NATURAL GAS COMMITTEE REPORT

This report summarizes policy developments and legal decisions that occurred at the Federal Energy Regulatory Commission (FERC or the Commission), the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the United States Courts of Appeals in the area of natural gas regulation between July 1, 2021, and June 30, 2022.*

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I. RULEMAKING AND POLICY ACTIONS

On February 18, 2022, FERC issued an updated certificate policy statement, *Certification of New Interstate Natural Gas Facilities*[1] (Updated Certificate Policy Statement) and an interim greenhouse gas (GHG) policy statement, *Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews*,[2] (Interim GHG Policy Statement) (collectively, "2022 Policy Statements"). The 2022 Policy Statements describe how FERC will determine whether a new interstate natural gas transportation project is required by the public convenience and necessity and explained how FERC will "assess the impacts of natural gas infrastructure projects on climate change in its reviews under the National Environmental Policy Act (NEPA) and [section 7 of] the Natural Gas Act (NGA)."[3]

On March 24, 2022, FERC issued an order designating the 2022 Policy Statements as drafts and requested further comments.[4] FERC explained that upon further consideration, it has decided to designate both 2022 Policy Statements as drafts.[5] FERC sought initial and reply comments on the draft policy statements.[6] Below are summaries of the 2022 Policy Statements issued on February 18, 2022.

1. *Certification of New Interstate National Gas Facilities*, 178 FERC ¶ 61,107 (2022).
2. *Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Reviews*, 178 FERC ¶ 61,108 (2022).
3. *Id.*; 178 FERC ¶ 61,107 at P 1. *See* 15 U.S.C. § 717f(e)(1988).
4. *Certification of New Interstate Nat. Gas Facilities,* 178 FERC ¶ 61,197 (2022).
5. *Id.*
6. *Id.*

A. Certification of New Interstate Natural Gas Facilities, Docket No. PL18-1-000, 178 FERC ¶ 61,107 (2022)

In April 2018 and February 2021, FERC issued Notices of Inquiry seeking information in furtherance of the Commission's endeavors to determine whether, and if so how, it should revise its 1999 Policy Statement on the certification of new interstate natural gas facilities.[7] FERC received over 38,000 comments in response to the April 2018 and February 2021 Notice of Inquiry.[8] The Updated Policy Statement represents the FERC's attempt "to provide a more comprehensive analytical framework for its decision-making process."[9] Specifically, the Updated Policy Statement "provide[s] clarity on how the [FERC] will evaluate all factors bearing on the public interest, including the balancing of economic and environmental interests, in determining whether a [new gas facility] project is required by the public convenience and necessity."[10]

1. Factors to be Balanced in Assessing the Public Convenience and Necessity & Consideration of Project Need

The Updated Policy Statement provides that "the [FERC] will weigh the public benefits of a proposal . . . against its adverse impacts" as it determines whether the grant of a certificate is warranted by the public convenience and necessity.[11] FERC stated that "the most important [public benefit] is the need that will be served by the project."[12] FERC will consider all relevant factors bearing on the need for a project.[13]

Although precedent agreements remain important evidence of need, and FERC expects that applicants will continue to provide precedent agreements, the existence of precedent agreements may not be sufficient in and of themselves to establish need for the project.[14] FERC stated that:

> While precedent agreements may indicate one or more shipper's willingness to contract for new capacity, such willingness may not in all circumstances be sufficient to sustain a finding of need, e.g., in the face of contrary evidence or where there is reason to discount the probative value of those precedent agreements. Accordingly, . . . looking only to precedent agreements, and ignoring other, potentially contrary, evidence may cause the [FERC] to reach a determination on need that is inconsistent with the weight of the evidence in any particular proceeding, in violation of both the NGA and the [FERC's] responsibilities under the Administrative Procedure Act. . . . [FERC] will also consider . . . the circumstances surrounding the precedent agreements (e.g.,[such as] whether the agreements were entered into . . . [as the] results of the open season, [specifics of the open season], including the number of bidders, whether the [precedent] agreements [were the result of] LDC or generator requests

7. *Certification of New Interstate Nat. Gas Facilities*, 163 FERC ¶ 61,042 (2018), *Certification of New Interstate Nat. Gas Facilities,* 174 FERC ¶ 61,125 (2021).

8. 178 FERC ¶ 61,107 at PP 17, 19.

9. *Id.* at P 51.

10. *Id.*

11. *Id.* at P *52.*

12. 178 FERC ¶ 61,107 at P 52.

13. *Id.* at P 51.

14. *Id.* at P 54.

> for proposals (RFP) and, if so, the details around that RFP process . . . as well as other evidence of need. . . .
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> For all categories of proposed projects, [FERC] encourage[d] applicants to provide specific information detailing how the gas to be transported by the proposed project will ultimately be used, why the project is needed to serve that use, and the expected utilization rate of the proposed project. . . . The absence of this [specific] information may prevent an applicant from meeting its burden of demonstrating that a project is needed.[15]

Other types of projects may require a different specific showing of need:

- Evidence of need for a market-driven projects to respond "to increased natural gas demand . . . could include a market study that projects volumetric or peak day load growth."[16]
- Projects for individual shippers could show evidence of project need through "load growth profiles, gas supply portfolios, and any advanced approval of contracts by state public service commissions."[17] Projects "driven by natural gas producers or natural gas utilities . . . may not directly serve a [specific] customer but rather are being undertaken to add supplies of natural gas to the market . . . to provide supply at lower cost or support reliability."[18] "For these projects, evidence to demonstrate consumer benefits may include projections of the net benefits, for example projected lower natural gas prices for consumers due to increased supply competition, compared to the incremental costs of transportation on the new pipeline. The [FERC] will consider record evidence of regional projections for both gas supply and market growth, as well as pipeline-specific studies in these areas."[19]
- Some projects are "intended to support more efficient system operations [through facility replacement and infrastructure improvements], or to respond to changing state and federal government pipeline safety or environmental requirements."[20] Evidence of need for these types of projects, may include expected system benefits of the project, "such as reduced operating costs, improved pipeline integrity, or reduced natural gas leaks. In addition, an applicant may document how a project avoids adverse impacts or satisfies any changing state or federal government regulations."[21]

"The [FERC] will consider both current and projected future demand for a project based on the evidence in the record."[22] FERC encourages applicant "to

15. *Id.* at PP 54-55.
16. 178 FERC ¶ 61,107 at P 56.
17. *Id.*
18. *Id.* at P 56.
19. *Id.*
20. 178 FERC ¶ 61,107 at P 58.
21. *Id.*
22. *Id.* at P 59.

[provide] analyses showing how market trends as well as current and expected policy and regulatory developments would affect future need for the project."[23]

With respect to affiliate precedent agreements, the Updated Policy Statement clarifies that they "will generally be insufficient to demonstrate need."[24] If a project is backed primarily by affiliate precedent agreements, "the Commission will consider additional information," with the extent of that evidence being determined on a case-by-case basis.[25] "Where an applicant fails to carry its burden of demonstrating the proposed project is needed, the Commission will not undertake any further consideration of the project's benefits or adverse effects."[26]

2. Consideration of Adverse Effects

In addition to assessing the need for proposed natural gas facilities, "the [FERC] will [also] consider [the following] four major interests that may be adversely affected by the construction and operation of new projects" and "may deny an application based on any of these types of adverse impacts."[27]

(1) "The interests of the applicant's existing customers": "the pipeline applicant must be prepared to financially support its proposed project without relying on subsidization by its existing customers."[28]

(2) The interests of "existing pipelines and their captive customers": FERC will consider the possible harm to captive customers that can result from a new pipeline, regardless of whether there is evidence of unfair competition.[29] The Updated Policy Statement makes clear that comments from existing pipelines and their captive customers, as well as comments from "state utility or public service commissions "[about the potential impacts from] a proposed project" will be an important piece of the review.[30]

(3) Environmental interests: FERC will consider economic and environmental impacts as it balances all impacts for "its public interest determinations under the NGA, [weighing] potential adverse impacts against the evidence of need and other potential benefits of a proposal as it determines "whether to issue a certificate of public convenience and necessity."[31]

FERC will consider environmental impacts and potential mitigation in both environmental reviews under NEPA and public interest determinations under the NGA.[32]

> The Commission expects applicants to structure their projects to avoid, or minimize, potential adverse environmental impacts. Additionally, [FERC] expect[s] applicants

23. *Id.*
24. 178 FERC ¶ 61,107 at P 60.
25. *Id.* at P 60.
26. *Id.* at P 61.
27. *Id.* at P 62.
28. 178 FERC ¶ 61,107 at P 63.
29. *Id.* at P 70.
30. *Id.*
31. *Id.* at P 73.
32. 178 FERC ¶ 61,107 at P 73.

> to propose measures for mitigating impacts, and we will consider those measures—or the lack thereof—in balancing adverse impacts against the potential benefits of a proposal. Further, the NGA grants the Commission broad authority to attach reasonable terms and conditions to certificates of public convenience and necessity.[33]

In the event that FERC determines that an applicant's proposed mitigation measures are not persuasive, FERC "may condition the certificate [to require additional] mitigation . . . [or] deny [the] application . . . if the adverse impacts as a whole outweigh the benefits of the project and cannot be mitigated or minimized."[34]

(4) "The interests of landowners and surrounding communities, including environmental justice communities:" Concerning the impacts on landowners and surrounding communities, "the potential adverse impacts to landowners, along with other adverse impacts, will be weighed against the evidence of need and potential benefits of a proposal in determining whether to issue a certificate of public convenience and necessity."[35] FERC also states that "[it] is committed to ensuring that environmental justice and equity concerns are . . . incorporated into [the] decision-making processes."[36] The Updated Policy Statement provides that FERC's "consideration of impacts to communities . . . will include an assessment of impacts to any environmental justice communities and of any necessary mitigation measures."[37] "[FERC] encourage[s] applicants to consult with guidance provided by EPA, CEQ, and other authoritative sources, to ensure that the Commission has before it all the data needed to adequately identify environmental justice communities potentially affected by a proposed project" and will evaluate and incorporate that guidance.[38] "[FERC] will also consider measures to eliminate or mitigate a project's adverse impacts on environmental justice communities" and "will look with disfavor on mitigation proposals that are proposed without sufficient community input."[39]

Regarding landowner impacts, FERC will be looking for "robust early engagement with all interested landowners, as well as continued evaluation of input from such parties during the course of any given proceeding."[40] The Policy Statement also addresses eminent domain, stating that

> pipeline applicants [must] take all appropriate steps to minimize the future need to use eminent domain. . . . [FERC] will look unfavorably on applicants that do not work proactively with landowners to address concerns. [FERC] will consider the steps a pipeline applicant has already taken to acquire lands through respectful and good faith negotiation, as well as the applicant's plans to minimize the use of eminent domain upon receiving a certificate.[41]

33. *Id.* at P 74.
34. *Id.* at P 74.
35. *Id.* at P 85.
36. 178 FERC ¶ 61,107 at P 79.
37. *Id.*
38. *Id.* at P 87.
39. *Id.* at PP 87, 91, 97.
40. 178 FERC ¶ 61,107 at P 82.
41. *Id.* at PP 82, 85.

3. Assessing Public Benefits and Adverse Effects

"In deciding whether to issue a certificate of public convenience and necessity, the [FERC] must decide whether, on balance, the project will serve the public interest."[42] This determination requires FERC to "consider all of the benefits of a proposal together with all of the adverse impacts."[43]

In assessing the public benefits of a project, "[FERC] intends to consider all benefits that will be provided by the project."[44] As described more fully above,

> the most important consideration in assessing benefits will be the evidence demonstrating that a project is needed. The Commission will also consider any benefits beyond demand that are alleged by the applicant and supported in the record, which may include evidence that the project will displace more pollution-heavy generation sources, facilitate the integration of renewable energy sources, and/or result in a significant source of jobs or tax revenues. . . .
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> In assessing the adverse impacts of a proposal, [FERC] will consider the range of impacts [and mitigation of adverse impacts] to (1) existing customers of the pipeline applicant; (2) existing pipelines in the market and their captive customers; (3) environmental resources; and (4) landowners and surrounding communities, including environmental justice communities. . . .[T]he more interests adversely affected or the more adverse impact a project would have on a particular interest, the greater the showing of public benefits from the project required to balance the adverse impact.[45]

B. Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews, Docket No. PL21-3-000, 178 FERC ¶ 61,108 (2022)

On February 18, 2022, FERC issued an Interim GHG Policy Statement.[46] FERC sought "comment[s] on all aspects of the interim [GHG] policy statement, including, in particular, on the approach to assessing the significance of the proposed project's contribution to climate change."[47]

The Interim GHG Policy Statement details the framework that the Commission intends to use to evaluate a proposed natural gas infrastructure project's GHG emissions and climate impacts under the NEPA and in its NGA public interest determination.[48] According to FERC, in order "to fulfill its statutory responsibilities, it is critical that [it] consider[s] and document[s] how its authorization of infrastructure projects under the NGA, particularly natural gas transportation facilities, will affect emissions of GHGs."[49] The issuance notes that "[FERC] will begin to apply the framework established in [the] policy statement in the interim" and will allow applicants with pending applications to "supplement the record and

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42. *Id.* at P 94.

43. *Id.*

44. 178 FERC ¶ 61,107 at P 97.

45. *Id.* at P 97-99 (FERC noting "that temporary impacts associated with a proposal will generally be given less weight").

46. *Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Reviews*, 178 FERC ¶ 61,108 (2022).

47. *Id.* at P 1.

48. *Id.* at P 1.

49. *Id.* at P 2.

explain how their proposals are consistent with [the Interim GHG] policy statement."[50]

1. Quantifying GHG Emissions and Determining Significance

The Interim GHG Policy states that:

> the [FERC] will quantify a project's GHG emissions that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action, including those effects that occur at the same time and place as the proposed action and effects that are later in time or farther removed in distance from the proposed action.[51]

This quantification will encompass "GHG emissions resulting from construction and operation of the project as well as, in most cases, GHG emissions resulting from the downstream combustion of transported gas."[52]

"The [FERC] will consider all evidence in the record relating to a project's estimated GHG emissions, utilization rate, or offsets: estimates presented by project sponsors, as well as opposing evidence from other parties."[53] FERC will not assume that a project will have 100% utilization; rather it estimate a project's GHG emissions based on the project's projected utilization rate.[54] "The [FERC] will also consider evidence of factors expected to reduce or offset the estimated direct or reasonably foreseeable downstream emissions of the project."[55]

Regarding emissions, FERC proposes to:

- Consider direct emissions of a project a reasonably foreseeable effect;
- Find that an NGA Section 3 export facility project is not the legally relevant cause of upstream and downstream emissions;
- Consider on a case-by-case basis whether downstream emissions are a reasonably foreseeable effect of an NGA Section 7 interstate projec; and
- Consider on a case-by-case basis whether upstream emissions are a reasonably foreseeable effect of an NGA Section 7 project.[56]

In the Interim GHG Policy Statement, FERC addressed commenters' assertions regarding direct emissions, downstream emissions and upstream emissions.[57] Regarding direct emissions, "commenters assert[ed] that the [FERC] must consider fugitive emissions."[58] FERC noted that "direct GHG emissions from the project's short [or] long-term operational activities are an effect of the proposed project . . . [which] the project sponsor" already accounts for in its application.[59] Regarding downstream emissions, FERC noted several cases where the Court held that "the downstream GHG emissions could be reasonably quantified by the

50. 178 FERC ¶ 61,108 at P 129.
51. *Id.* at P 28.
52. *Id.*
53. *Id.* at P 29.
54. 178 FERC ¶ 61,108 at P 29.
55. *Id.* at P 29.
56. *Id.* at P 31.
57. *Id.* at P 32.
58. 178 FERC ¶ 61,108 at P 32.
59. *Id.* at P 33.

[FERC]."[60] Therefore, FERC noted in the Interim GHG Policy Statement that "project sponsors may submit evidence they believe indicate that downstream emissions are not reasonably foreseeable."[61] FERC explained that for NGA Section 7 projects it will consider downstream GHG emissions.[62] "However, for . . . export projects under NGA Section 3, the [FERC] will not consider . . . GHG emissions," as only "the Department of Energy . . . has sole authority to . . . consider" such matters.[63] Regarding upstream emissions, FERC stated that in some cases, it has been "difficult to quantify upstream emissions due to several factors, including location of the supply source and whether transported gas will come from new or existing production."[64] Therefore, "the [FERC] will continue to consider upstream emissions on a case-by-case basis."[65]

2. Level of Review and Significance

The Interim GHG Policy Statement establishes that "unless refuted by record evidence" projects with estimated GHG emissions of 100,000 metric tons per year of carbon dioxide (CO_2) equivalent will be deemed to have a significant impact on the environment.[66] "For context, projects that likely have 100,000 metric tons per year or more of GHG emissions include projects transporting an average of 5,200 dekatherms per day and projects involving the operation of one or more compressor stations or LNG facilities."[67] The "proposed threshold of 100,000 metric tons per year would deem nearly three-quarters of Commission-regulated natural gas project[s], which collectively account for roughly 99% of GHG emissions from Commission-regulated natural gas projects, to have a significant impact on climate change."[68]

This new GHG threshold will serve as a metric for triggering the development of an Environmental Impact Statement (EIS), i.e., "if the proposed project may result in 100,000 metric tons per year of CO_2 . . . then the Commission staff will prepare an EIS."[69] "Commission staff will apply the 100% utilization or full burn rate for the proposed project's emissions to determine whether to prepare an . . . (EIS) or an Environmental Assessment (EA)."[70] In the order, FERC noted that it "believes this estimate is appropriate because it captures Commission projects that may result in incremental GHG emissions that may have a significant effect upon the . . . environment."[71] FERC also noted that "[e]stablishing a threshold

60. *Id.* at P 35 (discussing Sierra Club v. FERC, 867 F.3d 1374 (D.C. Cir. 2017); Birckhead v. FERC, 925 F.3d 510,518-20 (D.C. Cir. 2019); Allegheny Defense Project v. FERC, 932 F.3d 940 (D.C. Cir. 2019)).

61. *Id.* at P 38.

62. 178 FERC ¶ 61,108 at P 38.

63. *Id.* at P 41.

64. *Id.* at P 43.

65. *Id.*

66. 178 FERC ¶ 61,108 at P 81.

67. *Id.* at P 89.

68. *Id.* at P 95.

69. *Id.* at P 3.

70. 178 FERC ¶ 61,108 at P 3 (internal quotations omitted).

71. *Id.*

provides . . . clarity [if] . . . a project [will need] either an EA or EIS."[72] As part of this analysis, FERC "will . . . consider any emerging tools as well as any forthcoming frameworks or analysis issued by CEQ or other agencies on this issue."[73]

3. A Project's Reasonably Foreseeable GHG Emissions

The Interim GHG Policy Statement states that FERC, in order to consider climate impacts, will quantify a project's reasonably foreseeable GHG emissions "based on a projection of [the] amount of . . . capacity [that] will be actually used [i.e.,] projected utilization rate, as opposed to assuming 100% utilization," and any other factors impacting the quantification of project emissions.[74] "This will include GHG emissions resulting from construction and operation of the project as well as, in most cases, GHG emissions resulting from the downstream combustion of transported gas."[75] To enable the Commission's use of the best estimate of a project's GHG emissions, "project sponsors are encouraged to calculate project GHG emissions using a projected utilization rate and submit evidence of any other factors that might impact a project's net emissions."[76] "Because in most instances a 100% utilization rate estimate does not accurately capture the project's climate impacts, estimated emissions that reflect a projected utilization rate will provide more useful information."[77]

4. GHG Mitigation

FERC stated it has the authority to require mitigation of GHG emissions by a project sponsor.[78] The Commission's priority is for project sponsors to mitigate, to the greatest extent possible, a project's direct GHG emissions.[79] The Commission also encouraged project sponsors to propose mitigation of reasonably foreseeable indirect emissions and will take such proposals into account in assessing the extent of a project's adverse impacts.[80]

FERC also addressed claims that "downstream emissions . . . are outside of [its] jurisdiction and" therefore FERC cannot mandate mitigation of downstream emissions.[81] FERC "recognizes, as many commenters assert, that the Commission does not have the statutory authority to impose conditions on downstream users or other entities outside the [FERC's] jurisdiction, such as production, gathering, and local distribution entities."[82] Rather, FERC "encourages each project sponsor to

72. *Id.* at P 80.
73. *Id.* at P 81.
74. 178 FERC ¶ 61,108 at P 29.
75. *Id*. at P 28.
76. *Id.* at P 45.
77. *Id.* at P 50.
78. 178 FERC ¶ 61,108 at P 103.
79. *Id.* at P 106.
80. *Id.* at P 106.
81. *Id.* at P 104.
82. 178 FERC ¶ 61,108 at P 104.

propose measures to mitigate the impacts of reasonably foreseeable GHG emissions associated with its proposed project, and will consider such mitigation proposals in assessing the extent of a project's adverse impacts."[83] The Interim GHG Policy Statement states "that the Supreme Court's ruling in *Public Citizen* does not preclude the Commission from requiring project sponsors to mitigate reasonably foreseeable upstream or downstream emissions."[84] FERC "will consider the project's impact on climate change, including the project sponsor's mitigation proposal, as part of its public interest determination under NGA Section 3 or 7."[85] FERC may also "require additional mitigation of a project's direct GHG emissions as a condition of the authorization, should the Commission deem a project sponsor's proposed mitigation inadequate to support the public interest determination."[86] FERC states that it is

> best to allow project sponsors to demonstrate that their proposed mitigation measures are verifiable and propose means for the Commission to monitor or track the proposed measures through the life of the project. This approach allows project sponsors to take advantage of existing monitoring programs and tailor verification and tracking to their chosen mitigation proposals and prevents FERC from needing to establish a new monitoring program.[87]

The Interim GHG Policy Statement provides that FERC "will consider proposals by . . . project sponsor[s] to mitigate all or [part] of [their] project's climate change impacts."[88] Additionally, "project sponsors [may propose] measures to mitigate the reasonably foreseeable upstream or downstream emissions associated with their projects."[89]

> In order to ensure that any GHG emissions reduction mechanisms achieve real, verifiable, and measurable reductions, any proposed mechanisms should: (a) be both real and additional—the emissions reductions would not have otherwise happened unless the proposed reduction mechanism was implemented, and the associated reductions occur beyond regulatory requirements, (b) be quantifiable—any emissions reductions must be calculated using a transparent and replicable methodology, (c) be unencumbered—seller has clear ownership of or exclusive rights to the benefits of the GHG reduction, and (d) be trackable—the project sponsor must also propose means for the Commission to monitor and track compliance with the proposed mitigation measures for the life of the project.[90]

Furthermore, FERC laid out examples of mitigation mechanism that project sponsors may consider: market based mitigation (renewable energy credits, mandatory compliance, market participation, and voluntary carbon market participation), physical mitigation, and cost recovery.[91] "Pipelines may seek to recover GHG emissions mitigation costs through their rates, similarly to how they seek to

83. *Id.*
84. *Id.* at P 105.
85. *Id.* at P 107.
86. 178 FERC ¶ 61,108 at P 107.
87. *Id.* at P 112.
88. *Id.* at P 4.
89. *Id.* at P 106.
90. 178 FERC ¶ 61,108 at P 109.
91. *Id.* at PP 114-28.

recover other costs associated with constructing and operating a project, such as the cost of other construction mitigation requirements or the cost of fuel."[92]

FERC plans to evaluate proposed mitigation on a case-by-case basis and is not mandating a standard level mitigation.[93] However, FERC may condition its authorization of a project for further mitigation of those impacts.[94]

C. *Notice of Proposed Rulemaking, Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs, 179 FERC ¶ 61,114 (2022)*

On May 19, 2022, FERC issued a notice of proposed rulemaking to require natural gas pipelines, "when filing a general NGA section 4 rate case," to "submit all . . . statements, schedules and workpapers in native format with" formulas and links intact.[95] The NOPR was issued in response to a request for such a rulemaking from several trade associations representing natural gas pipeline shippers.[96] FERC stated that its proposed rule would provide clarity to shippers whether pipelines' rates were derived with the use of underlying links in spreadsheets, thereby facilitating more "timely and comprehensive analysis of a rate case filing."[97] FERC stated that "this will streamline the rate case process, including settlement discussions," and reduce the need for discovery.[98]

II. RATES, TERMS, AND CONDITIONS OF SERVICE

A. *Abandonment*

1. Gulf States Transmission LLC

On January 6, 2022, the Commission issued an order addressing arguments raised on rehearing and setting aside, in part, a prior order (Abandonment Order) that authorized Gulf States to abandon its pipeline system by sale to ETC Haynesville LLC (ETCH), a non-jurisdictional gathering company.[99]

> On July 26, 1990, the Commission issued a certificate of public convenience and necessity under section 7(c) of the NGA and a blanket certificate under Part 284, Subpart G of the Commission's regulations granting Gulf States authorization to construct and operate pipeline facilities extending from Harrison County, Texas, to Caddo Parish, Louisiana. The facilities were constructed and designed to provide up to 150,000 dekatherms per day of firm and interruptible transportation service from natural gas reserves in East Texas to intrastate facilities in northwest Louisiana.

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92. *Id.* at P 128.

93. *Id.* at P 107.

94. 178 FERC ¶ 61,108 at P 107.

95. Notice of Proposed Rulemaking*, Revised Filing and Reporting Requirements for Interstate Nat. Gas Co. Rate Schedules and Tariffs*, 179 FERC ¶ 61,114, 87 Fed. Reg. 31,783 (2022).

96. *Id*. at P 1.

97. *Id.* at PP 6-7.

98. *Id.* at P 7.

99. *Gulf States Transmission LLC*, 178 FERC ¶ 61,003 at PP 1, 15 (2022) (Danly, concurring in part and dissenting in part).

> On April 6, 2021, Gulf States filed an application pursuant to section 7(b) of the NGA and Part 157 of the Commission's regulations requesting authorization to abandon its entire pipeline system by sale to ETCH, a non-jurisdictional gathering company. In its application Gulf States also requested a determination that, once abandoned by sale to ETCH, the facilities would be non-jurisdictional gathering facilities exempt from the Commission's jurisdiction under section 1(b) of the NGA.
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> Commission staff issued the Abandonment Order granting the requested abandonment authorization. Regarding Gulf States' request for a jurisdictional determination, the Abandonment Order explained that it was not appropriate for the seller, Gulf States, rather than the buyer, ETCH, to make the request, which therefore would not be addressed in the Order.[100]

"Gulf States timely requested rehearing," contending that the Abandonment Order departs from prior Commission precedent "because necessitating that ETCH request a declaratory order contradicts the obligations of the Purchase Agreement, would require paying a filing fee, and would delay resolution of the issue of whether the facilities would be jurisdictional once abandoned."[101]

In the order, the Commission explained that while it has previously "has granted similar requests for jurisdictional determinations in abandonment proceedings, but in other instances has declined to make such a determination."[102] In this proceeding, the Commission held that "going forward, parties that desire a determination from the Commission as to the post-abandonment jurisdictional status of facilities must seek the Commission's formal guidance through a petition for declaratory order."[103]

> Under section 1(b) of the NGA, the Commission's jurisdiction does not extend to facilities used for the production or gathering of natural gas, or to gathering services. The NGA itself, however, does not define the term "gathering" [and a]s a result, the Commission has developed a number of legal tests to determine which facilities are non-jurisdictional gathering facilities and which facilities are jurisdictional transmission facilities. The Commission relies on the "primary function test," which considers the physical and geographical attributes of a facility, including: (1) the length and diameter of the pipelines; (2) the facilities' geographical configuration; (3) the extension of the facilities beyond the central point in the field; (4) the location of compressors and processing plants; (5) the location of the wells along all or part of a facility; and (6) the operating pressures of the pipelines.
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> In addition to the physical and geographical factors, the Commission also considers the purpose, location, and operation of the facilities; the general business activities of the owner of the facility; and whether the jurisdictional determination is consistent with the NGA and the Natural Gas Policy Act of 1978 (NGPA). The Commission does not consider any one factor to be determinative and recognizes that all factors do not necessarily apply to all situations. The Commission weighs any and all other relevant facts and circumstances of a particular case, including the non-physical criteria.[104]

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100. *Id.* at PP 3-5.
101. *Id.* at P 6.
102. *Id.* at P 7.
103. 178 FERC ¶ 61,003 at P 7.
104. *Id.* at PP 10-11.

Here, the Commission modified and set aside the Abandonment Order, in part, and granted Gulf States' request for a determination "that the abandoned facilities will perform a gathering function upon their acquisition by ETCH and accordingly will be exempt from Commission jurisdiction under NGA Section 1(b)".[105]

2. Gulf South Pipeline Company, LLC, Destin Pipeline Company, LLC

Gulf South Pipeline Company, LLC (Gulf South) and Destin Pipeline Company, LLC (Destin) filed applications seeking "approval for Gulf South to abandon 160,000 Mcf per day (Mcf/d) of leased transportation capacity on Destin's pipeline system in Mississippi and NGA . . . certificate authorization for Destin to reacquire the 160,000 Mcf/d of leased transportation capacity."[106]

On January 27, 2022, the Commission approved the abandonment:

> The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest in the lessor's pipeline subject to NGA section 7(b) abandonment and section 7(c) certification. Consequently, the lessee is required to obtain certificate authorization to acquire the leased capacity and the lessor must obtain abandonment authorization to cede its rights to the capacity.[107]

The Commission found that since neither of the two shippers utilizing the leased capacity protested the proposed abandonment, "there is a presumption that no continuity and stability of service issues are presented by the circumstances presented in these applications."[108] The Commission also issued the requested certificate authorization.[109]

3. Tennessee Gas Pipeline Company, LLC, Southern Natural Gas Company, LLC

On March 25, 2022, the Commission approved:

> Southern's request to abandon by lease to Tennessee Gas the capacity to support 1,100,000 Dth/d of firm transportation service. Consistent with [its] policy, [the Commission] require[d] Southern to file, within 10 days of the date of abandonment of the lease capacity to Tennessee Gas, a statement providing the effective date of the abandonment. [The Commission] also remind[ed] the Applicants that when the lease terminates, Tennessee Gas is required to obtain authority to abandon the lease capacity and Southern is required to obtain certificate authorization to reacquire that capacity.[110]

4. Transcontinental Gas Pipe Line Company, LLC

On March 31, 2022, the Commission issued an order approving a request of Transcontinental Gas Pipe Line Company, LLC (Transco), "for authorization to

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105. *Id.* at P 21.
106. *Gulf South Pipeline Co.,* 178 FERC ¶ 62,051 at P 1 (2022).
107. *Id.* at P 7.
108. *Id.* at P 9.
109. *Id.* at P 11.
110. *Tennessee Gas Pipeline Co.*, 178 FERC ¶ 61,199 at P 67 (2022).

implement its Happytown Abandonment Project (Project) located in Pointe Coupee Parish, Louisiana . . . subject to certain conditions."[111]

5. ANR Pipeline Company, Great Lakes Transmission Gas Limited Partnership

On April 21, 2022, the Commission granted a request submitted by ANR Pipeline Company (ANR) for a certificate of public convenience and necessity for to construct and operate the Alberta Xpress project.[112] In its application, ANR sought

> to construct a new compressor station in Evangeline Parish, Louisiana, to provide up to 165,000 dekatherms per day (Dth/d) of additional firm transportation service on ANR's Southeast Mainline . . . [and] request[ed] authorization to acquire by lease capacity on Great Lakes Gas Transmission Limited Partnership's (Great Lakes) transmission system . . . sufficient to provide 155,407 Dth/d of firm transportation service.[113]

Concurrently, Great Lakes sought approval to abandon capacity by lease pursuant to section 7(b) of the NGA.[114] The Commission determined that:

> (1) there are significant benefits to the lease arrangement; (2) the lease payments are equal to the lessor's firm transportation rates for comparable service; and (3) the lease will have no adverse effects on ANR and Great Lakes' existing customers. Therefore, [having] conclud[ed] that the proposed Lease Agreement [was] required by the public convenience and necessity . . . [the Commission] approv[ed] the Lease Agreement and grant[ed] ANR's request to acquire by lease capacity from Great Lakes and offer service on the leased capacity under its tariff. . . . [The Commission also] approv[ed] Great Lakes' request to abandon the capacity described in th[e] order.
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> . . . .
>
> [The Commission noted that] when the lease terminates, ANR will be required to obtain authority to abandon the lease capacity and Great Lakes will be required to obtain certificate authorization to reacquire that capacity.[115]

6. Equitrans, L.P.

On June 17, 2022, the Commission granted Equitrans, L.P.'s (Equitrans) application for abandonment, in part, and accepted notice of termination of gathering service.[116] Equitrans "provides interruptible gathering service to customers in West Virginia and Pennsylvania" through its low-pressure Gathering System.[117] Equitrans sought to abandon, either by sale or in place, all of its gathering facilities, both FERC certificated and non-certificated:

> (Equitrans) filed an application pursuant to sections 1(b), 4, and 7(b) of the NGA and Part 157 of the Commission's regulations for authority to abandon all of its existing certificated and non-certificated gathering facilities, consisting of approximately 932

111. *Transcon. Gas Pipe Line Co.*, 178 FERC ¶ 62,179 at P 1 (2022).
112. *ANR Pipeline Co.*, 179 FERC ¶ 61,040 at P 1 (2022).
113. *Id.*
114. *Id.*
115. *Id.* at PP 24-25.
116. *Equitrans, L.P.*, 179 FERC ¶ 61,204 at P 111 (2022).
117. *Id.* at P 7.

> miles of low-pressure pipelines, compressor stations, and appurtenant facilities in West Virginia and Pennsylvania. . . . Because Equitrans [sought] to abandon certain facilities for which there [was] in effect a certificate for the transportation of natural gas in interstate commerce, Equitrans' proposal was subject to the Commission's jurisdiction pursuant to section 7(b) of the NGA. The NGA explicitly excludes "the local distribution of natural gas . . . [and] the facilities used for such distribution" as well as "gathering of natural gas" from the Commission's jurisdiction.[118]

The Commission therefore "[had] no authority to deny a proposed abandonment of facilities the primary function of which is gathering," so the Commission granted abandonment of Equitrans' Gathering System.[119]

> Section 1(b) of the NGA gives the Commission jurisdiction to regulate the transportation of natural gas in interstate commerce, sales for resale of natural gas in interstate commerce, and natural gas companies engaged in such transportation and sale. This gives the Commission complete authority to regulate jurisdictional transportation service performed by interstate pipelines. In addition, section 1(b) specifically states that the provisions of the Act do not apply to "any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas." Thus, section 1(b) of the NGA by its terms exempts local distribution and gathering facilities and services from the Commission's jurisdiction. However, if an interstate pipeline provides gathering service in addition to jurisdictional transportation service, the Commission may have jurisdiction over the rates of that gathering service, as it may be considered as being performed "in connection with" the natural gas company's jurisdictional transportation service. This jurisdiction to determine the justness and reasonableness of the rates under which gathering service is provided derives from sections 4 and 5 of the NGA and is necessary to enable the Commission to properly regulate the pipeline's jurisdictional services, ensuring that the pipeline's jurisdictional transportation rates are just and reasonable and not discriminatory.[120]

The Commission explained that:

> [u]nder section 1(b) of the NGA, the Commission has no jurisdiction over gathering facilities, whether such facilities are certificated or non-certificated. Where gathering facilities were once certificated transportation facilities and, therefore, still have a certificate attached to them, a pipeline must file with the Commission an application under section 7(b) to abandon the facilities. [The Commission explained that it] has no authority to deny the abandonment of the certificated gathering facilities. Where gathering facilities were never certificated, a pipeline need not even file an application with the Commission to abandon such non-certificated facilities. Rather, when abandoning non-certificated gathering facilities, as well as when abandoning certificated gathering facilities, a pipeline must file with the Commission a notice under NGA section 4(d) to reflect the change in, or termination of, any "in connection with" service that occurs as a result of the abandonment.[121]

The Commission's order granted Equitrans "permission and approval to abandon its certificated gathering facilities."[122] The Commission accepted "Equitrans's notice to terminate gathering service on five segments of non-certificated gathering pipeline it is abandoning due to safety concerns associated with nearby

118. *Id.* at PP 1, 7, 54-55 (quoting 15 U.S.C. § 717f(b)).
119. *Id.*
120. 179 FERC ¶ 61,204 at PP 62-63.
121. *Id.* at P 107.
122. *Id.* at P 111.

longwall mining."[123] The Commission also required Equitrans to file separate notices "to terminate gathering services [for any other] non-certificated gathering facilities" it elects to abandon.[124]

B. Bankruptcy

1. ANR Pipeline Company

On June 2, 2021, FERC denied petitions for limited and temporary waivers of the regulations, rules and policies, and pipeline tariff provisions regarding capacity release, right of first refusal, as well as the shipper-must-have-title rule, the prohibition on buy-sell arrangements, and the prohibition against tying arrangements.[125] The requested waivers were intended to implement an agreement to allow ANR Pipeline Company, Columbia Gas Transmission , LLC, and Columbia Gulf Transmission, LLC (collectively, "TC Energy Pipelines") to remarket firm capacity contracted by Gulfport Energy Corporation (Gulfport), where those contracts are subject to a motion to reject in Gulfport's bankruptcy proceeding.[126] The TC Energy Pipelines had opposed the rejection by the bankruptcy court, but asked FERC to grant waivers of the capacity release rules and policies to enable the pipelines to remarket Gulfport's capacity, which otherwise must remain reserved for Gulfport despite non-payment.[127] FERC declined to grant the waiver requests on procedural grounds unrelated to the bankruptcy issues.[128]

2. Gulfport Energy Corporation v. FERC

On July 19, 2022, in *Gulfport Energy Corporation v. FERC*,[129] the U.S. Court of Appeals for the Fifth Circuit issued an order vacating FERC's orders in *Rover Pipeline*[130] that required Gulfport to continue to perform under its firm transportation agreement with Rover even if Gulfport were to declare bankruptcy and reject the contracts.[131] The court disagreed with FERC's analysis of the filed rate doctrine and with FERC's position on the impact of rejection of a contract under the Bankruptcy Code.[132] The court also addressed FERC's ability to review and reform the terms and conditions of a rejected contract, holding that "FERC cannot

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123. *Id.*

124. 179 FERC ¶ 61,204 at P 110.

125. *ANR Pipeline Co.*, 175 FERC ¶ 61,185 (2021).

126. *Id.*; *see* Motion of Gulfport Energy Corp. for Entry of an Order (I) Authorizing Rejection of Certain Negotiated Rate Firm Transp. Agreements and Related Contracts Effective as of the Petition Date and (II) Granting Related Relief, In re Gulfport Energy Corp., No. 20-35562 (DRJ), (Bankr. S.D. Tex. Docket 58).

127. 175 FERC ¶ 61,185 at PP 2-5.

128. *Id.* at PP 14-16.

129. Gulfport Energy Corp. v. FERC, 41 F.4th 667 (5th Cir. 2022).

130. *Rover Pipeline, LLC*, 173 FERC ¶ 61,133, *reh'g*;, 173 FERC ¶ 61,138 (Order on Paper Hearing); 173 FERC ¶ 61,019 (2020) (Order on Petition for Declaratory Order).

131. 173 FERC ¶ 61,019 at PP 25-26.

132. *Gulfport Energy Corp*., 41 F.4th at 667.

require continued performance on the rejected contract."[133] The court ruled that a bankruptcy court can authorize rejection of a filed-rate contract, and that, post-rejection:

> FERC can decide whether *actual* modification or abrogation of a filed rate contract would serve the public interest. It even may do so before a bankruptcy filing. But rejection is just a breach; it does not modify or abrogate the filed rate, which is used to calculate the counterparty's damage. So FERC cannot prevent rejection. It cannot bind a debtor to continue paying the filed rate after rejection. And it cannot usurp the bankruptcy court's power to decide Gulfport's rejection motions.[134]

C. *Capacity Release*

1. Six One Commodities LLC Six One Commodities Vega LLC

FERC granted a temporary and limited 60-day waiver of capacity release regulations and tariff provisions to facilitate the transfer of Vega LLC's (Vega) natural gas assets, via merger, to Six One Commodities (61C), including Vega's firm transportation contracts with Transcontinental Gas Pipe Line Company (Transco).[135] The waiver was requested by 61C "to facilitate [a] permanent release of capacity under the Transco contracts."[136] FERC applied its "four-factor test" and "good cause standard" and granted the waiver request.[137] FERC found:

> (1) the applicant[s] acted in good faith; (2) the waiver is of limited scope [because it is] a one-time waiver of the relevant capacity release provisions; (3) the waiver addresses a concrete problem because, [without] the waiver, the [applicants could not] permanently release and assign . . . the capacity to a party needing the capacity; and (4) the waiver does not have undesirable consequences [because] there is no evidence [that the waiver] . . . would harm . . . third parties.[138]

FERC also found the request "[was] adequately supported and appear[ed] consistent with previous waiver[s]" FERC has granted under similar circumstances, concluding the waiver request was supported by good cause.[139] FERC issued similar orders to grant waivers necessary to facility other transactions this year.[140]

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133. *Id*. at 684 (citing FERC v. Ultra Resources, Inc., 28 F.4th 629, 639 (5th Cir. 2022), Off. Comm. of Unsecured Creditors of Mirant Corp. v. Potomac Elec. Power Co., 378 F.3d 511, 523 (5th Cir. 2004)).

134. *Id.* at 685.

135. *Six One Commodities LLC*, 176 FERC ¶ 61,154 at PP 1-2 (2021).

136. *Id.* at P 2.

137. *Id.* at P 11.

138. *Id.* at PP 11-12.

139. 176 FERC ¶ 61,154 at P 13.

140. *See, e.g.*, *Six One Commodities LLC*, 178 FERC ¶ 61,221 (2022); *SWN Energy Services Co.*, 177 FERC ¶ 61,208 (2021); *Fieldwood Energy, LLC*, 176 FERC ¶ 61,036 (2021); *EQT Energy, LLC*, 176 FERC ¶ 61,009 (2021).

2. Roaring Fork Interstate Gas Transmission, LLC Kaiser-Frontier Midstream

In its order approving Kaiser-Frontier's abandonment by sale of its Silo Pipeline to Roaring Fork, FERC denied a requested waiver of its capacity release regulations.[141] Roaring Fork sought the waiver after stating that "opportunities for segmentation of capacity are limited or . . . capacity release may not occur frequently."[142] FERC noted that specific waivers of regulations are not needed if the regulations "do not on their face apply."[143] For example, FERC acknowledged "that the Silo Pipeline is small . . . with a single customer [and] . . . delivery point . . . [and] cannot comply with the segmentation requirements of section 284.7(d)" of FERC's regulations.[144] However, even though capacity release may not occur frequently, Roaring Fork is an interstate pipeline that must offer capacity release per section 284.8 of FERC's regulations, and FERC found "no evidence [on] the record to justify a waiver of the . . . capacity release regulations."[145]

D. Cost Trackers

1. Columbia Gas Transmission, LLC

On February 25, 2022, FERC issued an order approving a stipulation and agreement of final settlement filed to resolve outstanding issues related to multiple dockets initiated by Columbia Gas Transmission, LLC (Columbia), which included "Columbia's first general [NGA section 4] rate case filing [since] it agreed in 2016 to [its] Modernization II Settlement."[146] The Commission determined that the settlement was "fair and reasonable and in the public interest."[147] The settlement "extends [Columbia's] Capital Cost Recovery Mechanism (CCRM) for a third term, coterminous with the term of the Settlement."[148] It "requires Columbia to make an annual general plant maintenance investment of at least $150 million."[149] The settlement also sets forth the parameters for "which facilities are eligible for CCRM funding," the governance mechanism for reviewing the list of eligible facilities, and related accounting parameters and derivation of rates, and prohibits "Columbia from implementing any similar recovery mechanism other than the CCRM during the term of the settlement."[150] Pursuant to the final settlement, Columbia is permitted "to maintain regulatory assets for Modernization II Settlement property taxes, rate case costs, COVID-19 costs, and Pipeline and Haz-

141. *Roaring Fork Interstate Gas Transmission, LLC*, 177 FERC ¶ 62,153 at PP 1, 39 (2021).
142. *Id.* at P 38.
143. *Id.* at P 39.
144. *Id.* (citing 18 C.F.R. § 284.7(d)).
145. 177 FERC ¶ 62,153 at P 39.
146. *Columbia Gas Transmission, LLC*, 178 FERC ¶ 61,144 (2022).
147. *Id*. at P 10.
148. *Id*. at P 8.
149. *Id.*
150. 178 FERC ¶ 61,144 at P 8.

ardous Materials Administration maximum allowable operating pressure compliance."[151] On September 7, 2021, FERC approved a related partial settlement which resolved whether Columbia Gas had violated a moratorium provision in the Modernization II Settlement when it made its new NGA section 4 rate case filing.[152]

2. Southern Star Central Gas Pipeline, Inc.

FERC approved a Stipulation and Agreement of Settlement (Settlement) filed by Southern Star Central Gas Pipeline, Inc. (Southern Star) that implements "a new modernization program with a cost recovery mechanism (CRM)."[153] The CRM established by the Settlement describes facility costs eligible for inclusion in a new surcharge.[154] The Settlement states that the CRM will provide for surcharges that will be collected between March 1, 2023, and October 31, 2026.[155] Under the terms of the Settlement, "the annual eligible capital costs will not exceed . . . $88 million in 2022, $50 million in 2023, $50 million in 2024, and $50 million in 2025."[156] Southern Star will also have a capital maintenance obligation "no less than an amount equal to the combined depreciation and amortization expenses included in the applicable calendar year's FERC Form 2 Annual Filing."[157] "Customers are [permitted] to challenge the annual cost recovery filings."[158] The CRM will remain in effect through November 1, 2026, which is the effective date of Southern Star's next NGA section 4(e) rate case filing.[159] Once the CRM is terminated, "shippers . . . will remain subject to" all outstanding costs included in the CRM surcharge, and Southern Star must refund any over-recovered CRM costs.[160]

E. Fuel

1. Tennessee Gas Pipeline Company, LLC

On June 15, 2022, the administrative law judge issued an initial decision approving Tennessee's annual revisions, filed March 1, 2021, to the rates associated with its Fuel Adjustment Mechanism, which include Tennessee's fuel and loss retention (F&LR) and electric power cost rates (EPCR).[161] The key issue in the case was the justness and reasonableness of Tennessee's proposed adjustments to the incremental F&LR and EPCR for service on its Broad Run Expansion Project,

151. *Id.* at P 6.
152. *Id*. at P 2.
153. *S. Star Cent. Gas Pipeline*, *Inc.*, 179 FERC ¶ 61,137 (2022).
154. *Id*. at P 3.
155. Letter from Will Wathen, Southern Star Central Gas Pipeline, Inc., to Kimberly D. Bose, Secretary, FERC (June 10, 2022).
156. *Id*. at 32.2(d).
157. *Id*. at 32.3(b).
158. *Id*. at 32.2(f).
159. 179 FERC ¶ 61,137 at P 3.
160. Letter from Will Wathen to Kimberly D. Bose, *supra* note 147, at 32.5(b).
161. *Tennessee Gas Pipeline Co.*, 179 FERC ¶ 63,024 (2022).

which was designed to serve Antero Resources Corporation (Antero).[162] Antero asserted Tennessee's incremental fuel rates resulted in Antero subsidizing other shippers on Tennessee's system.[163]

The initial decision reviewed the proposed fuel allocation based on "the Commission's 1999 Certificate Policy Statement,"[164] which requires that incremental expansion projects—including fuel costs—not be subsidized by existing shippers on the system.[165] The initial decision found that Tennessee had met its burden of showing that it properly assigned Antero with the fuel impacts resulting from Antero's transportation, consistent with the Commission's "no-subsidy" policy and general principles of cost causation. [166]

Having satisfied its NGA section 4 burden, the initial decision found that Tennessee's proposed rates must be accepted.[167]

The initial decision found Tennessee's 2021 Fuel Filing and its proposed tariff records to be just and reasonable.[168] As of this writing, the initial decision is pending before the Commission.[169]

F. Force Majeure

1. Carlsbad Gateway, LLC

On January 25, 2022, the Commission issued an order (Order) granting Carlsbad Gateway, LLC (Gateway) a "blanket certificate of public convenience and necessity" (Certificate) and a "temporary waiver of certain regulatory obligations."[170] While the Commission issued Gateway the requested Certificate, the Commission directed Gateway to revise its proposed tariff provisions concerning *force majeure*.[171] Gateway had proposed to "define[] *force majeure* in part as . . . any other causes, whether of the kind herein enumerated or otherwise, not reasonably within the control of the party claiming suspension."[172] The Commission found that such definition is inconsistent with Commission policy that *force majeure* be defined as an event that is "both uncontrollable and unexpected" because Gateway's proposed definition did not address the latter criterion, and directed Carlsbad to file revised tariff records consistent with that finding.[173]

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162. *Id*. at P 1.
163. *Id.* at P 68.
164. *Id.* at P 77 (citing *Certification of New Interstate Nat. Gas Pipe Line Facilities*, 88 FERC ¶ 61,227 (1999) (1999 Certificate Policy Statement); *see* 90 FERC ¶ 61,128 (2000) (Order Clarifying 1999 Certificate Policy Statement); *see also* 92 FERC ¶ 61,094 (2000) (Order Further Clarifying 1999 Certificate Policy Statement).
165. 179 FERC ¶ 63,024 at P 77.
166. *Id.* at P 77.
167. *Id.* at P 1.
168. *Id.*
169. 179 FERC ¶ 63,024 at P 125.
170. *Carlsbad Gateway, LLC*, 178 FERC ¶ 61,053 (2022).
171. *Id*. at P 25.
172. *Id.* (internal quotations omitted).
173. *Id.* at P 26.

2. Roaring Fork Interstate Gas Transmission, LLC and Kaiser-Frontier Midstream, LLC

On December 21, 2021, the Commission issued an order (Order) approving Kaiser-Frontier Midstream, LLC's (Kaiser-Frontier) request to "abandon by sale its Silo Pipeline to Roaring Fork Interstate Gas Transmission (Roaring Fork)."[174] However, the Commission directed Roaring Fork to revise its proposed definition of *force majeure* in the General Terms and Conditions (GT&C) to its FERC Gas Tariff.[175] Roaring Fork had proposed to define governmental *force majeure* as certain occurrences that are not reasonably within Roaring Fork's control and non-governmental *force majeure* as certain occurrences that are not reasonably within Roaring Fork's control.[176] The Commission found that "there is no justification for this non-parallel construction."[177] The Commission therefore directed Roaring Fork to revise the definition of *force majeure* to limit such events, including interruptions by governments, to matters arising out of circumstances not within Roaring Fork's control and which Roaring Fork is "unable to overcome" by the exercise of due diligence.[178]

3. Portland Natural Gas Transmission System

On November 30, 2021, the Commission issued an order (Order) approving Portland Natural Gas Transmission System's (PNGTS) proposal to modify its reservation charge crediting (RCC) tariff provisions for both *force majeure* and non-*force majeure* events.[179] Among other things, National Grid Gas Delivery Companies (National Grid) "argue[d] that [the] safe harbor clauses" for *force majeure* and non-*force majeure* events in such RCC tariff provisions should: (1) "trigger when any *force majeure* event lasts 10 days, and not only when all 10 days suffer from service below historic levels" and (2) be revised to remove confusing language that could over-constrain the provision of RCC or that PNGTS could rely on to only apply RCC to the amounts that exceed the applicable safe harbor threshold, and "not the range of volumes from zero up to those amounts."[180] The Commission rejected such concerns in the Order, finding that "PNGTS's safe harbor [clauses are] (i) consistent with what the Commission has approved for PNGTS and other pipelines in the past" and (ii) "not so confusing as to render them unjust and unreasonable."[181]

174. 177 FERC ¶ 62,153 at P 1.
175. *Id*. at P 45.
176. *Id*. at PP 44-45.
177. *Id*. at P 45.
178. 177 FERC ¶ 62,153 at P 45.
179. *Portland Nat. Gas Transmission Sys.*, 177 FERC ¶ 61,146 (2021).
180. *Id*. at PP 13-14.
181. *Id*. at P 17.

G. Gas Quality

1. Great Basin Gas Transmission Company

On January 31, 2022, the Commission issued a letter order accepting tariff records filed by Great Basin Gas Transmission Company (Great Basin), "including modifications . . . to define and allow for the receipt and transportation of renewable natural gas (RNG) on its pipeline system."[182] Great Basin also proposed language "stating that RNG shall conform to the gas quality specifications of traditional gas sources and for processed biogas."[183] Great Basin also proposed language providing that,

> nevertheless . . . it may, in its reasonable judgment, accept RNG containing a combined level of not more than four percent by volume of inert substance and/or with a total gross heating value of not less than 950 Btu, as long as the RNG meets the other requirements in Great Basin's Operating Policy.[184]

Great Basin further proposed to include tariff provisions that limited its obligation to accept "RNG that does not meet the existing gas specifications" to the extent that "Great Basin can meet the tariff requirements for gas quality at Great Basin's Delivery Points by blending with traditional supplies."[185] Great Basin further proposed "tariff language that identified the maximum level for health-related and pipeline integrity constituents of concern (COCs) for RNG delivered to an RNG Receipt Point on [its] system."[186] The Commission found the "proposed tariff changes to be just and reasonable," but required the Operating Policy to be included in Great Basin's FERC Gas Tariff to eliminate the possibility of "undue discrimination as to new entrants in the market offering RNG or current shipper of RNG on [Great Basin's] system."[187]

2. Alliance Pipeline L.P.

On January 11, 2022, the Commission issued a letter order accepting the tariff records filed by Alliance Pipeline L.P. (Alliance), which proposed to permit Alliance to issue action reports or Operational Flow Orders (OFO) to "alleviate operational problems due to, [among other things], gas quality."[188] The proposed tariff language enabled Alliance to issue action reports and OFOs to respond to any operational problems related to the quality of the gas received on Alliance's system, irrespective of whether such gas meets the general gas quality specifications of Alliance's FERC Gas Tariff.[189] "On December 27, 2021, Tenaska Marketing Ventures (Tenaska) filed a motion to intervene and comment" on Alliance's proposed tariff records, taking issue with the phrase "irrespective of whether this gas meets

182. *Great Basin Gas Transmission Co.*, 178 FERC ¶ 61,071 at P 1 (2022).
183. *Id.* at P 6.
184. *Id*.
185. *Id*.
186. 178 FERC ¶ 61,071, at P 7.
187. *Id*. at P 11.
188. *Alliance Pipeline L.P.*, 178 FERC ¶ 61,013 at P 2 (2022).
189. *Id*. at P 3.

the specifications in section 2 of the GT&C" at the end of proposed GT&C Section 37.1.[190] Alliance agreed to remove that phrase to address Tenaska's concern, and the Commission accepted Alliance's revised tariff records subject to removal of the phrase.[191]

3. Paiute Pipeline Company

On August 27, 2021, the Commission issued an order rejecting revised tariff records filed by Paiute Pipeline Company (Paiute) without prejudice, in which Paiute "proposed to modify [the] gas quality specifications in the General Terms and Conditions (GT&C)" of its FERC Gas Tariff to accommodate acceptance of renewable natural gas (RNG) into its system.[192] The proposed gas quality specifications would have allowed Paiute to

> accept RNG containing [a combined level] of not more than four percent [(4%)] by volume of inert substances and a total gross heating value of not less than 950 Btu, as long as the RNG meets the other requirements in Paiute's Biomethane Verification Program and Operating Policy.[193]

The proposed gas quality specifications also would have "permit[ted] Paiute to determine the gross heating value of the gas and the gas component analysis at reasonable intervals."[194] The Commission determined that Paiute's proposal would have allowed Paiute to include gas quality and interchangeability specifications in documents outside the proposed tariff records, in contravention of Commission policy providing that "only natural gas quality and interchangeability specifications . . . in a Commission-approved . . . tariff" are enforceable.[195]

H. Jurisdiction

1. Jurisdictional Status of Facilities

a. Roaring Fork Midstream, LLC

On June 16, 2022, the Commission issued an order granting Roaring Fork Midstream, LLC's (Roaring Fork) petition for a declaratory order certifying that "[Roaring Fork's] planned natural gas pipelines in . . . Colorado and . . . Wyoming [would] perform a gathering function and not be subject to the Commission's jurisdiction under section 7 of the Natural Gas Act (NGA)."[196] The Commission explained that it relies on its "primary function test" "to determine which facilities are non-jurisdictional gathering facilities and which facilities are jurisdictional transmission facilities."[197] The Commission found that Roaring Fork's planned

190. *Id*. at PP 8-10.
191. *Id*. at PP 11-12.
192. *Paiute Pipeline Co.*, 176 FERC ¶ 61,134 at 2-3 (2021).
193. *Id*. at P 3.
194. *Id*. at P 4.
195. *Id*. at P 12.
196. *Roaring Fork Midstream, LLC*, 179 FERC ¶ 61,189 at P 1 (2022).
197. *Id*. at P 6.

facilities are non-jurisdictional under its primary function test because (1) the lengths, diameters, operating pressure, and geographical configuration of the planned pipelines, as well as the location of compressors, processing plants, and wells relative to such pipelines, are all consistent with a gathering function (notwithstanding the fact that "such pipelines will cross the Wyoming/Colorado border"), (2) its central point in the field test is inapplicable given the backbone-type structure of the planned pipelines, and (3) the planned pipelines otherwise qualified as gathering under the additional considerations applied by the Commission under its primary function test.[198] The Commission therefore found that Roaring Fork's planned pipelines are "exempt from the Commission's jurisdiction" because the primary function of such pipelines will have a primary function of non-jurisdictional gathering.[199]

b. Nopetro LNG, LLC

On March 25, 2022, the Commission granted Nopetro LNG, LLC's (Nopetro) petition for an order "declar[ing] that Nopetro's construction and operation of a natural gas liquefaction and truck loading facility and proposed trans-loading operations in Port St. Joe, Florida [collectively, the Nopetro Facility] would not be subject to the Commission's jurisdiction under section 3 or 7 of the Natural Gas Act (NGA)."[200] The Commission found that the "Nopetro . . . Facility is not an LNG terminal subject to [its] jurisdiction under [NGA] section 3 . . . because it is not located at the point of export such that LNG can be directly transferred to vessels for export."[201] The Commission explained that it lacked such jurisdiction over the Nopetro Facility because "the LNG-filled ISO containers would leave the Nopetro Facility and be transported by truck approximately a quarter of a mile to" a dock that would remain available for general public use, where the containers would then be loaded onto ocean-going vessels by a crane that, while owned by Nopetro, would be available for use by others through the dock operator for a fee.[202]

The Commission rejected intervenors' argument that the Nopetro Facility is a jurisdictional LNG facility "because [it] is only a quarter of a mile away from the export point [and is therefore effectively] transferring LNG directly to an ocean-going LNG tanker," instead finding that the Nopetro Facility is neither onshore nor in state waters, as would be required under section 2(11) of the NGA for the Commission to exercise jurisdiction over the Nopetro Facility.[203] The Commission also rejected intervenors' arguments that its prior decisions examining its jurisdiction over compressed natural gas (CNG) facilities are irrelevant to its analysis of an LNG facility such as the Nopetro Facility, finding instead that with the

198. *Id*. at PP 6-8, 10-16.
199. *Id*. at P 17.
200. *Nopetro LNG, LLC*, 178 FERC ¶ 61,168 at P 1 (2022).
201. *Id*. at P 10.
202. *Id*.
203. *Id*. at PP 11-12.

singular exception of exporting LNG rather than CNG, the Nopetro Facility is essentially identical to such facilities and therefore its prior decisions involving such CNG facilities is relevant to its jurisdictional analysis of the Nopetro Facility.[204] The Commission further determined that it could not assert jurisdiction over the Nopetro Facility pursuant to NGA section 7 because that statutory provision only applies to the transportation of natural gas via pipeline.[205] The Commission also rejected concerns about the creation of a potential regulatory gap if it did not exercise jurisdiction over the Nopetro Facility, explaining that the "need for regulation cannot alone create authority to regulate."[206] On July 29, 2022, the Commission issued an order denying requests for rehearing.[207]

c. Diversified Midstream, LLC

On February 10, 2022, the Commission issued an order granting a certificate authorizing Diversified Midstream, LLC (Diversified) to provide interstate transportation service for Columbia Gas Transmission, LLC (Columbia) "on Diversified's non-jurisdictional gathering system."[208] The Commission further granted Diversified's "request[] [for] a determination that the proposed interstate transportation service provided to Columbia will not otherwise affect the status of the Diversified system as a gathering system, nor affect the non-jurisdictional status of any other operation in which Diversified is currently engaged."[209] The Commission explained that it has previously "issued certificates with waivers to a gathering company to allow the gathering company to provide incidental interstate transportation service through its facilities without affecting the non-jurisdictional status of its gathering operations."[210]

The Commission determined that issuing Diversified such a certificate was appropriate "because of the limited . . . jurisdictional activities proposed and because Diversified's primary function is the non-jurisdictional gathering of gas."[211] The Commission also granted Diversified's request for waivers that would exempt it from all the filing and reporting requirements and any annual charges applicable to interstate companies.[212] The Commission found that "the public interest would not be served by subjecting Diversified to [such requirements and charges]" and that granting such waivers was consistent with prior orders granting such certificates to similarly non-jurisdictional companies engaged in comparatively minor jurisdictional activities.[213]

204. 178 FERC ¶ 61,168 at P 14.
205. *Id*. at P 15.
206. *Id*. at PP 17-18 (citing ExxonMobil Gas Mktg. Co. v. FERC, 297 F.3d 1071, 1088 (D.C. Cir. 2002)).
207. *Nopetro LNG, LLC*, 180 FERC ¶ 61,057 at P 25 (2022).
208. *Diversified Midstream, LLC*, 178 FERC ¶ 62,079 at PP 1-2 (2022).
209. *Id*. at PP 1-2.
210. *Id.* at P 11.
211. *Id*.
212. 178 FERC ¶ 62,079 at P 11.
213. *Id.* at PP 12-14.

d. Gulf States Transmission LLC

On January 6, 2022, the Commission issued an order (Rehearing Order) granting rehearing in part of its August 9, 2021 order (Abandonment Order) issued by Commission staff.[214] The Abandonment Order granted "Gulf States Transmission, LLC's (Gulf States) request to abandon its entire pipeline system by sale to ETC Haynesville LLC (ETCH)" but declined to grant Gulf States' request for a jurisdictional determination that the pipeline system would constitute non-jurisdictional gathering facilities following the abandonment by sale.[215] "[T]he Abandonment Order explained that it was not appropriate for the seller, Gulf States, rather than the buyer, ETCH, [to request such jurisdictional determination]," and therefore declined to address such request.[216] The Abandonment Order instead stated that "[ETCH], as the new operator of the facilities . . . could make a formal request for [a] declaratory order" as to such jurisdictional determination.[217] "Gulf States timely requested rehearing" of the Abandonment Order, "argu[ing] that Commission staff erred in declining to determine the post-abandonment jurisdictional status of the facilities and request[ing] that the Commission determine on rehearing that, once abandoned by sale to ETCH, the facilities will operate as non-jurisdictional gathering facilities."[218]

"[T]he Commission [acknowledged in the Rehearing Order that it] has granted similar requests for jurisdictional determinations in abandonment proceedings," but has declined to make such a determination in other instances.[219] Going forward, the Commission held that "parties that desire a determination from the Commission as to the post-abandonment jurisdictional status of facilities must seek the Commission's formal guidance through a petition for declaratory order."[220] However, the Commission elected to make the requested jurisdictional determination here in light of the fact that it "has not consistently required a request for declaratory order under circumstances similar to those presented here."[221]

Applying its "primary function test," the Commission determined that the subject facilities would be non-jurisdictional following the abandonment thereof to ETCH.[222] Specifically, the Commission found that "under the primary function test the facilities that ETCH plans to operate will have a primary function of gathering and they are therefore exempt from the Commission's jurisdiction under section 1(b) of the Natural Gas Act (NGA)."[223] The Commission accordingly "modified and set aside, in part," the Abandonment Order to grant "Gulf States' request for a determination that the abandoned facilities will perform a gathering function

214. 178 FERC ¶ 61,003 at P 1.
215. *Id.* at PP 1, 4-5.
216. *Id*. at P 5.
217. *Id*.
218. 178 FERC ¶ 61,003 at PP 5-6.
219. *Id*. at P 7.
220. *Id*.
221. *Id*. at P 9.
222. 178 FERC ¶ 61,003 at PP 10-20.
223. *Id*. at P 21.

upon their acquisition by ETCH and accordingly will be exempt from Commission jurisdiction under NGA section 1(b). . . ."[224]

e. Northern States Power Company, a Minnesota Corporation

On October 21, 2021, the Commission issued an order granting Northern States Power Company, a Minnesota Corporation's petition for an order declaring that, "upon acquisition of certain facilities owned by Northern Natural Gas Company (Northern) . . . Northern States Power [would] maintain its status as a local distribution company (LDC), exempt from the Commission's jurisdiction under the Natural Gas Act (NGA)."[225] Northern States Power intended to acquire facilities owned by Northern at the time, including: two "Town Border Station[s]," ".71 mile of the 3-inch-diameter MNB61801 Pipeline . . . and its terminus . . . 2.93 miles of the 6-inch-diameter MNB61802 Pipeline… [and] 1.13 miles of the 4-inch-diameter MNB61802 Pipeline."[226] Northern States Power intended to transfer and upgrade the acquired assets before "integrat[ing] the facilities into its existing local distribution system network."[227] "[After] incorporation into [the existing] local distribution system, the [only] function of [Northern States Power's] facilities w[ould] be the transportation and distribution of natural gas to its retail customers [in Minnesota.]"[228]

The Commission explained that "NGA section 1(b) . . . does not extend [its jurisdiction] to local distribution facilities," despite a lack of definition for what constitutes a local distribution system.[229] The Commission further explained that "[it] has cited factors such as pipe diameter, the physical characteristics of the local pipe system, and the function of the system in finding that facilities are used for local distribution and are [therefore] exempt from [the] Commission's jurisdiction."[230] Turning to the facilities at issue in this proceeding, the Commission found that such facilities "share the characteristics of facilities previously found to be local distribution systems."[231] Specifically, the Commission noted that the "pipeline segments [measure less than] six inches in diameter . . . and will not be operated . . . at transmission line pressure," and that "upon incorporation into Northern States Power's system, the facilities will be used to receive gas from interstate pipelines" for sale to local retail customers.[232] The Commission therefore declared that the facilities that Northern States Power sought to acquire will—following their integration into Northern States Power's system—be "exempt from the Commission's jurisdiction."[233]

224. *Id.*
225. *Northern States Power Co.*, 177 FERC ¶ 61,045 at P 1 (2021).
226. *Id.* at P 2.
227. *Id.* at P 3.
228. *Id.*
229. 177 FERC ¶ 61,045 at P 5.
230. *Id.*
231. *Id.* at P 6.
232. *Id.*
233. 177 FERC ¶ 61,045 at P 6.

f. New Fortress Energy LLC

On July 15, 2021, the Commission issued an order (Rehearing Order) denying rehearing of its March 19, 2021 order (Order), but modified the discussion in the Order as permitted by the Natural Gas Act (NGA) section 19(a) to reach the same result.[234] The Order found that "New Fortress' liquefied natural gas (LNG) facility located at the Port of San Juan, Puerto Rico, was an LNG facility terminal as defined by the NGA and thus subject to the Commission's jurisdiction."[235] The Commission explained in the Order that the New Fortress facility is a jurisdictional LNG terminal because it is "a dedicated LNG facility, located at the point of import, and connected to a pipeline."[236] New Fortress requested rehearing of the Order, alleging that "the Commission unreasonably departed from prior precedent in finding that 'the [New Fortress] facility's limited power-plant piping was a pipeline for the purposes of determining the Commission's jurisdiction under the NGA."[237] "New Fortress [also took] issue with the Commission differentiating between its jurisdiction over LNG terminals located in foreign commerce and interstate commerce because the NGA contains no such distinction."[238]

In rejecting New Fortress' first contention, the Rehearing Order clarified that, notwithstanding references in prior proceedings to "the physical or operational characteristics of a facility, . . . the physical characteristics of the piping" and connectivity of an LNG "facility to the interstate or intrastate pipeline grid" is nevertheless immaterial to whether an LNG facility operating in foreign commerce is a jurisdictional LNG terminal.[239] Rather, the Commission determines the jurisdictional status of an LNG facility based on "whether the [LNG] facility is connected to piping which enables the [LNG] facility to receive natural gas for liquefaction or send out revaporized LNG."[240]

The Rehearing Order rejected New Fortress' second contention that the Commission acted in an arbitrary and capricious manner or in violation of the NGA "by differentiating its consideration of the jurisdictional status of LNG terminals based on whether [an LNG facility is] operating in foreign or interstate commerce."[241] The Commission pointed to its decision in *Shell U.S. Gas & Power, LLC* (*Shell*),[242] explaining that

> when assessing the jurisdictional status of LNG facilities potentially involved in the transportation of LNG by waterborne vessel in interstate commerce, the Commission considers, in addition to the Commission's other criteria, whether the LNG will be revaporized for injection into either an interstate or non-jurisdictional local distribution company or Hinshaw pipeline system

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234. *New Fortress Energy*, *LLC*, 176 FERC ¶ 61,031 at P 2 (2021).
235. *Id*. at P 1.
236. *Id*. at P 5.
237. *Id.* at P 6 (internal citations omitted).
238. 176 FERC ¶ 61,031 at P 6 (internal citations omitted).
239. *Id*. at P 15.
240. *Id*.
241. *Id*. at P 18.
242. *Shell U.S. Gas & Power, LLC*, 148 FERC ¶ 61,163 (2014).

—not the physical characteristics of any piping connected to the LNG facility.[243] The Commission therefore held that New Fortress' "reliance on *Shell* for the proposition that the Commission has historically [analyzed] the physical aspects of an LNG facility's piping when considering its jurisdictional status was incorrect."[244] Additionally, the Commission referred to the discussion in its Order to summarily reject New Fortress' renewed argument that the LNG "facility is not located at a point of import or export because its facility receives LNG from smaller shuttle vessels that transport LNG from . . . larger carriers."[245]

Finally, the Commission rejected "New Fortress' argu[ment] that the [Order] . . . could be read to give the Commission a scope of authority broader than Congress intended . . .thereby . . . leaving the industry . . . 'at a loss regarding the bounds of . . . NGA section 3 jurisdiction.'"[246] The Commission asserted that the Order "clarified how [the Commission] considers a facility's connection to piping and facilities operating in interstate commerce when determining NGA section 3 jurisdiction," but the Order did not expand the Commission's jurisdiction to a limitless degree as alleged by New Fortress.[247] Because of the foregoing rejections, the Commission denied the requested rehearing but modified the discussion of the Order.[248]

On June 14, 2022, the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) denied New Fortress' petitions for review of the Rehearing Order.[249] Specifically, the D.C. Circuit held that the Commission's decision that the New Fortress facility satisfied the pipeline requirement to be a jurisdictional LNG facility was not arbitrary and capricious.[250] The D.C. Circuit rejected New Fortress' argument that the Commission failed to offer meaningful guidance as to its jurisdiction in not distinguishing between pipes and pipelines.[251] The D.C. Circuit instead found that the Commission's decisions "establish[ed] jurisdictional boundaries based on a pipeline's role in transporting gas to or from a facility rather than a pipeline's physical characteristics."[252] The D.C. Circuit also found reasonable the Commission's refusal to differentiate between pipelines and pipes, upholding the Commission's determination that such distinction could result in the Commission lacking jurisdiction over large-scale LNG export terminals that receive gas from nearby facilities or over LNG import facilities that are directly connected to large local distribution companies.[253] Finally, the D.C. Circuit also held the Commission was not required to consider any reliance interests engendered by its prior decisions

243. 176 FERC ¶ 61,031 at P 19.
244. *Id*. at P 20.
245. *Id*. at P 21.
246. 148 FERC ¶ 61,163 at P 23 (internal citations omitted).
247. *Id*.
248. *Id*. at P 27.
249. New Fortress Energy Inc., v. FERC, 36 F.4th 1172, 1175 (D.C. Cir. 2022).
250. *Id.* at 1173.
251. *Id.* at 1173.
252. *Id*. at 1178.
253. *New Fortress Energy, Inc.*, 36 F.4th at 1178.

that focused on the pipeline requirement because the Commission's decision did not depart from Commission policy articulated in those decisions, but rather reasonably applied it to the New Fortress facility.[254]

g. Equitrans, L.P.

On June 17, 2022, the Commission issued an order granting Equitrans, L.P.'s proposed abandonment of certain gathering facilities (Gathering System) either by sale to Big Dog Midstream, LLC (Big Dog Midstream) or in place.[255] The Commission explained that while Equitrans' proposed abandonment is subject to the Commission's jurisdiction pursuant to section 7(b) of the Natural Gas Act (NGA), "the Commission has no authority to deny a proposed abandonment of facilities" with a primary function of gathering.[256] The Commission rejected arguments raised by intervenors that it could exercise such authority because the Gathering System was once functionalized as a transmission facility and therefore certificated.[257] Instead, the Commission found that "to abandon certificated gathering facilities, a pipeline is [only] required to make a procedural filing under [NGA] section 7(b) to abandon the [NGA] section 7(c) certificate that still remains attached to the gathering facilities, which filing the Commission is not at liberty to deny."[258] The Commission further found that it also has no authority "to place conditions upon any approval of Equitrans' abandonment of its Gathering System—as [it] normally would" for the abandonment or certification of jurisdictional facilities pursuant to NGA sections 7(b) and 7(c), respectively—where the Commission lacks jurisdiction over the gathering facilities themselves pursuant to NGA section 1(b).[259]

The Commission also rejected a number of arguments raised by intervenors.[260] For example, the Commission rejected arguments contending that prior approval from the West Virginia Public Service Commission was required before the Commission could grant the requested abandonment, explaining that "[it] has sole jurisdiction over whether to grant an abandonment" of the Gathering System.[261] Furthermore, while the Commission questioned whether its approval of Equitrans' instant proposal could be considered a major federal action, such approval would nonetheless qualify for a categorical exclusion under the Commission's regulations implementing the National Environmental Policy Act, thereby obviating the need to prepare an environmental assessment or environmental impact statement.[262]

254. *Id.*
255. *Equitrans, L.P.*, 179 FERC ¶ 61,204 (2022).
256. *Id*. at PP 54-55.
257. *Id*. at P 67.
258. *Id*.
259. 179 FERC ¶ 61,204 at P 72.
260. *Id*.
261. *Id*. at P 77.
262. *Id.* at P 86.

The Commission found that it is possible that Equitrans' Taylor County Field facilities could be subject to the Commission's jurisdiction if all or any portion of those facilities function primarily as jurisdictional transmission facilities with respect to the 125 or more "farm tap customers served directly from" those facilities.[263] However, the Commission stated that it did not have sufficient information before it to make that determination.[264] The Commission therefore directed Equitrans to take one of three actions:

> (1) show cause why it should not be required to file an application seeking a certificate under NGA section 7 to operate the Taylor County Field facilities . . . , (2) file an application for such a certificate, or (3) file information demonstrating that its proposal to abandon the Taylor Country Field facilities to Big Dog Midstream is permitted by the present or future public convenience or necessity as required by NGA section 7(b).[265]

2. FERC Orders Addressing its Jurisdictional Authority

a. Rover Pipeline, LLC and Energy Transfer Partners, L.P.

On January 20, 2022, the Commission issued an order "establish[ing] a hearing to determine whether Rover Pipeline, LLC (Rover) and [its] parent company Energy Transfer Partners, L.P. [(ETP)] (collectively, Respondents) violated section 157.5 of the Commission's regulations" when the Respondents destroyed an 1843 farmstead (the Stoneman House) "eligible for listing in the National Register of Historic Places (NRHP)."[266] The Commission established such hearing because the Respondents had contested the Commission's earlier Order to Show Cause and Notice of Proposed Penalty, as well as an accompanying Office of Enforcement (OE) staff report (collectively, the Show Cause Order), that "direct[ed] Respondents to show cause why they should not be found to have violated section 157.5 of the Commission's regulations through alleged misrepresentations and omissions" in their 2015 and 2016 project application filings.[267] In their answer to the Show Cause Order, Respondents argued among other things "that the [Natural Gas Act] NGA vests . . . Federal district courts with exclusive jurisdiction over enforcement actions and, therefore, the Commission lacks the authority to adjudicate the alleged violations" in the Show Cause Order.[268]

The Commission denied the Respondents' request for dismissal of the Show Cause Order on procedural grounds, including (as relevant here) Respondents' argument that the Commission lacked jurisdiction to make legally binding determinations of NGA violations.[269] In rejecting such argument, the Commission found that Congress clearly

263. 179 FERC ¶ 61,204 at P 97.
264. *Id*.
265. *Id*.
266. *Rover Pipeline, LLC*, 178 FERC ¶ 61,028 at P 3 (2022).
267. *Id*.
268. *Id*. at P 8.
269. *Id*. at PP 19-20.

> inten[ded] to establish a delineated regulatory regime that delegates to the Commission the power to adjudicate NGA violations, provides for review of such Commission determinations in the Federal Courts of Appeals, and gives Federal district courts jurisdiction over only discrete causes of action such as criminal violations, suits for injunctive relief, and enforcement of final judgments.[270]

The Commission further found that decisions by federal courts as well as the Supreme Court further supported its interpretation of the Commission's jurisdiction under NGA section 24 relative to Federal district courts.[271] The Commission also found that its interpretation of its jurisdiction under the NGA is consistent with Congressional intent, legislative history, and Commission precedent.[272] Finally, the Commission found that neither the Appointments Clause nor the Fifth or Seventh Amendments to the U.S. Constitution stripped the Commission of its jurisdiction—or that of its Administrative Law Judges with respect to the Appointments Clause—to make legally binding determinations of NGA violations.[273]

b. Hartree Partners, LP v. Northern Natural Gas Company

On July 15, 2021, the Commission issued an order "declin[ing] to exercise primary jurisdiction over" a complaint (Complaint) filed by Hartree Partners, LP (Hartree) against Northern Natural Gas Company (Northern).[274] The Complaint alleged that Northern unlawfully sought to recover reservation charges (Disputed Amounts) from Hartree for quantities that Hartree nominated but were not transported by Northern during Winter Storm Uri due to alleged outages on Northern's system.[275] The Complaint further asserted that "the Commission should [have] assert[ed] jurisdiction over the matter [because, according to Hartree], Northern's claim to the Disputed Amounts [went] beyond interpretation" of the underlying service agreements and violated the Natural Gas Act (NGA), Commission policy, and Northern's FERC Gas Tariff.[276] Northern filed a motion to dismiss the Complaint, "arguing that Hartree failed to meet its burden to establish a *prima facie* case or provide adequate evidence to support its factual assertions."[277]

Notwithstanding Hartree's arguments in the Complaint, the Commission "declined to exercise primary jurisdiction over this dispute and thus granted Northern's motion to dismiss the Complaint."[278] The Commission stated that "[w]hether to exercise primary jurisdiction is a matter within [its] discretion," and that it is "guided by the decision in *Arkla La. Gas Co. v. Hall* [(*Arkla*)]" when determining whether to exercise such discretion.[279] Applying the three factors set forth in *Arkla*, the Commission decided that

270. 178 FERC ¶ 61,028 at P 38.
271. *Id*. at PP 42-44.
272. *Id*. at PP 45-54.
273. *Id*. at PP 65, 79, 84.
274. *Hartree Partners, L.P.*, 176 FERC ¶ 61,017 at PP 1-2 (2021).
275. *Id*. at PP 7-11.
276. *Id*. at P 11.
277. *Id*. at P 14.
278. 176 FERC ¶ 61,017 at P 20.
279. *Id*. at P 21 (citing *Arkla La. Gas Co*., 7 FERC ¶ 61,175, *reh'g denied*, 8 FERC ¶ 61,031 (1979)).

> [(1) it did] not possess special expertise beyond that of a court to determine the factual circumstances of Northern's provision of service during Winter Storm Uri [because] [t]his is a factual dispute of the type routinely dealt with by a court, . . . [(2)] there is no need for uniformity of interpretation with respect to the dispute here [and therefore] a determination of the parties' rights and obligations here will not have broad applicability to other customers or pipelines because the facts are unique to the dispute raised in the Complaint, . . . [and (3) its] determination of the factual circumstances at issue here would not raise a policy issue important to the Commission's regulatory responsibilities.[280]

The Commission therefore "declin[ed] to exercise primary jurisdiction over the issues raised here and accordingly dismissed the Complaint."[281]

c. Transcontinental Gas Pipe Line Co., LLC

On June 30, 2021, the Commission issued an order (Order) granting Transcontinental Gas Pipe Line Company, LLC's (Transco) petition for an order declaring that the Commission has exclusive and primary jurisdiction over a contractual dispute concerning "the proper rate for the firm transportation service that Transco provides to Fairless Energy, LLC (Fairless) under . . . Contract No. 9218326 (the Fairless Contract)".[282] Specifically, the Commission found that the instant dispute concerning the proper rate for the Fairless Contract meets the factors set forth in *Arkla La. Gas Co. v. Hall* (*Arkla*)[283] for exercising primary jurisdiction, and therefore elected to do so here.[284] Applying the three factors set forth in *Arkla*, the Commission decided that (1) it possessed special expertise beyond that of a court because determination of the applicable rate required interpretation of Transco's tariff and analysis of the relevant certificate orders relating to the facilities used in connection with the Fairless Contract, both of which the Commission frequently addresses, (2) there is a need for uniformity of interpretation with respect to this dispute because a determination of this dispute would affect other parties beyond Transco and Fairless, and (3) a determination of the factual circumstances at issue here would raise a policy issue important to the Commission's regulatory responsibility because "the Commission has an interest in enforcing service rates and ensuring that pipelines can collect Commission-approved rates to . . . recover the costs of the certificated facilities associated with such rates."[285]

After determining that it could elect to exercise primary jurisdiction, the Commission did so and found "that the appropriate rate for the Fairless Contract is the incremental rate for the MarketLink Expansion Project under Transco's Rate

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280. *Id*. at P 22-23.

281. *Id*. at P 23.

282. *Transcon. Gas Pipe Line Co.*, 175 FERC ¶ 61,260 at P 1 (2021). Fairless acquired capacity released from a shipper with a negotiated rate contract for Market Link Expansion capacity. *Id.* at P 3. The negotiated rate contract provided for the negotiated rate to remain in effect until November 1, 2018. *Id.* at P 4. Fairless claimed that the rate after that date should be Transco's general system rate, while Transco claimed that the rate should be the higher incremental rate established for Market Link Expansion service. *Id.* at P 5.

283. *Arkla La. Gas Co. v. Hall*, 7 FERC ¶ 61,175, at p. 61,322 (1979); *Arkla La. Gas Co. v. Hall*, 8 FERC ¶ 61,031 (1979) (*reh'g denied*).

284. 175 FERC ¶ 61,260 at P 13.

285. *Id*. at PP 44-49.

Schedule FT as set forth in Transco's [FERC Gas] Tariff."[286] "On July 30, 2021, Fairless filed a request for rehearing" of the Order (Rehearing Request).[287]

On November 18, 2021, the Commission issued an order (Rehearing Order) denying Fairless' Rehearing Request.[288] In the Rehearing Order, the Commission affirmed its prior determination that the incremental MarketLink Expansion rate applied, emphasizing that answering the question of the applicable rate under the contract required the Commission to examine its own orders and Transco's FERC Gas tariff rather than general state contract law principles.[289] Therefore, the Commission continued to find that it properly exercised primary jurisdiction over the dispute.[290] The Commission, in turn, rejected each of Fairless' arguments in its Rehearing Request.[291] With respect to jurisdiction, the Commission first found that Fairless' argument that the Commission departed from precedent incorrectly relied on a set of decisions about general state law contract interpretation, whereas the dispute here instead turned on how to interpret Transco's FERC Gas Tariff.[292] The Commission then affirmed that it had "properly examined the three [*Arkla*] factors" in determining that it was entitled to exercise jurisdiction over this contractual dispute.[293]

I. Market-Based Rates

1. Golden Triangle Storage, Inc.

On November 30, 2021, the Commission approved, by letter order, market-based rate (MBR) treatment for "new no-notice firm storage" service proposed by Golden Triangle Storage, Inc. (Golden Triangle).[294] Golden Triangle had existing MBR authorization for "firm and interruptible storage, park[] and loan, and wheeling services, as well as for interruptible hourly balancing service."[295] "In response to a customer request [it] proposed to offer no-notice firm storage service".[296] Under Golden Triangle's proposal, it intended to "combine firm storage service and no-notice injections and withdrawals under one new rate schedule and service agreement."[297] "Golden Triangle propose[d] to charge market-based rates for [its new] no-notice firm storage service" in accordance with the market-based rate authority previously granted by the Commission.[298] The Commission approved the new service and the proposed market-based rate treatment, and in so doing,

286. *Id*. at P 53.
287. *Transcon. Gas Pipe Line Co.,* 177 FERC ¶ 61,116 at P 1 (2021).
288. *Id.* at P 2.
289. *Id*. at P 16.
290. *Id*.
291. 177 FERC ¶ 61,116 at PP 18-21.
292. *Id*. at P 18.
293. *Id*. at P 19.
294. *Golden Triangle Storage, Inc*., 177 FERC ¶ 61,144 at PP 1, 8 (2021).
295. *Id.* at P 2.
296. *Id.*
297. *Id.*
298. 177 FERC ¶ 61,144 at P 4.

granted "Golden Triangle's request for waiver of the requirement that tariff filings for a new service include an estimate of the effect on revenues and costs for the 12 months after the new service begins."[299]

2. Spire Storage West LLC

On May 19, 2022, the Commission granted Spire Storage West LLC (Spire Storage) certificate authorization to "expand its natural gas storage facilities at the Clear Creek Storage Field (Clear Creek Expansion Project), and [in the process], reaffirm[ed] [Spire Storage's MBR] authority."[300] Spire Storage's existing MBR authorization obligated it to notify the Commission of changed circumstances that could affect its prior market study analysis.[301] Accordingly, as the "Clear Creek Expansion Project [was expected] to increase the storage capacity and injection and withdrawal capabilities" of its facilities, Spire Storage sought reaffirmation of its ability to charge MBRs for its proposed project.[302] Upon reviewing Spire Storage's market power study, the Commission concluded that even with these changes, Spire Storage would still be unable to exercise market power, and thus the Commission "reaffirm[ed Spire Storage's] authority to charge market-based rates for its firm and interruptible storage and interruptible wheeling services."[303]

J. Rate Cases

1. ANR Pipeline Company (Docket No. RP22-501-000)

On February, 28, 2022, FERC issued an order accepting and suspending ANR Pipeline Company's (ANR) tariff records to implement a general rate case.[304] On January 28, 2022, ANR proposed rate increases to reflect significant increases in its cost-of-service and rate base.[305] ANR's proposal would increase its rate base from $1.847 billion to $3.440 billion, primarily due to system modernization investments.[306] ANR also proposed changes to its depreciation rates and "total negative salvage" for several transmission, gathering, and storage categories.[307] Multiple parties filed protests, taking issue with the rate increases, rate design, and the proposal to recover $900 million associated with system modernization through a system improvement modernization mechanism (SIMM).[308] The Commission found that "ANR's filing raised issues of material fact" and set for

299. *Id.* at P 8.
300. *Spire Storage West, LLC*, 179 FERC ¶ 61,123 at P 1 (2022).
301. *Id.* at P 13.
302. *Id.*
303. *Id.* at P 41.
304. *ANR Pipeline Co.*, 178 FERC ¶ 61,149 at P 1 (2022).
305. *Id.* at P 6.
306. *Id.*
307. *Id.*
308. 178 FERC ¶ 61,149 at PP 1, 9, 15.

hearing issues including, but not limited to, capital structure, cost allocation, and "treatment of expansion project costs and the SIMM."[309]

2. Texas Eastern Transmission, LP (Docket No. RP21-1001-000)

On August 31, 2021, FERC issued an order rejecting Texas Eastern Transmission, LP's (Texas Eastern) tariff records to implement a general rate case as unjust and unreasonable because the inclusion "of an unsubstantiated increase in its income tax allowance rendered its rate filing unlawful."[310] In addition, pursuant to Section 5 of the Natural Gas Act (NGA), the Commission required Texas Eastern to show cause within 30 days that its reservation charge crediting provisions complied with Commission policy.[311] Texas Eastern filed a request for rehearing of the Commission order rejecting its tariff filing.[312] The Commission issued an order setting aside, in part, its August 31, 2021 order, and accepted and suspended the tariff records from Texas Eastern's July 30, 2021 tariff filing "subject to refund, conditions, and . . . outcome of [a] hearing."[313] Numerous parties filed requests for rehearing and subsequent petitions for review at the D.C. Circuit.[314] On March 24, 2022, the Commission accepted Texas Eastern's "revised tariff filing" and terminated its Section 5 investigation.[315] This proceeding was ultimately consolidated with Texas Eastern's rate proceeding in Docket No. RP21-1188-000.[316]

3. Texas Eastern Transmission, LP (Docket No. RP21-1188-000)

Following the Commission's order rejecting Texas Eastern's general rate case filing in Docket No. RP21-1001-000, Texas Eastern filed revised tariff records on September 30, 2021.[317] "Texas Eastern propose[d] [rate] increases" and revisions to "tariff provisions applicable to its various FERC jurisdictional services."[318] Texas Eastern also proposed to implement "the cost allocation and rate design methodologies required by [a] 2019 Settlement."[319] Texas Eastern proposed a total cost-of-rate service "of $2,218,359,340, . . . and a total rate base of $7,455,128,754," and a 14.50% return on equity (ROE).[320] Texas Eastern also proposed changes to its depreciation rates and "negative salvage rates for storage and transmission facilities."[321]

309. *Id.* at P 19.
310. *Texas E. Transmission, L.P.*, 176 FERC ¶ 61,138 at P 23 (2021).
311. *Id.* at P 24.
312. *Id.* at P 1.
313. *Texas E. Transmission, L.P.*, 178 FEC ¶ 61,024 at PP 2, 28 (2022).
314. *Texas E. Transmission, L.P.,* 178 FERC ¶ 63,012 (2022).
315. *Texas E. Transmission, L.P.*, 178 FERC ¶ 61,135 at PP 1-2 (2022).
316. 178 FERC ¶ 63,012 at P 1.
317. *Texas E. Transmission, L.P.*, 177 FERC ¶ 61,065 at P 1 (2021).
318. *Id.*
319. *Id.* at P 5.
320. *Id.* at P 6.
321. 177 FERC ¶ 61,065 at P 7.

Multiple parties filed protests raising several issues with Texas Eastern's rate filing, including the "proposed ROE of 14.50%, accumulated deferred income tax (ADIT), and cost of service."[322] On October 29, 2021, FERC issued an order "accept[ing] and suspend[ing] [Texas Eastern's] tariff records."[323] The Commission determined that Texas Eastern's rate filing raised issues of material fact and set for hearing issues "including but not limited to cost of service, depreciation, rate of return, cost allocation . . . , and billing determinants."[324] On July 7, 2022, Texas Eastern and the parties to the proceeding "reached a settlement in principle that would resolve all issues in th[e] proceeding."[325]

4. Eastern Gas Transmission and Storage, Inc. (Docket No. RP21-1187-000)

On October 29, 2021, FERC issued an order accepting and suspending Eastern Gas Transmission and Storage, Inc.'s (EGTS) tariff record to implement a general rate case.[326] On September 30, 2021, EGTS "proposed rate changes to . . . recover its cost of service."[327] EGTS's proposal included several changes due to significant capital investments to modify and expand its system, resulting in a substantial increase in its cost of service.[328] EGTS proposed an "annual cost of service of . . . $1,119.9 million, . . . a rate base of . . . $960.3 million, . . . [and an] ROE of 14.75%."[329] Multiple protestors raised several issues including EGTS's "cost-of-service components, depreciation and negative salvage rates, fixed fuel rates, revenue crediting, lease costs, income taxes, ADIT, excess accumulated deferred income tax (EDIT), capital structure, and the proposed ROE of 14.75%."[330] The Commission determined that EGTS's filing raised issues of material fact and set for hearing issues including but not limited to "depreciation, rate of return, cost allocation and rate design, billing determinants, treatment of ADIT, EDIT, fuel rate percentages, income tax, revenue crediting, and rolled-in projects."[331]

K. Rate Investigations

1. El Paso Natural Gas Co., LLC

On April 21, 2022, "pursuant to Section 5 of the Natural Gas Act," the FERC opened an investigation into whether El Paso Natural Gas Co., LLC's (El Paso) rates are unjust and unreasonable.[332] The Commission noted that it approved a

322. *Id.* at P 11.
323. *Id.* at P 1.
324. *Id*. at P 23.
325. *Texas E. Transmission, L.P*, FERC Docket No. RP21-1188-001 at P 3 (July 12, 2022).
326. *E. Gas Transmission & Storage, Inc.*, 177 FERC ¶ 61,064 at PP 1-2 (2021).
327. *Id*. at P 1.
328. *Id.* at P 4.
329. *Id*. at PP 7-8.
330. 177 FERC ¶ 61,064 at P 12.
331. *Id*. at P 21.
332. *El Paso Nat. Gas Co.,* 179 FERC ¶ 61,051 at P 1 (2022).

rate settlement in 2019 that required El Paso to file a cost and revenue study at the end of a rate moratorium period ending on January 1, 2022.[333] In its "Unadjusted Study," El Paso claimed a revenue shortfall of $3 million, based on "an illustrative return on equity (ROE) of 15.29%" (derived from the ROE "proposed by other pipelines in recent rate filings").[334] El Paso's "Adjusted Study," which made adjustments 1) increasing depreciation rates, 2) increasing negative salvage rates, 3) "includ[ing] transmission and storage terminal decommissioning cost allowances . . . , and 4) reduc[ing] park and loan revenues," showed a revenue deficiency of $43 million.[335] Using 2019 and 2020 Form 2 annual report data, the Commission estimated El Paso's ROE at 24.4% in 2019, and 20.4% in 2020.[336] Based on El Paso's Unadjusted Study data, the Commission estimated an ROE of 20.7%.[337] Although El Paso's Adjusted Study "propose[d] new depreciation rates, negative salvage rates, and decommissioning rates," the Commission removed these adjustments because it had not approved them and El Paso had not supported them.[338] The resulting ROE was estimated at 19.3%.[339] The Commission also found that the recent maturity date of $260 million in long-term debt could materially affect whether El Paso's use of its own capital structure remains appropriate for ratemaking purposes, "or whether it should rely upon its parent's capital structure."[340] To address these issues, the Commission directed El Paso to "file a [new] cost and revenue study" and set the matter for hearing.[341]

2. Guardian Pipeline, LLC

On April 21, 2022, "pursuant to Section 5 of the Natural Gas Act," the FERC opened an investigation into whether Guardian Pipeline, LLC's (Guardian) rates are unjust and unreasonable.[342] The Commission noted that Guardian's currently effective rates were set in a settlement approved on February 6, 2006, that the settlement approved the recourse rates authorized when Guardian was originally certificated, and that Guardian has not filed a Natural Gas Act Section 4 rate case since Guardian became subject to Commission jurisdiction.[343] Based on Guardian's annual Form 2 reports, the Commission estimated that the pipeline's "return on equity" was 16.1% in 2019 and 20.8% for 2020.[344] Based upon this analysis, the Commission found that Guardian may be recovering revenue substantially in excess of its estimated cost of service.[345] The Commission "direct[ed] Guardian

333. *Id.* at PP 3-4.
334. *Id.* at P 6.
335. 179 FERC ¶ 61,051 at PP 7-8.
336. *Id.* at P 14.
337. *Id.* at P 17.
338. *Id.*
339. 179 FERC ¶ 61,051 at P 17.
340. *Id.* at P 18.
341. *Id.* at P 20.
342. *Guardian Pipeline, LLC*, 179 FERC ¶ 61,050 at P 1 (2022).
343. *Id.* at P 3.
344. *Id.* at P 5.
345. *Id.*

to file a cost and revenue study based on . . . information for the latest 12-month period available."[346] "[A]s the Commission has done in other recent Section 5 proceedings," the Commission permitted Guardian to also "file a separate cost and revenue study that reflects [projected changes that] will occur during a[] . . . six-month adjustment period following the 12-month base period."[347] This matter was set for hearing before an administrative law judge.[348]

L. Reservation Charge Credits

1. Texas Eastern Transmission, LP

On August 31, 2021, pursuant to Section 5 of the Natural Gas Act, the Commission "direct[ed] Texas Eastern [Transmission, LP (Texas Eastern)] to show cause as to why [the] reservation charge crediting procedures" of its tariff comply with Commission policy.[349] This order was issued in response to Texas Eastern's general Section 4 rate case filing in Docket No. RP19-343.[350]

> Texas Eastern's procedures for reservation charge adjustments during outages. In the case of non-performance relating to *force majeure* events and certain orders issued by PHMSA Texas Eastern provides for adjustments to occur based on the Safe Harbor method, defined as "where reservation charges must be credited in full to the shippers after a short grace period when no credit is due the shipper (i.e., 10 days or less)." . . . [The Commission stated that] despite a history of recent curtailments on [its] system, Texas Eastern's crediting language fail[ed] to account for instances where historical usage may have been constrained by *force majeure* or other outages. . . .
>
> [The Commission found] that Texas Eastern's reservation charge crediting procedures rely on a shipper nominating supplies on a daily basis in order to qualify for credits. [But t]he Commission has found that when the pipeline proposes a method of reducing credits in the case of *force majeure*, and there is advance notice of an outage, credits for that day *must* be based solely on a measure of each shipper's historical usage, and not on the shippers' nominations. [Because] shippers that have notice of an outage should be permitted to focus on obtaining alternate supply routes, and not compelled to submit nominations that they do not reasonably expect the pipeline to honor, . . . [the Commission found] this provision in Texas Eastern's tariff to be unjust and unreasonable.[351]

Further, the Commission found that because "it is unjust and unreasonable for a pipeline to calculate credits based on usage levels that have been constrained by previous outages. . . . Texas Eastern should be required to eliminate periods in which shippers' use of the system was constrained in its calculation of historical usage."[352]

On September 30, 2021, in response to the Commission's show cause order, Texas Eastern filed "certain clarifying changes" to its reservation charge crediting

346. 179 FERC ¶ 61,050 at P 9.
347. *Id.* at P 10.
348. *Id.* at P 11.
349. 176 FERC ¶ 61,138 at P 1.
350. *Id.* at P 4.
351. *Id.* at PP 29-30.
352. *Id.* at P 31.

provisions.[353] Specifically, Texas Eastern proposed language clarifying that when an entire segment is unavailable for service, "no nominations are required" to receive reservation charge credits, and that "it [would] accept nominations" to and from secondary points subject to the availability of capacity.[354] Texas Eastern also proposed to clarify that in computing reservation charge credits, its calculations of historical usage would not include "times when customers' use of the system was constrained."[355]

On March 24, 2022, the Commission accepted Texas Eastern's tariff proposal and terminated the show cause proceeding.[356] On June 16, 2022, the Commission issued an order denying a rehearing request filed by the Northeast LDC Customer Group (Northeast LDC).[357] Northeast LDC requested the Commission grant rehearing of the Order because, according to Northeast LDC, Texas Eastern's reservation charge crediting provision violates Commission policy by "requir[ing] shippers to submit nominations to receive reservation charge credits for partial *force majeure* outages with advance notice."[358] The Commission disagreed, finding that a pipeline "should be allowed an opportunity to perform before having to provide reservation charge credits when a partial outage occurs but [the pipeline] can still meet some of its firm service obligations," and that—unlike a total outage—shippers must therefore continue to submit nominations in the event of a partial outage in order to be eligible to receive reservation charge credits.[359]

2. Eastern Gas Transmission and Storage, Inc.

On October 29, 2021, in Eastern Gas Transmission and Storage's (EGTS) general rate case proceeding, the Commission accepted and suspended tariff records, subject to refund and conditions, established hearing procedures.[360] The Commission also ordered EGTS to:

> (1) show cause as to why [the reservation charge crediting provisions of EGTS' tariff] (GT&C section 45) remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to its tariff would remedy the identified concerns if EGTS were to determine that the tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential, and therefore, proceeds to establish a replacement tariff.[361]

The Commission found that elements of EGTS' reservation charge crediting provisions may "not . . . comply with Commission policy."[362] More specifically, "GT&C section 45.B.3 describes how EGTS would calculate firm shipper capacity eligible for reservation charge crediting in the event of an outage where it is

353. 178 FERC ¶ 61,135 at P 2.
354. *Id*. at PP 17-18.
355. *Id*. at P 19.
356. *Id.* at P 2.
357. *Texas E. Transmission*, 179 FERC ¶ 61,201 (2022).
358. *Id.* at P 11.
359. *Id.* at PP 19, 22.
360. *Eastern Gas Transmission & Storage, Inc.,* 177 FERC ¶ 61,064 at P2 (2021).
361. *Id.* at P 28.
362. *Id.* at P 25.

not appropriate to use the past seven days' service numbers [and], in such a scenario, EGTS would use the quantities from exactly one year ago, adjusted for any changes to the shipper's contract quantity in the past year."[363] But the "tariff does not contemplate how it would handle" a situation where an outage occurred exactly one year prior while, the Commission observed, generally "it is unjust and unreasonable for a pipeline to calculate credits based on usage levels that have been constrained by previous outages."[364]

In addition, the Commission found that GT&C section 45 could be interpreted to give "shippers . . . reservation charge credits [only] if they nominate."[365] "While requiring nominations is appropriate in most scenarios, it becomes unreasonable during a pre-announced outage, when shippers know that none of their nominations will be honored."[366] In support, the Commission referred to a recent decision:

> [W]hen the pipeline proposes a method of reducing credits in the case of *force majeure*, and there is advance notice of an outage, credits for that day *must* be based solely on a measure of each shipper's historical usage, and not on the shippers' nominations. The Commission determined that shippers that have notice of an outage should be permitted to focus on obtaining alternate supply routes, and not compelled to submit nominations that they do not reasonably expect the pipeline to honor.[367]

3. Columbia Gulf Transmission, LLC

On November 30, 2021, the Commission accepted, effective December 1, 2021, Columbia Gulf Transmission's "revised tariff records filed pursuant to section 4 of the Natural Gas Act (NGA) and Part 154 of the Commission's regulations."[368] The Commission rejected protests challenging the tariff's reservation charge crediting language, finding Columbia Gulf's scheduling proposal substantially the same as those the Commission has found just and reasonable.[369] In addition, Columbia Gulf had previously revised the reservation charge crediting provision in 2020 "in order to base credits on historical usage in situations when advance notice of the outage would make it unreasonable to base credits on nominated volumes."[370] The Commission found no reason to "revisit [its] acceptance of those provisions."[371]

4. Portland Natural Gas Transmission System

On November 30, 2021, the Commission accepted the revised tariff record, effective December 1, 2021, "modify[ing] the reservation charge crediting provisions set forth in section 6.21 of the General Terms and Conditions (GT&C) of

363. *Id.* at P 26.
364. 177 FERC ¶ 61,064 at P 26 (citing 176 FERC ¶ 61,138 at P 31).
365. *Id* at P 27.
366. *Id.*
367. *Id.* (citing *Transcon. Gas Pipe Line Co., LLC*, 175 FERC ¶ 61,085 (2021)).
368. *Columbia Gulf Transmission, LLC,* 177 FERC ¶ 61,145 at P 1 (2021).
369. *Id.* at P 20.
370. *Id.* at P 23.
371. *Id.*

[Portland Natural Gas Transmission System (PNGTS)] tariff," subject to the conditions discussed in its order.[372]

"National Grid argue[d] that while PNGTS' proposed [tariff] revisions appear to be largely in conformance with Commission policy," PNGTS should make "three modifications . . . to comply with the Commission's reservation charge crediting policy."[373]

Although "PNGTS argue[d] that its previous filing should be accepted as just and reasonable, it agree[d] that all three changes [proposed by National Grid] are consistent with its intent, and thus it agree[d] to make changes to provide sufficient clarity for all parties."[374]

First, the Commission ordered PNGTS to "modify its proposed section 6.21.4.2 to delete the word 'nominated.'"[375] "Second, regarding the interaction of secondary service and reservation charge crediting, [the Commission] conditioned [its] acceptance upon PNGTS revising sections 6.21.4.2(a)(i) and (b)(i)" to "clarify that successful use of secondary service leads to a reduction of credits, not a total waiver of credits."[376] The Commission found that PNGTS' safe harbor provision was consistent with the Commission's prior approvals "for PNGTS and other pipelines in the past," and therefore declined to order changes.[377] Having stated in its answer that

> it "was not and never has been," its intention that its tariff liability provision should be read as exceeding the limit established by Commission precedent, PNGTS . . . propose[d] to add the following clause to its liability section: provided, however, unless otherwise agreed to by Transporter and Shipper, the foregoing shall not limit Transporter's liability, if any, to Shipper, nor Shipper's liability, if any, to Transporter, arising out of gross negligence, willful misconduct, or bad faith actions. Nothing herein will limit Transporter's liability, if any, to Shipper, nor Shipper's liability, if any, to Transporter, for direct damages.[378]

Because "PNGTS volunteered to change the tariff language regarding the limitation on damages for gross negligence, willful misconduct, or bad faith," the Commission also found the language to be "a more accurate reflection of Commission policy on legal liability [and] direct[ed] PNGTS to include th[e] revision in [its] compliance filing."[379]

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372. 177 FERC ¶ 61,146 at PP 1, 19. PNGTS proposed to change its methodology for calculating the volumes to which reservation charge credits (RCC) apply, and to further clarify those situations where RCC are not applicable. *Id.* at P 2.

373. *Id.* at P 7.

374. *Id.* at P 11 (internal quotations omitted).

375. *Id.* at P 15.

376. 177 FERC ¶ 61,146 at P 16.

377. *Id.* at P 17.

378. *Id.* at P 11.

379. *Id.* at P 18.

5. Roaring Fork Interstate Gas Transmission, LLC, Kaiser-Frontier Midstream, LLC

On December 21, 2021, the Commission issued an order granting Kaiser-Frontier Midstream, LLC's application "to abandon by sale its Silo Pipeline to Roaring Fork Interstate Gas Transmission (Roaring Fork) and to abandon its Part 157, Subpart F blanket certificate."[380] Concurrently, the Commission issued Roaring Fork's NGA section 7(c) application requesting: "(1) issuance of a certificate of public convenience and necessity authorizing it to acquire Kaiser-Frontier's Silo Pipeline; (2) a Part 157, Subpart F blanket certificate; (3) a Part 284, Subpart G blanket certificate; (4) approval of its proposed *pro forma* tariff; and (5) certain waivers."[381]

In the order, the Commission noted "that when a pipeline proposes a method of reducing reservation charge credits in the case of *force majeure*, and there is advance notice of an outage, credits for that day *must* be based on each shipper's historical usage, and not on the shippers' nominations."[382] Therefore, the Commission directed "Roaring Fork . . . to clarify [its tariff] language to ensure that there is an impartial mechanism for basing credits on historical usage in the context of a pre-announced *force majeure* outage."[383]

6. Range Resources-Appalachia, LLC and Columbia Gulf Transmission, LLC v. Texas Eastern Transmission, LP; Range Resources-Appalachia, LLC v. Texas Eastern Transmission, LP

On March 24, 2022, the Commission issued an order dismissing the two complaints filed against Texas Eastern Transmission, LP (Texas Eastern) by Range Resources-Appalachia, LLC (Range) in Docket No. RP22-435-000, and by Range and Columbia Gulf Transmission, LLC (Columbia Gulf) in Docket No. RP22-433-000.[384] Both complaints maintained that "Texas Eastern failed to deliver gas at the Adair Interconnect at the minimum pressure necessary for delivery into the Columbia Gulf system" during certain time periods in 2019 and 2021 and asserted "that Texas Eastern . . . violated its certificate obligations, [its] tariff, the [NGA], Commission regulations," and its firm service agreement with Range.[385]

The Commission "address[ed] the issue of reservation charge credits" because it involved the substantive issue of whether Texas Eastern violated its tariff by not providing reservation charge credits for the Curtailment Periods.[386] "Texas Eastern [argued, and the Commission agreed,] that while Range is eligible for reservation charge credits under its contract, it [was] not entitled to them under the

380. 177 FERC ¶ 62,153 at P 1.

381. *Id.* at P 1.

382. *Id.* at P 47 (citing *Transcon. Gas Pipe Line Co.*, 175 FERC ¶ 61,085 at P 19 (2021)).

383. *Id.* at P 47.

384. *Range Resources-Appalachia, LLC*, 178 FERC ¶ 61,217 at PP 1-2 (2022).

385. *Id.* at P 1.

386. *Id.* at P 68.

terms of the tariff because service was not completed due to Columbia Gulf's failure to confirm Range's volumes.[387] "Therefore, Texas Eastern has not violated its tariff."[388] Section 31.3 of Texas Eastern tariff states that:

> Notwithstanding any other provision in Pipeline's FERC Gas Tariff, in no event shall Customer be entitled to a decrease in its Reservation Charge for Pipeline's failure to deliver any Quantity of Gas as contemplated under this Section 31: . . . (iii) due to the conduct of the downstream operator of the facilities at the applicable Point(s) of Delivery, including, without limitation, the refusal to receive any Quantity of Gas from Pipeline that Pipeline has made available for delivery, as long as such conduct was outside the control of Pipeline. . . .[389]

The Commission found that "Texas Eastern appropriately scheduled Range's gas but Columbia Gulf failed to confirm the volumes at the Adair Interconnect due to pressure differentials," and "on days when a *force majeure* event was in effect, Texas Eastern only scheduled Range's nominations that could be delivered consistent with the *force majeure* restriction and provided reservation charge credits in accordance with GT&C section 31.2 for amounts that were not scheduled for delivery by Texas Eastern."[390] Finally, as Texas Eastern noted, "Range claim[ed] to be seeking reservation charge credits for reservation charges paid to Texas Eastern, [but] Range . . . withheld payment of those reservation charges for which it is seeking reservation charge credits."[391]

The Commission concluded that Range and Columbia Gulf "failed to meet their burden of proving that Texas Eastern violated its certificate obligations, the NGA, Commission regulations, Texas Eastern's Tariff, and Range's firm service agreement with Texas Eastern." Both Complaints were therefore dismissed.[392]

III. INFRASTRUCTURE

A. Pipelines

1. Tackett v. Equitrans. Ltd.

Plaintiffs removed a suit filed in state court to federal district court alleging that their claim of grossly negligent damage to their property from the pipeline's "construction, maintenance, operation[s], and repair[s]" in proximity to their property implicates federal questions under the "substantial-federal questions doctrine."[393] In remanding the case back to the state court, the District Court found that there were no significant federal issues arising under the state-law claims that required settlement in a federal forum.[394] Plaintiffs claimed that, because "FERC orders under the NGA supply the standard under which Defendants' conduct must

387. *Id.* at PP 68-69.
388. 178 FERC ¶ 61,217 at P 69.
389. *Id.*
390. *Id.*
391. *Id.*
392. 178 FERC ¶ 61,217 at P 70.
393. Tackett v. Equitrans, Inc., No. 22-18-DLB, 2022 WL 1157998 (E.D. Ky Apr. 19, 2022).
394. *Id.* at *5.

be measured, . . . FERC's exclusive control over pipeline construction and operation would be supplanted" if state law is applied to the duty of care in this negligence action instead of federal law.[395] The District Court found that the NGA does not create a relevant cause of action and the "Plaintiffs do not allege a violation of" the NGA, much less a dispute over the interpretation of federal law.[396] In concluding that any alleged federal issue was not "substantial," the District Court noted that there was no issue of whether a federal "agency . . . complied with a statute or regulation," and "the alleged federal . . . issue [of] whether . . . a pipeline complied with or exceeded the boundaries of its FERC certificate" involves the application of federal regulations to establish the standard of care in a state-law based negligence case, which is necessarily specific to this case, and would not establish "precedent [in] future cases"; the mere need to apply federal law does not confer federal-question jurisdiction.[397]

2. Wild Virginia v. United States Forest Service

For the second time, the Fourth Circuit vacated and remanded a "U.S. Forest Service (Forest Service) and Bureau of Land Management (BLM)" decision to authorize Mountain Valley Pipeline (MVP) to "cross three and a half miles of the Jefferson National Forest in Virginia and West Virginia" based on a "fail[ure] to comply with the National Environmental Policy Act (NEPA), the National Forest Management Act (NFMA), and Mineral Leasing Act regulations(MLA)."[398] After the initial remand, "the Forest Service and the BLM prepared a supplemental [Environmental Impact Statement] EIS which sought to address the pipeline's sedimentation impacts utilizing two hydrological analyses provided by MVP."[399] However, the Court found that "neither of these . . . analyses, nor the supplemental EIS, considered water monitoring data from the United States Geological Survey (USGS) monitoring stations fifteen miles outside the Jefferson National Forest" where such data showed that construction of this pipeline had significantly increased water turbidity and that no reason was supplied to show that factors that could affect streams inside the forest were different from those outside the forest where the USGS measurements took place.[400] The Court also found that the Forest Service and BLM improperly authorized "the use of conventional bore method to cross four streams in the Jefferson National Forest without" extensively considering the impacts of this method.[401] The Court noted that the supplemental EIS did include information on this method, but because MVP originally "planned to use . . . open cutting . . . [for] stream crossings," conventional bore was not extensively considered.[402]

395. *Id.* at *3.
396. *Id.*
397. *Tackett*, 2022 WL 1157998, at *3.
398. Wild Virginia v. U.S. Forest Service, 24 F.4th 915 (2022).
399. *Id.* at 924.
400. *Id.*
401. *Id.* at 929.
402. *Wild Virginia*, 24 F.4th at 929.

Subsequently, MVP requested authorization from FERC to switch to conventional bore for crossings outside of the Jefferson National Forest, which FERC is treating as an amendment to the certificate.[403] The Court concluded that the Forest Service and BLM "would surely benefit from FERC's environmental analysis of the" proposed amendment for its analysis of crossings within the Jefferson National Forest.[404] The Court also found that the Forest Service improperly amended its forest plan for the Jefferson National Forest to accommodate the MVP pipeline because it could not determine that the plan would meet the regulatory requirement to "maintain or restore" the ecosystem given the Forest Service's failure to adequately analyze sedimentation and the use of conventional bore for crossings.[405] As to Forest Service's reliance on the notion that "the [p]ipeline will affect only a minimal fraction of the entire forest," the Court found that this approach would allow circumvention of the regulations by simply passing project-specific amendments to the plan on an ad hoc basis.[406]

3. Mountain Valley Pipeline, LLC

On April 8, 2022, the Commission approved an amendment application by Mountain Valley Pipeline (MVP) to change most of its waterbody and wetland crossings "from open-cut to trenchless [(primarily conventional bore)], . . . slightly shift the . . . right-of-way [to avoid a wetland and a waterbody], . . . [and to] conduct 24-hour construction activit[y] at . . . trenchless crossings."[407] As to claims that the "amendment . . . trigger[ed] [requirements] for state certification under section 401 of the Clean Water Act" (required for "construction or operation of facilities, [that] may result in . . . discharge[s] into the navigable waters"), the Commission concluded that "the construction methods and mitigation measures proposed . . . would avoid discharges into waters of the United States" meaning that certification was not necessary.[408] The Commission stated that it solicited the opinions of the two states where the project is located (Virginia and West Virginia) and both states said it was up to the federal agency to make the determination as to whether a section 401 permit is required, and both also stated that their prior

403. *Id.*

404. *Id. See Mountain Valley Pipeline, LLC*, 179 FERC ¶ 61,013 (2022) (on April 8, 2022, the Commission granted MVP's requested amendment which included conversion of 183 crossings from open-cut to trenchless, including 119 conventional bore crossings).

405. *Wild Virginia*, 24 F.4th at 921.

406. *Id.* at 931.

407. *See* 179 FERC ¶ 61,013 at P 1. MVP initially relied upon an Army Corp of Engineer's Nationwide Permit 12 (NWP 12) verification that authorized MVP to cross waters in the United States using the open-cut method. *Id.* at P 4. The Fourth Circuit issued a stay of MVP's NWP 12 verification in *Sierra Club v. U.S. Army Corps of Eng'rs*. 981 F.3d 251 (4th Cir. Dec. 2020). Under the nationwide permitting approach, potential permittees seek verification that they qualify under the terms and requirements of the nationwide permit, rather than seeking a more arduous individual, project-specific permit. 179 FERC ¶ 61,013 at P 65. The order granting the stay found that the Corps likely violated the Endangered Species Act when it reissued NWP 12. *Id.* at P 20. MVP has filed an individual permit application with the Corps, pursuant to section 404 of the Clean Water Act, for utilizing the open-cut method for crossings not covered by the amendment to utilize trenchless crossings. *Id.* at P 4.

408. *Id.* at PP 135, 137.

2017 authorizations would cover any activities that would require certification.[409] As to the status of other authorizations, FERC stated that MVP is not permitted to commence any new construction until it has received all outstanding federal authorizations—the Corps authorizations to complete its open-cut crossings, authorization to cross the Jefferson National Forest,[410] and Fish and Wildlife Service authorizations regarding endangered species.[411]

4. Food & Water Watch v. FERC

On March 11, 2022, the D.C. Circuit remanded, without vacatur, Commission authorization of the Tennessee Gas Pipeline "Upgrade Project," which "involves the addition of 2.1 miles of new pipeline and a new compressor station in Agawam, Massachusetts."[412] The Court rejected all of the Plaintiff's environmental challenges to the certification of the project, except for the "indirect-effects" argument with respect to "downstream gas consumption and resulting greenhouse gas [(GHG)] emissions."[413] The Court noted that in *Sierra Club v. FERC*,[414] the downstream GHG emissions were "reasonably foreseeable" indirect effects of a pipeline project designed to transport gas to certain specific Florida power plants,[415] but in *Birckhead v. FERC*,[416] the Court rejected a similar claim when the Commission could establish only "that the gas was headed somewhere in the Southeast."[417] The Court declared that foreseeability depends on information about the "destination and end use of the gas in question."[418] The Court found that the record in this case more closely resembles *Sabal Trail* than *Birckhead* because "the Commission had evidence that the Upgrade Project would add . . . 72,4000 [Dth/day of capacity] to Tennessee Gas's system, [of which]40,000 [Dth/day] was under contract [to] Columbia Gas" of Massachusetts (local distribution company) which would use that capacity to serve existing customers in the Greater Springfield area.[419] The Court found that regardless of whether local distribution customer demand is more, or less, elastic and predictable than power plant demand, or whether or not the gas transported may displace existing gas supplies, the Commission is not excused from making emissions estimates in the first place.[420] Hence, the Court remands to the Commission "to perform a supplemental environmental assessment to either quantify and consider downstream carbon emissions or explain in more detail why it cannot do so."[421] In deciding not to vacate

409. *Id.* at P 141.
410. *Id.* at P 149.
411. 179 FERC ¶ 61,013 at P 149.
412. Food & Water Watch v. FERC, 28 F.4th 277, 282 (D.C. Cir. 2022).
413. *Id.* at 287.
414. *Sierra Club*, 867 F.3d at 1371.
415. *Id.* at 1380.
416. *Birckhead*, 925 F.3d at 510.
417. *Id.* at 518.
418. *Id.* at 519.
419. *Food & Water Watch*, 28 F.4th at 288.
420. *Id.* at 288-89.
421. *Id.* at 289.

the Commission's certificate order, the Court found that FERC could, "with further explanation, justify its decision to skip [this] procedural step," or the Commission could arrive at its same finding of no significant impact of the project on the environment after accounting for foreseeable GHG emissions.[422] As to the disruptive impact of vacatur, the Court found that the impact of vacatur would be significant because "the Upgrade Project is now either mid-construction or operational."[423]

5. Marcum v. Columbia Gas Transmission, LLC

In a suit brought against Columbia Gas Transmission, LLC (Columbia) to recover damages caused by storm water runoff following the installation of a gas pipeline through Plaintiffs' property, a U.S. District Court, among other things, rejected the pipeline's motion to dismiss the claim.[424] The court held that the "municipal ordinances upon which [the] Plaintiffs premise their [Pennsylvania Storm Water Management Act] SWMA claim are preempted by the FERC order approving the [pipeline]."[425] Columbia maintained that the pipeline "was not required to obtain a . . . township grading permit or [to] comply with the township's stormwater management ordinances," as the FERC certificate order did not mandate compliance with either requirement.[426] The Court first considered "'field preemption,' . . . where Congress intended to foreclose any state regulation in the area, irrespective of whether the state law is consistent or inconsistent with the federal standard[]."[427] The Court noted that the "Supreme Court has found FERC's regulatory authority under the Natural Gas Act to be . . . preemptive where a state law 'amounts to a regulation in the field of gas transportation and sales for resale that Congress intended FERC to occupy.'"[428] The Court stated that "where a law is not 'aimed at natural gas companies in particular, but rather at all businesses in the marketplace,' there is no field preemption."[429] "Here, state and local stormwater management laws . . . do not target the natural gas industry, but rather, apply broadly to '[a]ny landowner or any person engaged in alteration or development of land' . . . ."[430] As to "conflict preemption . . . where 'compliance with both state and federal law is impossible' or where state law 'stands as an obstacle to the . . . execution of federal law,'" the Court examined instances where "state or local action[] . . . serve[d] to prohibit or unreasonably delay the construction of pipeline

422. *Id.* at 292.

423. *Food & Water Watch*, 28 F.4th at 292.

424. Marcum v. Columbia Gas Transmission, 549 F. Supp. 3d 408, 423-24 (E.D. Pa. 2021).

425. *Id*. at 421.

426. *Id*. at 422.

427. *Id.* (quoting Oneok, Inc. v. Learjet, Inc., 575 U.S. at 377 (2015).

428. *Marcum*, 549 F. Supp. 3d at 422. (quoting Schneidewind v. ANR Pipeline Co., 845 U.S. 293, 304 (1988) (state law requiring state approval before issuing long-term securities preempted by the Natural Gas Act because it is directed at the control of rates and facilities of natural gas companies)).

429. *Id.* at 423 (quoting *Oneok, Inc.*, 575 U.S. at 385-86).

430. *Id.* (quoting 32 Pa. Stat. Ann. § 680.13 (1978)).

facilities approved by FERC."[431] The Court found these cases to be distinguishable from the instant case because the Columbia line has already been "installed and is operational . . . [and the] application of state law will [not] obstruct Congress's purpose in enacting the Natural Gas Act and empowering FERC with authority to facilitate the transmission of natural gas."[432] The Court found that Columbia failed to explain how compliance with SWMA "implicates FERC's authority . . . to regulate transportation of natural gas."[433]

6. Spire STL Pipeline LLC

On December 3, 2021, the Commission issued Spire STL Pipeline LLC (Spire) a temporary certificate of public convenience and necessity to maintain service to its customers while the Commission addresses issues on remand from the D.C. Circuit[434] which vacated the certificate authorizing the construction of the new, greenfield, Spire system.[435] "Section 7(c)(1)(B) of the [Natural Gas Act gives] 'the Commission [authority to] issue a temporary certificate in cases of emergency, to ensure maintenance of adequate services or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate . . . .'"[436] The Commission reviewed prior court decisions and Commission orders sustaining issuance of such certificates and determined that "issu[ing] [Spire] a temporary certificate" is consistent with precedent approving use of such certificates to supply consumers dependent on gas provided under the original certificate and to keep up pre-existing service.[437] The Commission examined alternatives, such as the customer acquiring capacity released by customers on other pipelines, or the customer moving its receipt point to other pipelines, and determined that none of the alternatives could prevent "a loss of gas supply potentially [affecting] hundreds of thousands of homes and business[es] during the winter heating season."[438] As to various proposals to limit the amount of service Spire can provide to quantities that the customer cannot obtain elsewhere, and other proposals to reduce the rates Spire can charge for service, the Commission rejected all such proposals as impractical (would require demand forecasting or Commission asserting jurisdiction over the distribution company customer) or inconsistent

431. *Id.* at 422 (quoting *Oneok, Inc.*, 575 U.S. at 377).

432. *Marcum*, 549 F. Supp. 3d at 422.

433. *Id*. at 424.

434. *Spire STL Pipeline LLC*, 177 FERC ¶ 61,147 (2021). After Spire was constructed and in operation, the D.C. Circuit vacated and remanded the authorization to build the system. Environmental Defense Fund v. FERC, 2 F.4th 953 (D.C. Cir. 2021). The Court found that the Commission improperly relied on a single precedent agreement with an affiliate as conclusive proof of the need for the pipeline where there no evidence that new load would be served or that the new pipeline would reduce cost and failed to consider evidence of self-dealing in that affiliate relationship between customer and the pipeline. *Id.* at 960.

435. 177 FERC ¶ 61,147. Following the vacating of its certificate, Spire filed for a temporary certificate on July 26, 2021; On September 14, 2011, to avoid an emergency from the immediate cessation of service by Spire, the Commission, *sua sponte* issued a temporary certificate for 90 days. *Spire STL Pipeline LLC*, 176 FERC ¶ 61,160 (2021).

436. 177 FERC ¶ 61,147 at P 19 (quoting 15 U.S.C. § 717f(c)(1)(B)).

437. *Id.* at P 26.

438. *Id.* at PP 33, 47.

with its rate design policies.[439] As to concerns raised about the pipeline obtaining land rights through eminent domain without certificate authority, the Commission determined that the issue of whether such authority extends to temporary certificates "is better resolved by the courts than the Commission."[440] In a February 17, 2022, rehearing order, the Commission noted that two Federal district courts have determined that temporary certificates confer eminent domain authority.[441] The rehearing order also rejected a request for a stay targeted specifically at eminent domain authority.[442]

7. Algonquin Gas Transmission, LLC

On January 20, 2022, the Commission issued an order on rehearing of its February 18, 2021, order setting for briefing rehearing of authorization of the operation of Weymouth Compressor Station, which is a part of the Atlantic Bridge Project.[443] Shortly after commencing operation, the "Weymouth compressor station experienced two emergency shutdowns [that involved] unplanned releases of natural gas [(blowdowns)]."[444] "Timely requests for rehearing of the" FERC staff delegated letter order authorizing the operation of the Weymouth station (Authorization Order) were filed shortly after the blowdown incidents (but well after rehearing and judicial review of the certificate order had concluded).[445]

On February 18, 2021, FERC issued a briefing order requesting briefs on whether (1) "it [would be] consistent with the Commission's responsibilities under the Natural Gas Act (NGA) to allow the . . . Station to enter into and remain in service;" (2) FERC should "reconsider the current operation . . . in light of any changed circumstances;" (3) if there would be "any additional mitigation measures the [FERC] should impose"; and (4) if there "would [be] consequences if the [FERC] were to stay or reverse the Authorization Order.[446]

FERC, in the instant rehearing order, found that its public interest responsibilities do not end with issuance of the certificate—it extends to the delegated authority to authorize the commencement of construction and commencement of operation—even though these steps do not afford an opportunity to relitigate the certificate proceeding itself.[447] As to the commencement of operation (i.e., Authorization Order) the Commission concluded that the record does not support setting aside the order or imposing additional mitigation measures because there was

439. *Id.* at P 58.

440. 177 FERC ¶ 61,147 at P 70.

441. *Spire STL Pipeline LLC*, 178 FERC ¶ 61,109 at P 11 (2022) (citing Spire STL Pipeline LLC v. Jefferson, No. 18-cv-03204, 2021 WL 6931805 at *5-7 (C.C. Ill. Oct. 28, 2021); Spire STL Pipeline LLC v. 3.31 Acres of Land, 2021 WL 5492897, at *3 (E.D. Mo. Nov. 23, 2021)).

442. 178 FERC ¶ 61,109 at P 14.

443. *Algonquin Gas Transmission, LLC*, 178 FERC ¶ 61,029 at P 1 (2022).

444. *Id.*

445. *Id.* at P 7.

446. *Algonquin Gas Transmission, LLC*, 174 FERC ¶ 61,126 (Briefing Order), *order on reh'g*, 175 FERC ¶ 61,150 (2021).

447. *Id.* at PP 17-20.

no showing of violation of the certificate order (no showing that emissions exceeded state or EPA limits) and upon review of the actions taken by the federal agency with pipeline safety authority, the Commission sees no basis for staying or modifying the Authorization Order.[448] As to arguments that FERC should, based on new information and changed circumstances, rescind, or modify, the certificate order itself, FERC said that it does not have Natural Gas Act authority to revisit the certificate order because judicial review has ended.[449] While Natural Gas Act section 16 gives FERC the authority to "perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of [the act]," which means that where significant issues not contemplated by the certificate arise FERC has the authority to take responsive action, these particular circumstances do not justify invoking such authority because there was insufficient evidence of health effects associated with the blowdowns.[450]

8. Tennessee Gas Pipeline Co.

On March 25, 2022, FERC issued an order authorizing Tennessee Gas Pipeline Company (Tennessee) to construct "pipeline looping and a new compressor station, and for Southern Natural Gas Co. (Southern) to construct a new compressor station," and for Tennessee to lease the capacity of the Southern project which will allow "Tennessee Gas to provide 1,100,000 Dth/day of firm transportation service for Venture Global Plaquemines, LNG (Venture Global)" (LNG exporter located in Louisiana).[451] Certain intervenors claimed "that the facilities being [built] by Southern to create the lease capacity constitute a cheap expansion, i.e., an incremental rate calculated to recover the cost of the new facilities would be lower than the existing system rate," and that the proposed lease rate to Tennessee is about half the applicable system rate that Southern is charging its customers.[452]

FERC noted that its "practice is to approve a lease if it finds that: (i) there are benefits from using a lease arrangement; (ii) the lease payments are less than, or equal to, the lessor's firm transportation rates . . . ; and (iii) the lease arrangement does not adversely affect existing customers."[453] In applying this test, FERC found that Tennessee providing the proposed service to Venture Global using facilities constructed entirely "on its own system would" have significantly more adverse impacts on the environment and landowners and would "cost approximately $1.55 billion, as compared to the estimated $172.412,811 cost of Southern" building a portion of the project.[454]

448. *Id.* at P 18.

449. *Id.* at P 25.

450. 174 FERC ¶ 61,126 at P 25.

451. 178 FERC ¶ 61,199 at P 1.

452. *Id.* at P 47. An incremental rate is a rate based on the cost of the facilities to be constructed. Typically, the cost per unit of capacity for new facilities is much higher than the per unit average cost of the existing system.

453. *Id.* at P 54.

454. *Id*. at P 56.

FERC concluded that the reduction of both cost and adverse impacts, plus the administrative benefits of Venture Global being able to receive service under a single contract with Tennessee, meets FERC's benefits test.[455] As for the lease payments, FERC acknowledged that its rate policy for project expansion capacity would require the rates for the expansion to be not less than the applicable system rate (if an "incremental rate would be lower than the [applicable] system rate," the system rate would be the expansion system rate), but, this lease is distinguishable because the shippers of the lessee have less rights than Southern's shippers (restrictions on access to secondary points, no capacity release rights or segmentation rights); this limitation of rights under a lease is a reason why FERC does not require lease payments to be set at the lessor's rate.[456]

FERC explained further that its requirement for expansion capacity rates to be set at the higher of the incremental rate or the existing system rate is intended to ensure that "existing shippers can compete with expansion shippers on an equal basis for markets on that pipeline," but when a pipeline obtains capacity under a lease, the "shippers that use the lease capacity are not transporting gas on, or competing for markets on, the lessor's pipeline (i.e., the Southern expansion capacity will be used by shippers transporting on Tennessee)."[457] As for the lease impact on Southern's existing customers, the Commission found that its policy of not permitting the lessor to reflect in its system rates any costs associated with the lease capacity, provides protection during the term of the lease, and after the lease expires, the lessor's customers would have the ability to challenge, in a rate proceeding, any proposal to include costs associated with the capacity in system rates.[458]

In its environmental review, FERC declined to consider the impacts of upstream and downstream greenhouse gas emissions (GHG) pursuant to National Environmental Policy Act (NEPA) regulations, because the natural gas will be delivered to an LNG export terminal and the independent decision of the Department of Energy to allow the "export . . . breaks the NEPA causal chain and absolves the [FERC] of responsibility [for such] analysis."[459] FERC provided estimates of GHG emissions caused by the construction and operation of the project and compared such estimates to national and state emission levels to assess the project's share of contribution to such levels, but declined to characterize the emissions as significant or insignificant because FERC is in the process of conducting a generic proceeding to determine whether and how it will conduct significance determinations going forward.[460] FERC also employed a "social cost of GHG . . . tool intended to quantify, in dollars, estimates of long-term damage that may result

455. 178 FERC ¶ 61,199 at P 66.

456. *Id*. at P 57.

457. *Id*. at P 58.

458. *Id*. at P 64.

459. 178 FERC ¶ 61,199 at P 87. *See* Sierra Club v. FERC, 827 F.3d 36, 48 (D.C. Cir. 2016). DOE's independent decision to allow exports—a decision over which FERC has not regulatory authority—absolves FERC from NEPA analysis responsibility because FERC cannot be the legally relevant cause of environmental impacts. *Id.* None of the consequences that could be reasonably foreseen and factored into FERC's analysis exist apart from DOE's decision to authorize exports. *Id*

460. 178 FERC ¶ 61,199 at P 89.

from emissions of carbon dioxide, nitrous oxide, and methane," but, noting that there are legal challenges to federal agencies use of the particular methodology, FERC stated that it was not relying on these estimates to make any "determination [of] either the impact of the project's GHG emissions or whether the project is in the public convenience and necessity."[461]

B. Storage Projects

1. Spire Storage West LLC

On May 19, 2022, the Commission granted Spire Storage West LLC's application amending its certificate of public convenience and necessity, "authorizing the Clear Creek Storage Field in Uinta County, Wyoming" and reaffirming its market "authority and related waivers" (Clear Creek Expansion Project).[462] The Clear Creek Expansion Project was intended to effectuate proposed increases in service capability by drilling and operating new wells at the Clear Creek Storage Field, installing new facilities at the Clear Creek Plan, and constructing "new pipeline facilities to provide interstate connections."[463] The Commission found that the applicant had "demonstrated a need for the Clear Creek Expansion Project, that [it] would not have adverse economic impacts on existing shippers or other pipelines and their customers, and that the benefits [would] outweigh . . . adverse economic effects on landowners."[464] The Commission also reaffirmed Spire Storage West LLC's "authority to charge market-based rates for its firm and interruptible storage and interruptible wheeling services."[465]

2. Northern Natural Gas Company

On March 24, 2022, the Commission issued a certificate of public convenience and necessity to Northern Natural Gas Company to expand the certificated boundary of its existing Redfield Storage Facility (Buffer Zone Project).[466] The purpose of the project was to "enable Northern to comply with PHMSA's revised minimum safety standards for underground natural gas storage facilities, which require storage operators to assess the risks related to storage operation and recommend . . . expanding buffer zones where connectivity with another porous zone is indicated."[467] The Commission found that Northern Natural Gas Company demonstrated need for the Buffer Zone Project because it would "enable Northern to comply with PHMSA's revised regulations and help ensure the integrity of the Northern's Redfield Storage Facility, [and] minimizing loss of the gas stored therein."[468]

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461. *Id*. at P 92.
462. 179 FERC ¶ 61,123 at P 1.
463. *Id.* at P 6.
464. *Id.* at P 67.
465. *Id.* at P 41.
466. *N. Nat. Gas Co.*, 178 FERC ¶ 61,203 at P 1 (2022) (order issuing certificate and stay).
467. *Id.* at P 12.
468. *Id.* at P 36.

C. LNG Projects

1. Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.

On October 21, 2021 the Commission granted Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.'s application pursuant to Section 3 of the NGA and Part 153 of the Commission's regulations to increase the liquefaction production capacity at the Sabine Pass Liquefied Natural Gas Terminal from "1,509 billion cubic feet per year (Bcf/y) to 1,661.94 Bcf/y" (Sabine Pass Uprate Amendment).[469] The increased LNG production was "achieved through modifications to maintenance and production processes made possible by enhancements made during the facilities' final design, construction, and initial operation."[470] The Sabine Pass Uprate Amendment did not require additional construction of facilities or "increase the annual number of LNG tankers . . . approved by the U.S. Coast Guard."[471]

2. Corpus Christi Liquefaction, LLC

On October 21, 2021 the Commission granted Corpus Christi Liquefaction, LLC's application pursuant to Section 3 of the NGA and Part 153 of the Commission's regulations to increase the liquefaction production capacity at the Corpus Christi Liquefaction facility from "767 billion cubic feet per year (Bcf/y) to 875.16 Bcf/y" (CCL Uprate Amendment).[472] The increased LNG production was achieved "through modifications to maintenance and production processes made possible by enhancements made during the facilities' final design, construction, and initial operation."[473] The CCL Uprate Amendment did not require additional construction, environmental permits or authorizations, "or increase the annual number of LNG tankers previously reviewed and approved by the U.S. Coast Guard."[474]

3. Delfin LNG LLC

On January 21, 2022, the Commission granted Delfin LNG LLC's (Delfin) request for an extension of time to construct and place into service certain onshore facilities previously authorized by the Commission that would be used to transport natural gas to Delfin's proposed offshore deepwater port.[475] Delfin stated that the delays in construction of the project were due to the "COVID-19 pandemic,

469. *Sabine Pass Liquefaction, LLC*, 177 FERC ¶ 61,030 at P 1 (2021) (order amending authorization under section 3 of the Natural Gas Act).

470. *Id.* at P 6.

471. *Id.*

472. *Corpus Christi Liquefaction, LLC*, 177 FERC ¶ 61,029 at P 1 (2021) (order amending authorization under section 3 of the Natural Gas Act).

473. *Id.* at P 4.

474. *Id*.

475. *Delfin LNG LLC*, 178 FERC ¶ 61,031 (2022) (order granting extension of time request). The Commission granted several requests for extensions of time to LNG companies this past year, along substantially similar grounds. *See Trunkline Gas Co*., 179 FERC ¶ 61,086 (2022); *Corpus Christi Liquefaction Stage III, LLC,* 179 FERC ¶ 61,087 (2022).

[which] complicated the task of negotiating offtake agreements with potential customers."[476] However, Delfin noted that "economic conditions are recovering . . . and that the spot and short-term markets for LNG [had] . . . improved . . . support[ing] long-term LNG offtake contract(s)."[477] Several environmental groups intervened in the proceeding,[478] and challenged Delfin's request and argued that the project was no longer needed, that the environmental analysis was no longer valid, and that good cause to grant the extension did not exist.[479]

The Commission rejected the environmental groups' arguments and found good cause to grant Delfin's request.[480] Additionally, the Commission found that the project was still commercially viable, and that Delfin continued to invest in the project despite encountering unforeseen circumstances.[481] Further, the Commission held that granting a request for an extension of time did not constitute a "major Federal action" significantly affecting the environment warranting supplemental NEPA review.[482]

4. Nopetro LNG, LLC

On March 25, 2022, the Commission granted a petition for declaratory order recognizing that Nopetro LNG, LLC's construction and operation of a liquefaction and truck loading facility and transloading facility "would not be subject to the Commission's jurisdiction under section 3" of the NGA.[483] The Commission found that Nopetro LNG LLC's facility was not an LNG terminal as defined by the NGA because "it is not located at the point of export such that LNG can be directly transferred to vessels for export."[484] Nopetro LNG, LLC's "LNG-filled ISO containers would leave Nopetro's facility and be [transferred] by truck" and loaded by a crane operated by third-party stevedores and managed by the port.[485] "Although the crane would be owned by Nopetro" LNG LLC, the Commission found that the crane acted as a general-use pier facility and was outside the scope of the natural gas facilities regulated by the Commission.[486]

476. *Id.* at P 4.

477. *Id*.

478. *Id.* at P 6. The Commission issued an order one day prior in *Adelphia Gateway LLC*, 178 FERC ¶ 61,030 (2022), which set aside the Commission's previous intervention policy with respect to extension of time proceedings. *Id.*

479. 178 FERC ¶ 61,031 at PP 11, 16, 20.

480. *Id.* at P 27.

481. *Id.* at PP 13-14. Environmental groups cited *Chestnut Ridge Storage LLC*, 139 FERC ¶ 61,149 (2012) and asserted that market changes from the COVID-19 Pandemic resulted in Delfin LNG LLC's project being no longer commercially viable. *Id.*

482. *Id.* at PP 24-26.

483. 178 FERC ¶ 61,168 at P 1 (order on petition for declaratory order).

484. *Id.* at P 10.

485. *Id.*

486. *Id.*

5. National Grid LNG, LLC

On June 16, 2022, the Commission granted an application by National Grid LNG, LLC "to amend its certificate of public convenience and necessity" to allow it "to revise the previously approved firm and interruptible" rates to adjust for construction costs that substantially increased from the original construction cost estimates and to increase the estimated transportation costs and submitted their new estimates.[487]

6. New Fortress Energy LLC

On July 15, 2021, the Commission issued an order addressing arguments raised on rehearing by New Fortress Energy LLC, and other parties on the Commission's prior order finding that New Fortress Energy LLC's LNG facility at the Port of San Juan was an LNG facility "subject to the Commission's jurisdiction."[488] New Fortress Energy LLC asserted that the Commission erred by "finding that [it was] connected to a pipeline," and that the Commission erred by "differentiating between its jurisdiction over LNG terminals in foreign and interstate commerce."[489] First, the Commission clarified "that in assessing whether an LNG facility operating in foreign commerce is a jurisdictional LNG terminal, the Commission considers whether the facility is connected to piping which enables the facility to receive natural gas for liquefaction or to send out revaporized LNG," but that the physical characteristics of the piping, or its connection to an "interstate or intrastate pipeline grid, [was] 'immaterial' to [a jurisdictional] determination."[490] The Commission also disagreed with New Fortress Energy LLC's second argument, finding that "the Energy Policy Act of 2005 modified the NGA [and] . . . expanded the Commission's previous section 3 jurisdiction [to include] facilities operating" in interstate commerce if they were not subject to the Commission's section 7 jurisdiction, closing a regulatory gap for facilities receiving LNG by waterborne vessel for consumption in state.[491]

7. EcoEléctrica, L.P.

On September 24, 2021, the Commission issued an order establishing a briefing schedule to further develop the record on EcoEléctrica L.P.'s (EcoEléctrica) "request for authorization to increase the operating liquid level of its [LNG] storage tank from 63 feet to 91 feet."[492] Following several earthquakes in Puerto Rico in 2019 and 2020, with the most severe occurring near EcoEléctrica's LNG Terminal, Commission staff received responses from EcoEléctrica that the LNG storage "tank was filled to" approximately 60% (or 63 feet) of its "maximum design capacity" and "that the maximum ground motion acceleration caused by the earthquake exceeded the design specifications of the storage tank" notwithstanding that

487. *National Grid LNG, LLC*, 179 FERC ¶ 61,205 at P 1 (2022) (order amending certificate).

488. 176 FERC ¶ 61,031 at P 1 (order addressing arguments raised on rehearing).

489. *Id.* at P 6.

490. *Id.* at P 15.

491. *Id.* at P 18.

492. *EcoEléctrica, L.P.*, 176 FERC ¶ 61,192 at P 1 (2021) (order establishing briefing).

there was no physical damage to the tank.[493] "On March 26, 2020, the Commission issued an order restricting [the] operation[s] of [the] LNG terminal by limiting the tank's liquid level" at 63 feet or less.[494] EcoEléctrica subsequently requested approval to increase the LNG storage tank's maximum liquid operating level to 91 feet.[495] In its September 24, 2021 decision, the Commission stated that it was requiring EcoEléctrica to demonstrate whether the tank can withstand 5,000 and 10,000-year events (as set forth in the 1996 edition of NFPA 59A) in addition to the 2,475-year event (as required under the 2019 edition of NFPA 59A).[496] The Commission also sought information on "a proposed liquid level and its risk tolerance basis," and "the potential reliability impacts based" on various LNG storage levels.[497] Since it lacked this information, the Commission established a briefing schedule to "determine whether, or by how much, the maximum liquid level can be increased."[498]

On December 2, 2021, the Commission partially granted EcoEléctrica's request for an extension of time to file its initial brief to provide more time to complete its detailed analyses.[499] While the Commission accepted EcoEléctrica's assertion that it was unable to complete the required analyses by the original briefing date, the Commission only partially granted the extension "in order to determine at what liquid level EcoEléctrica can safely operate" at before the onset of the next hurricane season.[500] On April 22, 2022, the Commission rejected EcoEléctrica's request for an interim liquid level of 91 feet and directed it to file the information requested in its initial briefing order, without establishing a new briefing schedule.[501] In its initial brief EcoEléctrica filed an "alternative seismic hazard analysis" which was consistent with the 2019 edition of NFPA 59A, but not the 5,000 or 10,000-year mean seismic recurrence.[502] The Commission found that the "record [had not] been sufficiently developed to demonstrate that the requirements of the Briefing Order [had] been satisfied," and stated that "EcoEléctrica's analysis may undervalue[d] the risk of similar . . . events."[503]

493. *Id.* at PP 7-8.
494. *Id* at P 1.
495. *Id.*
496. 176 FERC ¶ 61,192 at P 15, n.30.
497. *Id.* at PP 29-30.
498. *Id.* at P 29.
499. *EcoEléctrica, L.P.*, 177 FERC ¶ 61,164 (2021) (order partially granting request for an extension of time).
500. *Id.* at P 9.
501. *EcoEléctrica, L.P.*, 179 FERC ¶ 61,038 at P 28 (2022) (order on initial brief).
502. *Id.* at PP 9-10.
503. *Id.* at PP 20, 25.

IV. PHMSA & PIPELINE SAFETY

A. Revised Federal Pipeline Safety Regulations

1. PHMSA Rupture Mitigation Valves – Final Rule – Docket Number PHMSA-2013-0255

On April 8, 2022, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a final rule[504] revising the Federal Pipeline Safety Regulations[505] applicable to certain gas and hazardous liquid pipelines. Specifically, these revisions apply to onshore gas transmission, Type A gas gathering, and hazardous liquid pipelines, "with diameters of 6 inches or greater," that are newly constructed or entirely replaced after April 10, 2023.[506] The revisions define "entirely replaced" as a pipeline that has "2 or more miles being replaced with new pipe within any stretch of 5 contiguous miles within any 24-month period."[507] PHMSA issued this final rule under the authority of the Federal Pipeline Safety Statutes, 49 U.S.C. § 60101, as well as other provisions.[508]

This final rule requires "the installation of [rupture-mitigation valves] (RMVs)[509] or alternative equivalent technolog[ies]" on applicable pipelines.[510] Operators installing alternative equivalent technologies must demonstrate to PHMSA that the technologies provide an "equivalent level of safety."[511] These installation requirements do not apply to onshore gas pipeline segments in Class 1 or Class 2 locations that have a potential impact radius[512] "less than or equal to 150 feet."[513] Additionally, the only regulated rural gathering lines[514] "that are required to install RMVs or alternative equivalent technologies are those pipelines . . . that span water crossings more than 100 feet wide, from high water mark to high water mark."[515]

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504. *Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards*, 87 Fed. Reg. 20,940 (2022) (to be codified at C.F.R. pts 192, 195).

505. *Id.* The final rule specifically revises regulations at 49 C.F.R. parts 192 and 195. *Id.*

506. *Id*. at 29,041. References to diameter refer to the outer diameter of the pipe, and "hazardous liquid pipelines," unless otherwise noted in the rule, includes carbon dioxide pipelines. *Id*. The revisions explicitly exclude from their requirements Type B or C gas gathering pipelines. *Id*. at 20,972.

507. *Id.* at 20,941.

508. 87 Fed. Reg. 20,940, at 20,978. Regarding the other provisions, PHMSA specifically cites 49 U.S.C. § 5103 (regulatory authority to prescribe regulations for transportation of hazardous materials) and 30 U.S.C. § 185(w)(3)) (authority to prescribe reporting requirements for pipelines traversing Federal lands). *Id*.

509. *Id.* at 20,942. RMVs are defined to include both automatic shut-off valves and remote-control valves. *Id.* at 20,983.

510. *Id.* at 20,944.

511. *Id.*

512. 49 C.F.R. § 192.903 (2022) (defining "potential impact radius").

513. 87 Fed. Reg. 20,940, at 20,972.

514. 49 C.F.R. § 195.11 (2022) (defining "regulated rural gathering line").

515. 87 Fed. Reg. 20,940, at 20,975.

The final rule also includes provisions regarding valve spacing[516] and provisions regarding emergency response.[517] Additionally, the final rule specifies "operational requirements for RMVs."[518] Specifically, RMVs for onshore gas pipeline must generally be closed as soon as possible "but no later than within 30 minutes" after identifying a rupture,[519] while RMVs for hazardous liquid pipelines must generally be closed within 30 minutes or within the shut-down time used to calculate a worst-case discharge under 94 C.F.R. § 194.105(b)(1), whichever is less.[520]

PHMSA issued this rule following two 2010 pipeline rupture incidents that led to congressional action and National Transportation Safety Board recommendations to mitigate future rupture incidents.[521]

2. Final Rule "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments" – Docket Number PHMSA-2011-0023

On November 15, 2021, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a final rule titled "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments."[522] "The final rule responds to Government Accountability Office recommendations and a Congressional mandate by" revising the gathering line definition, expanding the scope of gas gathering line regulations, and updating reporting requirements under the Federal Pipeline Safety Regulations of "onshore natural gas gathering pipelines."[523] The rule's reporting requirements are intended "to prevent and detect threats to pipeline integrity, improve public awareness of pipeline safety, and improve emergency response to pipeline incidents."[524]

The final rule requires operators of onshore gas gathering lines, including "pipelines that are not currently designated as Type A or Type B regulated gathering lines nor newly designated as Type C" to file incident and annual reports under Code of Federal Regulations (C.F.R.) part 191.[525] The "final rule designates these reporting-regulated lines as 'Type R' gathering lines that are subject to reporting under C.F.R. part 191, but are not designated as regulated gathering lines"

516. *Id.* at 20,972-73, 20,975.

517. *Id.* at 20,973, 20,976.

518. *Id.* at 20,973, 20,977.

519. 87 Fed. Reg. 20,940, at 20,973-74.

520. *Id.* at 20,974, 20,977.

521. *Id.* at 20,940.

522. *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulations of Large, High-Pressure Lines, and Other Related* Amendments, 86 Fed. Reg. 63,266 (2021) (to be codified at 49 C.F.R. pts. 191,192).

523. *Id.*

524. *Id.*

525. *Id.* at 63,274. Subsection A focuses on reporting requirements for Code of Federal Regulation sections 191.1, 191.15, 191.17, 191.23, and 191.29. *Id.* at 63,274.

under C.F.R. part 192.[526] "Operators of previously unregulated gas gathering lines must begin submitting annual reports beginning with the first annual report cycle occurring after the endpoints of Type C or Type R gathering lines have been determined one year after the publication date of the final rule."[527] The final rule also limits "incidental gathering" to "new, replaced, relocated, or otherwise changed gathering lines."[528] Further, the final rule "[imposes] a limitation of ten miles on 'incidental gathering' for any such pipelines constructed after the effective date of the rulemaking."[529]

The final rule expands the scope of gas gathering line regulations.[530] PHMSA has changed the proposed "Type A, Area 2" designation for newly regulated gas gathering lines to "Type C" lines.[531] Type C lines continue to be defined as gas gathering lines in Class 1 locations that are 8.625 inches or greater in diameter and are:

> (1) metallic, with a maximum allowable operating pressure (MAOP) producing a hoop stress of 20 percent or more of specified minimum yield strength (SMYS); (2)

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526. *See* 86 Fed. Reg. 63,266, at 63,275 (2021) (49 C.F.R. pts. 191,192) (noting that PHMSA has the authority under Section 60,117(b) of Federal Pipeline Safety Law because it specifically authorizes the Secretary to "require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines."). *See also* H.R. Report No. 102–247(1), at 2,653 (102nd Cong., 1st Sess. (1991)) (explaining that the House Committee on Energy and Commerce instructed DOT to "find out whether any gathering lines present a risk to people or the environment, and if so, how large a risk and what measures should be taken to mitigate the risk"); 49 U.S.C. 60,101(b)(2)(A) (requiring the Secretary, when defining "regulated gathering line" to "consider factors as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas to determine which lines are functionally gathering and should be regulated because of their physical characteristics") (quoting 86 Fed. Reg. 63,266, at 63,275 n.66)).

527. *See* 86 Fed. Reg. 63,266, at 63,275 (explaining that Type R and Type C gathering lines must submit a 2022 annual report no later than March 15, 2023).

528. *See* 86 Fed. Reg. 63,266, at 63,278. PHMSA explained that it will consider updating the "definitions associated with defining gathering and production lines in a separate rulemaking after evaluating the second edition of API RP 80, *Definition of Onshore Gas Gathering Lines* and new API RP 1182, *Safety Provisions for Large Diameter Rural Gas Gathering Lines*" but declined to adopt "API RP 1182 or the 2d edition of API RP 80 in their entirety without providing the public an opportunity to review and comment upon those standards." *Id.*

529. *See* 86 Fed. Reg. at 63,278 (explaining that for gathering lines installed after the effective date of the rule, "the 'connection to another pipeline' endpoint in section 2.2(a)(1)(E) of API RP 80 may not be used if the connection is ten or more miles from the endpoints of gathering defined in paragraphs (a)(1)(A) through (a)(1)(D))". API RP 80 § 2.2(a)(1)(e) states "the connection to another pipeline downstream of: (i) the furthermost downstream endpoint identified in (A), (B), (C) or (D), or (in the absence of such endpoint), (ii) the furthermost downstream production operation"). Guidelines for the Definition of Onshore Gas Gathering Lines, 49 C.F.R. 192.8(a)(2000). The endpoints of gathering in paragraphs (a)(1)(A) through (a)(1)(D) include "(A) the inlet of the furthermost downstream natural gas processing plant, other than a natural gas processing plant located on a transmission line, (B) the outlet of the furthermost downstream gathering line gas treatment facility, (C) the furthermost downstream point where gas produced in the same production field or separate production fields is commingled, (D) the outlet of the furthermost downstream compressor station used to lower gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase gathering line pressure for delivery to another pipeline." *Id.*

530. *See* 86 Fed. Reg. 63,266, at 63,280 (citing 49 C.F.R. § 192.8).

531. *Id.* at 63,268.

> metallic, with an MAOP greater than 125 pounds per square inch gauge (psig) if the hoop stress is unknown; or (3) nonmetallic, with an MAOP greater than 125 psig.[532]

Gathering lines under 8.625 inches in outside diameter or lines operating below the pressure or stress level criteria will remain "unregulated under part 192 and are subject only to incident and annual reporting in part 191."[533] Additionally, the final rule created safety requirements for Type C gathering lines with outside "diameters of 8.625 inches and greater."[534] The final rule adopted requirements for Type C gathering lines with outside diameters greater than 12.75 inches.[535] The final rule includes a table with the applicability of all requirements, and operators must achieve compliance with the "Type C requirements no later than 1 year after the effective date of the rule, unless PHMSA has approved an alternative compliance schedule."[536]

On May 4, 2022, PHMSA issued a correction amending the safety-related condition reporting requirements in section 191.23 to be consistent with statements in the preamble to the final rule.[537] PHMSA also clarified that

> operators may, when identifying Type C gas gathering lines pursuant to [section] 192.8, use the default specified minimum yield strength (SMYS) at [section] 192.107(b)(2) when the yield strength is not known . . . . PHMSA . . . also issu[ed] a technical correction amending [section] 192.8 to align the regulatory text with statements in the final rule facilitating operators' consideration of maximum allowable operating pressure in making threshold determinations that gas gathering facilities qualify as Type C.[538]

When amending regulatory language pertaining to incident and annual reporting requirements of onshore gas gathering pipelines, "PHSMA inadvertently omitted language requiring offshore gas gathering pipelines to continue to submit the same" incident and annual reports.[539] To fix this, on June 13, 2022, PHMSA

532. 86 Fed. Reg. 63,266, at 63,268 (recognizing that not all gathering lines that meet these criteria pose the same level of risk, so the "requirements that Type C gathering lines must comply with will vary, based on the scale of risk associated with the particular characteristics of the pipeline" and section III.D of the final rule should be a guidance for section-by-section analysis).

533. *Id.* at 63,280.

534. *Id.* at 63,282 (the requirements include: "[d]esign, installation, construction, initial inspection and testing for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 per transmission line requirements in part 192; Corrosion Control (part 192, subpart I); Damage Prevention Program (§ 192.614); Emergency Plans (§ 192.615); Public Awareness (§ 192.616); Line Markers (§ 192.707); and Leakage Surveys (§ 192.706))". *Id.* at 63,279.

535. *Id.* at 63,282 (the requirements include: "[a]pplicable requirements of part 192 for plastic pipe and components; and Establishment of MAOP (§ 192.619)".

536. 86 Fed. Reg. 63,266, at 63,282, 63,284 (discussing how operators may encounter challenges in meeting the deadline and what procedures operators should follow to request an alternative compliance deadline).

537. *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Response to a Petition for Reconsideration; Technical Corrections; Issuance of Limited Enforcement Discretion*, 87 Fed. Reg. 26,296 (2022) (to be codified at 49 C.F.R. pts. 191-92).

538. *Id.*

539. *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Technical Corrections*, 87 Fed. Reg. 35,675 (2022) (to be codified at 49 C.F.R. pt. 191).

issued "corrections amending [sections] 191.15(a)(1) and 191.17(a)(1) [to be] consistent with statements in the preamble to the Final Rule."[540]

3. Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities – Docket Number PHMSA-2021-0050

On June 10, 2021, PHMSA issued an advisory bulletin to the owners and operators of gas and hazardous liquid pipeline facilities as a reminder that the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act) mandates operators update their inspection plan as well as their operation and maintenance (O&M) plans to address hazardous leaks and minimize releases of natural gas.[541] O&M plans are required to receive the proper updates by December 27, 2021, with state operators and PHMSA completing their review of the new plans by December 27, 2022.[542]

To properly comply with the PIPES Act, owners and operators need to consider three categories of updates for their O&M plans and support any made changes with sufficient technical analysis to show the alterations meet the goals of the act.[543] First, revised plans must be updated to minimize the "fugitive and vented emissions" released from the pipelines.[544] Second, the modified plans must address the remediation and replacement of equipment that is known to leak or has an expectancy to leak due to its design, material, or O&M history.[545] Third, the O&M plans must continue to contribute to increasing public safety and environmental protection.[546]

4. Pipeline Safety: Pipeline Safety Enhancement Programs – Docket Number PHMSA-2021-0004

On February 2, 2022, PHMSA issued a notice detailing the process PHMSA will use to review Pipeline Safety Enhancement Program (PSEP) requests submitted by the owners and operators of pipelines.[547] Established under 49 U.S.C. 60142, PSEP offers an opportunity for implementing innovative safety technologies and processes on a temporary basis.[548] If shown to be effective at increasing safety, the new technology may be incorporated into the existing pipeline safety

540. *Id*. (explaining that PHMSA also confirmed that each DOT Form PHMSA F 7100.2 (incident reporting) and PHMSA F 7100.2–1 (annual reporting) correctly referenced "offshore gathering lines" and therefore the forms did not need to be revised in accordance with the corrections).

541. *Pipeline Safety: Statutory Mandate To Update Inspection and Maintenance Plans To Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas From Pipeline Facilities*, 86 Fed. Reg. 31,002 (2021) (Statutory Mandate Notice).

542. *See* 49 U.S.C. § 60108(a)(2020).

543. 86 Fed. Reg. 31,002, at 31,003.

544. *Id.*

545. *Id.*

546. *Id.*

547. 86 Fed. Reg. 31,002, at 31,003.

548. *Pipeline Safety: Pipeline Safety Enhancement Programs*, 87 Fed. Reg. 5,939 (2022).

requirements through a PHMSA rulemaking.[549] PSEP applications close on December 21, 2023 and require the applicant to adhere to a precise application process.[550] "Applications must be submitted to PHMSA . . . in accordance with 49 C.F.R. § 190.341(b)(2)" and must include information "in accordance with 49 C.F.R. § 190.341(c)," "a draft environmental assessment" to ensure NEPA compliance, a map of the applicant's entire pipeline system with the fragment which will be effected by the program identified, all "accident and incident [reports] for the past 10 years," a description of the "safety measures [the] PSEP [is] designed to achieve" and how is compares to the current federal standard, and a description of the proposed technology including all research and development which lead to its final version.[551]

Once an application has been submitted, it is reviewed by PHMSA in accordance with the PIPES Act to ensure the technology achieves a proper level of safety above the federal standard.[552] Prior to approval, the PSEP will also be published in the federal register to receive public comments.[553] If approved, the PSEP will last for up to three years with no option for renewal but can be revoked if the operator has an accident involving death caused by the tests, "the operator fails to comply with the . . . conditions of the . . . program," or the continued implementation of the PSEP would be unsafe or harmful to the environment.[554] When the PSEP process is completed, "PHMSA will [send] a report" detailing their findings, conclusions, and recommendations to Congress for the potential creation of a new safety standard.[555]

5. Administrative Rulemaking—Criminal Referrals - Docket Number PHMSA-2021-0119

On May 11, 2022, in response to the Office of the Inspector General (OIG) determination that the Department of Transportation's (DOT) employee referral of actual or potential criminal activity policies were outdated, DOT issued an order recommending the updating of associated regulations.[556] PHMSA updated both its Hazardous Materials Program Procedures Criminal Referral Section (49 C.F.R. § 107.335) and its Pipeline Safety Enforcement and Regulatory Procedures Criminal Referral Section (49 C.F.R. § 190.293).[557] Both sections were updated to require criminal action to be reported by PHMSA employees to PHMSA's Office of Chief Counsel or directly to the OIG.[558] Once reported, the issue could be referred

549. *Id.*

550. *Id.*

551. *Id.* at 5,939-41.

552. 87 Fed. Reg. 5,939, at 5,939.

553. *Id.* at 5,940.

554. *Id.*

555. *Id.* at 5,940-41.

556. *Administrative Rulemaking – Criminal Referrals,* 87 Fed. Reg. 28,779 (2022) (to be codified at 49 C.F.R. pts. 107, 190).

557. *Id.* at 28,779.

558. *Id.*

to OIG by PHMSA's general counsel, referred to other law enforcement agencies, or handled internally.[559]

V. ENVIRONMENTAL

A. *Clean Air Act*

1. EPA Issues Proposed Rule Addressing New Source Performance Standards and Emissions Guidelines for the Crude Oil and Natural Gas Source Category

On November 15, 2021, the U.S. Environmental Protection Agency (EPA) issued a proposed rule in response to President Biden's January 20, 2021, Executive Order titled "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," which included three distinct groups of actions under the Clean Air Act (CAA).[560] First, EPA proposed revisions to "the standards of performance for the Crude Oil and Natural Gas source category."[561] Specifically, EPA proposed "to update, strengthen, and expand the current requirements under CAA section 111(b) for methane and [volatile organic compound] VOC emissions from sources that commenced construction, modification, or reconstruction after November 15, 2021."[562] Second, pursuant to CAA section 111(d), EPA proposed guidelines for states "developing, submitting, and implementing state plans to establish performance standards to limit [greenhouse gas emissions] GHGs from existing sources . . . in the Crude Oil and Natural Gas source category."[563] Third, EPA proposed amendments to address certain inconsistencies between the VOC and methane standards resulting from the disapproval of EPA's final rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review" and certain determinations made in the final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," specifically with respect to fugitive emissions monitoring at low production well sites and gathering

559. *Id.* at 28,781.

560. *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Nat. Gas Sector Climate Review*, 86 Fed. Reg. 63,110 (2021) (to be codified at 40 C.F.R. pt. 60).

561. *Id.* at 63,116.

562. *Id.*

563. *Id.* at 63,110.

and boosting stations.[564] EPA requested comments on the proposed rule by January 14, 2022, but subsequently extended the deadline for comments until January 31, 2022.[565] As of this writing, the proposed rule remains pending.[566]

B. Clean Water Act

1. EPA Issues Proposed Rule to Modify Its Requirements for Section 401 Certification Under the CWA

On June 9, 2022, EPA issued a proposed rule "revis[ing] and replac[ing]" the Agency's 2020 regulatory requirements for water quality certification under the Clean Water Act (CWA) section 401.[567] The proposed rule would:

> update existing regulations to be more consistent with the statutory text of the 1972 CWA; to clarify and provide consistency with respect to elements of the section 401 certification practice that have evolved since the 1971 rule was promulgated; and to support an efficient and predictable certification process that is consistent with water quality protection and cooperative federalism principles central to CWA section 401.[568]

Specifically, EPA provided a "necessary regulatory reset on significant issues."[569] These issues include "the scope of certification, Federal agency review, and the reasonable time period" to act on a certification request.[570] In addition, EPA proposed conforming amendments to the water quality certification regulations for EPA-issued National Pollutant Discharge Elimination System (NPDES) permits.[571] EPA requested comments on the proposed rule by August 8, 2022.[572]

C. National Environmental Policy Act

1. Council on Environmental Quality Issues Phase One NEPA Final Rule

On April 20, 2022, the White House Council on Environmental Quality (CEQ) issued a Phase One final rule, effective May 20, 2022, which "amends certain provisions of its regulations" that implement the National Environmental Policy Act (NEPA).[573]

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564. 86 Fed. Reg. 63,110, at 63,116.

565. *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Nat. Gas Sector Climate Review; Extension of Comment Period*, 86 Fed. Reg. 71,603 (2021) (to be codified at 40 C.F.R. pt. 60).

566. NEW SOURCE PERFORMANCE STANDARDS FOR CRUDE OIL AND NAT. GAS FACILITIES: REVIEW OF POLICY AND TECHNICAL RULES, REGINFO.GOV, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202104&RIN=2060-AV16.

567. *Clean Water Act Section 401 Water Quality Certification Improvement Rule,* 87 Fed. Reg. 35,318, at 35,325 (June 9, 2022) (to be codified at 40 C.F.R. pts. 121, 122, 124).

568. *Id.*

569. *Id*. at 35,326.

570. *Id.*

571. 87 Fed. Reg. 35,318, at 35,326.

572. *Id.*

573. *Nat. Env't Policy Act Implementing Regul. Revisions*, 87 Fed. Reg. 23,453 (Apr. 20, 2022) (to be codified at 40 C.F.R. pts. 1502, 1507-1508).

> CEQ is responsible for developing procedures for Federal agency implementation of NEPA. These procedures were initially promulgated in 1971 as guidelines, and were then issued as regulations in 1978. In July 2020, CEQ made wholesale revisions to the NEPA regulations for the first time in more than 40 years. . . . CEQ issued an Interim Final Rule on June 29, 2021, which extended the deadline by two years to September 14, 2023 for Federal agencies to develop or update their NEPA implementing procedures to conform to the CEQ regulations.[574]

CEQ's Phase One final rule makes three important changes to "restore longstanding provisions that were modified for the first time in 2020."[575] First, the final rule "restores the requirement that federal agencies evaluate all the relevant environmental impacts of the decisions they are making," including "the direct, indirect, and cumulative impacts of a proposed action" and any "climate change impacts."[576] Second, the rule "restores full authority" and flexibility to federal agencies to "work with project proponents and communities to mitigate or avoid environmental harms by analyzing . . . alternative" designs or approaches to project development.[577] Lastly, the rule "restores the ability of federal agencies to tailor their NEPA procedures, consistent with CEQ NEPA regulations, to help meet the specific needs of the agency, the public, and stakeholders."[578] CEQ continues to work toward proposing a set of broader changes to the NEPA regulations in Phase Two, which it hopes will "help ensure more public involvement in the environmental review process; meet the nation's environmental, climate change, and environmental justice challenges; [and] provide regulatory certainty to stakeholders."[579]

2. Food & Water Watch v. FERC, 28 F.4th 277 (D.C. Cir. 2022)

This case concerns a petition for review filed by two environmental groups challenging FERC's decision to authorize Tennessee Gas Pipeline Company's construction and operation of 2.1 miles of new natural gas pipeline and the replacement of two compressor units in Agawam, Massachusetts.[580] One of the petitioners, Food & Water Watch, raised challenges related to the "Commission's compliance with [NEPA]."[581] Notably, Food & Water Watch argued that the Commission failed to consider the impacts of upstream gas production, downstream gas consumption, and resulting greenhouse gas emissions (GHGs).[582]

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574. *CEQ NEPA Regulations*, NEPA.GOV, https://ceq.doe.gov/laws-regulations/regulations.html.

575. *CEQ Restores Three Key Community Safeguards during Federal Environmental Reviews,* THE WHITE HOUSE (Apr. 19, 2022), https://www.whitehouse.gov/ceq/news-updates/2022/04/19/ceq-restores-three-key-community-safeguards-during-federal-environmental-reviews/.

576. *Id.*

577. *Id.*

578. *Id.*

579. THE WHITE HOUSE, *supra* note 567.

580. *Food & Water Watch*, 28 F.4th at 281-82.

581. *Id.*

582. *Id.* at 285.

The court rejected most of Food & Water Watch's NEPA challenges.[583] However, the court did find that the Commission violated NEPA by failing to account for the reasonably foreseeable indirect effects of the project—specifically, downstream GHGs—in its environmental assessment (EA).[584] The court, without vacating the Commission's certificate order and rehearing order, remanded the matter "to the agency to perform a supplemental [EA] in which it must either quantify and consider the project's downstream carbon emissions, or explain . . . why it cannot do so."[585]

3. Sierra Club v. FERC, 38 F.4th 220 (D.C. Cir. 2022)

This case concerns a petition for review by several environmental groups seeking to vacate FERC's certificate order authorizing Mountain Valley, LLC to construct the Southgate Project, which "would extend Mountain Valley's Mainline System Project [by] connecting its terminus in Virginia to facilities in North Carolina."[586] "Petitioners challenged the Commission's certificate order and its denial of rehearing as arbitrary and capricious."[587] Specifically, Petitioners challenged the inadequacy of "[its] environmental impact statement" (EIS) related to potential mitigation measures and cumulative impacts on aquatic resources in the affected area.[588]

"NEPA requires the Commission to evaluate" a pipeline project's environmental impacts prior to authorizing its construction and operation.[589] "If the agency finds that the action is likely to significantly impact the environment, it must draft an EIS [which] detail[s] the action's environmental impacts," potential mitigation measures, cumulative "impacts . . . and reasonable alternatives to the action, including a no-action alternative."[590] NEPA requires agencies to "take a 'hard look' at the environmental consequences before taking a major action."[591] In its EIS, the Commission noted that it had "fleshed out specific practices to mitigate erosion . . . sedimentation, and [had] evaluated the cumulative impacts arising from [the project's] temporal and geographic proximity to the Mainline System."[592] Notably, "Commissioner (now Chairman) Glick partially dissented from . . . the certificate order, opposing the . . . failure to address the project's [GHG] effects."[593] The court ultimately dismissed the petitioners' NEPA claims.[594] The court deferred "to the Commission on issues that demand its technical and scientific expertise" and determined that FERC's EIS was adequate.[595]

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583. *Id.* at 281.
584. *Food & Water Watch*, 28 F.4th at 287-89.
585. *Id.* at 289.
586. Sierra Club v. FERC, 38 F.4th 220, 226 (D.C. Cir. 2022).
587. *Id.*
588. *Id.* at 232-33.
589. *Id.* at 226.
590. *Sierra Club*, 38 F.4th at 226.
591. *Id.*
592. *Id.* at 227.
593. *Id.*
594. *Sierra Club*, 38 F.4th at 234-35.
595. *Id.* at 235.