridge Parkway is managed by the NPS, and will also be crossed with a bore. The MVP Project will cross the Appalachian National Scenic Trail and the Brush Mountain Inventoried Roadless Area, both within the Jefferson National Forest and managed by the Forest Service. Mountain Valley proposes to bore under the Appalachian National Scenic Trail, to avoid all surface impacts on the trail.

222. Congressman Beyer expresses concerns about impacts on the Appalachian National Scenic Trail. Section 4.8 of the final EIS discusses impacts on the Appalachian National Scenic Trail and measures Mountain Valley will implement to avoid, reduce, or mitigate those impacts.[228]

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[227] Citing Final EIS at 4-281.

[228] Final EIS at 4-311 to 4-313.

223. The MVP Project will pass through the Jefferson National Forest for a total of 3.5 miles in three segments between MPs 196.2 and 197.8, MPs 218.5 and 219.4, and MPs 219.8 and 220.8 in Monroe County, West Virginia, and Giles and Montgomery Counties, Virginia. As listed on table 1.3-1 of the final EIS, the MVP Project will affect about 83 acres in the Jefferson National Forest during construction and 42 acres during operation.[229] The Jefferson National Forest operates under a Land and Resource Management Plan (LRMP).[230] The Forest Service analyzed the information provided by Mountain Valley and is amending its LRMP to allow for the MVP Project to be sited within the Jefferson National Forest. On June 23, 2017, the Forest Service issued a draft record of decision for the use and occupancy of the Jefferson National Forest for the MVP Project. The public objection period on the draft record of decision closed on September 21, 2017. After resolving the objections, the Forest Service will issue a final decision on the respective authorization before it. Mountain Valley will implement the measures outlined in its Plan of Development, pending approval by the Forest Service, and its *Construction, Operation, and Maintenance* Plan to minimize the impacts on National Forest resources.

224. The Equitrans Expansion Project will not cross any federally designated Wild and Scenic Rivers, National Parks, National Trails, National Landmarks, federal or state designed Wilderness Areas, national or state forests, wildlife refuges, natural preserves or game management areas, Indian reservations, or state or county parks or recreation areas. However, because the Riverview Golf Course will be crossed as a result of the Cline Variation that Equitrans incorporated into its proposal, we include Environmental Condition No. 37 requiring Equitrans to file a crossing plan and documentation that the landowners have reviewed it.

iii. <u>Visual Resources</u>

225. Mountain Valley conducted visual impact assessments for the Weston and Gauley Bridge Turnpike Trail, Blue Ridge Parkway, Appalachian National Scenic Trail, and the Jefferson National Forest.

226. Based on the visual impact assessments, the final EIS concludes that the MVP Project will not have significant adverse visual impacts on the Weston and Gauley Bridge Turnpike Trail, Blue Ridge Parkway, Appalachian National Scenic Trail, or the Jefferson National Forest.

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[229] Final EIS at 1-14.

[230] The LRMP was prepared pursuant to 16 U.S.C. § 1604(e) (2012) and is available at https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprd3834582.pdf.

227. We agree with the final EIS's conclusion that, with adherence to the applicants' proposed impact avoidance, minimization, and mitigation plans, and implementation of the environmental conditions in the appendix of this order, the overall impacts on land use will be adequately minimized.[231]

i. Socioeconomics

i. Property Values, Mortgages, and Insurance

228. Commenters expressed concerns regarding the potential effect of the projects on property values, mortgages, and homeowners insurance. Several commenters provided anecdotes about property values and public surveys and opinion polls about perceived reductions of property values. However, anecdotes, public surveys, or opinion polls do not constitute substantial evidence that natural gas projects decrease property values. Accordingly, we conclude here, as we have in other cases, that the proposed project is not likely to significantly impact property values in the project areas.[232]

229. A few landowners claim that prospective property buyers cannot obtain mortgages when property is encumbered by a pipeline easement. However, the evidence they provide is an article about natural gas drilling, not natural gas transmission; thus, it does not support their contention. The final EIS also states that banks regularly issues mortgages, including loans from the Veterans Administration and Federal Housing Administration, for properties encumbered with pipeline easements.[233] The final EIS found no evidence that banks or federal lenders refused to lend to prospective purchasers of property encumbered with a pipeline easement.[234]

230. With regard to concerns expressed by commenters regarding the ability to obtain homeowner's insurance, our staff has researched this extensively and has found little evidence that owners of property encumbered with pipeline easements were unable to obtain homeowner's insurance.[235] The final EIS finds that insurance companies do not

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[231] Final EIS at 4-347.

[232] *See, e.g.*, *Transco*, 158 FERC ¶ 61,125, at P 106 (2017); *Central New York Oil & Gas Co., LLC*, 116 FERC ¶ 61,277, at P 44 (2006).

[233] Final EIS at 4-367 and 4-392.

[234] Final EIS 4-368.

[235] Final EIS at 4-367, 4-368, and 4-392. *See also Transco*, 158 FERC ¶ 61,125 at PP 107-108.

consider the presence of natural gas pipeline when underwriting homeowner's insurance policies.[236] Nonetheless, Mountain Valley and Equitrans have agreed to document, track, investigate, and report to the Commission every quarter for a period of two years following in-service, complaints from any affected landowners whose insurance policy was cancelled or materially increased in price as a direct result of the projects.[237] The applicants have committed to consider any potential mitigation on a case-by-case basis, and address resolutions in quarterly reports to the Commission.[238]

231. Based on the foregoing, we agree with the final EIS's conclusion that the projects would not have significant adverse impacts on property values, mortgages, or insurance.

ii. <u>Environmental Justice</u>

232. Executive Order 12898 requires that specified federal agencies make achieving environmental justice part of their missions by identifying and addressing, as appropriate, disproportionately high and adverse human or environmental health effects of their programs, policies, and activities on minorities and low income populations.[239] Executive Order 12898 applies to the agencies specified in section 1-102 of that order. This Commission is not one of the specified agencies, and the provisions of Executive Order 12898 are not binding on this Commission. Nonetheless, in accordance with our usual practice, the final EIS addresses this issue and concludes that the proposed projects will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations.[240]

233. In its guidance to implement Executive Order 12,898, CEQ instructs that low-income populations be identified with annual statistical poverty thresholds from the

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[236] Final EIS at 4-392.

[237] *Id.* at 4-393.

[238] *Id.*

[239] Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, Executive Order 12,898 (Feb. 11, 1994), reprinted at 59 Fed. Reg. 7629.

[240] *See* sections 4.9.1.8 and 4.9.2.8 of the final EIS.

Bureau of the Census.[241] Minority groups compose of American Indian or Alaska Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic.[242] Further, minority populations are identified where either the minority population of the affected area exceeds 50 percent or the minority population percentage of the affected area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis.[243]

234. Relying on census data, the final EIS finds no counties or census blocks in the project areas that have minority populations exceeding 50 percent or have minority populations meaningfully greater than the minority population percentage in the respective states.[244] The final EIS identifies low-income populations within the MVP and Equitrans Expansion Project areas.[245] However, the projects would not result in disproportionate adverse health or environmental impacts on any low-income community because, as discussed in the final EIS, water and air quality would not be significantly affected.[246]

235. As we have stated in prior cases, the siting of linear facilities between two fixed end points is generally based on environmental and engineering factors.[247] Along the way, Mountain Valley selected its pipeline route to take advantage of ridgetop alignments, avoid sensitive natural resources (where possible), and avoid major population centers. The pipeline route mostly crosses rural regions with relatively low population densities. By avoiding metropolitan areas, the MVP Project should reduce impacts on communities with high percentages of minorities, low-income populations,

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[241] CEQ, *Environmental Justice Guidance Under the National Environmental Policy Act*, at 25 (Dec 1997) (CEQ Environmental Justice Guidance), https://www.epa.gov/sites/production/files/ 2015-02/documents/ej_guidance_nepa_ceq1297.pdf. The final EIS relies on the poverty line established by the U.S. Department of Health and Human Services: an individual income of $11,880 and a family of five income of $28,440 in 2016. Final EIS at 4-374.

[242] CEQ Environmental Justice Guidance at 25.

[243] *Id.*

[244] Final EIS at 4-399.

[245] Final EIS at 4-373 to 4-378.

[246] Final EIS at 4-400.

[247] *See, e.g., Florida Southeast Connection, LLC*, 154 FERC ¶ 61,080 at P 262.

and other vulnerable populations. Therefore, we conclude that environmental justice communities would not be significantly affected by the projects.

iii. Tourism, Transportation, and Housing

236. Commenters identify construction traffic, restriction of access to tourist attractions, limitations on business opportunities, and competition for accommodations as potential issues.

(a) Tourism

237. While construction of the projects will overlap with the peak tourist season, between May and October, the construction in most of the recreational use areas will take only a few weeks. Therefore, the final EIS concludes, and we agree, that the MVP Project would not have significant adverse impacts on specific federally-managed recreational areas in the region, including the Weston and Gauley Bridge Turnpike Trail, Blue Ridge Parkway, Appalachian National Scenic Trail, and the Jefferson National Forest.[248] Likewise, the final EIS also concludes, and we agree, that the Equitrans Expansion Project would not have a significant adverse impact on housing, tourism, or recreation in the project area.[249]

(b) Transportation

238. Commenters were also concerned about the MVP Project's impacts on local roads. The Virginia Department of Transportation submitted comments on the MVP Project on July 19, 2017, recommending Mountain Valley to continue to coordinate with the agency, conduct detours at times to minimize impacts, and provide signage to alert the public to utility work and detours. The Lynchburg District of the Virginia Department of Transportation also commented on the final EIS, stating that a Virginia Department of Transportation project along U.S. Route 29 in Pittsylvania County, Virginia is planned for the period from 2017 through 2018. In addition, road repaving is ongoing in the Lynchburg District.

239. Transportation and traffic issues are discussed in sections 4.9.1.5 and 4.9.2.5 of the final EIS. Mountain Valley prepared a *Traffic and Transportation Management Plan* that was reviewed by Virginia Department of Transportation. Mountain Valley will obtain permits from Virginia Department of Transportation prior to crossing roads in Virginia. Equitrans also prepared a *Traffic and Transportation Management Plan* for West Virginia and Pennsylvania and will obtain road crossing and encroachment permits from

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[248] Final EIS at 4-389 to 4-392.

[249] Final EIS at 4-308, 4-321, and 4-389.

the West Virginia Department of Transportation and highway occupancy permits from the Pennsylvania Department of Transportation. Mountain Valley and Equitrans will restore all roads to their pre-construction condition and will coordinate with state and local authorities to obtain the required permits to operate trucks on public roads. As a result, the final EIS finds, and we agree, that the MVP Project would result in temporary to short-term impacts on transportation infrastructure and that the Equitrans Expansion Project would not have significant adverse impacts on transportation infrastructure.[250]

240. Mountain Valley filed a response to recommended Environmental Condition No. 16 in the final EIS, which recommended that Mountain Valley provide an access plan for the right-of-way between MP 237.6 and 240.3 to avoid using proposed access road MVP-RO-279.01. The purpose of this recommendation was to avoid Virginia Outdoor Foundation's open space easement ROA-2563/MON-2563, and minimize impacts on environmental resources and landowners.[251]

241. Mountain Valley contends that access road MVP-RO-279.01 is needed to increase project safety, because of topography in the area. Without use of the road, Mountain Valley contends that it would only have two options. The first involves the use of additional winching. Specifically, Mountain Valley identifies three steeply-sloped areas along the right-of-way that would require up to 10 winch tractors daisy chained together to move a single load of materials, equipment, fuel, or personnel up and down the slopes. Without the use of access road MVP-RO-279.01. Mountain Valley contends that more than 700 additional winch loads would be necessary to transport the required materials, equipment, fuel, and workers along the right-of-way during construction using this chain technique. Mountain Valley contends that the number and complexity of these winching processes create safety concerns. In addition, the required winching is purportedly an extremely slow process that increases the amount of time that Mountain Valley is actively constructing in the area. This, in turn, could increase environmental impacts and safety risks in the area.

242. Mountain Valley states its second alternative is to transport pipe and certain materials to the right-of-way using helicopters. Mountain Valley contends that this could double the number of loads and increase noise impacts on surrounding properties for a much longer period of time. Similar to the winching processes, Mountain Valley believes that using helicopters to bring pipe and equipment to the right-of-way is an extremely slow process that increases the amount of time that Mountain Valley is actively constructing in the area, which increases environmental impacts and safety risks in the area.

[250] Final EIS at 4-389 to 4-392.

[251] Final EIS at 3-75 to 3-76.

243. Finally, Mountain Valley points out that without the use of access road MVP-RO-279.01, it could take up to two additional hours for emergency responders to reach an injured worker on the right-of-way. Similarly, without use of the road, access to repair a section of the pipeline during operation of the MVP Project would be slowed.

244. As stated in the final EIS, the impact of the access road would affect about 0.62 acre. Mountain Valley now proposes to reduce those impacts to 0.32 acre by limiting the width of the road improvements. Mountain Valley now proposes to limit the width of the road to 15 feet in straight sections and 20 feet on curved portions, and narrow additional workspaces to 20 feet on straight sections and 30 feet on curved portions. Mountain Valley will mitigate the impacts by acquiring about 10.25 acres of undisturbed high-quality forest adjacent to the Poor Mountain Natural Area Preserve and providing it to the VOF as compensatory mitigation.

245. We find Mountain Valley's request to use access road MVP-RO-279.01 reasonable because it would improve and ensure project safety. Thus, we include Environmental Condition No. 17 and a modified Environmental Condition No. 16 to this order, to allow use of the road, but require that Mountain Valley incorporate its proposed modifications to minimize impacts.

(c) <u>Housing</u>

246. The projects may have temporary impacts on local housing. The influx of non-local construction workers could affect local housing availability, as they compete with visitors for limited accommodations in rural areas with few hotels. Peak non-local employees working on the MVP Project would average between 536 and 671 people per construction spread; with a total of 11 spreads. The total peak workforce for the Equitrans Expansion Project, including pipelines and aboveground facilities, would be about 400 people. Non-local construction workers would need to find housing in vacant rental units, including houses, apartments, mobile home parks, hotels/motels, and campgrounds and recreational vehicle parks. The final EIS estimates that the housing stock in the affected counties of West Virginia would include 1,913 rental units, 5,202 hotel/motel rooms, and 2,704 recreational vehicle spaces; while the counties crossed in Virginia have about 1,986 rental units, 6,548 hotel/motel rooms, and 321 recreational vehicle spaces. In those counties where housing is limited, workers would likely find accommodations at adjacent larger communities that are within commuting distance, bring their own lodgings in the form of recreational vehicles, or share units. For the MVP Project, construction workers would be spread out along 11 separate pipeline spreads and 7 aboveground facilities across 17 counties. While it would take about 2.5 years to build the MVP Project, the average worker would only be on the job for about 10 months for the pipeline and 8 months for aboveground facilities. The final EIS

concludes, and we agree, that the projects should not have significant long-term adverse impacts on housing.[252]

j. Cultural Resources

i. Historic Districts

247. The final EIS states that the MVP Project will cross seven Historic Districts: (1) Big Stony Creek Historic District, (2) Greater Newport Rural Historic District, (3) North Fork Valley Rural Historic District, (4) Bent Mountain Rural Historic District, (5) Blue Ridge Parkway Historic District, (6) Coles-Terry Rural Historic District, and (7) the Lynchburg and Danville Railroad Historic District.[253] The Virginia Department of Historic Resources, representing the State Historic Preservation Office (SHPO), states that the Lynchburg and Danville Railroad Historic District is not eligible for inclusion in the National Register of Historic Properties (National Register) and therefore will not be affected by the MVP Project; and Commission staff agrees.[254] The Virginia Department of Historic Resources indicated that the MVP Project would have adverse effects on the Big Stony Creek Historic District, Greater Newport Rural Historic District, North Fork Valley Rural Historic District, Bent Mountain Rural Historic District, and Coles-Terry Rural Historic District because visual impacts will diminish the feelings and settings of these historic districts.[255] Commission staff agrees with the determination of the Virginia Department of Historic Resources.

248. The Equitrans Expansion Project does not cross any Historic Districts.

249. In comments on the final EIS, Preserve Roanoke raises concerns about the Blue Ridge Parkway Historic District and the Coles-Terry Rural Historic District. Preserve Roanoke indicates that construction of the MVP Project could result in visual impacts on the Blue Ridge Parkway Historic District that would impair its historic and cultural values. The Blue Ridge Parkway Historic District is discussed in section 4.10.7 of the final EIS, which states that the District is listed on the National Register. The final EIS also states that Mountain Valley filed a visual impact assessment for the Blue Ridge Parkway Historic District in February 2017. Based on that assessment, Mountain Valley

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[252] Final EIS at 4-447.

[253] Final EIS 4-447.

[254] *See* section 4.10.7.1 of the final EIS.

[255] *See* July 5, 2017 Letter from the Virginia Department of Historic Resources to Mountain Valley (filed July 20, 2017).

concluded that there would be no significant adverse impacts on the visual resources associated with the Blue Ridge Parkway Historic District at the crossing of the MVP Project. The Blue Ridge Parkway, however, is managed by the NPS which has not yet concurred on the visual impact assessments. In accordance with Environmental Condition No. 15 of this order, visual impacts related to the Blue Ridge Parkway Historic District will be fully identified and appropriate mitigation will be developed, to the extent necessary, once the NPS and the Virginia Department of Historic Resources file their opinions.[256]

250. Preserve Roanoke also contends that the Roanoke River contributes to the historic integrity of the Coles-Terry Rural Historic District. However, the Roanoke River is a geographic feature and not a cultural resource.

251. The Counties, in comments on the final EIS, also raise concerns about potential project-related effects on the Greater Newport Rural Historic District, Newport Historic District, Blue Ridge Parkway Historic District, Coles-Terry Rural Historic District, and the Bent Mountain Rural Historic District. These Historic Districts are discussed in section 4.10.7.1 of the final EIS. The Newport Historic District, Greater Newport Historic District, and Blue Ridge Parkway Historic District are already listed on the National Register. The final EIS states that the Coles-Terry Rural Historic District and Bent Mountain Rural Historic District are eligible for the National Register. The MVP Project will be outside the boundaries of the Newport Historic District and will not affect that District.

252. On August 28, 2017, after the final EIS was issued, Mountain Valley filed Treatment Plans with the Commission to resolve adverse effects on the Big Stony Creek Historic District, Greater Newport Rural Historic District, North Fork Valley Rural Historic District, Bent Mountain Rural Historic District, and Coles-Terry Rural Historic District. Mountain Valley also submitted these plans to the Virginia Department of Historic Resources. Environmental Condition No. 15 of this order will ensure future consultations with the SHPOs and reviews of treatment plans.

ii. <u>Previously Recorded Cultural Resources</u>

253. The final EIS identifies two previously-recorded historic properties[257] in the direct area of potential effect (150 feet from work areas) for the Equitrans Expansion Project's

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[256] Final EIS at 4-442 to 4-443.

[257] Historic properties include prehistoric or historic sites, districts, buildings, structures, objects, or properties of traditional religious or cultural importance that are listed or eligible for listing on the National Register, in accordance with 36 C.F.R. § 60.4 (2017). *See* final EIS at 1-41.

H-318 pipeline: (1) the Monongahela River Navigation System and (2) the Pittsburgh and Lake Erie Railroad. Equitrans will use an HDD to cross under the river and railroad to avoid impacts on these two historic properties.

254. In Braxton County, West Virginia, Mountain Valley identified one previously-recorded National Register-listed site (Weston and Gauley Bridge Turnpike Trail [NR#98001430]) in the direct area of potential effect, and intends to bore under the site. The West Virginia Department of Culture and History, representing the SHPO, states that this would result in no adverse effects. Commission staff agrees with this determination.

255. Mountain Valley identified one previously recorded archaeological site (44MY54) and three previously-recorded historic sites (Appalachian National Scenic Trail, Elijah Henry House, and Flora Farm) in the direct area of potential effect in Virginia that are eligible for the National Register. Commission staff and the Virginia Department of Historic Resources agree that the MVP Project would have no adverse effects on those sites.

256. James and Karen Scott (Scotts) state that supplemental materials filed by Mountain Valley on June 30, 2017, after the EIS was issued, misrepresent historic sites on their property, including the Elijah Henry House. Mountain Valley's June 30, 2017 filing indicates that the proposed MVP Project would be 425 feet from the Elijah Henry House, while the final EIS states that the pipeline would be about 139 feet away from the site. In a filing on September 5, 2017, Mountain Valley clarifies that the Elijah Henry House is located about 144 feet away from a proposed access road for the MVP Project. The final EIS states that the Elijah Henry House is eligible for the National Register, and may be considered a contributing resource to the Coles-Terry Rural Historic District. The Virginia Department of Historic Resources found, and Commission staff agrees, that the MVP Project will have no adverse effects on the Elijah Henry House.[258]

257. The Scotts claim that Mountain Valley's consultant misidentified the Elijah Henry Spring House as a "shed," and failed to record a root cellar at the site. As discussed in the final EIS, the Virginia Department of Historic Resources accepted the cultural reports that described the site, and made an assessment of eligibility and effects. In any case, the distinction the Scotts draw does not change our analysis.

258. The Scotts state that the pipeline would cross the Elijah Henry Spring House water line. The Spring House is outside the area of potential effect and will not be affected by the MVP Project. As indicated in the final EIS, Mountain Valley will attempt to install

[258] Final EIS at 4-446.

its pipeline below existing foreign utilities.[259] Therefore, Mountain Valley is expected to install its pipeline below the Spring House water line to avoid impacts.

iii. Newly-Recorded Cultural Resource Sites

259. The final EIS indicates that a total of 282 newly-recorded archaeological sites and 116 historic architectural sites have been identified in the direct area of potential effect for the MVP Project, outside of Historic Districts.[260] Based on Mountain Valley's cultural resources investigations reports, the final EIS determines that 220 of the newly-recorded archaeological sites and 107 of the newly-recorded historic architectural sites in the direct area of potential effect are not eligible for the National Register, are not historic properties, and require no additional evaluation. A total of 46 newly-recorded archaeological sites are unevaluated and avoidance of these sites was recommended. The final EIS concludes that, for the entire MVP Project, eleven newly-recorded archaeological sites and seven newly recorded historic architectural sites have been evaluated as eligible for nomination to the National Register.

260. Of the total of 18 National Register-eligible newly recorded resources in the direct area of potential (outside of Historic Districts) for the entire MVP Project discussed in the final EIS, eight archaeological sites and two historic architectural sites are located in West Virginia. Mountain Valley's cultural resources consultants recommended that the MVP Project would have either no effect or no adverse effects on the eligible historic architectural sites in West Virginia. Mountain Valley intends to avoid four of the eligible archaeological sites in West Virginia. In the case of the four other eligible archaeological sites in West Virginia, Mountain Valley indicated that significant data were already recovered, and recommended a finding of no adverse effects. Three archaeological sites and five historic architectural sites found to be eligible in the final EIS are located in Virginia. Mountain Valley intends to avoid the three eligible archaeological sites in Virginia. Mountain Valley's cultural resources consultants recommended that the MVP Project will have no adverse effects on the eligible historic architectural sites in Virginia. Commission staff concludes that the MVP Project will have no effect on sites that are avoided. No additional work will be required at historic properties where the MVP Project will have no effect or no adverse effects.

261. After the issuance of the final EIS, the West Virginia Division of Culture and History, made a finding that three National Register-listed or eligible historic architectural sites in West Virginia (Underwood Farmstead [LE-150], St. Bernard's Church [NR#85001583], and Losch Farmstead [BX-351] will be adversely effected by the MVP Project. On September 18, 2017, Mountain Valley filed Treatment Plans to

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[259] Final EIS at 2-48.

[260] Final EIS at 4-479.

mitigate adverse effects at these three historic architectural sites, and the plans are being reviewed by the West Virginia SHPO. Also after the final EIS was issued, the Virginia Department of Historic Resources found that the MVP Project will have adverse effects on three archaeological sites in the Virginia (44GS241, 44RN400 and 44RN401). Mountain Valley filed Treatment Plans to mitigate adverse effects at those three archaeological sites, to be reviewed by the Virginia SHPO.

262. The Scotts also comment on impacts of the MVP Project on the Henry-Waldron Cemetery. The final EIS states that Mountain Valley will avoid the cemetery. Mountain Valley's historic architectural consultant recommended that the Henry-Waldron Cemetery is not individually eligible for the National Register, but could be considered a contributing element to the Coles-Terry Rural Historic District.[261] The Virginia Department of Historic Resources agreed with the consultant's recommendations for the Henry-Waldron Cemetery in a June 27, 2017 letter accepting the consultant's report.[262] Mountain Valley's Treatment Plan for the Coles-Terry Rural Historic District indicates that the Henry-Waldron Cemetery is about 20 feet away from the construction limits for proposed Access Road MVP-EO-281. Mountain Valley will fence the cemetery to avoid impacts.

263. A minor route variation for the Scotts parcel was evaluated in section 3.5 of the final EIS. As stated in table 3.5.3-1 of the final EIS, desktop analysis showed a minor route deviation to address the Scotts' concerns is feasible, but would shift the route onto the properties of adjacent landowners. The minor route deviation was part of a larger route variation (the Poor Mountain Variation), which the final EIS concludes does not offer a significant environmental advantage when compared to the corresponding proposed route segment.[263]

264. Preservation Virginia expresses concerns about potential project impacts on pre-contact archaeological sites 44FR240, 372, 392, 398, 399, and 400, in Franklin County, Virginia. Preservation Virginia recommends additional archaeological test excavations at these sites.

265. Preservation Virginia acknowledges, however, that archaeological site 44FR240 is outside of the area of potential effect. Therefore, that site will not be affected by the MVP Project. In addition, the final EIS indicates that archaeological sites 44FR398, 399,

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[261] Final EIS at 4-463.

[262] Filed with the FERC by Mountain Valley on June 30, 2017, after the issuance of the final EIS.

[263] Final EIS at 3-80.

and 400 were evaluated as not eligible for the National Register based on a December 2016 survey report, and a determination which the Virginia Department of Historic Resources concurred with. Thus, no further investigations are necessary for those sites. Finally, because archaeological sites 44FR372 and 392 are eligible for the National Register, Mountain Valley proposes to avoid those sites.[264]

266. The Counties claim that the Commission did not directly consult with them regarding findings of eligibility and effects for cultural resources identified in the areas of potential effect within those counties.

267. We disagree. The Counties were sent copies of both the draft EIS and the final EIS. Those documents present the findings of the Commission staff regarding identification of historic properties and assessment of effects. Commission staff addresses the comments of the Counties on the draft EIS in Appendix AA of the final EIS.[265]

268. During surveys for the Equitrans Expansion Project, Equitrans' consultant identified six new archaeological sites within the direct area of potential effect and 115 historic architectural sites within the indirect area of potential effect (0.25-mile from the pipeline), all of which were evaluated as not eligible for the National Register. We have, however, included Environmental Condition No. 36 to this order to require Equitrans to file the results of cultural resource surveys for the New Cline Variation, which Equitrans incorporated into its proposal, prior to construction.

iv. Conclusion

269. The entire process of compliance with section 106 of the National Historic Preservation Act has not yet been completed for the projects. The applicants will need to conduct surveys and evaluation studies at areas where access was previously denied. Commission staff has not yet finished consultations with the SHPOs. If the Commission staff determines that any historic properties will be adversely affected, staff will notify the Advisory Council on Historic Preservation, and consult with appropriate consulting parties regarding the production of an agreement document to resolve adverse effects, in accordance with 36 C.F.R. § 800.6. Therefore, Environmental Condition No. 15 of this order restricts construction until after all additional required surveys and evaluations are completed, survey and evaluation reports and treatment plans have been reviewed by the

[264] Final EIS at 4-463 to 4-465.

[265] *See* responses to Comments LA4, LA7, LA2, and LA15 in Appendix AA of the final EIS.

appropriate consulting parties, the Advisory Council on Historic Preservation has had an opportunity to comment, and the Commission has provided written notification to proceed.

k. Air Quality and Noise Impacts

i. Air Quality

270. Air quality impacts associated with construction of the proposed projects will include emissions from construction equipment and fugitive dust. The final EIS concludes that such air quality impacts will generally be temporary and localized, and are not expected to cause or contribute to a violation of applicable air quality standards.

271. Operational emissions will be mainly generated by the four new compressor stations proposed for the projects. Mountain Valley submitted applications for construction and operation of the Bradshaw, Harris, and Stallworth Compressor Stations to the WVDEP and received construction permits. Equitrans' application for construction and operation of the Redhook Compressor Station is pending at the PADEP. All the compressor stations will be minor sources with respect to Prevention of Significant Deterioration and New Source Review under the Clean Air Act.

272. The Clean Air Act Title V permit program, as described in 40 C.F.R. Part 70, requires sources of air emissions to obtain federal operating permits if their criteria pollutant emissions reach or exceed the Title V major source threshold. The new Bradshaw Compressor Station will exceed the Title V major source threshold for nitrogen oxide and carbon monoxide. Therefore, Mountain Valley is required to file a Title V permit application with the WVDEP within 12 months of startup of operations of the Bradshaw Compressor Station. The Harris, Stallworth, and Redhook Compressor Stations will not exceed the major source emissions thresholds or be subject to a Title V operating permit.

273. As stated in the final EIS, minimization of operational air pollutant emissions from the projects' compressor stations, including greenhouse gases (GHG), will be achieved by operating the most efficient turbines available, installing best available technology, adhering to good operating and maintenance practices on turbines and combustion engines, and adhering to applicable federal and state regulations designed to reduce emissions. The screening analyses conducted for Mountain Valley's and Equitrans' compressor stations show criteria air pollutant concentrations are below the applicable National Ambient Air Quality Standards.

274. Mr. Workman asserts that the final EIS did not quantify GHGs. The EIS does quantify GHG emissions in table 4.13.2-2, and GHGs are further discussed in sections 4.11 and 4.13.

275. Based on the foregoing reasons, the final EIS concludes, and we agree, that emissions resulting from operation of the compressor stations will not result in significant impacts on local or regional air quality.[266]

ii. Noise Impacts

276. Noise levels are quantified according to decibels (dB), which are units of sound pressure. The A-weighted sound level, expressed as dBA, is used to quantify noise impacts on people. Sound level increases during pipeline construction will be intermittent and will generally occur during daylight hours, with the possible exception of some HDD activities. Construction equipment noise levels will typically be around 85 dBA at a distance of 50 feet. Blasting may be necessary to trench through shallow bedrock. Blasting noise levels have been documented at about 94 dBA at a distance of 50 feet. Noise impacts during construction will be transient as pipe installation progresses from one location to the next. HDD operations at the entry and exit locations will result in high noise levels at the source location. Typically, noise from HDD are estimated to be about 90 dBA at 50 feet. Therefore, Environmental Condition No. 38 of this order requires, prior to construction at HDD locations, Equitrans to file plans outlining measures to be implemented to reduce the projected noise level increases attributable to the proposed drilling operations at noise sensitive areas (NSA).

277. As stated in the final EIS, the applicants modeled noise levels at NSAs near each compressor station during operation. Worst case modeled noise levels at each NSA due to typical compressor station operation will be below the Commission's noise limit of 55 dBA. Increases over existing ambient noise levels will be barely noticeable, ranging from 0.1 dBA to 3 dBA. Environmental Condition Nos. 40 and 41 of this order requires the applicants to file the results of noise surveys during operation of the compressor stations, and if noise exceeds the day-night sound level of 55 dBA at any NSA, the applicants must install additional noise controls and refile noise survey results within one year.

l. Safety

278. Commenters questioned the safety of the projects. The final EIS states that the project facilities must be designed, constructed, operated, and maintained to meet or exceed the DOT's Minimum Federal Safety Standards[267] and other applicable federal and state regulations. These regulations include specifications for material selection and

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[266] Final EIS at 4-515-516.

[267] *See* 49 C.F.R. pt. 192 (2017).

qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion.

279. The final EIS concludes that the projects provide a safe, reliable means of transporting natural gas. The low number of incidents distributed over the more than 300,000 miles of natural gas transmission pipelines indicates that the risk is minimal for an incident at any given location. The final EIS concludes, and we agree, that the projects do not represent a significant safety risk to the public.[268]

280. We also received comments expressing concern that the projects may become a target for a future act of terrorism. The likelihood of future acts of terrorism or sabotage occurring along the project or at any of the myriad natural gas pipeline or energy facilities throughout the United States is unpredictable given the disparate motives and abilities of terrorist groups. Further, the Commission, in cooperation with other federal agencies, including the U.S. Department of Homeland Security, industry trade groups, and interstate natural gas companies, is working to improve pipeline security practices, strengthen communications within the industry, and extend public outreach in an ongoing effort to secure pipeline infrastructure. In accordance with the DOT surveillance requirements, the applicants will incorporate air and ground inspection of its proposed facilities into its inspection and maintenance program. In addition, the applicants propose security measures at the new aboveground facilities that will include secure fencing.

m. Cumulative Impacts

281. A number of commenters generally argue that the final EIS's discussion of the cumulative impacts of the projects is inadequate.

282. CEQ defines "cumulative impact" as "the impact on the environment which results from the incremental impact of the action [being studied] when added to other past, present, and reasonably foreseeable future actions . . . ."[269] The requirement that an impact must be "reasonably foreseeable" to be considered in a NEPA analysis applies to both indirect and cumulative impacts.

283. The "determination of the extent and effect of [cumulative impacts], and particularly identification of the geographic area within which they may occur, is a task assigned to the special competency of the appropriate agencies."[270] CEQ has explained

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[268] Final EIS at 4-573.

[269] 40 C.F.R. § 1508.7 (2017).

[270] *Kleppe*, 427 U.S. at 413.

that "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."[271] Further, a cumulative impact analysis need only include "such information as appears to be reasonably necessary under the circumstances for evaluation of the project rather than to be so all-encompassing in scope that the task of preparing it would become either fruitless or well-nigh impossible."[272] An agency's analysis should be proportional to the magnitude of the environmental impacts of a proposed action; actions that will have no significant direct and indirect impacts usually require only a limited cumulative impacts analysis.[273]

284. In considering cumulative impacts, CEQ advises that an agency first identify the significant cumulative effects issues associated with the proposed action.[274] The agency should then establish the geographic scope for analysis. Next, the agency should establish the time frame for analysis.[275] Finally, the agency should identify other actions that potentially affect the same resources, ecosystems, and human communities that are affected by the proposed action.[276] As noted above, CEQ advises that an agency should relate the scope of its analysis to the magnitude of the environmental impacts of the proposed action.[277]

285. Commission staff defined the geographic scope for its analysis of cumulative impacts on specific environmental resources to include projects/actions within the watersheds crossed by the projects for cumulative impacts on water resources and wetlands, vegetation, land use, and wildlife; cumulative impacts on air quality were evaluated within the Air Quality Control Regions (AQCR) where compressor stations are located; cumulative noise impacts on NSAs within 1 mile of compressor stations;

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[271] CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act* at 8 (January1997) (1997 Cumulative Effects Guidance).

[272] *Id*.

[273] *See* CEQ, *Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis* at 2-3 (June 2005).

[274] 1997 Cumulative Effects Guidance at 11.

[275] *Id.*

[276] *Id*.

[277] CEQ, *Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis* at 2 (June 2005).

cumulative impacts on visual resources within 0.25-mile of the pipelines; and cumulative impacts on cultural resources at the county level.

286. The types of other projects, in addition to the MVP and Equitrans Expansion Projects, considered by Commission staff that could potentially contribute to cumulative impacts on a range of environmental resources include other Commission-jurisdictional natural gas interstate transportation projects; non-jurisdictional pipelines and gathering systems; oil and gas exploration and production activities; mining operations: transportation or road projects; commercial/residential/industrial and other development projects; and other energy projects, including power plants or electric transmission lines. The MVP Project will cross 31 watersheds, and the Equitrans Expansion Project will cross 3 watersheds. The 33 watersheds cover a combined total of 4,557,727 acres (about 7,121 square miles).[278] The projects will account for about 6,487 acres of impacts (0.1 percent) within these watersheds, while other projects located within the same watersheds account for 83,722 acres (1.8 percent) of impact.[279] The final EIS concludes, and we agree, that when added to other past, present, and reasonably foreseeable future actions, the projects will not result in significant adverse cumulative impacts on environmental resources.[280]

n. <u>Downstream Greenhouse Gas Emissions</u>

287. Sierra Club[281] argues that because of the recent decision by the D.C. Circuit Court of Appeals in *Sierra Club v. FERC*[282] the Commission should reopen the record in this proceeding and issue a supplemental EIS to address greenhouse gas (GHG) emissions and impacts on climate change as a result of the end-use consumption of the natural gas transported by the pipeline. Sierra Club asserts that, although the final EIS estimated downstream GHG emissions from combustion of the transported natural gas, the final

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[278] The Fishing Creek watershed contains parts of both projects.

[279] As indicated in the final EIS, the footprint of other projects is provided where available. Footprint data for all projects considered was not available.

[280] Final EIS at 4-622.

[281] Sierra Club filed on behalf of Allegheny Defense Project, Appalachian Voices, Dominion Pipeline Monitoring Coalition, Friends of Nelson, Natural Resources Defense Council, Ohio Valley Environmental Coalition, Protect Our Water Heritage Rights, Sierra Club (including its West Virginia and Virginia Chapters), West Virginia Highland Conservancy, West Virginia Rivers Coalition, and Wild Virginia.

[282] Sabal Trail, 867 F.3d 1357.

EIS does not analyze the scope, significance, cumulative impact, and potential alternatives of the GHG emissions.[283]

288. Sierra Club claims that the final EIS was not only required to quantify the greenhouse gas emissions, but also must include a discussion of their significance and any cumulative impacts associated with greenhouse gas emissions. Sierra Club argues that the final EIS only provides a cursory analysis of the impact associated with downstream combustion. Sierra Club also states that the final EIS relies on the assertion that the projects would result in the displacement of some coal, but that this approach was rejected by the court in Sabal Trail because the Commission failed to assess whether total emissions would be reduced or increased, or what the degree of reduction or increase would be.[284]

289. Next, Sierra Club dismisses the final EIS's assertions that the Commission is unable to assess the significance of the projects' impacts on climate because it contends the social cost of carbon methodology was available when the Commission prepared the final EIS. Sierra Club asserts that the court in Sabal Trail held that the Commission must explain why it did not use the methodology to determine project-specific impacts.[285]

290. Last, Sierra Club states that the final EIS's statement that end-use "emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change that produces the impacts previously described" does not adequately address the cumulative impacts of the projects. Sierra Club avers that the final EIS incorrectly downplays the cumulative climate impacts associated with the natural gas infrastructure build out in Pennsylvania, West Virginia, Virginia, and other surrounding states, and does not quantify the project's GHG emissions in combination with these past, present, and reasonably foreseeable gas projects.

291. Sierra Club concludes that as a result of the final EIS's failure to address these concerns, the Commission did not conduct an informed public process and failed to provide information necessary to assess potential alternatives and mitigation measures.

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[283] Sierra Club also requests that the Commission supplement or revise the final EIS based on purported new information received after the close of the comment period on the draft EIS. However, as discussed in PP 134-135 of this order, there is no new information here that would necessitate a supplemental or revised EIS.

[284] Sabal Trail, 867 F.3d at 1375.

[285] *Id.*

292. The court in Sabal Trail held that where it is known that the natural gas transported by a project will be used for end-use combustion, the Commission should "estimate[] the amount of power-plant carbon emissions that the pipelines will make possible."[286] As Sierra Club acknowledges, the final EIS did just that.[287] Thus, the Commission and the public were fully informed of the potential impacts from the projects.

293. The final EIS conservatively estimates that full combustion of the volume of natural gas transported would produce GHG emissions of up to about 48 million metric tons per year.[288] We note that this estimate represents an upper bound for the amount of end-use combustion that could result from the gas transported by these projects. This is because some of the gas may displace other fuels, which could actually lower total GHG emissions. It may also displace gas that otherwise would be transported via different means, resulting in no change in GHG emissions.

294. In an effort to put these emissions in to context, we examined both the regional[289] and national emissions of GHGs. If only the regions identified by the applicants as prospective markets are considered, the volume of GHG emissions by the MVP and Equitrans Expansion Projects will result in a two percent increase of GHG emissions

[286] *Id*. at 1371. We note that the end users in Sabal Trail were known (i.e., FPL and Duke Energy Florida power plants in Florida), *see id.* at 1364 and n.8, which is dissimilar to the situation here. While Mountain Valley has entered into precedent agreements with two end users (Roanoke Gas and ConEd) for approximately 13 percent of the MVP project capacity, the ultimate destination for the remaining gas will be determined by price differentials in the Northeast, Mid-Atlantic, and Southeast markets and, thus, is unknown.

[287] Final EIS at 4-620 (providing table with Total Projected GHG Emissions from End-Use Combustion).

[288] Final EIS at 4-620. Our estimate here is based on GHG emissions caused by the combustion of the full design capacity of the projects.

[289] Commission staff looked at the Transco, Columbia, and Texas Eastern systems to identify the states where those pipeline systems serve. Natural gas can move anywhere on these systems. Thus, we used the combined inventory of: (1) states served by Transco's system; (2) states served by Transco and Columbia; and (3) states served by Transco and Texas Eastern (the Columbia system overlapped the Texas Eastern system). We compared the 2014 inventory of these states served by the three systems in comparison to the downstream emissions to arrive at the potential increase in GHG emissions.

from fossil fuel combustion in these states. From a national perspective, combustion of all the gas transported by the MVP and Equitrans Expansion Projects will, at most,result in a one percent increase of national GHG emissions.

295. The final EIS acknowledged that the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change.[290] However, as the final EIS explained, because the project's incremental physical impacts on the environment caused by climate change cannot be determined, it also cannot be determined whether the projects' contribution to cumulative impacts on climate change would be significant.[291]

296. We also disagree with Sierra Club's assertion that the Commission should have used the social cost of carbon methodology to determine how the proposed projects' incremental contribution to GHGs would translate into physical effects on the global environment. While we recognize the availability of the social cost of carbon methodology, it is not appropriate for use in any project-level NEPA review for the following reasons: (1) EPA states that "no consensus exists on the appropriate [discount] rate to use for analyses spanning multiple generations"[292] and consequently, significant variation in output can result;[293] (2) the tool does not measure the actual incremental impacts of a project on the environment; and (3) there are no established criteria identifying the monetized values that are to be considered significant for NEPA reviews. The methodology may be useful for rulemakings or comparing regulatory alternatives using cost-benefit analyses where the same discount rate is consistently applied; however, it is not appropriate for estimating a specific project's impacts or informing our analysis under NEPA. Moreover, Executive Order 13783, Promoting Energy Independence and Economic Growth, has disbanded the Interagency Working Group on Social Cost of Greenhouse Gases and directed the withdrawal of all technical support documents and instructions regarding the methodology, stating that the documents are "no longer representative of governmental policy."[294]

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[290] Final EIS at 4-620.

[291] *Id*.

[292] *See* Fact Sheet: *Social Cost of Carbon* issued by EPA in November 2013, https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html.

[293] Depending on the selected discount rate, the tool can project widely different present day cost to avoid future climate change impacts.

[294] Exec. Order No. 13,783, 82 Fed. Reg. 16093 (2017).

o. Alternatives

297. The final EIS analyzes alternatives, including the no-action alternative, system alternatives, and route alternatives. If the no-action alternative is selected, the environmental impacts outlined in the final EIS will not occur. However, if the projects are not authorized, their stated objectives will not be realized, and natural gas will not be transported from production areas in the Appalachian Basin to end-users in the Southeast and Mid-Atlantic regions. In response to the no-action alternative, shippers may seek other infrastructure to transport natural gas to customers, and construction of those other projects may result in environmental impacts that will be similar to or greater than the MVP and Equitrans Expansion Projects.

298. A number of commenters suggested that the contracted volumes of natural gas could be transported via existing pipeline systems. The final EIS concludes, and we agree, that no existing pipeline system in the vicinity of the projects can meet their stated objectives without major expansions, which might result in environmental impacts similar to or greater than the impacts of the proposed the MVP and Equitrans Expansion Projects.[295]

299. The final EIS also considers if the contracted volumes of the MVP and Equitrans Expansion Projects could be transported through the Supply Header - Atlantic Coast Pipeline (Atlantic Coast) proposed in Docket Nos. CP15-554-000 and CP15-555-000. The final EIS examines two hypothetical scenarios[296] for this: (1) the "one-pipe" alternative in which the MVP Project volumes would be transported together with the Atlantic Coast volumes in a single pipeline along the proposed Atlantic Coast route; and (2) the "two-pipe, one right-of-way" alternative, where the MVP Project would be relocated adjacent to the Atlantic Coast Project.[297]

300. A hypothetical "one-pipe" alternative to transport the combined volumes of both the MVP and Atlantic Coast Projects, totaling about 3.44 Bcf per day, would require either significant additional compression or a larger diameter pipeline as described below. If the alternative utilized Atlantic Coast Project's currently proposed single 42-inch-diameter pipeline, Commission staff estimated that transporting the MVP and Atlantic Coast Projects' combined volumes would require construction of eight additional new

[295] Section 3.3.1 of the final EIS.

[296] We note that no applicant has proposed to construct, and no shipper indicated an interest in utilizing, either of the hypothetical alternative pipeline systems.

[297] *See* sections 3.3.2.1 and 3.4.2.1 of the final EIS.

compressor stations totaling about 873,015 hp of additional compression.[298] Commission staff further estimated that the additional compression could triple air quality impacts compared to construction and operation of both the MVP and Atlantic Coast Projects as proposed. In addition, more laterals would need to be constructed in order to reach the MVP Project taps, thereby resulting in impacts to many new landowners, who have thus far not been part of the pre-filing or certification process. Ultimately, this alternative might not be able to provide service as contracted for to the MVP Project shippers, which is the purpose of the project.

301. Construction of an alternative system utilizing larger, non-typical 48-inch-diameter pipeline instead of the additional compression would require a wider construction right-of-way.[299] The final EIS found that the larger right-of-way could not be accommodated in many areas along route due to the topography of the area, rendering this alternative technically infeasible.[300] Moreover, each of these one-pipe scenarios (more compression or larger diameter pipeline) would require construction of at least 353 miles of greenfield pipeline in order to reach the contracted-for receipt and delivery points for the MVP Project.[301] We therefore find that based on all the factors described above, the "one-pipe" alternative is not technically feasible or practical, nor does it offer a significant environmental advantage over the proposed MVP and Equitrans Projects.[302]

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[298] Final EIS at 3-15 (noting that this amount of additional compression is greater than the total compression of both the Atlantic Coast and MVP Projects combined).

[299] Final EIS at 3-15 (installation of 48-inch-diameter pipeline would require 30 feet or more of additional construction right-of-way over the entire length of the pipeline route and would displace about 30 percent more soil).

[300] Final EIS at 3-16.

[301] Final EIS at 3-14.

[302] The Commission need not analyze "the environmental consequences of alternatives it has in good faith rejected as too remote, speculative, or . . . impractical or ineffective." *Fuel Safe Washington v. FERC*, 389 F.3d 1313, 1323 (10th Cir. 2004) (quoting *All Indian Pueblo Council v. United States*, 975 F.2d 1437, 1444 (10th Cir.1992) (internal quotation marks omitted)); *see also Nat'l Wildlife Fed'n v. F.E.R.C.*, 912 F.2d 1471, 1485 (D.C. Cir. 1990) (NEPA does not require detailed discussion of the environmental effects of remote and speculative alternatives); *Natural Resources Defense Council, Inc. v. Morton*, 458 F.2d 827, 837-38 (D.C.Cir.1972) (same).

302. Under a hypothetical "two-pipe, one right-of-way" scenario, the MVP Project would be collocated with the Atlantic Coast Project for about 205 miles.[303] While the final EIS identified environmental benefits that might be realized with such an alternative, there are also disadvantages such as additional environmental impacts associated with construction of multiple laterals necessary to reach the receipt and delivery points required to fulfill Mountain Valley's contractual obligations with its shippers.[304] Additionally, as described in the final EIS, the narrow ridgelines along the Atlantic Coast route are currently too narrow to accommodate two parallel 42-inch-diameter pipelines. To be able to fit two parallel 42-inch-diameter pipelines, the project sponsors would need to utilize extensive side-hill or two-tone construction techniques and disturb additional acres to prepare workspaces to safely accommodate equipment and personnel, as well as spoil storage. The final EIS concludes that collocating two pipes in a single right-of-way with the Atlantic Coast Project has constructability issues that likely render the "two-pipe" alternative technically infeasible.[305] Moreover, this alternative does not provide a significant environmental advantage over the proposed MVP Project.[306] We agree with the final EIS's conclusion.

303. We are mindful, as the D.C. Circuit has acknowledged, that "given the choice, almost no one would want natural gas infrastructure built on their block."[307] But as the court noted:

> [G]iven our nation's increasing demand for natural gas . . . it is an inescapable fact that such facilities must be built somewhere . . . . Congress decided to vest the [Commission] with responsibility for overseeing the construction and expansion of interstate natural gas facilities. And in carrying out that

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[303] *See* Final EIS at 3-29 (detailing this alternative). A collocated route would not be reach the receipt and delivery points for the MVP Project, which might adversely affect Mountain Valley's agreements with its shippers.

[304] *See* Final EIS at 3-29 through 3-32 (including table comparing the environmental impacts of the two-pipe, one-ROW alternative with the MVP project).

[305] Final EIS at 3-32.

[306] Final EIS at 3-32.

[307] *Minisink Residents for Environmental Preservation and Safety v. FERC*, 762 F.3d 97, 100 (D.C. Cir. 2014) (affirming the Commission's decision to approve project where two dissenting commissioners preferred an alternative pipeline project).

charge, sometimes the Commission is faced with tough judgment calls as to where those facilities can and should be sited.[308]

304. While "the existence of a more desirable alternative is one of the factors which enters into a determination of whether a particular proposal would serve the public convenience and necessity,"[309] that is not at issue in this case. Here, neither the "one-pipe" nor the "two-pipe, one right-of-way" alternative is a viable or desirable alternative. The final EIS nonetheless took a hard look at these alternatives.[310] We agree with the determination in the final EIS and need not consider either alternative any further.[311]

305. James Workman claims that the final EIS excluded consideration of the no-action alternative. However, the final EIS discusses the no-action alternative in section 3.1.[312] Mr. Workman suggests that an alternative route following the Rover Pipeline Project (Rover)[313] should be studied. While Rover's CGT Lateral is about five miles from the MVP Project near about MP 20.0 in Doddridge County, West Virginia, Rover heads northwest into Ohio. In order to reach Mountain Valley's proposed terminus and delivery point at Transco Station 165 in Pittsylvania County, Virginia, the MVP Project would need to be routed southeast from Doddridge County, West Virginia, which is the opposite direction from Rover. Therefore, collocating the MVP Project along Rover's CGT Lateral is not practical.

306. The final EIS also considers 3 other major route alternatives (Alternative 1, Hybrid 1-A, and Hybrid 1-B) and 15 route variations along the MVP Project, and 5 route

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[308] *Id.*

[309] *City of Pittsburgh v. FPC*, 237 F.2d 741, 751 n.28 (D.C. Cir. 1956).

[310] Indeed, CEQ regulations implementing NEPA explicitly permit the Commission, in rejecting alternatives, merely to "briefly discuss the reasons for their having been eliminated." *City of Rockingham, N. Carolina v. FERC*, No. 15-2535, 2017 WL 2875112, at *5 (4th Cir. July 6, 2017) (quoting 40 C.F.R. § 1502.14(a)).

[311] The Commission's NEPA obligation requires that it "'identify the reasonable alternatives to the contemplated action' and 'look hard at the environmental effects of [its] decision[ ].'" *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 967 (D.C. Cir. 2000) (quoting *Corridor H Alternatives, Inc. v. Slater*, 166 F.3d 368, 374 (D.C.Cir.1999)) (alterations in original).

[312] Final EIS at 3-4.

[313] *Rover Pipeline LLC*, 158 FERC ¶ 61,109.

variations along the Equitrans Expansion Project.[314] The final EIS finds, and we agree, that these alternative routes generally did not provide a significant environmental advantage over the proposed route segments to justify affecting additional landowners, and were not recommended. However, the final EIS recommends that Mountain Valley adopt Variation 250 into its proposed route between MPs 220.7 and 223.7, and we include that recommendation in Environmental Condition No. 16 of this order.

4. Environmental Analysis Conclusion

307. We have reviewed the information and analysis contained in the final EIS regarding the potential environmental effects of the MVP and Equitrans Expansion Projects, as well as the other information in the record. We are accepting the environmental recommendations in the final EIS, as modified herein, and are including them as conditions in Appendix C to this order.

308. Based on our consideration of this information and the discussion above, we agree with the conclusions presented in the final EIS and find that the projects, if constructed and operated as described in the final EIS, are environmentally acceptable actions. Further, for the reasons discuss throughout the order, as stated above, we find that the projects are in the public convenience and necessity.

309. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this certificate. We encourage cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[315]

310. The Commission on its own motion received and made part of the record in this proceeding all evidence, including the application, as amended and supplemented, and exhibits thereto, and all comments submitted, and upon consideration of the record,

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[314] *See* section 3.5 of the final EIS.

[315] *See* 15 U.S.C. § 717r(d) (state or federal agency's failure to act on a permit considered to be inconsistent with Federal law); *see also Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 310 (1988) (state regulation that interferes with FERC's regulatory authority over the transportation of natural gas is preempted) and *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 245 (D.C. Cir. 2013) (noting that state and local regulation is preempted by the NGA to the extent it conflicts with federal regulation, or would delay the construction and operation of facilities approved by the Commission).

The Commission orders:

(A) A certificate of public convenience and necessity is issued to Mountain Valley, authorizing it to construct and operate the proposed Mountain Valley Pipeline Project, as described and conditioned herein, and as more fully described in the application as supplemented.

(B) A certificate of public convenience and necessity is issued to Equitrans, authorizing it to construct and operate the proposed Equitrans Expansion Project, as described and conditioned herein, and as more fully described in the application.

(C) The certificate authority issued in Ordering Paragraphs (A) and (B) is conditioned on:

(1) Mountain Valley's and Equitrans' projects being constructed and made available for service within 3 years of the date of this order, pursuant to section 157.20(b) of the Commission's regulations;

(2) Mountain Valley's and Equitrans' compliance with all applicable Commission regulations, particularly the general terms and conditions set forth in Parts 154, 157, and 284, and paragraphs (a), (c), (e), and (f) of section 157.20 of the Commission's regulations;

(3) Mountain Valley's and Equitrans' compliance with the environmental conditions listed in Appendix C to this order; and

(4) Mountain Valley and Equitrans filing written statements affirming that they have executed firm contracts for volumes and service terms equivalent to those in their precedent agreements, prior to the commencement of construction.

(D) Equitrans' request to abandon facilities, as described in this order and in its application, is granted, subject to the conditions described herein and in Appendix C of this order.

(E) Equitrans shall notify the Commission within 10 days of the date(s) of its abandonment(s) of facilities as authorized by this order. Equitrans shall complete authorized abandonments within one year from the date of this order.

(F) Mountain Valley's request for a blanket construction certificate under Subpart F of Part 157 of the Commission's regulations is granted.

(G) Mountain Valley's request for a blanket transportation certificate under Subpart G of Part 284 of the Commission's regulations is granted.

(H) Mountain Valley's initial rates and tariff are approved, as conditioned and modified above.

(I) Mountain Valley is required to file actual tariff records reflecting the initial rates and tariff language that comply with the requirements contained in the body of this order not less than 30 days and not more than 60 days prior to the commencement of interstate service.

(J) Mountain Valley must file not less than 30 days and not more than 60 days before the in-service date of the proposed facilities an executed copy of the non-conforming agreements reflecting the non-conforming language and a tariff record identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations.

(K) Within three years after its in-service date, as discussed herein, Mountain Valley must make a filing to justify its existing cost-based firm and interruptible recourse rates. Mountain Valley's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Mountain Valley is advised to include as part of the eFiling description, a reference to Docket No. CP16-10-000 and the cost and revenue study.[316]

(L) Equitrans' proposal to use its existing Mainline System rates as the initial recourse rates for firm transportation service on the Equitrans Expansion Project is granted.

(M) Equitrans' request for a predetermination supporting rolled-in rate treatment for the costs of the Equitrans Expansion Project in its next NGA general section 4 rate proceeding is granted, absent a significant change in circumstances.

(N) Equitrans shall file an executed copy of the negotiated rate agreement as part of its tariff, disclosing and reflecting all non-conforming language not less than 30 days and not more than 60 days, prior to the commencement of service on the Equitrans Expansion Project.

(O) Mountain Valley and Equitrans shall notify the Commission's environmental staff by telephone, e-mail, and/or facsimile of any environmental noncompliance identified by other federal, state or local agencies on the same day that such agency notifies either Mountain Valley or Equitrans. Mountain Valley or

[316] *Electronic Tariff Filings*, 130 FERC ¶ 61,047 at P 17.

Equitrans shall file written confirmation of such notification with the Secretary of the Commission (Secretary) within 24 hours

(P) The late, unopposed motions to intervene filed before issuance of this order in each respective docket are granted pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure.

(Q) ICG Eastern, LLC's late, opposed motion to intervene filed before issuance of this order in Docket No. 16-10-000 is granted pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure.

(R) The requests for full evidentiary, trial-type hearing are denied.

By the Commission. Commissioner LaFleur is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

List of Timely Intervenors

Docket No. CP16-10-000 – Mountain Valley Pipeline Project

Adam Brauns

Alice Martin Taylor Wilson and Maurice E. Taylor Tate

Allegheny Defense Project

Alpha Natural Resources Services, LLC (and affiliates, Green Valley Coal Company and Brooks Run Mining Company, LLC)

American Electric Power Service Corporation

Andrew Geier

Anita M. Puckett

Ann Marie L. Conner

Anna L. Karr

Appalachian Mountain Advocates

Appalachian Trail Conservancy

Appalachian Voices

Ariel Darago

Association for the Study of Archaeological Properties

Becky Crabtree and Roger Crabtree

Bill Dooley

Black Diamond Property Owners, Inc.

Blue Ridge Environmental Defense League

Blue Ridge Land Conservancy

Bold Alliance

Border Conservancy

Brian R. Murphy

Bruce M. Coffey and Mary Coffey

Bruce W. Zoecklein

Cahas Mountain Rural Historic District

Cameron Bernand

Carl E. Zipper

Carol C. Bienstock

Carolyn Jake

Carolyn Reilly

Cave Conservancy of the Virginias

Charles D. Nikolaus

Charles F. Chong and Rebecca A. Eneix-Chong

Cheryl Borgman

Chesapeake Climate Action Network

Chris Asmann

Chris Roberts

Christian M. Reidys

Christina Witcher

Christopher B. Kaknis

Christopher L. Barrett

Clifford A. Shaffer

Clifford S. Cleavenger and Laura J. Cleavenger

Consolidated Edison Company of New York, Inc.

County Commission of Monroe County, West Virginia

County of Montgomery, Virginia

Craig County Board of Supervisors, Virginia

Craig-Botetourt Electric Cooperative

Cynthia B. Morris

Dana O. Olson

Dane Webster

Daniel C. Campbell

Daniel Moore

David J. Wemer

David M. Hancock

David Rauchle and Judith Rauchle

Deborah E. Hammond

Delwyn A. Dyer

Dennis Jones

Dennis M. Bryant

Don Barber

Donald Jones

Donna M. Riley

Donna Pitt and Joseph Pitt

Donna Reilly

Dragana Avirovik

Duke Energy Carolinas, LLC

Duke Energy Progress, LLC

Dwayne Milam

Edward M. Savage

Eleanor M. Amidon

Elizabeth D. Covington

Elizabeth E. Ackermann

Elizabeth Hahn

Elizabeth Struthers Malbon

Elizabeth Terry Reynolds

EQT Energy, LLC

Erin McKelvy

Ernest Q Reed, Jr.

Frank Terry, Jr.

Frank Wickline

Fred W. Vest

Friends of Nelson

Friends of the Lower Greenbrier River

General Federation of Women's Clubs

George Lee Jones

Gerald M. Jones

Getra Hanes

Giles County Board of Supervisors

Grace M. Terry

Greater Newport Historic District Committee

Greater Newport Rural Historic District Committee

Greenbrier River Watershed Association

Gwynn L. Kinsey

Harriet G. Hodges

Headwaters Defense

Heartwood

Helena Teekell

Hersha Evans

Highlanders for Responsible Development

Holly L. Scoggins

Holly Waterman

Hope Gas, Inc. d/b/a Dominion Hope

Howdy Henritz

Ian Reilly

Independent Oil & Gas Association of West Virginia, Inc.

Indian Creek Watershed Association

J. Phillip Pickett

James Chandler

James McGrady

Jana M. Peters

Jason Boyle

Jason Donald Jones

Jean L. Porterfield

Jennifer J. Henderson

Jobyl A. Boone

John Coles Terry, III

John M. Henrietta

Johnathan Lee Jones

Jonathan D. McLaughlin

Joseph H. Fagan

Julian Clark Hansbarger

Justin Haber

Kali Casper

Kara Jeffries

Keith M. Wilson

Kelley S. Sills

Landcey Ragland

Laura K. Berry and David E. Berry

Lauren C. Malhotra

Lauren Eanes Jones

Laurie Ardison

Lenora Montuori

Leon G. Gross

Leslie Day

Lindsay Newsome

Lois K. Waldron

Lois Martin

Loretta Broslma

Louisa Gay and Kenneth Gay

Lynda Majors

Madison A. Roberts

Margaret A. Roston

Marjorie Lewter

Mark A. Laity-Snyder

Marshall D. Tessnear

Mary Keffer

Matthew Denton-Edmundson

Maury W. Johnson

Michael Bortner

Michael T. Martin

Monroe County Organic District

Nadia Doutcheva

Nancy Guile

Natural Resources Defense Council

Nature Conservancy

NextEra Energy Power Marketing, LLC

Norfolk Southern Railway Company

Ohio Valley Environmental Coalition

Olivia F. Foskey

Orus Ashby Berkley

Pamela S. Tessnear

Patricia Tracy

Paula L. Mann and Herman Mann

Piedmont Natural Gas Company, Inc.

Pittsylvania County Historical Society

PJ Crabtree

Preserve Bent Mountain

Preserve Craig, Inc.

Preserve Giles County

Preserve Greenbrier County

Preserve Monroe

Preserve Montgomery County Virginia

Preserve the New River Valley

Protect Our Water, Heritage and Rights

Rachel L. Warnock

Raymond D. Roberts

Rebecca Dameron

Red Sulphur Public Service District

Renee Howell

Renee Powers

Rex Coal Land Co., Inc.

RGC Midstream, LLC

RGC Resources, Inc.

Richard Shingles

Roanoke County, Virginia

Roanoke Gas Company

Robert B. Lineberry

Robert E. Gross and Rosemary C. Gross

Robert J. Tracy

Robert K. Johnson

Roberta C. Johnson

Robin Austin

Robin S. Boucher

Ronald Tobey and Elisabeth Tobey

Roseanna E. Sacco

Roy S. Quesenberry

Samuel V. Gittelman

Sandra Schlaudecker

Save Monroe, Inc.

Serina Garst

Shenandoah Valley Battlefields Foundation

Shenandoah Valley Network

Sierra Club

Sierra Club (Virginia Chapter)

Stephen C. Browning, Jr.

Stephen D. Gallagher, Jr.

Stephen D. Slough

Stephen K. Wood

Stephen Legge

Stephen M. Miller

Stephen T. Whitehurst

Steven C. Hodges and Judy R. Hodges

Steven Hanes

Steven Hodges

Steven L. Cass

Steven L. Powers

Summers County Residents Against the Pipeline

Susan A. Cornish

Susan B. Ryan

Susan G. Barrett

Susan M. Crenshaw

Tammy A. Capaldo

Taylor Johnson

Terry Hrubec

Thomas Tyler Bouldin

Timothy Ligion

Tina Badger

Tom Ryan and Susan Ryan

Ursula Halferty

Valerie Ughetta

Vicki Pierson

Victoria J. Stone

Virginia Cross

Virginia Wilderness Committee

W. Sam Easterling and Pamela J. Easterling

Washington Gas Light Company

West Virginia Highlands Conservancy

West Virginia Rivers Coalition

WGL Midstream, Inc.

Wild Virginia

Wildest Society

William J. Sydor

Wilmer E. Seago and Patricia A. Seago

Yvette Jones

Zane R. Lawhorn

Docket No. CP16-13-000 – Equitrans Expansion Project

Appalachian Mountain Advocates

Appalachian Voices

Betty Jane Cline

Blue Ridge Environmental Defense League

Bold Alliance

Chesapeake Climate Action Network

Eleanor Sawyers

EQT Energy, LLC

Friends of the Lower Greenbrier River

Greenbrier River Watershed Association

Headwaters Defense

Highlanders for Responsible Development

Hope Gas, Inc. d/b/a Dominion Hope

Independent Oil & Gas Association of West Virginia, Inc.

Natural Resources Defense Council

Nature Conservancy

NJR Energy Services Company

Norfolk Southern Railway Company

Norfolk Southern Railway Company

Ohio Valley Environmental Coalition

Peoples Gas WV LLC

Peoples Natural Gas Company LLC (including its Equitable Division)

Peoples TWP LLC

Preserve Bent Mountain

Preserve Craig, Inc.

Preserve Giles County Virginia

Preserve Greenbrier County

Preserve Monroe

Preserve Montgomery County Virginia

Protect Our Water, Heritage, Rights

Roanoke County, Virginia

Save Monroe, Inc.

Shenandoah Valley Battlefields Foundation

Shenandoah Valley Network

Sierra Club

Sierra Club (Virginia Chapter)

Summers County Residents Against the Pipeline

Thomas W. Headley	Virginia Wilderness Committee
Thomas Prentice	West Virginia Highlands Conservancy
Timothy Detwiler	West Virginia Rivers Coalition

Appendix B

List of Untimely Intervenors

Docket No. CP16-10-000 – Mountain Valley Pipeline Project

Ann Petrie Brown

Ashley L. Johnson

Bradley R. Foro

Brian Murphy

Bruce Bzoeckle

Carol Geller

Coronado Coal, LLC

County of Franklin, Virginia

Culy Hession

Darlene Cummingham

David A. Brady

Donna Pitt

Dorothy W. Larew

Eldon L. Karr

Felicia Etzkornik

Friends of Claytor Lake

Gordon Jones

Guy W. Buford

ICG Eastern, LLC

Jean Porterfield

Jennifer Fenrich

Joe Pitt

John Garrett Baker

Joseph L. Scarpaci

Kelsey A. Williams

Linda E. Parsons Sink

Michael E. Slayton

Mode A. Johnson

Nan Gray

New River Conservancy

Pamela L. Ferrante

Patricia Ann Cole

Patrick Robinson

Paul E. Washburn

Rebecca Dameron

Rick Shingles

Robert M. Jones

Roberta Motherway Bondurant

Russell Chisholm

Shirley J. Hall

Smith Mountain Lake Association

Suzie Henritz

Thomas Gilkerson and Betty Gilkerson

Thomas W. Triplett

Tina Smusz

Tom Hoffman

Tom J. Bondurant, Jr.

Town of Rocky Mount, Virginia

Victoria Jordan Stone

Wilbur Larew and Irene Larew

Docket No. CP16-13-000 – Equitrans Expansion Project

Consolidated Edison Company of New York, Inc.

Coronado Coal, LLC

Smith Mountain Lake Association

Appendix C

Environmental Conditions

As recommended in the final environmental impact statement (EIS) and otherwise amended herein, this authorization includes the following conditions. The section number in parentheses at the end of a condition corresponds to the section number in which the measure and related resource impact analysis appears in the final EIS.

These measures would further mitigate the environmental impact associated with construction and operation of the projects. We have included several conditions that require the applicants to file additional information **prior to construction**. Other conditions require actions **during operations**. Some are standard conditions typically attached to Commission Orders. There are conditions that apply to both applicants, and other conditions are specific to either Mountain Valley Pipeline LLC (Mountain Valley) or Equitrans LP (Equitrans).

Conditions 1 through 11 are standard conditions that apply to both Mountain Valley and Equitrans.

1. Mountain Valley and Equitrans shall each follow the construction procedures and mitigation measures described in their application and supplements, including responses to staff data requests and as identified in the final EIS, unless modified by the order. The applicants must:
   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);
   b. justify each modification relative to site-specific conditions;
   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and
   d. receive approval in writing from the Director of Office of Energy Projects (OEP) **before using that modification**.

2. The Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the order, and take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the project and activities associated with abandonment. This authority shall allow:
   a. the modification of conditions of the order;
   b. stop work authority; and
   c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the order as well

as the avoidance or mitigation of unforeseen adverse environmental impacts resulting from project construction and operation and abandonment.

3. **Prior to any construction**, Mountain Valley and Equitrans shall each file an affirmative statement with the Secretary of the Commission (Secretary), certified by a senior company official, that all company personnel, environmental inspectors (EI), and contractor personnel will be informed of the EIs' authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the final EIS, as supplemented by filed alignment sheets, and shall include all of the staff's recommended facility locations identified in conditions 16, 17, and 23. **As soon as they are available, and before the start of construction**, Mountain Valley and Equitrans shall each file any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the order. All requests for modifications of environmental conditions of the order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

   The exercise of eminent domain authority granted under Natural Gas Act Section 7(h) in any condemnation proceedings related to the Mountain Valley Pipeline (MVP) Project or Equitrans Expansion Project must be consistent with the facilities and locations approved in the Commission Order. The right of eminent domain granted under Natural Gas Act Section 7(h) does not authorize either Mountain Valley or Equitrans to increase the size of the natural gas pipelines approved in the Commission Order to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

5. Mountain Valley and Equitrans shall each file detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area**.

   This requirement does not apply to extra workspace allowed by the FERC *Upland Erosion Control, Revegetation, and Maintenance Plan* and/or minor field realignments per landowner needs and requirements, which do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or special concern species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **Within 60 days of their acceptance of a Certificate and before construction begins**, Mountain Valley and Equitrans shall each file their respective Implementation Plans for review and written approval by the Director of OEP. Mountain Valley and Equitrans must each file revisions to their plans as schedules change. The plans shall identify:

a. how Mountain Valley and Equitrans will each implement the construction procedures and mitigation measures described in their applications and supplements (including responses to staff data requests), identified in the final EIS, and required by the Order;

b. how the Mountain Valley and Equitrans will each incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;

c. the number of EIs assigned to each project and spread, and how Mountain Valley and Equitrans will each ensure that sufficient personnel are available to implement the environmental mitigation;

d. company personnel, including EIs and contractors, who will receive copies of the appropriate materials;

e. the location and dates of the environmental compliance training and instructions Mountain Valley and Equitrans will each give to all personnel involved with construction and restoration (initial and refresher training as the projects progress and personnel change) with the opportunity for OEP staff to participate in the training sessions;

f. the company personnel (if known) and specific portion of the company's organization having responsibility for compliance;

g. the procedures (including use of contract penalties) that Mountain Valley and Equitrans will each follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:

i. the completion of all required surveys and reports;
ii. the environmental compliance training of onsite personnel;
iii. the start of construction; and
iv. the start and completion of restoration.

7. Mountain Valley and Equitrans shall each employ a team of EIs for each construction spread. The EIs shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;
b. responsible for evaluating the construction contractor’s implementation of the environmental mitigation measures required in the contract (see condition 6 above) and any other authorizing document;
c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;
d. a full-time position, separate from all other activity inspectors;
c. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and
d. responsible for maintaining status reports.

8. **Beginning with the filing of its Implementation Plan**, Mountain Valley and Equitrans shall each file updated status reports with the Secretary on a **weekly basis until all construction and restoration activities are complete**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. an update on Mountain Valley and Equitrans efforts to obtain the necessary federal authorizations;
b. the construction status of their respective project facilities, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;
c. a listing of all problems encountered and each instance of noncompliance observed by the EIs during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);
d. a description of corrective actions implemented in response to all instances of noncompliance, and their cost;
e. the effectiveness of all corrective actions implemented;

f. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and
g. copies of any correspondence received by Mountain Valley and Equitrans from other federal, state, or local permitting agencies concerning instances of noncompliance, and the responses of Mountain Valley and Equitrans to each letter.

9. Mountain Valley and Equitrans must receive written authorization from the Director of OEP **before commencing construction of any project facilities**. To obtain such authorization, Mountain Valley and Equitrans must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

10. Mountain Valley and Equitrans must each receive separate written authorization from the Director of OEP **before placing their respective projects into service**. Such authorization will only be granted following a determination that rehabilitation and restoration of areas affected by the projects are proceeding satisfactorily.

11. **Within 30 days of placing the authorized facilities in service**, Mountain Valley and Equitrans shall each file an affirmative statement with the Secretary, certified by a senior company official:
    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or
    b. identifying which of the Certificate conditions Mountain Valley and Equitrans has complied or will comply with. This statement shall also identify any areas affected by their respective projects where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

Conditions 12 to 15 apply to both Mountain Valley and Equitrans, and shall be addressed <u>before construction is allowed to commence</u>.

12. **Prior to construction**, Mountain Valley and Equitrans shall each file with the Secretary the location of all water wells, springs, and other drinking water sources within 150 feet (500 feet in karst terrain) of construction work areas and aboveground facilities. *(section 4.3.1.2)*

13. **Prior to construction**, Mountain Valley and Equitrans shall file with the Secretary, for review and written approval by the Director of OEP, revised erosion control plans that contain only native species. *(section 4.4.2.7)*

14. **Prior to construction**, Mountain Valley and Equitrans shall each file with the Secretary copies of their environmental complaint resolution procedures. The procedures shall provide landowners with clear directions for identifying and resolving concerns resulting from construction and restoration of the projects. Mountain Valley and Equitrans shall mail copies of their complaint procedures to each landowner whose property would be crossed by the projects.

    In their letters to affected landowners, Mountain Valley and Equitrans shall:

    a. provide a local contact that the landowners shall call first with their concerns; the letter shall indicate how soon a landowner shall expect a response;
    b. instruct the landowners that if they are not satisfied with the response, they shall call the Mountain Valley or Equitrans Hotline, as appropriate. The letter shall indicate how soon to expect a response from the company; and
    c. instruct the landowners that if they are still not satisfied with the response from the company Hotline, they shall contact the Commission's Landowner Helpline at 877-337-2237 or at LandownerHelp@ferc.gov.

    In addition, Mountain Valley and Equitrans shall include in their weekly status reports to the FERC a table that contains the following information for each problem/concern:
    a. the identity of the caller and date of the call;
    b. the location by milepost and engineering station number from the alignment sheet(s) of the affected property;
    c. a description of the problem/concern; and
    d. an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved. (Section 4.8.2.2)

15. Mountain Valley and Equitrans **shall not begin construction** of facilities and/or use staging, storage, or temporary work areas and new or to-be-improved access roads **until**:

    a. Mountain Valley and Equitrans each files with the Secretary:
    b. remaining cultural resources survey reports;
    c. site evaluation reports, avoidance plans, or treatment plans, as required; and comments on the reports and plans from the appropriate State Historic Preservation Offices, federal land managing agencies, interested Indian tribes, and other consulting parties.
    d. the Advisory Council on Historic Preservation has been afforded an opportunity to comment if historic properties would be adversely affected; and
    e. the FERC staff reviews and the Director of OEP approves all cultural resources reports and plans, and notifies Mountain Valley and/or Equitrans

in writing that either treatment measures (including archaeological data recovery) may be implemented or construction may proceed.

All materials filed with the Commission containing **location, character, and ownership** information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "**CUI//PRIV- DO NOT RELEASE**." (*section 4.10.10.3*)

Conditions 16 through 34 are project-specific conditions that apply only to Mountain Valley and shall be addressed <u>before construction is allowed to commence</u>.

16. **Prior to construction**, Mountain Valley shall adopt Variation 250 into its proposed route. As part of its Implementation Plan, Mountain Valley shall file with the Secretary the results of all environmental surveys, an updated 7.5-minute USGS topographic quadrangle map, and a large-scale alignment sheet that illustrates this route change. *(section 3.5.1.11)*

17. **Prior to construction,** Mountain Valley shall file with the Secretary, for review and approval by the Director of OEP, a segment-specific construction and operation access plan for the area between mileposts 237.6 and 240.3, that includes access road MVP-RO-279.01. The plan shall incorporate the measures proposed in Mountain Valley's July 20, 2017 filing to minimize and mitigate impacts resulting from use of the road. *(section 3.5.1.12)*

18. **Prior to construction**, Mountain Valley shall file landowner-specific crossing plans developed in coordination with the affected landowners which contain impact avoidance, minimization, or mitigation measures, as appropriate, for review and written approval of the Director of OEP. The landowner-specific crossing plans shall be prepared in relation to the draft EIS comments in the following accession numbers: 20161024-5011 (water well), 20161212-5046 (steep ravines), 20161212-5234 (forest impacts, road frontage), 20161213-5021 (cattle and hay operations), 20161223-0033 (gravel road and reconfiguration of temporary workspaces), 20161228-0073 (water well and waterline for the campground), and 20170324-5140 (home under construction and septic system). *(section 3.5.3.1)*

19. **Prior to construction**, Mountain Valley shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Landslide Mitigation Plan* that includes the following best management practices and measures:

    a. describe methods that will ensure backfill, compaction, and restoration activities occur only during suitable soil moisture content conditions for steep (greater than 15 percent) slopes perpendicular to the slope contour, not just for steep (greater than 15 percent) side slopes;

b. as identified for steep side slopes, place backfill material in compacted lifts no greater than 12 inches thick and compact using an excavator bucket, sheep's foot, roller, or similar for all steep slopes;

c. geotechnical personnel that will be employed and onsite to prescribe additional mitigation measures for steep slopes shall have regional experience for constructing in and mitigating steep slopes and associated hazards; and

d. monitoring of all landslide hazard areas identified in the final EIS in addition to any hazard areas identified during construction using the methods prescribed for the Jefferson National Forest. (section 4.1.2.4)

20. **Prior to construction,** Mountain Valley shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Karst Mitigation Plan* that includes monitoring of all potential karst areas for subsidence and collapse using the same acquired Light Imaging Detection and Ranging (LiDAR) monitoring methods and procedures currently proposed to monitor for earth movements at landslide hazard areas within the Jefferson National Forest. LiDAR data shall be provided in a form that is conducive to comparison of repeat surveys, such as a Digital Elevation Model or Digital Terrain Model. *(section 4.1.2.5)*

21. **Prior to construction**, Mountain Valley shall file with the Secretary, for review and written approval of the Director of OEP, a revised *Water Resources Identification and Testing Plan* which includes:

a. water quality testing for oil and grease, volatile organic compounds, and hydrocarbons; and

b. post-construction monitoring, with the landowner's permission, of all water wells, springs, and other drinking water supply sources within 150 feet of construction workspaces or 500 feet of construction workspaces in karst terrain. *(section 4.3.1.2)*

22. **Prior to construction**, Mountain Valley shall file with the Secretary, for review and written approval of the Director of OEP, source, location, and quantities of water which would be used for dust control. (*section 4.3.2.1*)

23. **Prior to construction**, Mountain Valley shall adopt into its proposed pipeline route the alternative alignment for the crossing of the Pigg River and adopt a horizontal directional drill (HDD) as the crossing method. As part of its Implementation Plan, Mountain Valley shall file with the Secretary a revised alignment sheet, a summary comparison of impacts between the HDD alignment and the original alignment, and an HDD Contingency Plan, for the review and approval of the Director of OEP. *(section 4.3.2.2)*

24. **Prior to construction**, Mountain Valley shall file with the Secretary, for review and written approval of the Director of OEP, water supply contingency plans, prepared in coordination with the Public Service/Supply Districts, outlining measures to minimize and mitigate potential impacts on public surface water supplies with intakes within 3 miles downstream of the workspace, and Zones of Critical Concern within 0.5 mile of the workspace. The measures shall include, but not be limited to, providing advance notification to water supply owners prior to the commencement of pipeline construction. *(section 4.3.2.2)*

25. **Prior to construction**, Mountain Valley shall file with the Secretary, for review and approval by the Director of OEP, either a plan to maintain a 15 foot buffer from the tributary to Foul Ground Creek or proposed mitigation measures to minimize impacts on the waterbody. *(section 4.3.2.2)*

26. **Prior to construction,** Mountain Valley shall file with the Secretary, for review and written approval by the Director of OEP, site plans and maps that illustrate how permanent impacts on wetlands W-EE6 and W-EE7 will be avoided at the Stallworth Compressor Station. *(section 4.3.3.2)*

27. **Prior to construction**, Mountain Valley shall file with the Secretary its final *Migratory Bird Conservation Plan*. The plan shall include impact avoidance, minimization, restoration, and/or mitigation measures for the impacts on migratory birds and it shall be prepared in coordination with the U.S. Fish and Wildlife Service (FWS), West Virginia Department of Natural Resources, and the Virginia Department of Game and Inland Fisheries. Appendix D (Restoration and Rehabilitation Plan) of the final *Migratory Bird Conservation Plan* shall be modified to match the seed list in appendix N-14 and N-15 of the EIS; and shall include only native species, as required in Environmental Condition 13 of this order. (*section 4.5.2.6*)

28. Mountain Valley shall not begin construction of the proposed facilities **until**:

    a. all outstanding and required biological surveys for federally listed species are completed and filed with the Secretary;

    b. the FERC staff completes any necessary Endangered Species Act Section 7 informal and formal consultation with the FWS; and

    c. Mountain Valley has received written notification from the Director of OEP that construction and/or use of mitigation (including implementation of conservation measures) may begin. *(section 4.7.1.3*)

29. **Prior to construction**, Mountain Valley shall file with the Secretary the results of all remaining environmental surveys (water resources, wetlands, cultural resources, and threatened and endangered species) for all cathodic protection groundbeds. *(section 4.8.1.2)*

30. **Prior to construction**, Mountain Valley shall file with the Secretary evidence of landowner concurrence with the site-specific residential construction plans for all locations where construction work areas will be within 10 feet of a residence. Mountain Valley shall also file with the Secretary a site-specific residential construction plan, including site-specific justification for locating project components within 50 feet of structures located on parcel VA-GI-5673 at about MP 216.6. *(section 4.8.2.2)*

31. **Prior to construction**, Mountain Valley shall file with the Secretary documentation that the U.S. Highway 50 and North Bend Rail Trail Crossing Plan was provided to the West Virginia Department of Transportation and WVDNR for review and comment. *(section 4.8.2.4)*

32. **Prior to construction**, Mountain Valley shall file with the Secretary documentation that The Nature Conservancy (TNC) Property Crossing Plan was provided to the TNC for review and comment. *(section 4.8.2.4)*

33. **Prior to construction of the Pig River Horizontal Directional Drill** (HDD) **crossing**, Mountain Valley shall file with the Secretary an HDD noise analysis identifying the existing and projected noise levels at each noise sensitive area (NSA) within 0.5 mile of the HDD entry and exit site. If noise attributable to the HDD is projected to exceed a day-night sound level (L_{dn}) of 55 decibels on the A weighted scale (dBA) at any NSA, Mountain Valley shall file with the noise analysis a mitigation plan to reduce the projected noise levels for the review and written approval by the Director of OEP. During drilling operations, Mountain Valley shall implement the approved plan, monitor noise levels, and make all reasonable efforts to restrict the noise attributable to the drilling operations to no more than an L_{dn} of 55 dBA at the NSAs. *(section 4.11.2.3)*

Recommendations 35 through 39 are project-specific conditions that applies only to Equitrans and shall be addressed <u>before construction is allowed to commence.</u>

34. **Prior to construction**, Equitrans shall offer to conduct, with the landowner's permission, post-construction monitoring of all water wells, springs, and other drinking water supply sources within 150 feet of construction workspaces or 500 feet of construction workspaces in karst terrain. (*section 4.3.1.2)*

35. **Prior to construction**, Equitrans shall file with the Secretary, for review and written approval by the Director of OEP, a plan to identify septic systems and avoidance, minimization, and mitigation measures. (*section 4.3.1.2*)

36. **Prior to construction**, Equitrans shall file with the Secretary the results of all environmental surveys (water resources, wetlands, cultural resources, and threatened and endangered species) for the New Cline Variation. (*section 4.3.2.1*)

37. **Prior to construction,** Equitrans shall file with the Secretary, for the review and written approval of the Director of OEP, a crossing plan for the Riverview Golf Course that includes mitigation measures and documentation that the plan was reviewed by the landowners. (*section 4.8.2.4*)

38. **Prior to construction of the South Fork Tenmile Creek and Monongahela River HDD crossings**, Equitrans shall file with the Secretary, for the review and written approval by the Director of OEP, an HDD noise mitigation plan to reduce the projected noise level increase attributable to the proposed drilling operations at NSAs. **During drilling operations**, Equitrans shall implement the approved plan, monitor noise levels, include noise levels in weekly reports to the FERC, and make all reasonable efforts to restrict the noise attributable to the drilling operations to no more than a 10 dBA increase over ambient noise levels at the NSAs. *(section 4.11.2.3)*

Condition 40 is a project-specific condition that applies only to Mountain Valley and shall be addressed during <u>operation of facilities</u>.

39. Mountain Valley shall file noise surveys with the Secretary **no later than 60 days** after placing the equipment at the Bradshaw, Harris (including the WB Interconnect), and Stallworth Compressor Stations into service. If full load condition noise surveys are not possible, Mountain Valley shall provide interim surveys at the maximum possible horsepower load **within 60 days** of placing the equipment into service and provide the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at each station under interim or full horsepower load exceeds an L_{dn} of 55 dBA at the nearest NSA, Mountain Valley shall file a report on what changes are needed and shall install the additional noise controls to meet the level within **1 year** of the in-service date. Mountain Valley shall confirm compliance with the above requirement by filing a second noise survey with the Secretary for each station **no later than 60 days** after it installs the additional noise controls. *(section 4.11.2.3)*

Condition 41 is a project-specific condition that applies only to Equitrans and shall be addressed during <u>operation of facilities.</u>

40. Equitrans shall file a noise survey with the Secretary **no later than 60 days** after placing the Redhook Compressor Station into service. If a full load condition noise survey is not possible, Equitrans shall provide an interim survey at the maximum possible horsepower load **within 60 days** of placing the Redhook Compressor Station into service and provide the full load survey **within 6 months**. If the noise attributable to operation of the equipment at the Redhook Compressor Station exceeds an L_{dn} of 55 dBA at the nearest NSA, Equitrans shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. Equitrans shall confirm compliance

with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(section 4.11.2.3)*

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Mountain Valley Pipeline, LLC — Docket Nos. CP16-10-000
Equitrans, L.P. — CP16-13-000

(Issued October 13, 2017)

LaFLEUR, Commissioner *dissenting*:

With the increasing abundance of domestic natural gas, the Commission plays a key role in considering applications for the construction of natural gas infrastructure to support the delivery of this important fuel source. Under the Certificate Policy Statement, which sets forth the Commission's approach to evaluating proposed projects under Section 7 of the Natural Gas Act, the Commission evaluates in each case whether the benefits of the project as proposed by the applicant outweigh adverse effects on existing shippers, other pipelines and their captive customers, landowners, and surrounding communities.[1] For each pipeline I have considered during my time at the Commission, I have tried to carefully apply this standard, evaluating the facts in the record to determine whether, on balance, each individual project is in the public interest.[2] Today, the Commission is issuing orders that authorize the development of the Mountain Valley Pipeline Project/Equitrans Expansion Project (MVP) and the Atlantic Coast Pipeline Project (ACP). For the reasons set forth herein, I cannot conclude that either of these projects as proposed is in the public interest, and thus, I respectfully dissent.

Deciding whether a project is in the public interest requires a careful balancing of the need for the project and its environmental impacts. In the case of the ACP and MVP projects, my balancing determination was heavily influenced by similarities in their respective routes, impact, and timing. ACP and MVP are proposed to be built in the

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[1] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999) (Certificate Policy Statement), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000); 15 U.S.C. 717h (Section 7(c) of the Natural Gas Act provides that no natural gas company shall transport natural gas or construct any facilities for such transportation without a certificate of public convenience and necessity.).

[2] *See Millenium Pipeline Company*, *L.L.C.*, 140 FERC ¶ 61,045 (2012) (LaFleur, Comm'r, *dissenting*).

same region with certain segments located in close geographic proximity. Collectively, they represent approximately 900 miles of new gas pipeline infrastructure through West Virginia, Virginia and North Carolina, and will deliver 3.44 Bcf/d of natural gas to the Southeast. The record demonstrates that these two large projects will have similar, and significant, environmental impacts on the region. Both the ACP and MVP cross hundreds of miles of karst terrain, thousands of waterbodies, and many agricultural, residential, and commercial areas. Furthermore, the projects traverse many important cultural, historic, and natural resources, including the Appalachian National Scenic Trail and the Blue Ridge Parkway. Both projects appear to be receiving gas from the same location, and both deliver gas that can reach some common destination markets. Moreover, these projects are being developed under similar development schedules, as further evidenced by the Commission acting on them concurrently today.[3] Given these similarities and overlapping issues, I believe it is appropriate to balance the collective environmental impacts of these projects on the Appalachian region against the economic need for the projects. In so doing, I am not persuaded that both of these projects as proposed are in the public interest.

I am particularly troubled by the approval of these projects because I believe that the records demonstrate that there may be alternative approaches that could provide significant environmental advantages over their construction as proposed. As part of its alternatives analysis, Commission staff requested that ACP evaluate an MVP Merged Systems Alternative that would serve the capacity of both projects.[4] This alternative would largely follow the MVP route to deliver the capacity of both ACP and MVP in a single large diameter pipeline. Commission staff identifies significant environmental advantages of utilizing this alternative. For example, the MVP Merged Systems Alternative would be 173 miles shorter than the cumulative mileage of both projects individually. This alternative would also increase collocation with existing utility rights-of-way, avoid the Monongahela National Forest and the George Washington National Forest, reduce the number of crossings of the Appalachian National Scenic Trail and Blue Ridge Parkway, and reduce the amount of construction in karst topography. Commission staff eliminated this alternative from further consideration because it failed to meet the project's objectives, in particular that it would "result in a significant delay to the delivery of the 3.44 Bcf/d of natural gas to the proposed customers of both ACP and MVP"[5] due to the significant time for the planning and design that would be necessary to

[3] ACP and MVP filed their applications for approval pursuant to section7(c) of the Natural Gas Act on September 18, 2015 and October 23, 2015, respectively.

[4] ACP Final Environmental Impact Statement (FEIS) at 3-6 – 3-9.

[5] *Id.* at 3-9.

develop a revised project proposal.[6]

Similarly, in the MVP FEIS, Commission staff evaluated a single pipeline alternative to the MVP project that would utilize the proposed ACP to serve MVP's capacity needs.[7] While this alternative was found to have certain environmental disadvantages, such as the need for additional compression to deliver the additional gas, the EIS acknowledges that this alternative would "essentially eliminate all environmental impacts on resources along the currently proposed MVP route."[8]

I recognize that the two alternatives described above were eliminated from further consideration because they were deemed not to meet each project's specific stated goals. However, I believe that these alternatives demonstrate that the regional needs that these pipelines address may be met through alternative approaches that have significantly fewer environmental impacts.

While my dissents rest on my concerns regarding the aggregate environmental impacts of the proposed projects, particularly given the potential availability of environmentally-superior alternatives, I believe that the needs determinations for these projects highlight another issue worthy of further discussion.

The Commission's policy regarding evaluation of need, and the standard applied in these cases, is that precedent agreements generally are the best evidence for determining market need. When applying this precedent here, I believe there is an important distinction between the needs determinations for ACP and MVP. Both projects provide evidence of precedent agreements to demonstrate that these pipelines will be fully subscribed. ACP also provides specific evidence regarding the end use of the gas to be delivered on its pipeline. ACP estimates that 79.2 percent of the gas will be transported to supply natural gas electric generation facilities, 9.1 percent will serve residential purposes, 8.9 percent will serve industrial purposes, and 2.8 percent will serve other purposes such as vehicle fuel.[9] In contrast, "[w]hile Mountain Valley has entered into precedent agreements with two end users … for approximately 13% of the MVP

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[6] Staff also found that this alternative would likely limit the ability to provide additional gas to the projects' customers, another of the stated goals for the original proposal. *Id*.

[7] MVP FEIS at 3-14.

[8] *Id*.

[9] ACP FEIS at 1-3.

project capacity, the ultimate destination for the remaining gas will be determined by price differentials in the Northeast, Mid-Atlantic, and Southeast markets, and thus, is unknown."[10]

In my view, it is appropriate for the Commission to consider as a policy matter whether evidence other than precedent agreements should play a larger role in our evaluation regarding the economic need for a proposed pipeline project. I believe that evidence of the specific end use of the delivered gas within the context of regional needs is relevant evidence that should be considered as part of our overall needs determination. Indeed, the Certificate Policy Statement established a policy for determining economic need that allowed the applicant to demonstrate need relying on a variety of factors, including "environmental advantages of gas over other fuels, lower fuel costs, access to new supply sources or the connection of new supply to the interstate grid, the elimination of pipeline facility constraints, better service from access to competitive transportation options, and the need for an adequate pipeline infrastructure."[11] However, the Commission's implementation of the Certificate Policy Statement has focused more narrowly on the existence of precedent agreements.

I believe that careful consideration of a fuller record could help the Commission better balance environmental issues, including downstream impacts, with the project need and its benefits.[12] I fully realize that a broader consideration of need would be a change in our existing practice, and I would support a generic proceeding to get input from the regulated community, and those impacted by pipelines, on how the Commission evaluates need.[13]

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[10] *Mountain Valley Pipeline, LLC, Equitrans, L.P.*, 161 FERC ¶ 61,043 at FN 286 (October 13, 2017).

[11] *Certificate Policy Statement*, 88 FERC ¶ 61,227 at 61,744.

[12] I note that this approach would not necessarily lead to the rejection of more pipeline applications. Rather, it would provide all parties, including certificate applicants, the opportunity to more broadly debate and consider the need for a proposed project. This could, for example, support development of new infrastructure in constrained regions where there may be demand for new capacity, but barriers to the execution of precedent agreements that are so critical under the Commission's current approach. In such situations, evidence of economic need other than precedent agreements might be offered as justification for the pipeline.

[13] *See also*, *National Fuel Gas Supply Corporation, Empire Pipeline, Inc.*, 158 FERC ¶ 61,145 (Bay, Comm'r, *Separate Statement*).

I recognize that the Commission's actions today are the culmination of years of work in the pre-filing, application, and review processes, and I take seriously my decision to dissent. I acknowledge that if the applicants were to adopt an alternative solution, it would require considerable additional work and time. However, the decision before the Commission is simply whether to approve or reject these projects, which will be in place for decades. Given the environmental impacts and possible superior alternatives, approving these two pipeline projects on this record is not a decision I can support.

For these reasons, I respectfully dissent.

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Cheryl A. LaFleur
Commissioner

People's Dossier: FERC's Abuses of Power and Law → Undermining Federal Authority

Federal Authority Undermined Attachment 5, Letter from the Delaware River Basin Commission to FERC, Docket No. CP15-558, September 27, 2018.

Delaware River Basin Commission
DELAWARE • NEW JERSEY
PENNSYLVANIA • NEW YORK
UNITED STATES OF AMERICA

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West Trenton, New Jersey
08628-0360
Phone: (609) 883-9500 Fax: (609) 883-9522
Web Site: http://www.drbc.gov

Steven J. Tambini, P.E.
Executive Director

September 27, 2018

Via eFile

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **PennEast Pipeline Project, FERC Docket No. CP15-558-000**
Re-Submission of DRBC Letter Dated April 3, 2018

Dear Ms. Bose:

On April 3, 2018, through its Executive Director Steve Tambini, the Delaware River Basin Commission (DRBC) wrote to FERC Outreach Coordinator David Hanobic, with a "Recommendation and Request Concerning Tree-Felling by Sponsors of FERC-Approved Pipeline Projects" (copy provided as Attachment A). The DRBC's letter referenced a similar request submitted on February 8, 2018 by the Pennsylvania Department of Environmental Protection, Pennsylvania Department of Conservation and Natural Resources, and Pennsylvania Fish and Boat Commission (copy provided as Attachment B).

The DRBC proposed in our April 3 letter to coordinate a meeting among representatives of FERC and other resource agencies with jurisdictions overlapping DRBC's to discuss a mutually agreeable approach to our concern that the premature felling of trees before all federal and state approvals are issued for interstate transmission projects such as the PennEast Pipeline, could result in water resource impacts that could go unmitigated unless and until such projects are actually built. We requested that FERC amend its PennEast approval and condition future approvals of similar projects by prohibiting the project sponsors from felling trees within the Delaware River Basin within delineated wetlands and floodplains, in riparian areas (extending 150 feet from either bank of any stream), and within reservoir and recreation areas that have been designated in the DRBC's Comprehensive Plan, until such time as DRBC has approved the project or activity in accordance with Section 3.8 of the Delaware River Basin Compact and DRBC's implementing regulations.

The DRBC received no response. We recently learned through the statements of a FERC spokeswoman (see Attachment C), that because the PennEast proposal was being considered for rehearing, letters concerning the project must be sent to the FERC secretary, not a staff member, and that all such letters must include the FERC docket number. FERC's spokeswoman reportedly stated that "if the DRBC resends the letter in accordance with the [FERC's] Rules … their request will be taken into consideration."

I am surprised that we received no response, at least to the portion of our letter that addressed a *class* of projects rather than the PennEast Pipeline in particular. With all due respect, we note that FERC's Rules of Practice and Procedure provide that when a document is rejected for failure to conform to the rules, "the Secretary, or the office director to whom the filing has been referred, will notify the submitter and indicate the deficiencies in the filing and the reason for the rejection." 18 C.F.R. 385.2001(b)(3). The DRBC received no such notification.

I am hereby re-submitting our letter, provided as Attachment A, with the request that it be included in the PennEast docket along with our other attachments and this transmittal. I am also respectfully requesting a response to the DRBC's more general request for a meeting. I can be reached at the address on this letterhead and by phone at 609-883-9500. Thank you.

Sincerely,

Steven J. Tambini
Executive Director

Attachments

c: DRBC Commissioners

Delaware River Basin Commission
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ATT. A

Steven J. Tambini, P.E.
Executive Director

April 3, 2018

Via U.S. Mail
Mr. David Hanobic
Office of Energy Projects
Federal Energy Regulatory Commission (FERC)
888 First Street NE
Washington, DC 20426

Re: Recommendation and Request Concerning Tree-Felling by Sponsors of FERC-Approved Pipeline Projects

Dear Mr. Hanobic:

I am writing you on behalf of the Delaware River Basin Commission (DRBC) to request your assistance in addressing the potential problem of premature tree-felling for the construction of FERC-approved transmission lines that are subject to and/or currently under review by DRBC. The DRBC is concerned that the felling of trees for such projects months or years before essential DRBC and state approvals have been issued can cause unnecessary or long-term and potentially substantial impacts to water resources, particularly in the context of very large projects involving hundreds of river, stream and wetland crossings.

As FERC has recognized, proposals for the construction of interstate electrical and natural gas transmission lines traversing the Delaware River Basin are in many instances required to obtain the approval of the DRBC as well as permits from state and federal agencies. In particular, Section 3.8 of the Delaware River Basin Compact, the DRBC's organic statute, provides in relevant part that:

> *[n]o project having a substantial effect on the water resources of the basin shall hereafter be undertaken by any person, corporation or governmental authority unless it shall have been first submitted to and approved by the commission.... The commission shall approve a project whenever it finds and determines that such project would not substantially impair or conflict with the comprehensive plan and may modify and approve as modified, or may disapprove any such project whenever it finds and determines that the project would substantially impair or conflict with such plan.*

FERC's certificates of public convenience and necessity for interstate transmission projects, including its Order issued on January 19, 2018 for the natural gas transmission line proposed by the PennEast Pipeline Company, LLC ("PennEast"), have been silent on the matter of tree-felling before all federal and state approvals are issued. DRBC anticipates that having obtained its FERC certificates, and in view of the many months required to construct its pipeline, PennEast, like other transmission and pipeline project sponsors, may seek to initiate tree felling for its project as early as possible. The DRBC is concerned that the premature felling of trees could result in water resource impacts related to streambank stability, soil erosion, and instream sedimentation that could go unmitigated unless and until the pipeline is actually built.

In view of this concern, we respectfully request that FERC amend its PennEast approval and condition future approvals of similar projects by prohibiting the project sponsors from felling trees within the Delaware River Basin, including within delineated wetlands and flood plains, in riparian areas (extending 150 feet from either bank of any stream), and within reservoir and recreation areas that have been designated in the DRBC's Comprehensive Plan, until such time as the DRBC issues an approval for the project or activity.

Please note that this request echoes a similar request submitted jointly by the Pennsylvania Department of Environmental Protection, Pennsylvania Department of Conservation and Natural Resources, and Pennsylvania Fish and Boat Commission. We would be pleased to coordinate a meeting among representatives of FERC and these and other resource agencies with jurisdictions overlapping DRBC's to discuss a mutually agreeable approach to this concern.

Sincerely,

Steven J. Tambini, P.E.
Executive Director

c: Commissioners

ATT. B

pennsylvania
DEPARTMENT OF ENVIRONMENTAL
PROTECTION

February 8, 2018

Federal Energy Regulation Commission
Attn: Mr. David Hanobic
888 First Street, NE
Washington, DC 20426

RE: Request for FERC Consideration
Recommendation Regarding Vegetative Cover Alteration or Removal

Dear Mr. David Hanobic:

The Pennsylvania Department of Environmental Protection (PADEP), the Pennsylvania Department of Conservation and Natural Resources and the Pennsylvania Fish and Boat Commission are requesting assistance from the Federal Energy Regulatory Commission (FERC) to protect the rights of property owners in Pennsylvania when issuing Certificates of Public Convenience and Necessity (Certificates) for utility infrastructure including interstate natural gas pipeline projects. Because FERC issues its Certificates before PADEP completes its review of all required permits for these projects, applicants often begin what may later become the unnecessary clearing of land based on the location of the final approved project within Pennsylvania.

Pennsylvania's environmental regulatory programs require project applicants to perform proper planning, design, construction, maintenance and monitoring to protect natural resources. Primarily, the regulatory programs managed by PADEP require applicants to avoid and minimize impacts created by water obstructions, wetland encroachments, and earth disturbance activities. These projects will typically be constructed on private or non-applicant owned property. An applicant must obtain the FERC Certificate prior to completing the PADEP permit applications because state permit applications cannot be completed until an applicant has site access to survey, delineate wetlands and obtain other field information required to complete the technical portions of PADEP permit applications.

In Pennsylvania, a project cannot be constructed until *or unless* required state permits are authorized or issued to an applicant as required by conditions to the PADEP State Water Quality Certification. Until PADEP has completed its full review of the permit applications and can assure that the proposal's technical details comply with federal and state environmental law, any project that has been issued a FERC Certificate remains tentative and subject to changes based upon the information revealed by field information obtained after the FERC Certificate is issued.

Property rights flow from the Certificate based upon the original, but not yet final, project proposals and assumes that the construction of the project will proceed or occur without modifications to the project's location or technical details.

The problem arises when a Certificate holder is authorized to alter the vegetation in rights-of-way or easements that cross private and public property before the applicant has final state permits that delineate the final location of the project authorized by the FERC Certificate. This enables the Certificate holder to temporarily or permanently alter resources and environmental features based upon a premature assumption that the Certificate holder will be constructing its project along the proposed right-of-way or easement or, frankly, at all. In reality, the project location may change during the PADEP permit review process to minimize the impacts to sensitive resources and environmental features.

PADEP cannot prevent a Certificate holder from altering the resources and environmental features if the Certificate holder conducts its activities in a manner that does not necessitate the issuance of a state permit, e.g., cutting mature trees by hand. However, FERC has the authority to prevent the premature alteration of environmental features located in what can best be described as a tentative project location by not allowing such alteration until the entire project is properly permitted by the PADEP.

For the reasons articulated above, the Commonwealth of Pennsylvania requests that FERC prohibit or condition alteration or removal of vegetative cover along the proposed project rights-of-way or easements on PADEP's final approval and permitting of the project or portion of the project in Pennsylvania. Absent this prohibition, private and public property owners may experience the unnecessary alteration of their property and/or loss of resources for a project that may either ultimately not be constructed or not be constructed in the location originally proposed by the Certificate holder in its application to FERC.

If you have questions related to this request, please do not hesitate to contact PADEP's Aneca Atkinson at 717.772.1839.

Sincerely,

Timothy Schaeffer, Acting Deputy Secretary for Water
Department of Environmental Protection

2/8/18
Date

John Norbeck, Deputy Secretary for Parks and Forestry
Department of Conservation & Natural Resources

2/8/18
Date

John Arway, Executive Director
Fish and Boat Commission

15 Feb 2018
Date

ATT. C

Bucks County Courier Times

Regulator seeks to prevent ‘premature’ tree-clearing for PennEast pipeline

By Kyle Bagenstose

Posted Sep 19, 2018 at 2:15 PM

In a letter obtained by an environmental nonprofit, the Delaware River Basin Commission asks federal regulators to ensure no trees are cleared for the controversial pipeline before the commission considers the project.

The main regulatory agency tasked with protecting the Delaware River has asked the federal government to prevent “premature” tree clearing associated with the proposed PennEast natural gas pipeline, according to a letter sent by the agency.

The letter was sent in April by Steven Tambini, executive director of the Delaware River Basin Commission, to an employee within the Federal Energy Regulatory Commission. It was publicly released last week by the Bristol Borough-based Delaware Riverkeeper Network, after having been obtained by the nonprofit via a Freedom of Information Act Request.

In January, FERC approved the $1 billion pipeline, which if constructed would carry Marcellus Shale natural gas from northwest Pennsylvania to Mercer County, New Jersey, passing through the far northern corner of Bucks County along the way. However, the pipeline has yet to win approval from the DRBC, which also has federal standing.

“The DRBC is concerned that the felling of trees for such projects months or years before essential DRBC and state approvals have been issued can cause unnecessary or long-term and potentially substantial impacts to water resources,” Tambini wrote in the letter. “Particularly in the context of very large projects involving hundreds of river, stream and wetland crossings.”

The Riverkeepers and other environmental groups have vigorously opposed the pipeline since it was first proposed four years ago. Earlier this year, the groups urged DRBC to prohibit any tree clearings prior to full approval. They claimed that in the past such activities have been used as an intentional tactic.

“We know the pipeline company playbook,” wrote Maya van Rossum, head of the Riverkeepers, in a prepared statement. “First they get FERC approval, then they get eminent domain, then they cut the trees, and then they tell the other agencies and the judge that the project is too far along to stop or say no to and urge the granting of all permits and denial of all legal challenges.”

Reached by email Monday, van Rossum added that the DRBC letter seemed to suggest the DRBC was changing its approach from past projects.

“I am hopeful that they are trying to avoid the errors of the past,” van Rossum wrote.

According to the Riverkeepers and DRBC, no tree clearing has yet taken place.

Pat Kornick, a spokeswoman for the PennEast Pipeline Co., did not provide a direct response when asked if any tree clearing has begun. However, her responses suggested no such work has yet taken place.

“PennEast is working with landowners to complete the remaining land and environmental surveys, which are necessary to help minimize impacts, update data and adhere to federal and state permitting guidelines,” Kornick wrote via email. “At the appropriate time, PennEast will proceed within the limits of the approvals that have been granted.”

The January approval by FERC was a major milestone for the pipeline, as it granted PennEast the power of eminent domain to access and survey property whose owners had not previously allowed the company to do so. Approximately 200 eminent domain proceedings were then filed against landowners in Pennsylvania and New Jersey, including a pair in Durham and land owned by the state of New Jersey.

Court records show the proceedings have continued throughout the summer, with several already being completed. According to Kornick, approximately 85 percent of landowners have provided survey access, and the company is aiming to start construction in 2019.

However, several hurdles remain in the way. New Jersey Attorney General Gurbir Grewal is contesting PennEast's use of eminent domain on approximately 40 parcels owned by the state. Leland Moore, a spokesman for Grewal's office, said Tuesday the matter is pending before the court, and that the state is also suing FERC in federal court over its original approval of PennEast.

Without access to all lands, it remains to be seen whether PennEast can obtain the data needed to receive approvals from the DRBC or the New Jersey Department of Environmental Protection. The NJDEP has regulatory authority delegated from the federal government in regards to crossings of streams and wetlands.

Kate Schmidt, a spokeswoman for the DRBC, said the commission has received application materials from PennEast but has requested more. If such materials are received, it will begin a public process that includes written comments and public hearings.

Larry Hajna, a spokesman for the NJDEP, said PennEast pulled its most recent filing several months ago and has not resubmitted any materials.

Whether or not New Jersey's permits are needed appears to be the subject of debate. In its order, FERC wrote that it "encourages cooperation between interstate pipelines and local authorities."

"However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operations of facilities approved by this commission," its order continued.

The issue of tree clearing too, has ambiguity. When first pressed by activists on the issue earlier this year, the DRBC said it was studying whether tree felling constitutes significant construction activity, which is prohibited by DRBC until it approves a project. The DRBC said this week it has not yet made a determination and has not received a reply from its April letter to FERC.

"The commissioners are waiting to hear FERC's reply before making any determinations," wrote Schmidt.

In his letter, the DRBC's Tambini wrote that FERC's January approval makes no reference to tree-clearing and that his commission "anticipates" PennEast would do so for its project "as early as possible."

"The premature felling of trees could result in water resource impacts related to stream bank stability, soil erosion, and in-stream sedimentation that could go unmitigated unless and until the pipeline is actually built," Tambini said.

Asked about the letter, FERC spokeswoman Tamara Young-Allen said it was sent to the wrong place. At the time it was sent, Young-Allen said the PennEast proposal was being considered for a rehearing, meaning letters had to be sent the commission's secretary, not a staff member. It also did not include the "docket" number assigned to PennEast's application.

"Communications not adhering to our Rules of Practice and Procedure are not considered," Young-Allen wrote in an email. "If the DRBC resends the letter in accordance with the Commission's Rules of Practice and Procedure, their request ... will be taken into consideration."

Young-Allen wrote that FERC has not received any requests for tree-felling activities from PennEast, nor a plan pertaining to how the company will mitigate the environmental impacts of any such activities.

Document Content(s)