# **Nat. Gas Trans. Info. Serv. ¶501**

***Natural Gas Transportation Information Service (Thompson Energy)***

**¶501 Cost-Based Rates**

**Overview**. Order No. 436, issued in 1986, required rates for firm and interruptible transportation by interstate pipelines to be cost-based. Thus, the rate for each service must be designed to recover only the costs of providing that service. The pipeline must identify and justify the cost components of each rate. Order No. 436, *FERC Stats & Regs., Regulations Preambles 1982-1985* ¶30,665 (1986).

   In 1992, FERC issued Order No. 636 to restructure the natural gas industry. Order No. 636 required a generic change in pipeline transportation rates to eliminate potential competitive distortions. The Commission held that certain allocations of fixed transportation and storage costs, as well as some usage charges, were inappropriate for the restructured natural gas market. The restructuring rule required pipelines to develop *pro forma* restructured rates based on the throughput and cost of service of the pipeline's then current rate case. Order No. 636, *FERC Stats & Regs., Regulations Preambles 1991-1996* ¶30,939 (1992).

**Ratemaking process**. In Order No. 636, FERC summarized the process of ratemaking. "The Commission engages in five steps in fashioning a pipeline's rates for its jurisdictional customers. The first task is to determine the pipeline's overall cost of service. The second task is to functionalize the pipeline's costs by determining to which of the pipeline's various operations or facilities the costs belong. This step is known as functionalization and mainly turns on the particular characterization of the pipeline's facilities as production area, transmission or storage facilities. The third task is to categorize the costs assigned to each function as fixed costs (which do not vary with the volume of gas transported) or variable costs, and to classify ( *i.e.*, assign) those costs to the reservation and usage charges of the pipeline's rates. This step is known as classification. The fourth task is to apportion the costs classified to the reservation and usage charges among the pipeline's various rate zones and among the pipeline's various classes of jurisdictional services. This step is known as allocation. The fifth task is to design each service's rates for billing purposes by computing unit rates for each service. This step is known as rate design. The entire process is known as ratemaking."

   The goal of rate design under Order No. 636 is that "all gas supplies are moved to market on even terms."

   Order No. 636, *FERC Stats & Regs., Regulations Preambles 1991-1996* ¶30,939 (1992).

**Regulations**. Under section 284.10(c)(4), any maximum rate must be designed to recover, on a unit basis, solely those costs which are properly allocated to the service to which the rate applies. Any minimum rate must be based on the average variable costs which are properly allocated to the service to which the rate applies.

**Backhauls and exchanges**. Because backhauls and exchanges "can be performed without the incurrence of variable costs, it is appropriate that the minimum rate can be zero."

*Midwestern Gas Transmission Corp.*, 50 FERC ¶61,084 (1990).

**Alternative ratemaking**. As discussed in ¶¶502-505, the Commission can waive the regulatory requirement that rates be cost-based and permit other types of rates to be charged, including incentive rates, negotiated rates and market-based rates.

**Projected units of service**. Section 284.10(c)(2) requires interstate pipelines to design rates for self-implementing transportation to recover costs based on projected units of service. FERC has said that the purpose of this regulation is to encourage pipelines to make full use of their facilities. *Northern Natural Gas Co.*, 37 FERC ¶61,272 (1986), *order on reh'g*, 41 FERC ¶61,158 (1987). If a pipeline fails to meet its projection, it may not recover its cost of service. The pipeline is at risk for underrecovery of its costs between rate cases, but may retain any overrecovery. This gives the pipeline an incentive both to minimize its costs and maximize the service it provides. *Canyon Creek Compression Co.*, 99 FERC ¶61,351 (2002).

**Tab 500: Transportation Rates**

   The Federal Energy Regulatory Commission (FERC) regulates interstate natural gas transportation rates to ensure that they are just and reasonable, and not unduly discriminatory. This chapter describes FERC's treatment of different types of rates, including:

• traditional, cost-based rates;

• incentive rates;

• negotiated rates;

• market-based rates;

• interruptible rates;

• firm rates;

• discounted rates;

• seasonal rates;

• term-differentiated rates;

• distance-based rates;

• postage stamp rates; and

• intrastate transportation rates.

   Project-financed pipelines are generally exempt from the projected units of service requirement of section 284.10(c)(2). *Overthrust Pipeline Co.*, 44 FERC ¶61,077 (1988); *Northern Border Pipeline Co.*, 45 FERC ¶61,534 (1988).

**Cost of service trackers**. FERC has permitted the use of cost of service trackers in special circumstances. Under normal circumstances, a mechanism such as a tracker that would periodically increase rates to match increases in costs would undercut the incentive both to minimize costs and maximize service because it would guarantee the pipeline a set revenue recovery. In a 2002 case, FERC ruled that a pipeline supported its claim of special circumstances and justified the use of a cost of service tracker by demonstrating a sufficiently significant probability of declining throughput. *Canyon Creek Compression Co.*, 101 FERC ¶61,233 (2002).

   Three days after the Sept. 11, 2001, terrorist attacks, FERC issued a policy statement indicating that it would approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of energy supply infrastructure. A pipeline proposed to recover security-related costs as they are incurred through a special surcharge on rates. FERC said that while it generally disfavors cost trackers, it "finds it appropriate that, once recovery in a special surcharge is permitted, there also be a mechanism to track the costs. Such a tracking mechanism not only assures that the pipeline will not underrecover the costs in question, it also protects the customers by assuring that the special surcharge will not result in the pipeline overrecovering the costs." However, FERC ordered the pipeline to remove costs not related to security from the surcharge as contrary to the requirement to design rates based on estimated units of service. *Florida Gas Transmission Co.*, 105 FERC ¶61,171 (2003).

**Volumetric rates**. With the exception of reservation charges for firm service, section 284.10(c)(1) requires rates for self-implementing transportation to be one-part, volumetric rates. Under volumetric rates, charges are determined by multiplying the rate times the volumes of gas actually transported or purchased. The pipeline bears the financial risks of underutilization of capacity.

   In a capacity release situation, the replacement shipper pays a two-part volumetric rate: a volumetric rate relating to the reservation charge, which is determined through the capacity release bidding procedure, and a usage charge negotiated directly with the pipeline.

**Reservation fees for firm service**. Section 284.7(e) states that where the customer purchases firm service, a pipeline may impose a reservation fee or charge on a shipper as a condition for providing such service. If a reservation fee is charged, it must recover all fixed costs attributable to the firm transportation service, unless FERC permits the pipeline to recover some of the fixed costs in the volumetric portion of a two-part rate. A reservation fee may not recover any variable costs or fixed costs not attributable to the firm transportation service.

**Straight-fixed variable rate design**. FERC generally prefers use of the straight-fixed variable (SFV) rate design method. Under SFV, all fixed costs related to transportation are allocated to the reservation charge and removed from the usage charge.

   FERC has departed from strict adherence to SFV rate design on occasion. In addition to alternative ratemaking (see ¶¶502-505), FERC has approved non-SFV rate designs or waived the SFV requirement in certain circumstances. In *Tennessee Gas Pipeline Co.*, 77 FERC ¶61,083 (1996), *reh'g denied*, 78 FERC ¶61,069 (1997), the Commission approved a settlement involving non-SFV rate design as necessary to ameliorate the problem of unsubscribed capacity and to address customers' need to cut costs. Similar settlements were approved in *Northwest Pipeline Corp.*, 81 FERC ¶61,242 (1997) and *Texas Gas Transmission Corp.*, 98 FERC ¶61,244 (2002). FERC permitted a pipeline providing firm section 311 service for the first time to depart from SFV rate design to allow it to compete with competitors not subject to the SFV rate design requirement. *EPGT Texas Pipeline L.P.*, 99 FERC ¶61,295 (2002).

   FERC "has not allowed a pipeline to implement a shift to non-SFV rates in an NGA section 4 rate filing and ... will not do so here where the proposal was heavily protested, and there is currently no substantial support among the parties for any departure from SFV." However, FERC said it would consider a future settlement with a non-SFV rate design supported by a large majority of the pipeline's customers. FERC also noted that, where a pipeline has already filed a general section 4 rate case, it would similarly consider, "and not summarily reject, a broadly supported settlement filed by a pipeline in lieu of a general section 4 rate case, even if the settlement contained a deviation from the SFV rate design. Thus, as long as the departure from the SFV-mandated rate design was supported by the vast majority of a pipeline's shippers and other relevant parties, the Commission would consider it." *Transwestern Pipeline Co. LLC*, 150 FERC ¶61,034 (2015).

**Small customers**. When it restructured the natural gas industry, to lessen the impact of restructuring on small customers, FERC ordered pipelines to maintain one-part volumetric rates for small customers and to continue selling them gas at cost-based rates. A small customer has a peak requirement of 10,000 MMBtu/day or less.

**De minimis refunds**. In a 1998 settlement, the Gas Research Institute (GRI) agreed to refund over-collected amounts to its member pipelines, and the pipelines agreed to pass through the refunds to their customers. In 2006, GRI issued a $ 264.60 refund to a pipeline. The pipeline asked for a waiver so that it could donate the money to the Low Income Home Energy Assistance Program. FERC granted the request. "The amount involved ... is so small that it would be impractical to disburse it to customers."

*Williston Basin Interstate Pipeline Co.*, 120 FERC ¶61,191 (2007). *See also, Gas Technology Institute, et al.*, 121 FERC ¶61,134 (2007) (2007 GRI refunds are also relatively small and shall be donated to the same or similar low income house energy assistance program).

**Ice storm damage expenses**. FERC's chief accountant denied a pipeline's request to record as extraordinary property losses ice storm damage repair expenses. "We are not persuaded that the ... ice storm meets the Commission's requirements for treatment as an 'extraordinary item.' Ice storms are not an infrequent or unusual event for [the pipeline]. ... Although not extraordinary, [the pipeline's] prudently incurred ice storm damage costs that are not recoverable in current rates and probable for future rate recovery do qualify for regulatory asset treatment." The "other regulatory assets" account includes amounts of regulatory created assets not includable in other accounts. "Therefore, the ice storm damage costs may be recorded in [this] account, to the extent it is probable that the amounts will be recovered in future rates. Finally, if rate recovery of all or part of the amount included in this account is disallowed, the disallowed amount should be charged to [the 'other deductions' account], in the year of disallowance."

*Westar Energy Inc. and Kansas Gas and Electric Co.*, Docket No. AC08-30-000 "Letter Order Denying Request" (March 25, 2008) (Chief Accountant Molony) (Unreported).

**ROEs and proxy groups**. In a 2020 policy statement, FERC explained that the Supreme Court "has stated that 'the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.' ... Since the 1980s, the Commission has determined natural gas and ***oil*** pipeline [returns on equity (ROEs)] using the [Discounted Cash Flow (DCF)] model. The DCF model is based on the premise that 'a stock's price is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk.' The Commission uses the DCF model to estimate the return necessary for the pipeline to attract capital based upon the range of returns that the market provides investors in a proxy group of publicly traded entities with similar risk profiles." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC "estimates the required rate of return for each member of the proxy group using the following formula: k = D/P(1 + .5g) + g where k is the discount rate (or investors' required return), D is the current dividend, ¶ is the price of stock at the relevant time, and g is the expected growth rate in dividends based upon the weighted averaging of short-term and long-term growth estimates (referred to as the two-step procedure). The Commission multiplies the dividend yield (dividends divided by stock price or D/P) by the expression (1 + .5g) to account for the fact that dividends are paid on a quarterly basis. For purposes of the (1 + .5g) adjustment, the Commission uses only the shortterm growth projection." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   In the two-step DCF model, FERC "computes the expected growth rate ( *g*) by giving two-thirds weight to a short-term growth projection and one-third weight to a long-term growth projection. For the short-term growth projection, the Commission uses security analysts' five-year forecasts for each company in the proxy group, as published by the Institutional Brokers Estimated System (IBES). The long-term growth projection is based on forecasts, drawn from three different sources, of longterm growth of the economy as a whole as reflected in the Gross Domestic Product (GDP)." The three sources used by FERC are Global Insight: *Long-Term Macro Forecast — Baseline (U.S. Economy 30-Year Focus*); Energy Information Agency, *Annual Energy Outlook*; and the Social Security Administration. "For proxy group members that are master limited partnerships (MLPs), the Commission adjusts the long-term growth projection to equal 50% of GDP." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   According to FERC, because most natural gas pipelines are wholly owned subsidiaries and their common stocks are not publicly traded, it must use a proxy group of publicly traded firms with corresponding risks to set a range of reasonable returns. "The firms in the proxy group must be comparable to the pipeline whose ROE is being determined, or, in other words, the proxy group must be 'risk-appropriate.' The range of the proxy group's returns produces the zone of reasonableness in which the pipeline's ROE may be set based on specific risks. Absent unusual circumstances showing that the pipeline faces anomalously high or low risks, the Commission sets the pipeline's cost-of-service nominal ROE at the median of the zone of reasonableness." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   In February 2019, in *Trailblazer Pipeline Co. LLC*, 166 FERC ¶61,141 (2019), FERC observed that investors in natural gas pipelines presumably rely upon multiple methodologies for analyzing ROEs, rather than the DCF methodology alone, and invited the parties to address alternative financial models at hearing. In a Notice of Inquiry (NOI) issued on March 21, 2019, FERC requested comment on whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional public utility rates and whether any changes to the Commission's policies concerning public utility ROEs should be applied to interstate natural gas and ***oil*** pipelines. *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶61,207 (2019).

   On May 21, 2020, upon reviewing the comments filed in response to the NOI and based on its findings concerning public utility ROEs, FERC issued the 2020 policy statement to revise its policy for analyzing interstate natural gas and ***oil*** pipeline ROEs. "Under this revised policy, we will (1) determine ROE by averaging the results of DCF and [Capital Asset Pricing Model (CAPM)] analyses while retaining the existing two-thirds/one-third weighting of the short and long-term growth projections in the DCF; (2) give equal weight to the DCF and CAPM analyses; (3) consider using *Value Line* data as the source of the short-term growth projection in the CAPM; (4) consider proposals to include Canadian companies in pipeline proxy groups while continuing to apply our proxy group criteria flexibly until sufficient proxy group members are obtained; (5) exclude Risk Premium and Expected Earnings analyses; and (6) continue to address outliers in pipeline proxy groups on a case-by-case basis and refrain from applying specific outlier tests." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC explained that investors use CAPM analysis "as a measure of the cost of equity relative to risk. The CAPM is based on the theory that the market-required rate of return for a security is equal to the 'risk-free rate' plus a risk premium associated with that security. The CAPM estimates cost of equity by adding the risk-free rate to the 'market-risk premium' multiplied by 'beta.' The formula for the CAPM is as follows: R = r[f] + β[a](r[m] – r[f]) [where] r[f] = risk free rate (such as yield on 30-year U.S. Treasury bonds)[,] r[m] = expected market return [and] β[a] = beta, which measures the volatility of the security compared to the rest of the market. The risk-free rate is represented by a proxy, typically the yield on 30-year U.S. Treasury bonds. The market-risk premium is calculated by subtracting the risk-free rate from the 'expected return,' which, in a forward-looking CAPM analysis, is based on a DCF analysis of a large segment of the market, such as the dividend paying companies in the S&P 500. Betas measure the volatility of a particular stock relative to the market and are published by several commercial sources. An entity may also seek to apply a size premium adjustment to the CAPM zone of reasonableness to account for the difference in size between itself and the dividend paying companies in the S&P 500." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC found that "investors in pipelines, like investors in public utilities, consider multiple models for measuring cost of equity, including the DCF model and CAPM, in making investment decisions. Accordingly, under the rationale set forth in Opinion No. 569, [169 FERC ¶61,129 (2019), which applies to public utilities,] we will expand our methodology for determining natural gas and ***oil*** pipeline ROEs and will consider the CAPM in addition to the DCF model. We conclude that as with public utilities, expanding the methodology we use to determine ROE for natural gas and ***oil*** pipelines to include the CAPM in addition to the DCF model will better reflect how investors in those industries measure cost of equity while tending to reduce the model risk associated with relying on the DCF model alone. This should result in our ROE analyses producing cost-of-equity estimates for natural gas and ***oil*** pipelines that more accurately reflect what ROE a pipeline must offer in order to attract capital." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC determined to continue to base the long-term growth projection on forecasts of long-term growth of GDP, adjust the long-term growth project of MLPs to equal 50 percent of GDP consistent with a 2008 policy statement ( *Composition of Proxy Groups for Determining Gas and* ***Oil*** *Pipeline Return on Equity*, 123 FERC ¶61,048 (2008)), and use only the short-term growth projection for purposes of the (1 + .5g) adjustment to dividend yield. FERC retained the existing two-thirds/one-third weighting for the short and long-term growth projections. *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   In determining the CAPM market risk premium for natural gas and ***oil*** pipelines, FERC "will (1) use, as the risk-free rate, the 30-year U.S. Treasury average historical bond yield over a six-month period corresponding as closely as possible to the six-month financial study period used to produce the DCF study in the applicable proceeding, (2) estimate the expected market return using a forward-looking approach based on a one-step DCF analysis of all dividend paying companies in the S&P 500, and (3) exclude S&P 500 companies with growth rates that are negative or in excess of 20%." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC found reasonable the use of *Value Line* adjusted betas in the CAPM analysis because of substantial evidence indicating that investors rely on them in making their investment decisions. "Although we recognize that the distinct risks facing interstate natural gas and ***oil*** pipelines may in some cases bear upon whether an alternative beta source would be more appropriate, we will address such issues as they arise in specific proceedings." FERC also found reasonable the use of the size premium adjustment based on the New York Stock Exchange. "The use of such adjustments is 'a generally accepted approach to CAPM analyses' that improves the accuracy of the CAPM results and causes such results to better correspond to the cost-of-capital estimates that investors use in making investment decisions. As such, we find that use of these adjustments will improve the accuracy of cost-of-equity estimates for natural gas and ***oil*** pipelines under our revised ROE methodology." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC said it continues to prefer use of IBES three to five-year growth projections as the short-term growth projection in the two-step DCF analysis, but will allow participants to propose using *Value Line* growth projections as the source of the short-term growth projection in the one-step DCF analysis embedded within the CAPM. *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   To ensure that companies included in pipeline proxy groups are risk-appropriate, FERC "has required that each proxy group company satisfy three criteria: (1) the company's stock must be publicly traded; (2) the company must be recognized as a natural gas or ***oil*** pipeline company and its stock must be recognized and tracked by an investment information service such as *Value Line*; and (3) pipeline operations must constitute a high proportion of the company's business. In determining whether a company's pipeline operations constitute a high proportion of its business, the Commission has historically applied a 50% standard requiring that the pipeline business account for, on average, at least 50% of the company's assets or operating income over the most recent three-year period. Furthermore, in addition to the foregoing criteria, the Commission has declined to include Canadian companies in pipeline proxy groups." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   In addition, FERC "has explained that proxy groups 'should consist of at least four, and preferably at least five members' and that pipeline proxy groups should only exceed five members if each additional member satisfies the 50% standard. At the same time, the Commission has also explained that although 'adding more members to the proxy group results in greater statistical accuracy, this is true only if the additional members are appropriately included in the proxy group as representative firms.' " *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   However, in the 2020 policy statement, FERC recognized that the number of qualifying proxy group members has declined in recent years, "resulting in inadequately sized proxy groups. Consolidation in the natural gas and ***oil*** pipeline industries has resulted in the absorption of many natural gas and ***oil*** pipeline companies into larger, diversified energy companies that own a variety of energy-related assets in addition to interstate pipelines. In addition, major companies in the ***oil*** pipeline industry have recently acquired natural gas pipeline assets. The proliferation of these diversified energy companies has reduced the number of companies satisfying the 50% standard. Recent acquisitions of pipeline companies by private equity firms have further reduced the number of eligible natural gas and ***oil*** pipeline proxy group members by converting those pipeline companies from publicly traded to privately held entities." To address the problem of the shrinking proxy groups, FERC has relaxed the 50 percent standard when necessary to construct a proxy group of five members, while emphasizing that it will only include firms not satisfying the 50 percent standard until five proxy group members are obtained. *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC decided to maintain a flexible approach to forming natural gas and ***oil*** pipeline proxy groups and continue to relax the 50 percent standard when necessary to obtain a proxy group of five members. "In addition, we clarify that in light of continuing difficulties in forming sufficiently sized natural gas and ***oil*** pipeline proxy groups, we will consider proposals to include otherwise-eligible Canadian entities." FERC noted that parties may continue to propose alternative screens and methods for selecting proxy group members in cost-of-service rate proceedings. "We recognize that difficulties in forming a proxy group of sufficient size may be enhanced under current market conditions, including those resulting from the COVID-19 pandemic. In light of these conditions, the Commission will consider adjustments to our ROE policies where necessary." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   FERC declined to adopt specific outlier tests for use in determining natural gas and ***oil*** pipeline ROEs. "Rather, we will continue to address outliers in pipeline proxy groups on a case-by-case basis in accordance with our policy to remove 'anomalous' or 'illogical' cost-of-equity estimates that do not provide meaningful indicia of the returns that a pipeline needs to attract capital from the market. ... Using this approach, the Commission will retain flexibility to determine whether a given proxy group company is truly an outlier or whether it contains useful information in light of the particular array of ROEs presented by the potential proxy group companies." *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶61,155 (2020).

   In order to determine an intrastate pipeline's ROE for NGA section 311 transportation service, FERC "generally uses the same proxy group as has been used in recent NGA section 4 rate cases. The Commission finds that Guadalupe's proposal to use the same proxy group as the Commission approved in ***Kern*** *River* [ *Gas Transmission Co.*, 126 FERC ¶61,034, *order on reh'g*, 129 FERC ¶61,240 (2009),] is consistent with this policy." *Duke Energy Guadalupe Pipeline Inc.*, 131 FERC ¶61,037 (2010).

   Unless "a pipeline makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's return at the median of the range of reasonable returns. However, the Commission permits parties to present evidence to support any return on equity that is within the zone of reasonableness, and the Commission has recognized that an examination of the risk factors specific to a particular pipeline may warrant setting its ROE either higher or lower than the middle of the zone of reasonableness established by the proxy group." *Portland Natural Gas Transmission System*, 142 FERC ¶61,197 (2013), *reh'g denied*, 150 FERC ¶61,107 (2015).

   For "the first time since Opinion No. 414-A [( *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶61,084 (1998))] established our current policies concerning the assessment of a pipeline's risk as compared to the proxy group, we must determine the ROE for a pipeline with a below investment grade credit rating. We find that Portland's below investment grade credit rating, combined with its inability to reflect its unsubscribed capacity in its rate design, present highly unusual circumstances justifying setting Portland's ROE at the top of the range of reasonable returns." *Portland Natural Gas Transmission System*, 142 FERC ¶61,197 (2013), *reh'g denied*, 150 FERC ¶61,107 (2015).

   Commission staff approved Roaring Fork's initial rate structure, except for its proposed return on equity. "Roaring Fork has proposed an ROE of 14.0%, which has commonly been granted by the Commission in certificate orders for greenfield projects. ... While the Commission has allowed returns up to 14.0% for new greenfield pipeline projects to reflect the greater risk faced by new entrants, those risks do not exist to the same extent with Roaring Fork. Roaring Fork is not constructing new pipeline facilities but is continuing to operate facilities that are already in service and have been operating for several years. ... Roaring Fork has more in common with existing or converted pipelines than with the greenfield pipeline projects that have received returns of 14.0%. ... The last litigated ROE applicable to this situation was from *El Paso Natural Gas Company*, where the Commission adopted an ROE of 10.55% [( *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040, at ¶ 642 (2013), *reh'g denied*, Opinion No. 528-A, 154 FERC ¶ 61,120 (2016))]. Therefore, an ROE of 10.55% is appropriate for Roaring Fork, and Roaring Fork will be required to recalculate its rates accordingly." *Roaring Fork Interstate Gas Transmission, LLC and Kaiser-Frontier Midstream, LLC*, 177 FERC ¶ 62,153 (2021) (Chief Gray).

**PSIA costs**. A pipeline sought to recover costs incurred under the Pipeline Safety Improvement Act of 2002 (PSIA). "In its filings, [the pipeline] included ... a description of each invoice and the corresponding reference to the U.S. Department of Transportation's pipeline integrity regulations. Further, [the pipeline] stated that, were it not for the PSIA, it would not have replaced the pipeline segments or incurred the operating and maintenance expenses that are the subject of the instant proceeding. The Commission finds that in the instant filing, [the pipeline] has ... shown that the costs it seeks to recover are 'Qualifying Costs' pursuant to [its] tariff. ... [T]he Commission ... accepts [the] proposal." *Equitrans L.P.*, 123 FERC ¶61,321 (2008).

**Rational basis for initial rates I**. FERC rejected a proposal to implement meter access service. Among other things, FERC found that the proposed rates for the service are not justified. The pipeline "attempts to support using its existing FTS-1 rates as a proxy here by citing to the Commission's statement in *Columbia Gas* [ *Transmission Co.*, 122 FERC ¶61,239 (2008),] that '[i]n between rate cases, the Commission accepts initial rates for new services if designed properly based on a currently approved cost-based rate. Issues regarding the levels and allocation of costs can be addressed in the pipeline's next rate case.'" However, FERC explained, the phrase "if designed properly" requires that initial proxy rates for new services must be properly designed, not simply borrowed from other services without regard to whether there is a rational basis for the choice of the proxy rate. "Here, there is no similarity between the proposed service and the FTS-1 service whose rate is being proposed as a proxy (i.e., 'access' to the transmission system even if considered a 'service' is not the same as point to point transmission service). Further, there is no similarity between the costs to be recovered by the proposed rates and the costs recovered by the FTS-1 rates. ... [T]here is no rational basis for the proposed rates."

*Columbia Gulf Transmission Co.*, 124 FERC ¶61,113 (2008).

**Rational basis for initial rates II**. Transcontinental Gas Pipe Line Co. LLC (Transco) argued that it should not be required to charge for lost and unaccounted-for (LAUF) gas on a new lateral. Transco cited *Columbia Gulf Transmission Co.*, 124 FERC ¶61,113 (2008) ( *Columbia Gulf*), to support its argument that initial rates for a new service should be established on a rational basis, i.e., specific to that particular service, and not by simply borrowing a rate from another service and using that rate and its design factors as a proxy for the rate for a new service. Fuel losses on its mainline are not representative of losses that would be sustained on the lateral, Transco said. FERC concluded Transco's reliance on *Columbia Gulf* is misplaced. "In this proceeding we are not saying that Transco should necessarily use the same rate to recover LAUF gas on the ... lateral as it does to recover LAUF gas on its general system. Rather, we are saying that to the extent there is LAUF gas on the ... lateral, Transco should develop a mechanism for recovering it from the lateral shippers, just as shippers on the existing system are a[ss] essed for LAUF gas on these facilities."

*Transcontinental Gas Pipe Line Co. LLC*, 130 FERC ¶61,019 (2010).

**Greenhouse gas costs I**. FERC rejected a pipeline's proposal for a greenhouse gas cost recovery mechanism to recover its costs for purchasing emissions allowances, paying emissions taxes or other forms of compensation required by federal, state or local government authorities with jurisdiction over the pipeline. The pipeline "concedes that no such legislation currently exists, and that currently there are no greenhouse gas costs to recover. ... In the Commission's view, it is speculative to anticipate what types of costs [the pipeline] may be subject to under federal, state or local legislation, whether such costs should be recoverable, and, if recoverable, the manner in which they should be recovered. This action is without prejudice to any future ... proposal if [the pipeline] actually incurs such costs."

*Southern Natural Gas Co.*, 127 FERC ¶61,003 (2009).

**Greenhouse gas costs II**. In *Southern* (see "Greenhouse gas costs I," above), FERC found that there was no legislation that imposed greenhouse gas costs on the pipeline and rejected the proposal to recover such costs. Ruby Pipeline L.L.C. (Ruby) "proposes to recover voluntary [greenhouse gas-related] costs, capped at $ 12.5 million per year. Ruby has not provided details about these voluntary offsets, including whether they are currently available or the source from which they may be acquired. Therefore, we reject Ruby's proposal, without prejudice to Ruby's submitting additional tariff language and information that identifies existing voluntary offsets, credits or allowances. While no party protests Ruby's proposal to recover future mandatory costs, we reject it consistent with *Southern*, because there is not yet any legislation that would impose such costs on Ruby. Further, we find the provision to be vague and overly broad with respect to what specific costs could be recovered. Our rejection is without prejudice to Ruby filing a more fully developed and detailed proposal in the event it actually incurs mandatory costs."

*Ruby Pipeline L.L.C.*, 128 FERC ¶61,224 (2009).

**Greenhouse gas costs III**. "In *Southern*, the Commission rejected a proposed greenhouse gas cost recovery mechanism because no legislation existed that would impose such costs and therefore it was speculative to anticipate costs to comply with the legislation. However, in this case, Florida Gas [Transmission Co. LLC] has shown that a specific [Environmental Protection Agency (EPA)] rule is pending that would impose the calculated costs. Therefore, the Commission finds that Florida Gas may include expenses for monitoring greenhouse gases in its rates. However, the calculation of greenhouse gas expenses is a cost-of-service issue that will be included in the issues discussed at the hearing. ... In addition, if the EPA Rule does not go into effect prior to April 1, 2010, the greenhouse gas costs must be removed from the rates, and Florida Gas must file revised tariff sheets to reflect the elimination of these costs when it files a motion to place the rates into effect."

*Florida Gas Transmission Co. LLC*, 129 FERC ¶61,092 (2009).

**Greenhouse gas costs IV**. In March 2010, Florida Gas removed greenhouse gas monitoring costs from its rates because the provisions of the EPA Rule related to ***oil*** and gas were deferred and would not be addressed prior to April 1, 2010.

*Florida Gas Transmission Co. LLC*, 130 FERC ¶61,250 (2010).

**Greenhouse gas costs V**. FERC granted rehearing "to accept Ruby's proposed voluntary recovery of greenhouse gas costs because Ruby has now provided sufficient information to accept the proposal, and the proposal is supported by the parties. ... Ruby explains that it has discussed with its shippers the available methods for mitigation, displacement and offset of the 523,000 metric tons of carbon dioxide or equivalent amounts of other greenhouse gases it estimates it may emit per year. Ruby states that the most likely measures include Renewable Energy Credits, Greenhouse Gas Allowances, and Greenhouse Gas Offsets, but anticipates that other valid products and services may become available in the future." Ruby defined these terms, and described in greater detail the anticipated measures it may undertake to achieve carbon neutrality. Shippers will have the right to review and challenge the costs in Ruby's periodic cost recovery mechanism. However, FERC denied rehearing of its rejection of Ruby's mandatory cost recovery mechanism because Ruby provided no new information to warrant deviating from *Southern* (see "Greenhouse gas costs I," above).

*Ruby Pipeline L.L.C.*, 131 FERC ¶61,007 (2010).

**Rate differential for new shippers**. FERC reversed an ALJ's finding that Transco's incremental rate proposal was unlawfully discriminatory. "The Commission determines that Transco's proposal to charge different rates to ... new shippers is not unduly discriminatory because [they] are not similarly situated to historic shippers of the ... storage field. The Commission considers the rate differential reasonable, because the historic shippers were required to provide the base gas used to serve them, whereas the new shippers do not provide base gas. ... The Commission further disagrees with the ALJ's assessment that [the new shippers] should not be charged a bifurcated rate because they 'stepped into the shoes' of their predecessors. ... Transco's ... tariff is already designed so that historic shippers and replacement shippers are not similarly situated."

*Transcontinental Gas Pipe Line Corp.*, 130 FERC ¶61,043 (2010).

**Cost and revenue studies**. FERC opened investigations into the rates of three pipelines after reviewing their annual financial form filings and ordered them to file cost and revenue studies. FERC rejected their objections to this filing requirement and said that it was necessary to fulfill its responsibilities under NGA section 5 to ensure that rates are just and reasonable. "[W]e will have the burden under NGA section 5 both to show that [the pipelines'] current rates are unjust and unreasonable and that any new rates we may impose are just and reasonable. ... The Commission readily admits that the information that it has requested ... is the type of information necessary to craft rates. Where rates are changed pursuant to the procedures and burdens in NGA section 4 or in NGA section 5, the same information and calculations are required to determine the rates. ... [T]he Commission has expressly stated that it is not requiring [the filing of] revised rate schedules under NGA section 4, but is simply requiring an informational filing of the type ... permissible under NGA section 10(a)." *Natural Gas Pipeline Co. of America LLC*, 130 FERC ¶61,133 (2010). *See also Northern Natural Gas Co.*, 130 FERC ¶61,134 (2010); *Great Lakes Gas Transmission Limited Partnership*, 130 FERC ¶61,132 (2010); *MIGC LLC*, 138 FERC ¶61,011 (2012); *Bear Creek Storage Co. L.L.C.*, 138 FERC ¶61,019 (2012).

   In 2016, FERC initiated NGA section 5 investigations of the rates charged by four interstate pipelines after finding that, based on the information filed in their 2013 and 2014 annual financial reports (FERC Form No. 2), their level of earnings may substantially exceed their actual cost of service, including a reasonable return on equity. FERC ordered them to file cost and revenue studies based on cost and revenue information for the latest 12-month period available, and including all the schedules required for submission of a section 4 rate proceeding as set forth in section 154.312. "Because the Commission is seeking actual cost and revenue information, the information submitted ... must exclude any adjustments or projections that may be attributable to a test period referenced in the schedules and statements set forth in section 154.312." FERC also did not require Statement ¶ (explanatory text and prepared testimony) because the pipelines do not have an NGA section 4 burden and will be filing testimony in response to other parties. *Tuscarora Gas Transmission Co.*, 154 FERC ¶61,030, *reh'g denied*, 154 FERC ¶61,273 (2016); *Empire Pipeline Inc.*, 154 FERC ¶61,029, *reh'g denied*, 154 FERC ¶61,274 (2016); *Iroquois Gas Transmission System L.P.*, 154 FERC ¶61,028 (2016); *Columbia Gulf Transmission LLC*, 154 FERC ¶61,027, *reh'g denied*, 154 FERC ¶61,275 (2016).

   However, as we have done in other recent section 5 proceedings, in addition to the cost and revenue study, ... [the pipeline] may file a separate cost and revenue study that reflects adjustments for changes [it] projects will occur during an abbreviated six-month adjustment period following the 12-month base period used for the cost and revenue study. Given the expedited hearing schedule established herein, the adjustment period must be limited six-months in order to permit the parties to perform discovery and prepare testimony for the hearing based on actual data for both the base period and the adjustment periods." *Id.*

   The Commission found, "based upon our preliminary analysis of the information provided by El Paso in its Form 2s for the calendar years 2019 and 2020 and its cost and revenue studies, that El Paso's currently effective tariff rates may be unjust and unreasonable. The analysis of this information indicates that El Paso's currently effective tariff rates may allow El Paso to recover revenue substantially in excess of its estimated cost of service. Accordingly, we are initiating an investigation to examine the justness and reasonableness of El Paso's rates pursuant to section 5 of the NGA and setting the matter for hearing." FERC directed "El Paso to file a cost and revenue study based on cost and revenue information for the latest 12-month period available. The filing should be made within 75 days of the date this order issues and include all the schedules required for submission of a section 4 rate proceeding as set forth in section 154.312 of the Commission's regulations [(18 C.F.R. § 154.312 (2021))]." *El Paso Natural Gas Company, L.L.C.*, 179 FERC ¶ 61,051 (2022). *See also: Guardian Pipeline, L.L.C.*, 179 FERC ¶ 61,050 (2022).

   Additionally, FERC noted, "as the Commission has done in other recent section 5 proceedings, in addition to the cost and revenue study required above, El Paso may file a separate cost and revenue study that reflects adjustments for changes El Paso projects will occur during an abbreviated six-month adjustment period following the 12-month base period used for the cost and revenue study [( *see, e.g., Ozark Gas Transmission, LLC*, 134 FERC ¶ 61,062 (2010), *reh'g granted in part and denied in part*, 134 FERC ¶ 61,193 (2011))]. ... Due to the potential for continued over-recovery of revenues, we are establishing a date for an initial decision from an administrative law judge. Such a date will expedite the proceeding. We believe that conducting the hearing in this case pursuant to the Track II Hearing Timeline is reasonable. ... Therefore, the initial decision must be issued within 47 weeks of the date the cost and revenue study is due." *El Paso Natural Gas Company, L.L.C.*, 179 FERC ¶ 61,051 (2022).

   The Commission noted that "courts have recognized that the Commission has wide discretion to decide whether to initiate an NGA section 5 investigation into a pipeline's tariff rates [( *see Vt. Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc.*, 435 U.S. 519, 524-25 (1978); *Mich. Pub. Power Agency v. FERC*, 963 F.2d 1574, 1578-79 (D.C. Cir. 1992); *Woolen Mill Assoc. v. FERC*, 917 F.2d 589, 592 (D.C. Cir. 1990); *Gen. Motors Corp. v. FERC*, 613 F.2d 939, 944 (D.C. Cir. 1979). *See also Algonquin Gas Transmission Co.*, 84 FERC ¶ 61,174, at 61,912 (1998))]. The Investigation Order found that initiating an NGA section 5 rate investigation into Overthrust's rates was justified because Overthrust's level of earnings may substantially exceed its actual cost of service, including a reasonable ROE [( *MountainWest Overthrust Pipeline, LLC*, 180 FERC ¶ 61,174, at ¶ 5 (2022) (Investigation Order))]. ... And, in any event, the Commission has previously addressed and rejected arguments similar to those raised by Overthrust concerning the Commission's authority to require a cost and revenue study to facilitate its NGA section 5 investigation. For the reasons discussed in the cited precedent, the Commission's directive here to require a cost and revenue study is authorized under NGA sections 5, 10(a) and 14(a) to enable the Commission to carry out its investigation and ensure that rates are just and reasonable [( *see Stagecoach Pipeline & Storage Co. LLC*, 168 FERC ¶ 61,054 at ¶ 4 & n.16 (2019) (citations omitted))]. ... Overthrust's arguments are dismissed without prejudice, and Overthrust may re-raise these issues, if appropriate, at the time the Commission issues a final order in this proceeding." *MountainWest Overthrust Pipeline, LLC*, 181 FERC ¶ 61,246 (2022).

**Hurricane surcharges I**. Sea Robin Pipeline Co. LLC (Sea Robin) proposed a hurricane surcharge to record and recover hurricane-related costs not recovered from insurance proceeds or from third-parties. Two parties argued that the proposal is inconsistent with FERC's periodic rate adjustment regulations (18 C.F.R. §154.403). "The Commission finds that Sea Robin's proposed Hurricane Surcharge is generally consistent with section 154.403. ... While the claimed costs related to Hurricane Ike do predate the effectiveness of the proposed surcharge, section 154.403(d)(4) expressly allows the Commission to permit an exception to the general rule against including such costs. In the instant case, the Commission finds Sea Robin's proposal to include the previously incurred Hurricane Ike costs in the proposed surcharge to be reasonable. ... [T]he inclusion of Hurricane Ike costs does not violate the filed rate doctrine or the rule against retroactive ratemaking. In addition, because the Hurricane Ike costs are the same type of costs as the prospective hurricane-related costs Sea Robin proposes to include in the surcharge, it is reasonable to use the same mechanism to recover those costs."

   The parties also argued that the periodic rate adjustment regulations are not designed for hurricane costs, which are by their very nature rare, catastrophic, and nonrecurring events that FERC has specifically determined are unrecoverable in tracking mechanisms. "The Commission disagrees. While it is unpredictable just when a hurricane will occur, experience unfortunately shows that hurricanes do repeatedly occur in the Gulf of Mexico area. It can therefore be expected that offshore pipelines in the Gulf of Mexico, such as Sea Robin, will suffer hurricane damage at recurring, if irregular, intervals. In such circumstances it is reasonable for the pipeline to have in its tariff a mechanism for the recovery of such costs, thereby providing both the pipeline and its customers some certainty as to what categories of such costs may be recovered and how they will be allocated among customers."

*Sea Robin Pipeline Co. LLC*, 130 FERC ¶61,191 (2010).

**Hurricane surcharges II**. In an order on initial decision, FERC affirmed in part and reversed in part the ALJ's initial decision (133 FERC ¶63,009 (2010) (J. Johnson)) on Sea Robin's hurricane surcharge proposal. FERC affirmed that (1) Sea Robin should be permitted to include capital costs in the hurricane surcharge, (2) the actual costs Sea Robin has included in the surcharge are reasonable, and (3) Sea Robin's proposal concerning the volumes to be used to design the surcharge is reasonable. FERC reversed the ALJ's finding that a 21.4-year recovery period is just and reasonable and found instead that Sea Robin's proposed 4-year recovery period is just and reasonable. FERC reversed the ALJ's holding that carrying charges at the FERC published interest rate should begin to accrue on the date that FERC authorized the hurricane surcharge to take effect, subject to refund. Instead, FERC found that carrying charges should begin to accrue the later of the date Sea Robin filed to establish the surcharge, or the date the associated cost is incurred. FERC found that Sea Robin's discount agreements with certain shippers permit it to recover the hurricane surcharge from those shippers. Therefore, there is no need to modify those agreements, as the ALJ sought to do pursuant to an analysis under the *Mobile-Sierra* public interest standard.

*Sea Robin Pipeline Co. LLC*, 137 FERC ¶61,201 (2011), *order on compliance tariff filing*, 138 FERC ¶61,131 (2012); 138 FERC ¶61,242 (2012); *order on requests for reh'g*, 143 FERC ¶61,129 (2013).

**Section 154.303(c)(2)**. FERC "finds that section 154.303(c) (2) ... requires removal of any costs associated with facilities not in service as of the end of the test period, regardless of whether the facilities are being constructed under a specific certificate for the facilities in question or under the pipeline's blanket certificate granted pursuant to §157.203. Section 154.303(c)(2) provides 'that when a pipeline files a motion to place the rates into effect, the filing must be revised to exclude the costs associated with *any* facilities that will not be in service as of the end of the test period. ... At the end of the test period, the pipeline must remove from its rates costs associated with *any* facility that is not in service' [(emphasis supplied by FERC)]. Section 154.303(c)(2) does not make distinctions regarding its applicability based upon the type of certificate under which the facilities is to be constructed. Therefore, the Commission directs Florida Gas to remove any costs associated with facilities not in service as of the end of this test period from its rates, including costs associated with facilities to be constructed under its blanket certificate."

*Florida Gas Transmission Co. LLC*, 130 FERC ¶61,250 (2010).

   The Commission accepted and suspended, "subject to refund and the outcome of a hearing, the proposed tariff records in Appendix A to be effective upon motion April 1, 2022. Texas Eastern must adhere to section 154.303(c) (2) of the Commission's regulations which provides that at the end of the test period, the pipeline must remove from its rates costs associated with any facility that is not in service or for which certificate authority is required but has not been granted [(18 C.F.R. § 154.303(c)(2))]." Finally, FERC noted that "[b]ecause Texas Eastern included both the rate decreases and rate increases on the same tariff record, Texas Eastern is required to make a ministerial filing to update eTariff to reflect the effective dates established in this order. Accordingly, we direct Texas Eastern to file a revised version of the tariff record in eTariff that includes both proposed rate decreases and rate increases, but replace the rate increases with currently effective rates, to be effective November 1, 2021. Texas Eastern is directed to make this compliance filing within 15 days of the date of this order." *Texas Eastern Transmission, LP*, 177 FERC ¶ 61,065 (2021).

**High equity percentages**. In a proceeding involving an intrastate pipeline's proposal for rates to be charged for transportation service under section 311 of the NGPA, FERC noted that the pipeline's capital structure contains only 29.2 percent debt, as compared to 70.8 percent equity. FERC said the pipeline's capital structure "has a proportion of equity at the very high end of what the Commission has approved as reasonable. The Commission has long recognized that an equity-rich capital structure increases costs to ratepayers, because a pipeline's cost-of-equity is higher than its cost of debt." For example, in this case, the pipeline's cost of debt is 7.38 percent, as compared to the 11.26 return of equity approved by FERC. "While the Commission is accepting [the pipeline's] proposed capital structure with its high equity ratio, the Commission finds that such a capital structure should not be accompanied with a return on equity above the median [of the proxy group]."

*Duke Energy Guadalupe Pipeline Inc.*, 131 FERC ¶61,037 (2010).

**No refund authority under section 5**. FERC granted a motion submitted by a group of customers to terminate an NGA section 5 investigation into a pipeline's rates. They said that the pipeline intended to file a substantial increase in rates under NGA section 4 that would become effective before FERC could act in the section 5 proceeding, unless the investigation was terminated. The pipeline agreed not to file for any increase in rates for another year if the investigation was terminated. "Balancing the equities and based on the evidence before us, we agree with these parties that the immediate benefit of the rate certainty provided by [the pipeline's] commitment not to file a section 4 rate increase [for one year] ... outweighs the potential benefits of proceeding with the section 5 investigation. ... [G]iven that the ultimate outcome of a continuation of this section 5 proceeding is uncertain and we lack authority under NGA section 5 to order refunds for the period before a merits decision in the section 5 proceeding, we hereby terminate this section 5 proceeding." Chairman Wellinghoff, dissenting, and Commissioner Norris, concurring, urged Congress to revise the NGA to provide FERC refund authority paralleling that provided in the Federal Power Act.

*Northern Natural Gas Co.*, 131 FERC ¶61,178 (2010), *reh'g denied*, 133 FERC ¶61,111 (2010).

**Capital cost surcharges**. FERC "has previously found that capital costs of the type [the applicant] seeks to include in its Capital Cost Surcharge, including costs incurred to comply with the requirements of the Pipeline Safety Improvement Act of 2002 and pipeline relocation costs, should not be included in such surcharges. The Commission stated that pipelines commonly incur capital costs in response to regulatory requirements intended to benefit the public interest, and recovering those costs in a tracking mechanism is contrary to the requirement, in section 284.10(c)(2), to design rates based on estimated units of service." Pipelines are entitled to seek recovery of such costs, with a just and reasonable return, through general NGA section 4 rate proceedings.

*Granite State Gas Transmission Inc.*, 132 FERC ¶61,089 (2010).

**Fixing NGA section 5 rates**. "NGA section 5 provides that, once the Commission has found a tariff provision unjust and unreasonable, the Commission 'shall determine the just and reasonable rate ... to be thereafter observed and in force, and shall fix the same by order.' " A pipeline argued that, because FERC accepted the proposed rates subject to conditions requiring changes to various components of the rates, the rates were indeterminable as of the date of the order and FERC did not "fix" the rates as required. FERC said that if it requires the pipeline to make a compliance filing, it makes the section 5 rate change effective on the date the Commission issues an order accepting the pipeline's initial compliance filing, thereby "fixing" the new just and reasonable rate. "The Commission does this, even if its acceptance of the initial compliance filing is subject to the pipeline making a second compliance filing to correct errors in its first compliance filing." The changes required by FERC were limited, i.e., "a mechanical change that involved substituting one number for another and did not permit any discretion on the part of the pipeline." ***Kern*** *River Gas Transmission Co.*, 133 FERC ¶61,162 (2010).

   In 2015, the D.C. Circuit affirmed FERC's decision and rejected the pipeline's argument that FERC could not have fixed the rates under section 5 while it waited for the pipeline to submit an additional compliance filing. "FERC's conditional acceptance of Period One rates in Opinion No. 486-C [(129 FERC 61,240 (2009))] simply required ***Kern*** River to substitute one number for another when allocating costs to the rolled-in shippers. ... The Shippers, moreover, could have calculated the rates on their own. ... Because the Shippers could 'supply their own inputs to the [models] and thereby know the numerical rates,' FERC reasonably fixed the rates 'within the meaning of Natural Gas Act §5' as of the date it accepted ***Kern*** River's compliance filings in Opinion No. 486-C. *City of Anaheim v. FERC*, 558 F.3d 521, 524 (D.C. Cir. 2009) (citing *Transwestern* [ *Pipeline Co. v. FERC*, 897 F.2d 570, 578 (D.C. Cir. 1990)])." *Aera Energy LLC v. FERC*, No. 13-1138 (D.C. Cir. June 16, 2015).

**Abbreviated adjustment periods for section 5 cases**. FERC directed two pipelines whose rates are under investigation to file actual cost and revenue information for the latest 12-month period available and exclude any adjustments or projections that may be attributable to a test period. Later, FERC clarified that it did not intend to preclude consideration in this NGA section 5 proceeding of evidence concerning changes in costs and revenues occurring after the 12-month base period, but rejected the contention it must use the full nine-month adjustment period used in section 4 cases. Under the current procedural schedule, the last month for which actual data could reasonably be expected to be available sufficiently in advance of the hearing would be approximately four months after the close of the 12-month base period. The pipelines should be able to provide actual data to all participants by approximately two and a half months before the hearing. They can propose in their answering testimony adjustments based on the actual data, and staff and intervenors can address those adjustments, as well as propose their own, in cross-answering and rebuttal testimony. *Kinder Morgan Interstate Gas Transmission L.L.C.*, 134 FERC ¶61,061 (2011); *Ozark Gas Transmission L.L.C.*, 134 FERC ¶61,062 (2011).

   FERC denied rehearing of its decision not to allow a full nine-month adjustment period, except to clarify that the rate design used in the pipelines' cost and revenue study will not serve as evidence of their preferred rate design or cost allocation. *Ozark Gas Transmission L.L.C.*, 134 FERC ¶61,193 (2011).

**Pipeline proposals in NGA Section 5 cases**. "When the Commission has found that a pipeline's existing rates or practices are unjust and unreasonable as in this case, the Commission then has the burden of showing that its chosen remedy is just and reasonable. ... In order to satisfy that burden, we may rely on any evidence in the record, regardless of the source of that evidence. In this case, [the pipeline] and its shippers have submitted various competing proposals concerning the just and reasonable ... rates that we should adopt pursuant to NGA section 5. [The pipeline], like any other party proposing a remedy in a section 5 proceeding, must produce sufficient evidence in support of its proposed remedy, to enable us to satisfy our section 5 burden of demonstrating that the remedy it desires us to adopt is just and reasonable. Absent such evidence, we would be unable to satisfy our obligations under section 5, and therefore we could not adopt [the pipeline's] proposed remedy. ... However, if we are satisfied that [the pipeline's] proposed remedy is just and reasonable, we will adopt that remedy in preference to other just and reasonable remedies that may have been proposed by other parties." ***Kern*** *River Gas Transmission Co.*, 136 FERC ¶61,045 (2011), *reh'g denied*, 142 FERC ¶61,132 (2013).

   NGA section 4 "delegates to the pipeline the primary initiative to propose the rates, terms and conditions for its services. ... If the rates, terms and conditions proposed by the pipeline are just and reasonable, the Commission must accept them, regardless of whether other rates, terms and conditions may be just and reasonable. Consistent with this structure of the NGA, the Commission believes it appropriate in this case, where [the pipeline] agrees that its current tariff is unjust and unreasonable, to give [the pipeline] a similar initiative in proposing remedial tariff provisions. To the extent [the pipeline's] proposed remedy is just and reasonable, the Commission will approve that remedy, even though other just and reasonable remedies might exist." *ANR Pipeline Co.*, 109 FERC ¶61,138 (2004).

   FERC said its precedent "reveals that the pipeline's proposal is granted a preference. ... Given that the Commission may rely on the entire record in order to establish a just and reasonable rate and that the Commission will accept a pipeline's proposed remedy if it is found to be just and reasonable, pipelines often propose their own remedy to the proceeding. ... To the extent that [the pipeline] must support its proposal to enable the Commission to find it just and reasonable, [the pipeline] has a burden. However, it is clear that the Commission has the ultimate burden in a section 5 proceeding of establishing a just and reasonable rate to be implemented in the proceeding." ***Kern*** *River Gas Transmission Co.*, 136 FERC ¶61,045 (2011), *reh'g denied*, 142 FERC ¶61,132 (2013).

**Contributions in aid of construction (CIAC)**. In *Texas Gas Transmission LLC*, 128 FERC ¶61,104 (2009), FERC approved a tariff proposal permitting the pipeline to pay for modification or construction of non-jurisdictional facilities in exchange for a long-term contract to provide jurisdictional service, but required the pipeline to functionalize CIAC of non-jurisdictional facilities and related transactions in non-jurisdictional accounts. The pipeline did not challenge this requirement. However, when FERC imposed this same requirement on ANR Pipeline Co. (ANR), ANR sought rehearing and argued that it was an unexplained departure from long-standing policy.

   FERC granted rehearing. "The Commission historically has authorized natural gas pipeline companies to record CIAC payments as intangible gas plant in Account 303, Miscellaneous Intangible Plant, even if the costs are related to non-jurisdictional facilities. This accounting records CIAC within the Intangible Plant function of Gas Plant Accounts, separate from the Transmission Plant function, and does not provide a guarantee of rate recovery of these costs in jurisdictional rates. The Commission has held that a natural gas pipeline must still make a showing in a rate proceeding that the CIAC payment was reasonable, prudent, and allowable in jurisdictional rates before it can collect the CIAC costs from its customers." FERC required ANR to amortize the CIAC payments over the term of the related transportation agreement by debiting Account 404.3, Amortization of Other Limited-Term Gas Plan, and crediting Account 111, Accumulated Provision for Amortization and Depletion of Gas Utility Plant.

*ANR Pipeline Co.*, 140 FERC ¶61,181 (2012).

**Regulatory compliance cost surcharges**. "Following the events of September 11, 2001, the Commission issued a Policy Statement on Security Costs providing for recovery of expenses necessary to safeguard energy infrastructure via a surcharge. [The applicant's] proposal to recover security-related costs as they are incurred through a surcharge and a tracking mechanism is generally consistent with the Policy Statement and proposals accepted by the Commission in subsequent orders. [ *Florida Gas Transmission Co.*, 105 FERC ¶61,171 (2003) ( *Florida Gas*).] ... However, [the] proposal to include environmental and pipeline safety costs is inconsistent with current Commission policy as described in *Florida Gas* and *Granite State* [ *Gas Transmission*, 132 FERC ¶61,089 (2010)]. In those cases the Commission stated that the cost-of-service tracking provisions related to such regulatory requirements are contrary to the requirement, in section 284.10(c)(2), to design rates based on estimated units of service." *CenterPoint Energy — Mississippi River Transmission LLC*, 140 FERC ¶61,253 (2012).

   FERC explained that the requirement to design rates based on estimated units of service places the pipeline at risk for under-recovery of its costs between rate cases, but allows it to retain any over-recovery. "This gives the pipeline an incentive both to be efficient and to provide effective service. The Commission found that cost trackers undercut these incentives by guaranteeing the pipeline a set revenue recovery. The Commission also stated that jurisdictional pipelines commonly incur capital costs in response to regulatory requirements intended to benefit the public interest. Pipelines are entitled to seek recovery of such costs, along with a just and reasonable return, at any time through a general NGA section 4 rate proceeding. Therefore, the proposal to recover costs related to environmental and pipeline safety regulations are not eligible costs under the *Policy Statement on Security Costs* and should be removed from any such proposal." *CenterPoint Energy — Mississippi River Transmission LLC*, 140 FERC ¶61,253 (2012).

   FERC acknowledged that the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 will increase regulatory requirements concerning the safe operation of pipelines, and said it is tracking the Act's impacts. "The Commission understands the importance of investment and other expenditures to improve the safe operation of the nation's pipeline infrastructure, and will consider the need for further action as PHMSA's implementation process moves forward." *CenterPoint Energy — Mississippi River Transmission LLC*, 140 FERC ¶61,253 (2012).

   FERC found that a capital cost recovery mechanism (CCRM) in a settlement provides a reasonable means for the pipeline to recover the substantial costs of addressing urgent public safety and reliability concerns, without undercutting its incentives to operate efficiently and to maximize service to the extent that previously proposed and rejected surcharges would have done. FERC found "that the very substantial benefits that will inure to [the pipeline's] shippers through the settlement outweigh the inclusion of an otherwise disfavored surcharge, particularly given the customer protections inherent in the CCRM." *Columbia Gas*

*Transmission Corp.*, 142 FERC ¶61,062 (2013).

**Treatment of bad debts**. FERC "generally requires that a pipeline be at risk for any cost under-recovery between rate cases. At the same time, the pipeline may retain any cost over-recoveries between rate cases. However, when the pipeline files its next rate case, the pipeline's rates will be designed to recover 100 percent of the pipeline's projected just and reasonable costs of service, subject to any at-risk condition established in its certificate proceeding. ... The Commission's treatment of bad debt follows this general policy. Thus, the Commission treats bad debts incurred between rate cases as a risk of doing business, and the Commission does not permit a pipeline to recover in its next rate case, any losses incurred as a result of a customer's failure to make payments for past service performed before the effective date of the new rates."

   However, FERC does not require the pipeline to continue to bear this risk in connection with payments for service to be performed in the future after the rates in a new rate case take effect. "In the next rate case, the pipeline may design its rates to recover its full cost of service taking into account any rejection of a contract in bankruptcy and any inability to obtain full recovery of the future payments. ... By the same token, we believe that ... if a pipeline is able to collect on the debt and the amount collected relates to services to be covered by the pipeline's newly filed rate case, that amount should be taken into account in designing the pipeline's new rates."

*Portland Natural Gas Transmission System*, 142 FERC ¶61,198 (2013), *reh'g dismissed as moot*, 150 FERC ¶61,106 (2015).

**Surcharges, discounts and negotiated rates**. "The costs eligible for recovery in the Storm Event Surcharge clearly include fixed costs, which would be included in [the pipeline's] maximum rates and not in its minimum rates. Therefore, the Commission's regulations require that the Storm Event Surcharge be discountable down to whatever portion of that surcharge might reflect variable costs. Accordingly, consistent with our holding in *Sea Robin Pipeline Co. LLC*, [137 FERC ¶61,201, at ¶ 93-94 (2011)], [the pipeline] must file revised tariff records removing any language from its tariff records indicating that the Storm Event Surcharge is not discountable." FERC said the pipeline may elect not to discount the storm event surcharge with respect to future discounted rate agreements, provided it does so on a non-discriminatory basis. "However, if [the pipeline] provides a discount, future section 4 rate filings cannot modify the discount, so long as the rate remains within the maximum and minimum rates." *High Island Offshore System L.L.C.*, 138 FERC ¶61,114 (2012).

   FERC "also permits pipelines to enter into negotiated rates without any requirement that they be within the bounds set by the maximum and minimum recourse rates. Therefore, [the pipeline] must also remove any tariff language indicating that all negotiated rate shippers must pay the Storm Event Surcharge, without regard to the terms of their individual negotiated rate agreements. Of course, [the pipeline] need not enter into negotiated rates which exempt the shipper from paying the Storm Event Surcharge. That is a matter to be addressed in each negotiated rate agreement." *High Island Offshore System L.L.C.*, 138 FERC ¶61,114 (2012).

   FERC denied rehearing of its finding that the pipeline could apply its Storm Event Surcharge to certain shippers with negotiated rate letter agreements because those agreements encompass every surcharge that is applicable to the maximum rates for service, without limitation. FERC said that, if it were the intent of the parties to limit the "applicable surcharges" to those in effect on the date they executed the agreement, they could have added language expressing such intent. "But, they did not." *High Island Offshore System L.L.C.*, 145 FERC ¶61,155 (2013).

   FERC has held that pipelines cannot rely on a *Memphis* clause (see ¶492 — Contract Interpretation and Modification) to modify rates specifically agreed to in a negotiated rate agreement. *See, e.g., Bay Gas Storage Co.*, 131 FERC ¶61,034 (2010). Here, however, the only discount provided in the negotiated rate agreement is the discount of the pipeline's base transportation rate. Clearly, the *Memphis* clause does not permit the pipeline to increase the base transportation rate under the negotiated rate agreement above the agreed upon rate. However, the agreement "does not provide for any other discounts." Such an interpretation "does not render the negotiated rate letter agreement meaningless. The negotiated rate continues to prevent [the pipeline] from charging [the shipper] a base transportation rate greater than [the agreed upon rate]." *High Island Offshore System L.L.C.*, 145 FERC ¶61,155 (2013).

   Unlike *Bay Gas*, this is not a situation where the pipeline is shifting an ordinary, recurring cost formerly included in the base rate, such as the lost and unaccounted for gas at issue in *Bay Gas*, to a separate surcharge and trying to add that recurring cost to the previously agreed-upon discounted base rate. Here, [the pipeline] has proposed a new rate mechanism which it will use solely to recover new, extraordinary one-time costs it may incur in the future to repair damage to its pipeline caused by future significant storm events." Because the negotiated rate agreement contained no express agreement to discount surcharges, FERC ruled that the pipeline could apply the Storm Event Surcharge to the negotiated rate shipper. *High Island Offshore System L.L.C.*, 145 FERC ¶61,155 (2013).

   Adding a surcharge found to be just and reasonable by FERC and permitted by the negotiated rate agreement, "does not violate our negotiated rate policy." *High Island Offshore System L.L.C.*, 145 FERC ¶61,155 (2013).

**Storm surcharges**. FERC found that the costs related to bracing modifications to offshore platforms required by government regulations were not eligible for recovery in the pipeline's storm surcharge pursuant to its tariff. The costs were not incurred "to repair damage and/or recover system operations related to a Storm," as required by the tariff. FERC ordered the pipeline to reduce its Storm Surcharge Deferred Cost Account accordingly. FERC clarified that its ruling is without prejudice to the pipeline seeking to recover the costs through tariff revisions or as part of a general rate proceeding. *Dauphin Island Gathering Partners*, 147 FERC ¶61,250 (2014).

   Over the objections of shippers, FERC accepted the pipeline's proposal to raise its storm surcharge from $ 0.03/ Dth to $ 0.08/Dth, and the storm surcharge cap from $ 0.03/ Dth to $ 0.10/Dth. FERC "does not prescribe any particular cap or amortization period for tracking mechanisms to recover storm costs. As a result, the Commission has found a wide range of proposed caps and amortization periods for hurricane or storm surcharges to be just and reasonable." While there could be circumstances in which the level of a storm cost recovery surcharge "may be so high as to cause shippers significant financial hardship thus requiring a longer amortization period or other relief, the Commission found [in *Sea Robin Pipeline Co. LLC*, 143 FERC ¶61,129 (2013) ( *Sea Robin*)] that simply comparing the level of the surcharge to the level of the pipeline's existing maximum rates is insufficient to show such financial hardship." The shippers made no argument that a surcharge up to the level of the proposed cap will cause them significant financial hardship beyond comparing the level of the cap to the level of the pipeline's maximum rates, a contention FERC found unpersuasive in *Sea Robin*. Accordingly, FERC found the proposal to increase the storm surcharge cap just and reasonable. *Dauphin Island Gathering Partners*, 162 FERC ¶61,273 (2018).

**Modernization cost surcharges I**. FERC issued a policy statement explaining that, effective Oct. 1, 2015, it will allow "interstate natural gas pipelines to seek to recover certain capital expenditures made to modernize system infrastructure through a surcharge mechanism, subject to conditions intended to ensure that the resulting rates are just and reasonable and protect natural gas consumers from excessive costs." Pipelines have to satisfy five standards in order to establish trackers or surcharges to recover certain costs associated with replacing old and inefficient compressors and leak-prone pipelines and performing other infrastructure improvements and upgrades to enhance the efficient and safe operation of their pipelines.

   The five standards for acceptable modernization cost surcharges are (1) the pipeline's base rates must have been recently reviewed in a general rate case, a cost and revenue study, or through a collaborative effort with shippers; (2) the eligible costs must be limited to one-time capital costs incurred to modify the existing system to comply with safety or environmental regulations or other federal or state government agencies, or other capital costs shown to be necessary for the safe, reliable, and/or efficient operation of the pipeline, and the pipeline must specifically identify each projects' costs or capital investment to be recovered; (3) avoidance of cost shifting by designing the surcharge so that it will protect captive customers from cost shifts if the pipeline loses shippers or must offer increased discounts to retain business; (4) periodic review of the surcharge and base rates; and (5) the pipeline works collaboratively with shippers to seek their support for the proposal.

*Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶61,047 (2015).

**Modernization cost surcharges II**. FERC denied a request to clarify the policy statement on modernization cost recovery mechanisms, 151 FERC ¶61,047 (2015). The requested clarifications are antithetical to the policy statement's flexible approach to such mechanisms, FERC said. Among other things, FERC declined to spell out in more detail what types of data pipelines should submit to demonstrate that their existing rates, to which the surcharges would be added, are just and reasonable. As FERC explained in the policy statement, the "type of rate review necessary to determine whether a pipeline's existing rates are just and reasonable is likely to vary from pipeline to pipeline ... therefore, we remain open to considering alternative approaches for a pipeline to justify its existing rates." FERC encourages pipelines to engage in a full exchange of information with their customers. "If that process fails to satisfy interested parties that existing base rates are no higher than a just and reasonable level, then the Commission will establish procedures to resolve any disputed issue of fact raised in the parties' protests to the filing based upon substantial evidence on the record."

   FERC also found no reason to clarify that if a pipeline has over-collected through a surcharge or tracker, such that its rates are later found to be unjust and unreasonable after a protest or complaint proceeding, the pipeline must pay refunds calculated from the date a protest or complaint was filed. FERC noted that, if it is unable to determine whether a proposed tracker or surcharge is just and reasonable within 30 days of its filing, it will suspend the filing, which will remain subject to refund until the Commission makes the determination. Once approved, the mechanism's required true-up provision will ensure that the pipeline only recovers eligible costs approved for recovery.

   FERC declined to state that replacement shippers in existing capacity release agreements are responsible for modernization costs. Section 284.8(f) "provides that, unless otherwise agreed by the pipeline, the contract of the releasing shipper will remain in full force and effect during the release, with the net proceeds from any release to a replacement shipper credited to the releasing shipper's reservation charge. Therefore, to the extent the releasing shipper's service agreement permits the pipeline to recover the surcharge from the releasing shipper, the releasing shipper would remain liable for the surcharge during the term of any temporary release. The replacement shipper's liability for the surcharge would turn on the terms of its release. If the release requires the replacement shipper to pay any portion of the surcharge, those payments would be credited to the releasing shipper." FERC concluded that the issue of cost responsibility for modernization costs during the term of a capacity release "is a contractual issue between the relevant parties, and that issue cannot be resolved on a generic basis."

*Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 152 FERC ¶61,046, *denying clarification of* 151 FERC ¶61,047 (2015).

**Modernization cost surcharges III**. "The Commission has consistently approved tracker mechanisms to recover pipeline safety and environmental costs in the context of uncontested settlements, including before issuance of the *Policy Statement* on modernization costs [(151 FERC ¶61,047 (2015))]. Moreover, the *Policy Statement* emphasized that the Commission 'continues to favor settlements' and that the *Policy Statement* would 'provide pipelines and their customers wide latitude to reach agreements' on methods to recover pipeline safety and environmental costs. Thus, the Commission did not intend the *Policy Statement* to restrict the ability of parties to reach uncontested settlements concerning tracker mechanisms for the recovery of these costs that do not strictly conform to the guidelines in the Commission's *Policy Statement* on modernization costs." *Alliance Pipeline L.P.*, 157 FERC ¶61,204 (2016).

**Preferred rate cases**. FERC reversed its decision not to set for hearing the applicant's "preferred case," contained in *pro forma* tariff records, filed with its "primary case," contained in actual tariff records. FERC "has permitted natural gas pipelines, as part of a general section 4 rate case filing, to propose prospective changes to their existing cost allocation and rate design methodologies that will only take effect if and when the Commission finds the proposed changes to be just and reasonable. Pipelines set forth these proposals in *pro forma* tariff records which illustrate how such a proposal would be implemented if the Commission approves the proposal and allows it to be implemented in actual tariff records." FERC explained that allowing pipelines to propose prospective changes in cost allocation and rate design in *pro forma* tariff records "permits a pipeline to make such a proposal without taking the risk that it will under-recover its cost of service if the Commission ultimately rejects the proposal." This procedure also benefits shippers "because they will not be subject to the cost shifts that result from the rate design changes unless and until the Commission finds those changes to be just and reasonable." *ANR Pipeline Co.*, 155 FERC ¶61,217 (2016).

   Pipelines proposing prospective changes in their rate designs "must, of course, comply with all the requirements of Part 154 of our regulations concerning the materials that must be filed in support of any rate change proposal." *ANR Pipeline Co.*, 155 FERC ¶61,217 (2016).

**Suspension of proposed rates**. FERC granted rehearing of an order that inadvertently suspended proposed rate decreases for the maximum five-month period allowed by the Natural Gas Act (NGA). In Order No. 582-A, 74 FERC ¶61,224 (1996), "the Commission stated that it would generally accept rate decreases without suspension, so that no motion to put the rate into effect would be required and the rate decrease could take effect immediately. Moreover, in *Northeast Energy Associates, et al., v. FERC* ( *Northeast Energy*), [158 F.3d 150 (D.C. Cir. 1998),] the United States Court of Appeals for the District of Columbia Circuit reversed a Commission order suspending a proposed rate decrease under certain incremental rate schedules for five months. The court held that the five-month suspension was contrary to the Commission's general policy of assuring prompt implementation of rate decreases." *Texas Eastern Transmission LP*, 167 FERC ¶61,177 (2019).

   Upon further review, "the Commission recognizes that its policy of accepting proposed rate decreases without suspension applies in these circumstances. Accordingly, [the applicant's] proposed rate decreases ... are accepted to become effective January 1, 2019 ... In order to correct its error of suspending the rate decreases, the Commission has the equitable authority to put the parties where they would have been had the Commission not initially acted in error. If the Commission had accepted [the applicant's] proposed rate reductions without suspension, they would have taken effect on January 1, 2019, rather than being suspended until June 1, 2019. Therefore, the Commission directs [the applicant] to refund to any affected shippers the difference between the rates actually charged and the lower rates [it] proposed, with interest between January 1, 2019, and the date refunds are made in accordance with [18 C.F.R. §154.501]." *Texas Eastern Transmission LP*, 167 FERC ¶61,177 (2019).

   FERC denied rehearing of its decision to accept a pipeline's proposed rate decreases without suspension, but suspending its proposed rate increases for five months. "The Commission has broad discretion to determine the length of the suspension period. The Commission's ordinary practice is to accept rate decreases without suspension in order to ensure that the rate decrease goes into effect as soon as possible." *Trailblazer Pipeline Co. LLC*, 168 FERC ¶61,005 (2019).

   In *Transcontinental Gas Pipe Line LLC*, 140 FERC ¶61,251 (2012) ( *Transco*), and *Northeast Energy Assocs. v. FERC*, 158 F.3d 150 (D.C. Cir. 1998) ( *Northeast Energy Associates*), "the Commission either accepted, without suspension, proposed rates that included overall rate decreases for separate services, or was reversed on appeal for not doing so in circumstances that are similar to those present here. Here, the Commission determined that the Expansion System tariff records and the Existing System tariff records propose rates for 'separate services subject to separate rate schedules.' [The applicant] does not rebut this determination, but instead echoes its earlier reliance on *Tennessee* [ *Gas Pipeline Co.*, 133 FERC ¶61,266 (2010) ( *Tennessee*),] arguing that there are changes to the 'components of the cost of service allocated among all services' and that some components have increased while others have decreased by a lesser amount, so all changes should be reflected in rates at the same time. The Commission rejected this argument in the [underlying] Order, and we again find it unpersuasive. Unlike [the applicant's] proposal in the instant proceeding, in *Tennessee* the pipeline did not propose an overall rate decrease for any service; rather, it proposed a substantial increase in the non-fuel rates for all services." *Trailblazer Pipeline Co. LLC*, 168 FERC ¶61,005 (2019).

   As with the pipeline in *Northeast Energy Associates*, the applicant "has proposed an increase to its overall cost of service, but has proposed decreases to other, incremental rates (i.e., for the Expansion System). Furthermore, the proposed decreases for the Expansion System are also due to the costs of service for the relevant facilities having decreased, not because of a proposed reallocation of costs among services or a change in rate design, as [the applicant] contends. Accordingly, because [the applicant's] proposed tariff records for the Expansion System and the Existing System involve separate services subject to separate rate schedules, the [underlying] Order appropriately directed [the applicant] to implement the decreased rates on the Expansion System without suspension." *Trailblazer Pipeline Co. LLC*, 168 FERC ¶61,005 (2019).

   The Commission noted that "where the pipeline proposes a rate decrease for a service, the Commission cannot order refunds, and no point would be served by a rate suspension [( *Transcon. Gas Pipe Line Co., LLC*, 140 FERC ¶ 61,251 at ¶ 30 (2012))]. Accordingly, the Commission's ordinary practice is to accept rate decreases without suspension in order to assure that the rate decrease goes into effect as soon as possible [( *Filing & Reporting Requirements for Interstate Nat. Gas Co. Rate Schedules & Tariffs*, Order No. 582-A, FERC Stats. & Regs. ¶ 31,034, at 31,562 (1996) (cross-referenced at 74 FERC ¶ 61,224))]." *Eastern Gas Transmission and Storage, Inc.*, 177 FERC P 61,064 (2021).

   FERC found "that one of Texas Eastern's Rate Schedules contains rate decreases. Consistent with Commission policy, we accept the rate reductions proposed in Rate Schedule FT-1 for this incremental rate project to be effective November 1, 2021, without suspension, and set the rate reductions for hearing along with the remainder of Texas Eastern's rate case. ... Pursuant to NGA section 4(e), the Commission may only require pipelines to order refunds of proposed rate increases above the level of the pipeline's prior rates. ... Because the tariff record for Rate Schedule FT-1 also contains rate increases that are being suspended, along with the accepted rate decreases, we will accept and suspend the filed version of the tariff record for Rate Schedule FT-1, to be effective April 1, 2022, subject to condition, refund and hearing." *Texas Eastern Transmission, LP*, 177 FERC ¶ 61,065 (2021).

   The Commission granted "Texas Eastern's request for clarification and [found] that NGA section 16 provides authority for the Commission's decision to suspend Texas Eastern's rate filing in the January 2022 Rehearing Order [( *Tex. E. Transmission, LP*, 178 FERC ¶ 61,024 (2022) (January 2022 Rehearing Order))]. In *Xcel Energy Services* [(815 F.3d 947)], the court held specifically that the Commission had the authority, in acting on a rehearing request, to suspend a filing it had failed to suspend in the initial order [( *Id.* at 954-55)]. The court relied on FPA section 309 (the equivalent of NGA section 16) finding that provision 'vests the Commission with broad remedial authority' and 'unquestionably gives [the Commission] the authority, in fashioning remedies, to consider equitable principles, one of which is to regard as being done that which should have been done,' and that such authority includes directing a rate suspension when acting on rehearing [( *Id.* at 954-55)]." *Texas Eastern Transmission, LP*, 179 FERC ¶ 61,120 (2022).

   Additionally, "[t]he Commission acknowledged in the January 2022 Rehearing Order that its decision to reject the entire July 2021 Rate Case Filing in the August 2021 Order 'arguably represents a departure from Commission precedent and practice [( *Tex. E. Transmission, LP*, 176 FERC ¶ 61,138 at ¶ 27 (2021) (August 2021 Order)].' The Commission was therefore authorized to undo what was wrongfully done in the August 2021 Order and fashion a remedy that would put Texas Eastern in the same place as if the error had not occurred. ... Because we have granted Texas Eastern's requested clarification, we dismiss Texas Eastern's alternative request for rehearing as moot. As a result, we do not reach Texas Eastern's claims that the August 2021 Order was *ultra vires* and thus *void ab initio*. However, we note that Texas Eastern's rates did not, as it asserts, take effect by operation of law on September 1, 2021." *Texas Eastern Transmission, LP*, 179 FERC P 61,120 (2022).

   FERC noted that "Northern motioned '...to place the Base Case Tariff sheets into effect at the expiration of any suspension period set by the Commission, provided the Base Case Tariff sheets are approved as filed and without condition.' The Commission's regulations at 18 C.F.R. § 154.7(a)(9) (2021) provide two options regarding the filing of a motion to place suspended rates into effect pursuant to NGA section 4(e). In the case of a minimal suspension, the pipeline may include in its filing a motion to: (1) place the proposed rates into effect at the end of the suspension period; or (2) reserve the right to file a later motion. Northern includes with its filing a motion to place the proposed tariff provisions into effect at the end of any suspension period. Pursuant to 18 C.F.R. § 154.7(a)(9), such a motion only applies to minimal suspensions and cannot apply to five-month suspensions. Thus, the motion included in Northern's filing is ineffective for purposes of moving the proposed tariff records into effect at the end of the suspension period. If and when Northern decides to move the suspended tariff records into effect, it must do so consistent with 18 C.F.R. § 154.206(a) (2021) [( *Am. Midstream (AlaTenn), LLC*, 149 FERC ¶ 61,123, at ¶ 30 (2014))]." *Northern Natural Gas Company*, 180 FERC P 61,066 (2022).

**Concurrent NGA section 4 & 5 cases**. If FERC "issues an order pursuant to NGA section 5 fixing a new just and reasonable rate before the natural gas pipeline moves its newly proposed rates into effect under NGA section 4, then the rate established in the section 5 proceeding will be the refund floor for the section 4 proceeding." However, in this consolidated proceeding, the procedural schedule prevents FERC from issuing a merits decision in the NGA section 5 investigation before the suspension period ends in the pipeline's section 4 proceeding, when the pipeline is free to move its proposed NGA section 4 rates into effect. On rehearing, parties argued that, after the pipeline moves the section 4 rates into effect, FERC should retain the authority under section 5 to reset the refund floor for the section 4 proceeding prospectively from the date FERC acts in the section 5 case. FERC rejected this argument and denied rehearing. *Panhandle Eastern Pipe Line Co. LP and Southwest Gas Storage Co.*, 171 FERC ¶61,244 (2020).

   FERC explained that this argument is "contrary to NGA section 4(e). NGA section 4(e) provides that, after a pipeline moves a proposed rate increase into effect subject to refund, the Commission may require the pipeline 'to keep accurate accounts in detail of all amounts received by reason of such increase,' and that the Commission may order refunds of 'the portion of such increased rates or charges by its decision found not justified.' The courts have interpreted this provision as limiting the Commission's NGA refund authority to rate increases above the pre-existing lawful rate, holding that 'the pre-existing lawful rate provides a refund floor in a section 4 proceeding.' Here, the pre-existing lawful rate is the rate effective before the end of the suspension period.... Subsequent Commission action in the Section 5 Proceeding after [the end of the suspension period] cannot reduce the refund floor." *Panhandle Eastern Pipe Line Co. LP and Southwest Gas Storage Co.*, 171 FERC ¶61,244 (2020).

   Although the pipeline's rates in effect at the time of its NGA section 4 filing and subsequent motion to move the proposed rates into effect are subject to an investigation under NGA section 5, they remain the pipeline's "lawful rates," because any FERC action under NGA section 5 must be prospective only. "Moreover, once [the pipeline] moves its NGA section 4 proposed rates into effect, it is entitled to charge those rates subject to refund until such time as the Commission makes a ruling on the merits in the NGA section 4 rate case. Therefore, ... the Commission could not, based on a record developed separately in [the pipeline's] NGA Section 5 Proceeding, 'determine the just and reasonable rate ... to be thereafter observed and in force' pursuant to NGA section 5(a)." *Panhandle Eastern Pipe Line Co. LP and Southwest Gas Storage Co.*, 171 FERC ¶61,244 (2020).

   FERC rejected the argument that, if the section 5 proceeding rates do not reset the refund floor, a pipeline filing an NGA section 4 rate case could effectively nullify any NGA section 5 investigation. "The Commission has recognized that, by filing a new rate case under NGA section 4 after a section 5 rate investigation has commenced, a pipeline can delay a merits resolution of the investigation into its rates. However, this does not constitute a 'nullification' of the NGA section 5 rate investigation. The Commission and the parties continue to have the authority in the NGA section 4 proceeding to seek a rate reduction under NGA section 5, if the record justifies such a rate reduction." *Panhandle Eastern Pipe Line Co. LP and Southwest Gas Storage Co.*, 171 FERC ¶61,244 (2020).

   FERC said it lacks the statutory authority under NGA section 5 to reset the refund floor for the section 4 proceeding prospectively from the date it acts in the section 5 proceeding, and explained that it "is bound by the NGA's structure, which includes limiting factors such as: the lack of refund and suspension authority under NGA section 5, a pipeline's ability to file an NGA section 4 rate case at the pipeline's chosen time, and the limit of a suspension period for new NGA section 4 rates to a maximum of five months, among other things. We further note that this statutory framework limits the Commission's redress regarding refunds pursuant to the Tax Cuts and Jobs Act. However, the Commission maintains control over the timing of the issuance of its orders, particularly the NGA section 4 and 5 proceedings that do not have statutory deadlines, and may direct changes to procedural schedules to ensure the timely issuance of such orders." *Panhandle Eastern Pipe Line Co. LP and Southwest Gas Storage Co.*, 171 FERC ¶61,244 (2020).

   FERC defended the consolidation of the pipeline's section 4 and section 5 rate cases. "Consolidation will provide the most efficient and effective forum to handle issues common to both proceedings, while reducing administrative burden for the Commission and the participants. For example, because the test periods for the NGA Section 4 and 5 Proceedings overlap, the record for the Section 5 Proceeding is also applicable to the Section 4 Proceeding. Consolidation will allow for the orderly development of the record without duplication of prepared testimonies, exhibits, data requests, pleadings, briefs, and other materials. Similarly, consolidation will also result in substantial time and cost savings for the participants, who will no longer have to reproduce the same information for a separate proceeding, perhaps thereby permitting more time for settlement discussions." *Panhandle Eastern Pipe Line Co. LP and Southwest Gas Storage Co.*, 171 FERC ¶61,244 (2020).

**Modernization cost surcharges IV**. The presiding ALJ noted that "[n]o participant disputes the NCUC's assertion that the Settlement does not meet one of the standards that the Modernization Policy Statement says that modernization cost tracking mechanisms must meet to obtain Commission approval. However, that fact does not justify rejection or modification of the Settlement. ... The purpose served by the criteria set forth in the Modernization Policy Statement is to protect the pipeline's ratepayers from excessive modernization costs. The parties may invoke the pipeline's failure to satisfy one or more of these criteria to protect themselves against such excesses." *Columbia Gas Transmission, LLC*, 177 FERC ¶ 63,025 (2021) (J. Coffman).

**Proposed rate reductions**. "For the reasons explained below, we do not agree that we were required to proceed under NGA section 5, that we have required EGTS to take anything other than a ministerial action, or that the Hearing Order was otherwise erroneous. ... Requiring EGTS to implement the full rate reductions for the seven rate schedules, including the reduction in usage charge, falls within the Commission's authority under NGA section 4," and "accepting EGTS' November Compliance Filing without correction would have resulted in its customers being charged rates that are higher than the rates EGTS proposed in the Rate Case Filing, to the detriment of the public, and different from its preexisting rates." *Eastern Gas Transmission and Storage, Inc.*, 179 FERC ¶ 61,095 (2022).

**Section 4 rate case filing and reporting requirements**. Previously, "[i]n the [Notice of Proposed Rulemaking (NOPR)], the Commission proposed to require natural gas pipelines to submit all statements, schedules and workpapers in native format with formulas and links intact when filing a general NGA section 4 rate case. As the Commission explained in the NOPR, requiring all statements, schedules and workpapers to be filed in native format will reconcile any ambiguity in the current requirements [( *Revised Filing & Reporting Requirements for Interstate Nat. Gas Co. Rate Schedules & Tariffs*, 179 FERC ¶ 61,114, at ¶ 6 (2022) (NOPR))]. Moreover, the Commission explained that this requirement would address the information gap that currently exists because, when a pipeline submits a section 4 rate case filing the Commission often cannot verify whether there were underlying links used to develop a spreadsheet or whether a pipeline severed those links before filing its rate case [( *Id.*)]. ... The Commission also stated that submitting all statements, schedules and workpapers in native format will provide for a timely and comprehensive analysis of a rate case filing [( *Id.* ¶ 7)]. ... Finally, the Commission stated that the current policy on this issue is outdated because information technology has significantly improved since the issuance of Order No. 582 in 1995, and pipelines now routinely develop rate cases using Microsoft Excel and submit them electronically [( *Id.* P 8)]." Accordingly, the Commission adopted "the proposal set forth in the NOPR to require natural gas pipelines to submit all supporting statements, schedules and workpapers in native format with all links and formulas included when filing an NGA section 4 rate case." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC P 61,121 (2022).

   The Commission disagreed "with Energy Transfer's argument that the NOPR proposal which we adopt in this final rule is unjust and unreasonable. First, we find that this final rule does not unreasonably shift litigation costs from intervenors to the pipeline. ... This final rule merely requires pipelines to provide intact links and formulas in the workpapers and schedules that must be included in the case in chief [(18 CFR 154.312 to 154.314 (2021))]. This final rule does not require pipelines to fund the litigation costs of other participants. ... Finally, we deny BHE GT&S's request for clarification that a natural gas pipeline is not required to create links across statements and schedules where they did not already exist. Rather, this final rule *does* require natural gas pipelines to create links and formulas to show the pipeline's progressive calculations in the supporting statements, schedules and workpapers." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC ¶ 61,121 (2022).

   The Commission disagreed "with Energy Transfer's contention that an information gap does not exist. A rate model without formulas and links intact is much less useful to rate case participants who are trying to evaluate a natural gas pipeline's rate design, cost allocations, or rate calculations. When a pipeline files a rate model without formulas and links, rate case participants must recreate the natural gas pipeline's model, which is inefficient and duplicative. ... Moreover, under this final rule, rate case participants can begin evaluating a natural gas pipeline's rate design, cost allocations, and rate calculations immediately in the comment period after a pipeline files a section 4 rate case and thus file better-informed comments. Furthermore, requiring pipelines to file all statements and schedules with formulas and links intact will enable all rate case participants to evaluate the filing and any settlement offers from the same baseline, as opposed to all rate case participants creating their own rate models." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC ¶ 61,121 (2022).

   The Commission declined "to adopt Joint Commenters' requested clarification. A filer may request confidential treatment, and the Commission will evaluate such requests on a case-by-case basis. In such cases, the data sets and spreadsheets should be submitted in both privileged, unredacted form and in public, redacted form, pursuant to 18 CFR 388.112 [( *see* Order No. 582, FERC Stats. & Regs. ¶ 31,025, at 31,435, Order No. 703, 121 FERC ¶ 61,171 at ¶ 26)]. As Joint Commenters note, however, the information in a rate model is generally already public information and pipelines seeking confidential treatment will have the burden of proof that confidential treatment is warranted." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC ¶ 61,121 (2022).

   The Commission affirmed "that the final rule's requirement that rate models be filed with 'formulas and links intact' applies to statements, schedules, and workpapers filed in the same rate case and not to formulas contained in or links to spreadsheets not required as part of the initial filing. However, we clarify that to the extent a natural gas pipeline creates a workpaper to create a statement or schedule required by § 154.312 of the Commission's regulations (e.g., an allocation workpaper that informs the I Schedules), the pipeline must file that workpaper with formulas and links intact, as that workpaper is essential to understanding the rate model's inputs and calculations." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC ¶ 61,121 (2022).

   The Commission additionally granted "the request to clarify that Statements O and ¶ do not contain links within the statement or to other statements or schedules, and therefore may continue to be filed in any manner consistent with the FERC Implementation Guide for these statements. We also affirm that this final rule does not expand the information that pipelines must submit when initiating an NGA section 4 general rate case but clarifies the format requirements with which such information must comply." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC ¶ 61,121 (2022).

   FERC stated that "[t]he NOPR did not propose to require rate case participants to provide supporting statements, schedules and workpapers in native format during NGA section 5 proceedings as suggested by BHE GT&S. We decline to apply the final rule to NGA section 5 complaint cases, as they are outside the scope of this proceeding. The final rule applies solely to natural gas pipelines filing general NGA section 4 rate cases. Moreover, we decline to require all rate case participants to a general NGA section 4 rate case to comply with the final rule." *Order No. 884: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 181 FERC ¶ 61,121 (2022).

   FERC noted "that WBI's statements, schedules and workpapers were not submitted in native file format, consistent with Order No. 884 [( *Revised Filing & Reporting Requirements for Interstate Nat. Gas Co. Rate Schedules & Tariffs*, Order No. 884, 181 FERC ¶ 61,121 (2022))]. As set forth in Order No. 884, the Commission requires natural gas pipelines to submit all supporting statements, schedules and workpapers in native format (e.g., Microsoft Excel) with all links and formulas included when filing an NGA section 4 rate case. Therefore, we direct WBI to refile its statements, schedules and workpapers in native format with formulas and links, consistent with Order No. 884 within 10 days of the issuance of this order." *WBI Energy Transmission, Inc.*, 182 FERC ¶ 61,136 (2023).

   The Commission was "unpersuaded by Joint Requesters' Request for Rehearing and continue to find that the Commission need not adopt a presumption that native format files, with formulas intact, of publicly filed material should be publicly available. In Order No. 884, the Commission stated that 'the information in a rate model is generally already public information and pipelines seeking confidential treatment will have the burden of proof that confidential treatment is warranted [(Order No. 884, 181 FERC ¶ 61,121 at ¶ 24)].' We do not agree that a blanket finding that embedded links and formulas in publicly filed statements are public information is warranted at this time." *Order No. 884-A: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 182 FERC ¶ 61,144 (2023).

   The Commission denied "Joint Requesters' request for clarification regarding the scope of what is required to be filed pursuant to Order No. 884. While Order No. 884 specifically requires that workpapers created to create a statement or schedule required by 18 C.F.R. § 154.312 (2022) of the Commission's regulations must be filed with formulas and links intact, as that workpaper is essential to understanding the rate model's inputs and calculations, we decline to broaden the scope of Order No. 884 to require any information beyond what Part 154, subpart D requires [(Order No. 884, 181 FERC ¶ 61,121 at ¶¶ 27-28)]. Section 154.314 of the Commission's regulations applies to other support for a filing, including workpapers [(18 C.F.R. § 154.314 (2022))]. Pursuant to Order No. 884, natural gas pipelines are now responsible for identifying and submitting those data with links and formulas included. Any additional information participants believe that would help them to better evaluate a rate case can be sought through the discovery process." *Order No. 884-A: Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, 182 FERC ¶ 61,144 (2023).

**Superseded tariff records**. "Consistent with *Northern* [( *N. Nat. Gas Co.*, 170 FERC ¶ 61,058 (2020) ( *Northern*); *see also Nw. Pipeline Corp.*, 78 FERC ¶ 61,317, at 62,357 (1997))], we acknowledge Northern's right, upon 30-days' notice, to terminate the effectiveness of the Interim Rates. However, Northern will need to make a tariff filing to place the superseded tariff records into effect. A superseded tariff record cannot be automatically reactivated as an effective tariff record. Consequently, if Northern wishes to place its superseded tariff records into effect, Northern must file tariff records as required by section 154.7 of the Commission's regulations to supersede the currently effective tariff records [(18 C.F.R. § 154.7 (2021))]." *Northern Natural Gas Company*, 182 FERC ¶ 61,032 (2023).

Indicates new or revised material.

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