# **Nat. Gas Trans. Info. Serv. ¶613**

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

**¶613 Setting Rates for New Facilities**

**1999 policy statement**. In 1999, the Commission issued a policy statement that replaced the presumption in favor of rolled-in pricing for major pipeline expansions (allowing recovery of construction costs from existing customers) with a preference for incremental pricing in which construction costs are recovered only from customers benefiting from the new project.

   Once a certificate application is filed, the Commission will consider whether the project can proceed without subsidies from the applicant's existing customers. If the Commission concludes that a proposed construction project cannot be built without subsidies from existing customers, it will deny the application.

   Although application of the 1999 policy statement will usually mean that proposed projects will be incrementally priced, there are cases where rolled in pricing will be permitted. For example, rolled-in pricing might be appropriate if the proposed project is an inexpensive expansion made possible by earlier, costly construction. This is because incremental pricing would result in the new customers receiving a subsidy from the existing customers; the new customers would not face the full cost of the construction that makes their new service possible. Another situation in which rolled-in pricing is appropriate is when the new project is designed to improve existing service for existing customers by replacing existing capacity, improving reliability or providing flexibility. Increasing the rates of existing customers to pay for these improvements is not a subsidy.

   The fact that a pipeline must be prepared to financially support a project without relying on subsidization from its existing customers does not mean that the pipeline has to bear all the financial risk of the project. The risk can be shared with the new customers in preconstruction contracts, but it cannot be shifted to existing customers. For new pipeline companies, without existing customers, this requirement will have no application.

   By leaving the pipeline responsible for the costs of underutilized capacity and cost overruns, the 1999 policy obviates the need for the "at-risk" condition that the Commission used to impose on pipelines failing to demonstrate sufficient demand.

   The 1999 policy statement applies to major construction projects, but not to projects built pursuant to Part 157 blanket certificates. Pending a final rule that would remove the optional expedited certificate regulations, the 1999 policy statement applies to new applications for optional certificates. If the record shows that under the policy statement analysis, the adverse effects of the proposed project outweigh the benefits, then the presumption that the proposed new service is or will be required by the present or future public convenience and necessity will be deemed to have been rebutted, and the optional certificate will not be issued.

*Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy*, 88 FERC ¶61,227 (1999), *clarified*, 90 FERC ¶61,128 (2000).

**Cross references**. *See* ¶604 for pricing policies applicable to the construction of facilities for the purpose of providing NGPA section 311 transportation.

*See* ¶606 for a discussion of the pricing policies applicable to projects constructed pursuant to blanket certificates.

*See* ¶607 for the pricing policies applicable to projects constructed under optional expedited certificates.

*See* ¶608 for a discussion of the criteria the Commission uses to certify major construction projects under the 1999 policy statement and for related precedent.

**One-part v. two-part rates**. The Commission ordered Iroquois to modify its initial rate proposal. "Commission policy under Order No. 636 dictates that pipelines cannot discount their rates below the mini[m]um rate. In proposing a one-part rate ... and failing to charge a commodity charge, Iroquois is, in essence, assessing a rate that is below its mini[m]um rate. As such, the proposed rate allows the [expansion] shippers to receive the rights, responsibilities, and access of a Part 284 shipper without having to pay at leas[t] the minimum required rate. In order to receive such service, Iroquois must charge its expansion shippers the full ... rate, including both the demand and the commodity charge. Therefore, we will require that Iroquois revise its rates and charge a two-part rate, including the commodity charge."

*Iroquois Gas Transmission System L.P.*, 100 FERC ¶61,275 (2002).

**Changed requirements**. "Trans-Union seeks to change the billing determinants for its initial rate calculation because its largest shipper, Union Power, requires less gas than originally planned. The Commission will not approve that request. ... [T]he Commission's policy regarding construction of pipeline facilities is that the rates should be based on the actual capacity of the facilities. ... It appears that Union Power will make the same monthly payment to Trans-Union as originally agreed, which has the effect of increasing Union Power's unit cost for capacity. This is an appropriate agreement between the pipeline and its shipper as to the allocation of costs. We note that it has always been contemplated that Union Power, an affiliate of Trans-Union, would underwrite the costs of the pipeline. However, the recourse rate available to the third-party shippers should be a cost-based, fully allocated rate based on the capacity of the system. ... Trans-Union appropriately proposes initial rates based on the capacity of the system."

*Trans-Union Interstate Pipeline L.P.*, 104 FERC ¶61,315 (2003).

**$ 0.0000 commodity recourse rates**. "In setting the commodity recourse rate, Cheyenne Plains proposes $ 0.0000 since unit variable costs are $ 0.0008. This rate reflects variable costs (such as lubricants and desiccants) which make up approximately $ 150,000 of the total annual cost of service ($ 73.8 million). Cheyenne Plains rounded the rate to zero because assessment of the charge could result in administrative costs greater than the rate. ... Commission policy under Order No. 636 dictates that pipelines cannot discount their rate below the minimum rate. Failing to set the commodity rate essentially assesses a rate below its minimum rate. As such, the proposed rate allows any future shippers on Cheyenne Plains' system to receive the rights of a Part 284 shipper without having to pay at least the minimum required rate. Because all of Cheyenne Plains' contracts are at a fixed negotiated reservation rate with no commodity charge for at least the next ten years, there is no administrative burden. Although not an issue on Cheyenne Plains' system initially, we direct Cheyenne Plains to revise its tariff to reflect the appropriate commodity rate consistent with Commission policy."

*Colorado Interstate Gas Co. and Cheyenne Plains Gas Pipeline Co.*, 105 FERC ¶61,095 (2003).

**Calculation of ROE**. Petal sought rehearing of an order rejecting its request for a rate of return (ROE) on equity of 15 percent.

*Use of parent's cost of equity*. "Petal proposes to use the 15 percent cost of equity determined by reference to its parent, El Paso Energy, because it is publicly traded, engaged in the natural gas transmission business, and owner of Petal. ... Petal presented a [discounted cash flow (DCF)] cost of equity calculation (for its parent) deriving a 16.73 percent ROE for El Paso Energy to support its proposed 15 percent ROE. ... Petal's parent is engaged in many non-pipeline operations and Petal has not demonstrated that its risks are similar to the risks of its parent."

*Reference to electric utilities*. The Commission also rejected Petal's reliance on an electricity rate case to support the use of its parent's cost of equity in part because there are significant differences between the natural gas industry and the electric utility industry. "Moreover, the Commission's long-standing policy is to derive the cost of equity by use of a proxy group to set a range of reasonable returns for gas pipelines. This is because most gas pipelines are wholly-owned subsidiaries and their common stock is not publicly traded. We find this approach appropriate here."

   "However, we will grant rehearing of the ... Order's use of the 11-company proxy group, including some electric utilities, for purposes of setting Petal's [ROE]. ... [I]n *Williston Basin*, [104 FERC ¶61,036 (2003)], the Commission recognized that changing conditions in the natural gas industry have resulted in few companies qualifying for use in the proxy group under the standards set forth in [ *Transco*, 84 FERC ¶61,084 (1994)]. The Commission accordingly adopted a proxy group based on companies listed among the Value Line group of diversified natural gas companies that own FERC-regulated natural gas pipelines. Among other things, *Williston Basin* found no need at this time, for inclusion of electric utilities in the proxy group used to establish ROE for a natural gas pipeline. ... In establishing an ROE for Petal, we find it appropriate to rely on ... *Williston Basin*. In *Williston Basin*, the Commission performed a DCF analysis using the nine companies comprising the proxy group based on the new criteria. The result of that analysis was a range of equity returns from a low of 9.82 percent to a high of 13.76 percent, and approving a 12.48 percent ROE at the median of the range."

*Use of Williston Basin's proxy group*. "[W]e conduct our risk analysis with the presumption that existing pipelines fall into a broad range of average risk, absent highly unusual circumstances that indicate anomalously high or low risk as compared to other pipelines. In this case, Petal has not made a sufficient showing that it is outside the broad range of average risk. Petal is not a new entrant to the gas business, rather it is an existing jurisdictional corporate entity engaged in providing jurisdictional storage services. Constructing a new pipeline to transport gas from the Petal storage facilities to Southern's pipeline interconnection is simply an expansion of its existing jurisdictional business. Moreover, Petal proposed financing the pipeline internally through its parent ... using a 50/50 debt/equity capitalization. A review of the average capital structure of the proxy group used in *Williston Basin* shows it is comparable to Petal's capital structure, *i.e.*, 50/50 debt/equity capitalization. Under these circumstances, we find that Petal has average business and financial risks, and overall is an average risk pipeline."

   "[W]e deny rehearing of the risk analysis we used for placing Petal within the zone of reasonableness. Consequently, we will approve the use of a 12.48 percent ROE using the median return in *Williston Basin* for Petal."

*Petal Gas Storage L.L.C.*, 106 FERC ¶61,325 (2004).

**Calculation of ROE II**. *Proxy group*. In determining the rate of return on equity, the ALJ rejected the use of a proxy group proposed by the pipeline. The pipeline proposed to include four pipeline master limited partnerships (MLPs) in the proxy group. The Commission approved the ALJ's decision. "The Commission's decision in *SFPP*, [86 FERC ¶61,022 (1999)], to employ MLPs as a comparison group is limited to ***oil*** pipelines as there no longer existed sufficient companies in that industry to provide a satisfactory reference group, so that the only entities in the ***oil*** pipeline business that could be included in the proxy group were MLPs. By contrast, here, there are pipeline's involved in the interstate natural gas pipeline business which can be issued in the proxy group. Also, in *SFPP*, the issue of whether the dividend amounts used were comparable to corporate dividends was not raised."

   The pipeline also objected to the ALJ's inclusion of local distribution companies (LDCs) in the proxy group. The Commission rejected the pipeline's objections. "The companies that the ALJ included in the proxy group are all companies listed in the Value Line Group of diversified natural gas companies whose business includes FERC-regulated natural gas pipelines. Thus, the companies are not solely in the distribution business. In *Williston*, the Commission approved the use of a proxy group with the same diversified natural gas companies as in the proxy group adopted by the ALJ. We agree that each of these gas companies in the proxy group also have significant distribution functions but that does not disqualify their inclusion in a pipeline oriented proxy group. As emphasized by the ALJ, because of changes in the natural gas industry, gas companies can no longer be classified as pure transmission or pure distribution companies, and thus, the proxy companies reflect characteristics of both. While not pure transmission companies as is [applicant], these diversified gas companies are the best available proxies on the current record on which to base the DCF analysis.

*Capital structure*. "The Commission prefers to use a capital structure of real entities that obtain financing for the pipeline, the pipeline itself or a company associated with the pipeline, such as its parent. However, the Commission may use a hypothetical capital structure if the capital structure of the entity obtaining the financing is anomalous. The Commission has recently stated that the 'anomalies include circumstances where either (a) the capital structure of the financing entity is not representative of the regulated pipeline's risk profile, or (b) the capital structure is different from the capital structure approved for other pipelines, or if a DCF analysis is performed, outside the range of the proxy group used in the DCF analysis.' [ *Enbridge Pipelines (KPC)*, 109 FERC ¶61,042 (2004).] ... [W]e find that [the applicant's parent's] capital structure may be found to be anomalous on the ground that it is not representative of the pipeline's risk profile. ... [S]uch a finding may be justified where there is evidence that the parent issued its debt in order to finance non-pipeline activities that have risks different from the pipeline's risks." Because the parent's bond rating was below investment grade, and because the parent provides no debt capital to applicant, the Commission affirmed the ALJ's finding that the parent's capital structure is not representative of the pipeline's risk profile. The Commission approved the use of a hypothetical capital structure based on the average equity ratio of the proxy group.

*High Island Offshore System L.L.C.*, 110 FERC ¶61,043 (2005).

**Calculation of ROE III**. On Aug. 7, 2007, the U.S. Court of Appeals for the District of Columbia Circuit remanded to FERC the *Petal Gas Storage L.L.C.* and *High Island Offshore System L.L.C.* proceedings regarding the issue of the proper composition of proxy groups. The court held that FERC had not shown that the proxy group arrangements it approved in the two cases were risk-appropriate. Recognizing that its policy on proxy groups needed to change in light of the fact that the number of eligible companies that could be included in proxy groups was shrinking, FERC issued a new policy statement (see below) allowing the inclusion of master limited partnerships in proxy groups. As a consequence, FERC established settlement procedures in the two remanded proceedings and said that if the parties were unable to reach a settlement, it would establish additional procedures to address the proxy group issues consistent with the policy statement.

*Petal Gas Storage L.L.C.*, 123 FERC ¶61,059 (2008); *High Island Offshore System L.L.C.*, 123 FERC ¶61,058 (2008).

**Policy statement on proxy groups**. On April 17, 2008, FERC issued a new policy statement on the composition of proxy groups used for determining the return on equity (ROE) for natural gas and ***oil*** pipelines. FERC concluded that: (1) master limited partnerships (MLPs) should be included in the ROE proxy group for both ***oil*** and gas pipelines; (2) there should be no cap on the level of distributions included in the Commission's current discounted cash flow (DCF) methodology; (3) the Institutional Brokers Estimated System (IBES) forecasts should remain the basis for the short-term growth forecast used in the DCF calculation; (4) there should be an adjustment to the long-term growth rate used to calculate the equity cost of capital for an MLP; and (5) there should be no modification to the current respective two-thirds and one-third weightings of the short- and long-term growth factors. In addition, FERC said it will not explore other methods for determining a pipeline's equity cost of capital at this time. "The Commission also concludes that this Policy Statement should govern all gas and ***oil*** rate proceedings involving the establishment of ROE that are now pending before the Commission, whether at hearing or in a decisional phase at the Commission."

*Composition of Proxy Groups for Determining Gas and* ***Oil*** *Pipeline Return on Equity*, 123 FERC ¶61,048 (2008).

**Calculation of ROE and 2008 policy statement I**. FERC rejected a contested settlement filed by ***Kern*** River Gas Transmission Co. (***Kern*** River) after finding that the settlement's 12.50 percent return on equity (ROE) was excessive and would result in unjust and unreasonable rates. This was the first ROE finding by FERC since issuance of the 2008 policy statement on proxy groups allowing the inclusion of master limited partnerships (MLPs) in proxy groups (see above). Based on the record, FERC found that the ROEs of the two companies and three MLPs selected for the proxy group yield a range of reasonable returns of 8.80 percent to 13 percent, with a median ROE of 11.55 percent. FERC ordered ***Kern*** River to submit a compliance filing using a 11.55 percent ROE.

***Kern*** *River Gas Transmission Co.*, 126 FERC ¶61,034 (2009).

**Calculation of ROE and 2008 policy statement II**. Parties argued on rehearing that ***Kern*** River's ROE should be set at less than the median of reasonable returns because it has a lower than average risk. FERC denied rehearing. "The Commission has consistently held that it will not find that a firm has risk outside the broad range of average in which most pipelines fall, unless a party presents a very persuasive case to the contrary. ... ***Kern*** River's relative strength reflects its prudent expansion and low rates and it should not be penalized for its accomplishments by having its ROE lowered below the median of the proxy group."

***Kern*** *River Gas Transmission Co.*, 129 FERC ¶61,240 (2009).

 **2020 ROE policy statement**. On May 21, 2020, FERC issued a policy statement revising its policy for determining natural gas and ***oil*** pipeline returns on equity (ROEs). "Under this revised policy, we will (1) determine ROE by averaging the results of [Discounted Cash Flow (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).

   See Gas Trans. Info. Serv. ¶501 Nat. Gas Trans. Info. Serv. ¶501 — Cost-based Rates for more information on this policy statement, ROEs and proxy groups.

**Spur facilities**. FERC approved rolled-in rates for firm and interruptible transportation services on Bay Gas's facilities under section 311 of the NGPA. Bay Gas sought rehearing, arguing that FERC incorrectly calculated the rolled-in rates. "Bay Gas states that [FERC] failed to use the rolled-in billing determinants provided by Bay Gas in its ... filing to design rates. Bay Gas contends that, instead, [FERC] combined certain ... data responses for the original facilities ... with certain other ... data responses for ... spur facilities, which resulted in billing determinants greatly in excess of system capacity, contrary to Commission precedent. Use of the billing determinants in the ... data responses would double count [the] spur facilities capacity, according to Bay Gas. ... The Commission agrees with Bay Gas's arguments in its rehearing request that rolled-in rates for the facilities should be calculated using billing determinants proposed in Bay Gas's original ... petition and not its ... data response. ... The ... spur facilities extend the length of the system, but do not increase the total capacity of the existing system. ... These re-calculated rolled-in rates are higher than non-rolled-in maximum rates for service on the original facilities. ... Consequently, Bay Gas's adjusted billing determinants require that the Commission reverse its decision to approve a rolled-in approach for Bay Gas's original system and ... spur facilities. ... This rate increase would require service on the original facilities potentially to subsidize the ... spur expansion shippers. ... Because the rolled-in rates will exceed the maximum rates applicable to service on the original facilities, we find these rates not to be fair and equitable."

*Bay Gas Storage Co. Ltd.*, 113 FERC ¶61,140 (2005).

**Theoretical vs. contractual capacity**. FERC ordered a pipeline to base its rates upon theoretical pipeline capacity instead of firm contractual commitments. The pipeline contended on rehearing that FERC "generally requires pipelines to use their total physical capacity in determining their rates to guard against possible cost overrecovery or the over-sizing of facilities, but has employed a more flexible approach where, as here, that policy concern is not implicated. The fact that ... the Commission is requiring [the pipeline] to submit a rate filing after three years of actual operation to justify its recourse rates will serve as an appropriate vehicle for the Commission to determine if there has been cost overrecovery. [The pipeline] also agrees to credit any additional revenues from interruptible service to firm shippers. ... Upon further consideration, we agree ... that the circumstances of this case warrant a departure from the Commission's general policy of requiring a pipeline to base its rates on actual capacity. Because there are physical limitations to ... transporting more than [the contractual commitments] for a sustained period, there is little likelihood of overrecovery of the pipeline's costs. We are also persuaded that other protections against overrecovery of costs are in place. ... In view of these safeguards against cost overrecovery, the Commission concludes that it is appropriate to grant rehearing and permit [the pipeline] to design its [firm] reservation rate based on the actual firm capacity that it has subscribed to its shipper, and is permitted to design its [interruptible] rates as a 100 percent load factor derivative of such firm rate."

*Weaver's Cove Energy LLC and Mill River Pipeline LLC*, 114 FERC ¶61,058 (2006).

**Spur facilities II**. FERC denied Bay Gas's request for rehearing and reaffirmed its prior holdings that rolling in the costs of the spur facilities would increase the maximum rate applicable to service on the original facilities, and that the spur facilities do not provide sufficient benefits to justify roll-in.

   "First, rolling in the costs of the ... spur facilities would increase the maximum rate applicable to the original facilities, regardless of whether the rate impact comparison is made with or without a discount adjustment. ... [U]nder either scenario, ... a rate increase results from a roll-in that would require shippers on the original facilities potentially to subsidize the ... spur expansion shippers."

   Bay Gas argued that roll-in does not change either the current contract discounted rates or services for any shipper on the original facilities and that, therefore, the no-subsidy requirement is met. FERC rejected this argument. "The 1999 Pricing Policy Statement clarifies that a shipper with an expiring contract 'could be required to match a bid up to a maximum rate higher than the historic maximum rate applicable to its capacity in certain limited circumstances. ... Application of this approach could lead to rates for shippers ... that are higher than their existing vintaged rate. But this will occur only if the preconditions are met — the pipeline is full and there is a competing bid higher than the pre-expansion rate so that a higher rate is needed to allocate available capacity — and the Commission has accepted the pipeline's mechanism for determining rates as just and reasonable.' However, under Bay Gas's rolled-in rate proposal, it could require its existing shippers to pay a rolled-in rate upon expiration of their current contracts, regardless of whether the preconditions in the 1999 Pricing Policy Statement are met. Moreover, Bay Gas has proposed no tariff mechanism 'for reallocating costs between the historic and incremental rates so all rates remain within the pipeline's cost-of-service,' as required by the policy statement."

   FERC rejected claims that the rolled-in rate proposal is beneficial to shippers on the system. The minor savings in reduced regulatory commission expense is negligible to system shippers and does not justify roll-in. Furthermore, there "appears to be no reason why Bay Gas should incur more expenses filing a petition using an incremental rate design as opposed to one using a rolled-in rate design." Also, access to additional gas supplies and flexibility cannot be considered a benefit for those shippers in light of the fact that Bay Gas will not permit those shippers to use the spur facilities under their existing contracts.

*Bay Gas Storage Co. Ltd.*, 115 FERC ¶61,049 (2006).

**Spur facilities III**. FERC denied Bay Gas's second request for rehearing. "Since the discount adjustment would exist regardless of whether the ... spur facilities costs are rolled-in, the Commission finds that the rate impact of the roll-in should be determined by comparing the maximum non-rolled-in rate for the ... spur facilities designed with discounted-adjusted rate design volumes, with a rolled-in rate also designed with discount adjusted rate design volumes. Bay Gas suggests that this is somehow improper, because 'comparing greater levels of roll-in costs ... with lesser levels of no-roll-in costs,' while using discount adjusted rate design volumes to calculate both rolled-in rates and non-rolled-in rates, 'meant only that the latter, letter, no roll-in costs resulted in lower rates. ... Roll-in costs were greater, making roll-in rates always higher, by definition.' But that is just our point. If rolling in the higher costs of an expansion, along with using any additional rate design volumes resulting from the expansion, increases the per unit maximum rate for service on the pre-expansion system, that rate increase is caused by the roll-in and would require service on the pre-expansion system to subsidize service on the expansion system. ... This conclusion is not altered by the fact discounted rate transactions on the pre-expansion reduce the rate design volumes associated with service on the pre-expansion system."

*Bay Gas Storage Co. Ltd.*, 116 FERC ¶61,216 (2006).

**Foundation shippers**. "All firm shippers executing precedent agreements for service on [the expansion] have elected to pay negotiated reservation rates. ... [T]he negotiated rate and other contractual terms are dependent on whether the shipper qualifies as a Foundation Shipper, Anchor Shipper or Standard Shipper. [Applicant] seeks approval of the conduct of its open season that led to the execution of the precedent agreements, the rates and contractual terms offered, and certain non-conforming provisions in the precedent agreements. While the Commission usually does not review negotiated rate agreements in the context of a certificate application, we will do so here given the size of the project and the associated financial commitments required. ... [W]e find that the conduct of the open season was consistent with the Commission's open-season policies."

   FERC also approved applicant's rate and contractual offerings that are based on a shipper's status as a Foundation Shipper, Anchor Shipper or Standard Shipper. "Here, [applicant] has explained that it offered rates and contractual incentives to secure adequate support for the project. [Applicant] held a transparent open season where the rate and contractual incentives offered were clearly defined. Qualification for these incentives was based on a shipper's commitment to the project which was set forth in each shipper's executed precedent agreement and therefore publicly verifiable. Additionally, all potential shippers had an opportunity to become Foundation Shippers or Anchor Shippers. Under these circumstances, we find that the negotiated rates and contractual terms offered to Foundation Shippers and Anchor Shippers are not unduly discriminatory."

*Rockies Express Pipeline LLC*, 116 FERC ¶61,272 (2006).

**Incremental plus pricing rejected I**. Several factors "lead us to a finding that the proposed expansion ... will be integrated and operated as part of [applicant's] existing pipeline system. ... Expansion shippers will be able to use ... existing facilities on a secondary basis, and existing shippers will be permitted to use the expansion facilities on a secondary basis. In addition, ... [applicant] is proposing to install ... compression at [a station] located upstream of the ... expansion project in order to provide pressure maintenance for gas coming into the project from other pipelines. ... Three ... expansion project shippers ... will have to use [existing] facilities to transport their gas supplies to the ... expansion project. ... [T]he Commission has not permitted incremental plus pricing under similar circumstances [(see *Gulf South Pipeline Co. L.P.*, 119 FERC ¶61,281 (2007))], and we will therefore require [applicant] to modify its proposal. ... [W]e will reject [the] proposal to charge incremental rates as initial rates for services using the expansion capacity and require [it] to use its generally applicable firm and interruptible system rates as initial recourse rates for service on the expansion facilities."

*Gulf South Pipeline Co. LP and Destin Pipeline Co. L.L.C.*, 120 FERC ¶61,291 (2007), *aff'd*, 122 FERC ¶61,162 (2008).

**Incremental plus pricing rejected II**. The pipeline's compliance filing "continues to propose incremental plus pricing. For each of the firm rate schedules, [the pipeline] has added tariff language that states, 'The above charges shall be increased to include an incremental transportation charge of [a certain amount] for utilization of the ... expansion facilities.' Under this pricing methodology, existing shippers that use the ... expansion facilities on a secondary basis will be charged the incremental rate in addition to their existing rates. This pricing methodology was rejected by the Commission in the certificate and rehearing orders and [the pipeline] is ordered to revise it. [The] revised tariff sheets should clearly state that the approved incremental rate applies to those customers contracting for capacity on the ... expansion project. In addition, the revised tariff sheets should not require that existing shippers with primary rights in Zone 3 pay the incremental rate in addition to their current rate when using the ... expansion facilities on a secondary basis."

*Gulf South Pipeline Co. LP*, 123 FERC ¶61,322 (2008).

**Incremental plus pricing rejected III**. FERC denied rehearing of *Gulf South Pipeline Co. LP*, 163 FERC ¶61,124 (2018), which rejected a proposal to establish a separate, incremental recourse reservation rate and usage charge for service on the authorized expansion project. "We affirm the Certificate Order's determination that Gulf South's 'incremental plus' pricing proposal is not appropriate because the Westlake Expansion Project will be integrated and operated as part of Gulf South's existing Lake Charles Zone facilities." The Westlake Expansion Project "is integrated with the Lake Charles Zone facilities because the components of the expansion project are divided by, and rely upon, the existing mainline. The presence of the Westlake Compressor Station and further pressurization of the gas does not change the fact that the project is integrated because it receives gas on the existing Lake Charles Zone facilities." *Gulf South Pipeline Co. LP*, 166 FERC ¶61,089 (2019).

   FERC found that "an existing shipper's ability to access the incremental capacity at a lower rate on a secondary basis in no way hinders the pipeline's ability to recover its costs. The Commission's secondary point policy, which allows existing shippers on the pipeline system to access other points within the zone for which they are paying reservation charges, when capacity is available, reflects the fact that these shippers are paying for the underlying facilities under which the pipeline is providing service, such as Gulf South's existing Index 198-3 facilities through which the incremental service is provided." *Gulf South Pipeline Co. LP*, 166 FERC ¶61,089 (2019).

**Incremental plus pricing approved**. In *Gulf South Pipeline Co., LP v. FERC*, 955 F.3d 1001 (D.C. Cir. 2020), the court vacated and remanded parts of *Gulf South Pipeline Co. LP*, 163 FERC ¶61,124 (2018). The court found FERC's rejection of the proposed incremental-plus rates arbitrary and capricious. "Under FERC's order, materially identical shippers will pay dramatically different rates for the use of the same facilities. FERC failed to justify that disparity, and its decision violated fundamental rate-making principles — namely, that rates should generally reflect the burdens imposed and benefits drawn by a given shipper. We therefore vacate the part of FERC's order denying incremental-plus rates and remand for further proceedings consistent with this opinion." On remand, FERC reversed its decision and granted Gulf South's request to charge rates on an incremental-plus basis for all shippers accessing the expansion facilities. *Gulf South Pipeline Co. LP*, 172 FERC ¶61,192 (2020).

   After considering the court's opinion, FERC found that incremental-plus rates are appropriate for the Westlake Expansion Project despite the project's integration with the existing system "because Gulf South will be able to track which shippers are using expansion facilities.... As explained by the D.C. Circuit, permitting incremental-plus rates in this instance is supported by the principle of cost causation, which holds that rates should 'reflect "burdens imposed or the benefits drawn by" the given shipper.' Without an incremental-plus rate structure, [the expansion shipper] would pay $ 0.1325 per Dth to use the expansion facilities whereas existing shippers within the Lake Charles Zone using the same facilities would only pay their existing Lake Charles Zone rate of $ 0.03 per Dth. However, with incremental-plus rates for the expansion project, [the expansion shipper] and existing shippers will pay the same rate to use the expansion facilities. Though it can be appropriate to deviate from the principle of cost-causation, there is no reason to do so here, and the Commission agrees that existing Lake Charles Zone shippers should pay the incremental rate to access the expansion facilities." *Gulf South Pipeline Co. LP*, 172 FERC ¶61,192 (2020).

**Amendments to proposed rates**. A pipeline asked for authorization to revise the initial recourse rates for its previously approved expansion project to reflect the increased estimated cost of materials and labor. "The Commission accepts [the] revised proposed maximum rates. ... The instant amendment does not change the benefits of the project or result in any adverse impacts. Transco has executed a binding agreement ... for 100 percent of the firm transportation service under the project. The recourse rates are incremental rates. Thus, the project amendment does not affect the Commission's prior finding of no subsidization or conclusion that the project is in the public convenience and necessity." *Transcontinental Gas Pipe Line Corp.*, 121 FERC ¶61,083 (2007).

   FERC granted a pipeline's request to amend its initial rates to reflect an overall increase in the cost of construction of the certificated facilities. The certificate order, as conditioned, found that the pipeline's proposal was consistent with the criteria in the 1999 Certificate Policy Statement and was in the public convenience and necessity. The "proposed amendment does not alter this finding." FERC said it "has repeatedly recognized its ability to change initial rates when, as here, the pipeline seeks to adjust initial rates prior to newly authorized facilities being placed into service to account for updated estimates and actual construction costs. Accordingly, we reject the argument [from protestors] that [the pipeline] should have filed for rehearing to amend its proposed rates." In addition, FERC explained that the pipeline's amendment request constitutes a new proceeding. Therefore, approval is not barred by the fact that the project certificate and rehearing orders are pending judicial review. *Algonquin Gas Transmission LLC*, 157 FERC ¶61,011 (2016).

**Access charges vs. incremental rates**. The Commission rejected a proposal to recover the costs of an upgrade through a separate access charge and ordered the pipeline to charge incremental firm transportation rates to recover those costs. According to FERC, the upgrade would add transportation capacity, not simply create access to the pipeline's system. FERC denied the pipeline's request for rehearing, but granted its request for clarification that it is not required to offer firm transportation to expansion shippers. FERC will allow the pipeline to offer only incremental interruptible transportation (IT) service that will apply to the additional capacity. In addition, the pipeline may enter into negotiated rate IT agreements for transportation service on the additional capacity.

*Dominion Transmission Inc.*, 121 FERC ¶61,164 (2007).

**Cost allocation for new vs. expansion projects**. While applicant "must use the actual system capacity in designing its rate, we find that [applicant] does not need to allocate a portion of the ... expansion project cost of service to interruptible service. [Applicant] did not propose in its application to allocate any costs to interruptible transportation. It later allocated $ 8 million to interruptible service in response to [a] ... Commission data request suggesting that [applicant] must allocate costs to interruptible service or credit interruptible revenues to [firm transportation] shippers. While it is Commission policy to require one of these options for new pipelines, the Commission does not require this for expansions of existing systems, such as [applicant's], which have already addressed the allocation issue in a previous rate case. Under these circumstances, the Commission will not require [applicant] to remove these costs from its cost of service in designing its firm transportation rates and will include the $ 8 million in its revised rate calculations."

*Gulf South Pipeline Co. LP and Destin Pipeline Co. L.L.C.*, 122 FERC ¶61,162 (2008).

**Incremental rates for expansions**. For mainline expansion facilities, FERC permits pipelines to charge an incremental rate for service utilizing such facilities if that rate is higher than the generally applicable firm transportation rate. FERC found "that the appropriate firm incremental daily rate for the ... expansion project would be higher than [applicant's] existing Part 284 ... rate. ... Accordingly, under these circumstances, ... an incremental [firm transportation] rate for the ... expansion project is appropriate for firm service on the expansion facilities. Consistent with Commission precedent, we will require [applicant] to utilize its existing system-wide [interruptible transportation] rate for interruptible services."

*Gulf South Pipeline Co. LP and Destin Pipeline Co. L.L.C.*, 122 FERC ¶61,162 (2008).

   Regarding the Evangeline Pass Project, FERC stated that it "has determined that, in general, where a pipeline proposes to charge incremental rates for new construction, the pipeline satisfies the threshold requirement that the project will not be subsidized by existing shippers. Tennessee Gas demonstrates that the illustrative incremental rate for the Evangeline Pass Project is lower than the existing system rates. Accordingly, we find that Tennessee Gas's proposal to charge its existing applicable system reservation rates as the initial recourse rates for the project will not result in existing customers subsidizing the Evangeline Pass Project and we accept the proposed rates." *Tennessee Gas Pipeline Company, L.L.C. and Southern Natural Gas Company, L.L.C.*, 178 FERC ¶ 61,199 (2022).

   The Commission "reviewed Tennessee Gas's proposed cost of service and initial rates and find that they reasonably reflect current Commission policy. Under the 1999 Certificate Policy Statement, there is a presumption that incremental rates should be charged for proposed expansion transportation service if the incremental rate calculated to recover the costs of such service exceeds the maximum system recourse rate [( *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 at 61,745 (1999))]. ... Because the currently effective maximum Rate Schedule FT-A recourse reservation and usage charges are greater than the illustrative incremental reservation and usage charges, we will approve Tennessee Gas's request to use its existing rates under Rate Schedule FT-A as the initial recourse rates for project service. We also approve Tennessee Gas's proposal to use its existing interruptible rate under Rate Schedule IT." *Tennessee Gas Pipeline Company, L.L.C. and Southern Natural Gas Company, L.L.C.*, 178 FERC ¶ 61,199 (2022). *See also Columbia Gulf Transmission, LLC*, 178 FERC ¶ 61,198 (2022).

   "In designing rates for incremental expansions, the Commission has stated that the incremental rate should only include the incremental costs associated with the new facilities [( *Transcontinental Gas Pipe Line Co., LLC*, 169 FERC ¶ 61,051, at P 45 (2019)]." FERC acknowledged that it "has previously allowed for the inclusion of increased A&G costs in incremental rates." In *Paiute Pipeline Co.*, 153 FERC ¶ 61,292 (2015), the Commission "found that Paiute would indeed experience an incremental cost associated with the additional common A&G expenses to be allocated from its parent, and thus allowed Paiute to include that increase in costs in its rates. ... Only costs that a pipeline has demonstrated it will actually incur should be included in its rates. Here, Iroquois has failed to persuasively show that it will actually incur an additional $ 3,701,209 of A&G costs as a result of its Enhancement by Compression Project. Therefore, Iroquois is directed to remove all A&G costs from its incremental rate calculations." *Iroquois Gas Transmission System, L.P.*, 178 FERC ¶ 61,200 (2022).

**Costs of nonjurisdictional extensions**. FERC authorized the applicant to construct a 41.4-mile lateral to serve one customer and an additional 10.78 miles of nonjurisdictional extension lines that will be transferred to the customer before service commences. A party argued on rehearing that FERC erred in permitting the applicant to include the costs of the extension lines in the initial incremental negotiated and recourse rates that it will charge for service on the lateral. FERC granted rehearing and ordered the costs of the extension lines to be removed from the recourse rates, but not from the negotiated rates.

   FERC said that it recognizes "that in prior instances where the Commission has made recovery of contributions in the aid of construction subject to scrutiny in a future rate case, the pipelines intended to charge their existing system-wide rates for the relevant services until a future rate case in which they would propose to include the contributions in aid of construction in their rate bases. Here, ... the construction costs associated with the non-jurisdictional facilities would be included in [the applicant's] incremental recourse rate as soon as service commences on the ... lateral. We further note that [the customer] has not subscribed the full capacity of the ... lateral until the second five-year period of operation. Thus, it is possible that a shipper other than [the customer] seeking to acquire available capacity on this incrementally-priced line would be required to pay for facilities that are not owned and operated by [the applicant] and that would not benefit such shipper."

   FERC did not require the removal of the costs from the negotiated rates "because these rates were freely negotiated under the Commission's negotiated rate program."

*Kinder Morgan Interstate Gas Transmission LLC*, 124 FERC ¶61,024 (2008).

**Rates on merged pipelines**. Missouri Interstate Gas LLC (Missouri Interstate), Missouri Gas Co. LLC (Missouri Gas) and Missouri Pipeline Co. LLC (Missouri Pipeline) (collectively, MoGas) proposed to merge into a new interstate natural gas company, MoGas Pipeline LLC. MoGas proposed that Zone 1 would comprise the facilities that had previously been owned and operated by Missouri Pipeline and Missouri Interstate, and Zone 2 would comprise the facilities previously owned and operated by Missouri Gas. FERC approved this approach in its certificate order, but on rehearing, the Commission found that MoGas had designed its Zone 1 firm rate using only the contracted capacity of Missouri Pipeline and had not included any billing determinants for Missouri Interstate. Because of this omission, "Missouri Pipeline's former customers that do not subscribe to service over the former Missouri Interstate facilities would subsidize those customers who do take such service. ... [A]lthough the Certificate Policy Statement [does] not strictly apply to the applicants' merger proposal, its prohibition against existing customers' subsidizing other customers should guide the Commission's determination of whether the proposal ... [is] in the public interest. Accordingly, to avoid any subsidization by Missouri Pipeline's existing customers, the Commission required MoGas either to include the billing determinants for Missouri Interstate in the calculation of its Zone 1 rates or to create a separate, third rate zone for service over the Missouri Interstate facilities. ... The Commission will deny MoGas' request for rehearing on the issue of the Zone 1 billing determinants."

*Missouri Interstate Gas LLC, et al.*, 127 FERC ¶61,011 (2009).

**Two options for setting rates**. FERC granted a pipeline's request for a predetermination that rolling the costs and fuel associated with its 2010 expansion into those of its 2003 expansion for transportation rate and fuel reimbursement purposes in its next rate case is appropriate. However, FERC ruled that the 2010 expansion shippers should also pay any lower, "step-down" rates afforded to 2003 expansion shippers.

   FERC granted rehearing of this ruling. "Traditionally, in setting initial rates for services to be provided by new facilities in certificate proceedings, the Commission has authorized natural gas pipelines to charge either a proposed new incremental rate based on the costs of providing the new service, or an existing cost-based rate which [the] Commission has already approved as just and reasonable for a similar service provided by the pipeline. In this case, [the pipeline] ... chose the latter avenue of charging an existing just and reasonable rate as a proxy rate for the 2010 expansion service, i.e., the existing rates on file for its 2003 expansion service. ... [We] granted that request and, recognizing that the rates applicable to the 2003 expansion shippers were due to 'step-down' in the near term, required that the rates assessed the 2010 expansion shippers 'step-down' at the same time. However, on rehearing, we are persuaded that the near-term 'step down' in rates applicable to the 2003 expansion shippers is contract-specific and applicable only to the 2003 expansion shippers, as determined in [previous orders]. Therefore, we will grant [the pipeline's] request that it be authorized to charge as an initial rate for the 2010 expansion service the 'pre-step-down' rates currently applicable to the 2003 expansion shippers."

***Kern*** *River Gas Transmission Co.*, 128 FERC ¶61,024 (2009).

**Base period calculation**. A protestor argued that the base period used by the pipeline violates FERC's regulations. FERC disagreed. "The Commission's regulations do not require that the pipeline operate as in interstate pipeline during the base period. [The applicant], operating as a new entity, appropriately used the 12 months of its most recently available actual experience. In addition, a review of [the applicant's] rate schedules indicate that the [two] months in question ... reported lower operating costs than the 10 succeeding months. Therefore, if [the applicant] had waited until it had 12 months of actual interstate operating experience, [its] section 4 filing may have resulted in rates higher than what it has proposed."

*MoGas Pipeline LLC*, 128 FERC ¶61,101 (2009).

**Recourse rates**. A new pipeline used 95 percent of the predicted total sustainable average capacity of its pipeline to design its firm rates. For the commodity rate calculation, it used commodity units which are the demand units annualized at 90 percent load factor. The recourse rates for interruptible services were derivative of the firm transportation rate. "The Commission's policy is that the recourse rate should be a cost-based, fully allocated rate based on the capacity of the system. [ *See Trans-Union Interstate Pipeline L.P.*, 104 FERC ¶61,315 (2003).] [The pipeline's] proposal is not consistent with our policy of setting reservation rates based on 100 percent load factor equivalent of the reservation rates. We will therefore require [the pipeline] to revise its recourse rates accordingly."

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

**Return on equity; capital structure**. For its new pipeline, Ruby Pipeline L.L.C. (Ruby) proposed a capital structure of 40 percent equity and 60 percent debt and a 14 percent return on equity (ROE). "Ruby declares it has reviewed the returns the Commission has granted in other major construction projects and new pipeline development, with emphasis on the indicated basis differential between the costs of long-term debt and the costs of equity. Ruby contends that the proposed 14 percent return is a conservative request for its project, given what it describes as a currently uncertain and difficult capital market environment. ... We find Ruby's proposed return on equity and capital structure are reasonable for a new pipeline company and are consistent with our orders in other proceedings. [ *See, e.g., Mid-Atlantic Express LLC*, 126 FERC ¶61,019 (2009); *MarkWest Pioneer L.L.C.*, 125 FERC ¶61,165 (2008); *Ingleside Energy Center LLC*, 112 FERC ¶61,101 (2005).] In *MarkWest*, we approved a 14 percent ROE, but required that the project sponsor design its cost-based rates on a capital structure with at least 50 percent debt. Ruby's proposed 14 percent ROE and proposed capital structure of 40 percent equity and 60 percent debt is in line with our recent orders." *Ruby Pipeline L.L.C.*, 128 FERC ¶61,224 (2009), *order amending certificate*, 136 FERC ¶61,054 (2011) ("Because Ruby will not have at least 50 percent debt under its realized financing, Ruby proposes to use an imputed capital structure of 50 percent debt and 50 percent equity to determine its pre-tax and after-tax returns included in its rates. We find that the use of an imputed capital structure of 50 percent debt and 50 percent equity is consistent with *MarkWest*.").

   FERC "has generally approved higher rates of return on equity for greenfield projects to reflect the higher risks associated with such a project. With respect to developing incremental rates for expansions of existing pipeline systems, our general policy is to use the rate of return components approved in the pipeline's last NGA section 4 general rate proceeding. ... Although [the applicant] has not filed a section 4 rate case since it went into service, we do not believe it is appropriate to use the 14 percent ROE used in [the applicant's] initial certificate application in determining the cost of service for the ... expansion, because it would not reflect the lower risks associated with expanding an existing pipeline system. Since the lateral pipeline [the applicant] is proposing has more in common with the incremental expansions constructed by existing pipelines than with greenfield pipeline projects the Commission believes it is more appropriate to use the most recent ROE approved in a litigated section 4 rate case as the ROE for designing the incremental rates for this project. This is the approach the Commission adopted in determining the ROE to be used in developing initial rates for existing facilities being acquired by a new interstate pipeline and the Commission believes it is appropriate to use in these circumstances. The last litigated ROE applicable to this situation is 12.99 percent." FERC required the applicant to use a 12.99 percent ROE. *Alliance Pipeline L.P.*, 140 FERC ¶61,212 (2012).

   FERC's "general policy in developing incremental rates is to use the rate of return and depreciation rates approved in the pipeline's last general [Natural Gas Act] section 4 rate case." In the pipeline's most recent general section 4 rate proceeding, it proposed an overall rate of return of 10.81 percent and a deprecation rate of 2.89 percent. However, FERC ultimately approved a settlement of that rate case with no approved stated rate of return and a lower approved depreciation rate of 2.18 percent. When the pipeline subsequently sought authorization for an expansion project, it proposed incremental rates using the 10.81 percent overall rate of return and 2.89 percent depreciation rate. FERC authorized the project, on condition that the pipeline refile its rates to incorporate the most recent *approved* rate of return and depreciation rate. In its compliance filing, rather than comply with this policy, the pipeline argued that it would be inappropriate to use a 20-year old rate of return, which it argued is not representative of its current market value and does not establish a just and reasonable rate for the expansion project. While it agreed to use the lower 2.18 percent depreciation rate, it insisted on using the rejected 10.81 percent rate of return instead of the 10.41 percent approved 20 years before. FERC rejected the compliance filing, after reminding the pipeline that a compliance filing "is not a vehicle for the pipeline to provide additional justification for its rejected proposal." *Gulf South Pipeline Co. LP*, 162 FERC ¶61,060 (2018).

**Timing of AFUDC I**. A pipeline argued that because FERC issued its guidance regarding the timing of interest capitalization prior to the establishment of pre-filing review of project proposals, the Commission should allow the pipeline to start the accrual period for the Allowance for Funds Used During Construction (AFUDC) when it requests the use of the pre-filing process and not when it files a certificate application. FERC denied the request based on the record in this proceeding. "AFUDC is not available for all costs necessarily incurred to bring a project to fruition. AFUDC can only be accrued on construction costs incurred on a continuous, planned, progressive basis. Preliminary survey and investigation costs, including those which may be incurred during the pre-filing process, are costs incurred prior to the commencement of construction, and therefore would not constitute construction costs eligible for the accrual of AFUDC." FERC said it intends to begin examining this issue "in the near future, through a public process."

*Florida Gas Transmission Co. LLC*, 129 FERC ¶61,150 (2009). *See also, Texas Eastern Transmission LP*, 129 FERC ¶61,151 (2009).

**Timing of AFUDC II**. FERC revised its policy regarding the timing of the accrual of Allowance for Funds Used During Construction (AFUDC) for natural gas construction projects. "[I]n light of the current landscape in the natural gas industry, the certificate application date is no longer an appropriate milestone for determining when construction project-related expenditures begin, and thus for when to begin accruing AFUDC. ... [FERC] will revise its policy and allow natural gas pipelines to begin accruing AFUDC on construction projects when the following two conditions are met: (1) capital expenditures for the project have been incurred and (2) activities that are necessary to get the construction project ready for its intended use are in progress." FERC said the term "activities" is to be construed broadly. "It includes all the actions required to prepare the construction project for its intended use. Also, it includes activities prior to physical construction, such as the development of plans or the process of obtaining permits from governmental authorities. Moreover, 'activities' include costs pursuant to Gas Plant Instruction No. 3. ... The term 'activities' does not include preliminary survey and investigation activities."

   FERC said that "construction project-related costs incurred subsequent to the pre-filing date will be eligible for AFUDC accrual, save a showing to the contrary, provided that capital expenditures have been incurred and activities are underway to get the asset ready for its intended purpose. However, the pre-filing date in and of itself is not to be construed as the date that a natural gas pipeline may begin to accrue AFUDC without applying the revised policy conditions. Furthermore, to accrue AFUDC prior or subsequent to the initiation of pre-filing, we reiterate that natural gas companies must be prepared to demonstrate that capital expenditures are being incurred and activities necessary to get the construction project ready for its intended use are in progress. Therefore, the Commission will require applicants seeking a certificate of public convenience and necessity for authorization to construct pipeline facilities to make a representation in their filing that AFUDC accruals included in the cost of the facilities are calculated in accordance with the Commission's rules and regulations and pursuant to and consistent with" the two conditions discussed above.

   Pipelines "must retain records supporting the commencement of AFUDC accruals, and such AFUDC accruals will be subject to scrutiny through Commission audit or rate review, just as any other cost would be."

*Southern Natural Gas Co.*, 130 FERC ¶61,193 (2010); *Florida Gas Transmission Co. LLC*, 130 FERC ¶61,194 (2010).

**Cost and revenue studies**. FERC noted that the proposed pipeline expansion project was "extremely large, ... the estimated cost of which is almost $ 2.5 billion. In addition, while the approval of incremental rates for the expansion service is sufficient to insure that existing customers will not subsidize the project, the fact remains that some 214,000 MMBtu per day, or 26 percent, of the capacity created by the project remains unsubscribed. The establishment of incremental recourse rates based on [the applicant's] cost estimates may not be sufficient to fully protect the interests of future shippers who take service at those rates. Therefore, the Commission will require [the applicant] to file a cost and revenue study at the end of its first three years of actual operation to justify the authorized cost-based firm recourse rates." Commissioner Spitzer dissented from the decision to impose this requirement. The fact that 26 percent of the expansion capacity is unsubscribed "does not provide a sufficient basis to require the submission of a cost and revenue study and does not reflect reasoned decision-making," Spitzer said.

*Florida Gas Transmission Co. LLC*, 129 FERC ¶61,150 (2009).

**Applicability of 1999 policy statement**. FERC reversed an ALJ's ruling that the 1999 policy statement weighs against Transco's showing that its bifurcated rate proposal is just and reasonable after determining that the policy statement is inapplicable to the facts of the proceeding. The purpose of the 1999 policy statement "was to provide the natural gas industry with guidance as to the analytical framework the Commission will use to evaluate proposals for certificating new construction. ... [It] was never intended to be used as a tool to evaluate the proper rate treatment of a preexisting facility that has not been expanded or upgraded to provide service enhancements. In this case, there was no 'construction' or 'expansion' but only the replenishment of base gas at a preexisting facility."

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

**Usage charges**. FERC granted rehearing to allow Ruby to use a projected 90 percent utilization rate for its usage charge, to recover the minimal variable costs that comprise the usage charge. "The Commission notes that it has accepted pipeline proposals to base the usage charge on billing determinants that represent a load factor of less than 100 percent of the maximum capacity, especially for initial rates for new pipeline entities such as Ruby." FERC ordered Ruby to make a filing within three years after its in-service date to either justify its existing recourse rates or to propose alternative rates. The Commission and Ruby's shippers will have an opportunity at that time to review Ruby's rates to consider the appropriate load factor for the usage charge."

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

**No Need for Higher ROE**. FERC rejected the 15 percent return on equity (ROE) proposed by ETC Tiger Pipeline LLC (ETC Tiger) for its new pipeline. "ETC Tiger asserts that lower projected overall economic growth in the United States, increased volatility in the equity markets, and lower commodity prices have led to lower unit prices — and hence, a higher cost of equity capital — for publicly traded companies. However, we see no need to provide for higher returns on equity in order to encourage new construction. Accordingly, we find that ETC Tiger has not provided sufficient justification to support a higher return on equity than the Commission has recently approved for new pipeline companies, and ETC Tiger is directed to revise its proposed cost of service to incorporate a rate of return on equity of 14.0 percent."

*ETC Tiger Pipeline LLC*, 131 FERC ¶61,010 (2010).

**Acquisition premiums**. Under FERC policy, the seller's depreciated original cost is included in the cost-of-service computations, even though the price paid by the purchaser may exceed that amount. Any cost above the depreciated original cost (or "net book value") is an "acquisition premium." FERC disallows acquisition premiums unless the purchaser demonstrates specific dollar benefits resulting directly from the sale. To qualify under the benefits exception, the benefits must be tangible, non-speculative and quantifiable in monetary terms. The burden of proof for a utility seeking to demonstrate specific dollar amounts is heavy. The D.C. Circuit said FERC's order allowing MoGas Pipeline L.L.C. (MoGas) to charge initial rates containing "acquisition premium" costs was the antithesis of reasoned decisionmaking. "There is no question that FERC did not apply the 'specific dollar benefits requirement in allowing the alleged acquisition premium from [a predecessor] to be included in the initial rates of the MoGas pipeline. Indeed, FERC did not directly evaluate the ... premium according to any of the elements of the benefits exception test." According to the court, FERC simply relied on the 2002 order approving the predecessor's initial rates. Reliance on this order "is entirely inadequate to justify the Commission's action in this case." The court remanded the issue to FERC. *Missouri Public Service Commission v. FERC*, 601 F.3d 581, 588 (D.C. Cir. 2010).

   FERC established a hearing on the matter, and the presiding ALJ issued an initial decision finding that the benefit exception test does not permit the recovery of any of the acquisition premium in rates because: the pipeline in question is being put to a new use to transport gas out of Missouri as well as into Missouri; but there are no specific dollar benefits resulting directly from the sale of the pipeline emanating from increased billing determinants, secondary rights, capacity release, or increased contract demand and throughput; and the transaction was not an "arm's-length" sale between unaffiliated parties; and the acquisition premium is greater than the cost of constructing a comparable facility to the pipeline. *Missouri Interstate Gas LLC, et al.*, 137 FERC ¶63,014 (2011) (J. Glazer).

   FERC affirmed in part and reversed in part the ALJ's initial decision. FERC "finds that MoGas can continue to include the full purchase price of certain pipeline assets in rate base because the record demonstrates that the acquisition of these facilities at more than their net book value results in substantial benefits to ratepayers." FERC said that MoGas has demonstrated specific dollar benefits associated with the acquisition of the facilities because the cost to construct comparable facilities is $ 1.4 million or more than the purchase price of the facilities. Allowing the full purchase price of the facilities in the rate base in these circumstances "provides specific benefits to MoGas's ratepayers because the approved recourse rates will be no higher, if not somewhat lower, than if the pipeline built new facilities. This ruling also provides jurisdictional companies appropriate incentives to purchase and utilize existing facilities in lieu of constructing new facilities, thereby avoiding unnecessary construction and the attendant environmental impacts." *Missouri Interstate Gas LLC, et al.*, 142 FERC ¶61,195, *reh'g denied*, 144 FERC ¶61,220 (2013).

**Rates for expansion facilities**. FERC denied rehearing of its rejection of a proposed access charge and separate interruptible transportation (IT) and fuel retainage rates for an expansion project. "By charging an access fee to its current customers for the ability to transport gas on a secondary basis to the same points on its system, the access charge shifts the cost of the [expansion] to [the pipeline's] current customers. Therefore, we find this charge at odds with the [1999 Certificate Policy Statement]. Since the expansion is integrated into the pipeline's existing systems, and since the pipeline uses only a single "zone," all Part 284 shippers have the right to secondary receipt points on the entire system, including the expansion, without incurring any additional costs. *Equitrans L.P.*, 143 FERC ¶61,108 (2013).

   FERC generally does not allow a separate IT rate for new projects, but has done so when the shippers using the new facilities would be separately identified and accounted for. *See, e.g.,* ***Kern*** *River Gas Transmission Co.*, 117 FERC ¶61,077 (2006); *Transcontinental Gas Pipe Line Corp.*, 79 FERC ¶61,286 (1997). Because Equitrans' expansion will be fully integrated with its existing facilities, it cannot specifically identify and account for shippers only using the expansion facilities. Therefore the expansion does not qualify for incremental IT rates. *Equitrans L.P.*, 143 FERC ¶61,108 (2013).

   "It is Commission policy that the use of its currently effective system fuel rate is appropriate where the incremental fuel rate is lower tha[n] the system rate." However, because the pipeline lowered its system fuel rate after FERC rejected the proposed expansion retainage rate, FERC modified the expansion fuel rate to match the new system fuel rate. *Equitrans L.P.*, 143 FERC ¶61,108 (2013).

**Initial rates subject to refund**. FERC rejected the argument that it lacks the authority to accept initial rates subject to refund. As FERC explained in *KN Energy Inc.*, 50 FERC ¶61,290 (1990), and *Black Marlin Pipeline Co.*, 48 FERC ¶61,024 (1989), "a pipeline cannot commence service until the Commission issues a certificate, finding that the service, including the initial rate, is consistent with the public interest standards in NGA section 7. The Commission's authority under NGA section 7 to establish a condition that the initial rate is subject to refund enables the Commission to permit the pipeline to start service before the Commission has completed its rate investigation." The D.C. Circuit upheld this practice in *Transcontinental Gas Pipe Line Corp. v. FERC*, 54 F.3d 893, 899 (D.C. Cir. 1995).

*Southern Natural Gas Co. L.L.C. and High Point Gas Transmission LLC*, 143 FERC ¶61,207 (2013).

**Design capacity vs. projected usage**. FERC's general policy is to calculate initial recourse rates for a new pipeline based on its engineering design capacity. "This approach ensures that a pipeline constructing facilities is placed at risk for underutilization of the facilities if it does not contract with customers for the full capacity of the pipeline. The pipeline is given an opportunity to recover its full costs if it is fully subscribed. If it does not sell the full capacity, the pipeline has the option of filing a section 4 rate proceeding to propose shifting the cost burden onto shippers." *Ruby Pipeline L.L.C.*, 131 FERC ¶61,007 (2010) (requiring the pipeline to base initial rates on 100 percent of capacity instead of the proposed 95 percent of annual average capacity).

   FERC explained that it has departed from this general policy in limited situations, such as when markets will be phased in or initial utilization will be lower because the proposed pipeline has been sized to accommodate the addition of future markets. *Ruby Pipeline L.L.C.*, 131 FERC ¶61,007 (2010).

   Another reason for departure is the existence of specific operational constraints preventing the pipeline a reasonable opportunity to recover its cost of service. " *See, e.g., East Tennessee Natural Gas LLC*, 114 FERC ¶61,122 (2006) (allowing rate to be designed using lower capacity due to an operating constraint on an upstream gathering facility limiting the amount of gas that could be transported); and *Weaver's Cove Energy LLC*, 114 FERC ¶61,058 (2006) (allowing rate to be designed at lower capacity due to a downstream constraint on Algonquin limiting take-away capacity from the [liquefied natural gas] terminal). *See also Cheniere Creole Trail*, 118 FERC ¶61,125 [(2007)] (Commission approved the use of annual usage determinants at 65 load factor in order to design the firm usage rate, not the firm reservation rate, for the new pipeline). ... Those circumstances do not exist here. Therefore, [applicant] is ordered to recalculate its firm transportation rates utilizing billing determinants based on its total system capacity." *Sonora Pipeline LLC*, 120 FERC ¶61,032 (2007).

   FERC also departed from the general policy when a pipeline proposed a 9.5-mile, 30-inch diameter mainline extension to connect its system to a new platform and to accommodate pigging of its existing offshore mainline. FERC allowed the pipeline to calculate its incremental recourse rates using billing determinants of 170,000 Dth per day based on production forecasts for volumes committed to transportation through the extension, instead of the 600,000 Dth per day based upon the physical capacity of the extension. "We will accept Discovery's assertion that it specifically used 30-inch diameter pipeline in sizing the Mainline Extension to physically accommodate system pigging needs, not primarily to enable it to meet a reasonably-anticipated demand for additional capacity." FERC also took note of the steep decline curves for similar offshore production, as well as the fact that the pipeline is not guaranteed any level of revenue recovery for the project because the service to be provided on it does not include any reservation charge. *Discovery Gas Transmission LLC*, 145 FERC ¶61,145 (2013).

   FERC found a pipeline's proposal to establish an initial incremental recourse reservation rate and an interruptible rate based on daily contract quantities of its expansion shippers "to be inconsistent with Commission policy with regard to system expansions. This is in contrast to a general NGA section 4 rate case where rates are designed based on billing determinants reflective of projected usage of the pipeline. Initial rates in a certificate proceeding or as in this case a limited section 4 rate case to implement initial certificate rates are generally designed based on the capacity of the pipeline. This approach ensures that a pipeline constructing facilities is placed at risk for underutilization of the facilities if it does not contract with customers for the full capacity of the pipeline." FERC ordered the pipeline to file a revised tariff record and workpapers reflecting rates based on its design capacity at the time of commencement of partial service. *Cameron Interstate Pipeline LLC*, 160 FERC ¶61,009 (2017).

**Frequency of AFUDC compounding**. FERC denied a request to compound allowance for funds used during construction (AFUDC) monthly rather than semiannually. The pipeline argued that monthly compounding was appropriate given that it agreed to pay interest and principal on its debt and dividends on a monthly basis. Since 1977, the Federal Power Commission and its successor, FERC, have required that compounding of AFUDC occur no more frequently than semiannually because it provides for a rate of AFUDC that is in the zone of reasonableness and a uniform standard that can be effectively implemented and administered. FERC "has denied more frequent compounding on the basis that (1) the calculated AFUDC rate exceeded the overall rate of return on operating assets; or (2) the company did not have cash outlays representative of monthly payments of interest and dividends. In addition, the Commission has denied past requests to retroactively adjust AFUDC on the part that is not offset by the overcollection of AFUDC adjusting entry." ***Kern*** *River Gas Transmission Co.*, 154 FERC ¶61,186 (2016).

   Although a pipeline may make cash outlays on a monthly basis, this does not mean that "it is entitled to compute AFUDC compounded on a monthly basis. It must follow the same rule applicable to everyone else and compute AFUDC compounded no more frequently than semiannually." The rule is one "of general application." The fact that the pipeline agreed to pay interest on a monthly basis "does not change this requirement and does not dictate a different result." Pipelines are not prevented from making interest payments more frequently, but doing so does not justify an exception to the rule. ***Kern*** *River Gas Transmission Co.*, 154 FERC ¶61,186 (2016).

   FERC denied a proposal that would allow the pipeline to later switch the frequency of AFUDC compounding because such a proposal "is not easily implemented or administered," and "would add an unnecessary complication to oversight of its actions. Because AFUDC is such an important part of ratemaking, permitting a pipeline to switch on its own terms the method it uses to compound AFUDC would require constant vigilance by the Commission to ensure proper accounting." ***Kern*** *River Gas Transmission Co.*, 154 FERC ¶61,186 (2016).

**Reserved capacity costs and revenues**. A pipeline reserved existing capacity for its proposed pipeline expansion. Protesting shippers argued that the pipeline must establish an incremental recourse rate for the project that includes the costs of the existing capacity reserved for the project. They asserted that, if the cost of that capacity is included in calculating an incremental rate for project service, the project costs will exceed the project revenues, thus mandating an incremental rate for the project. "We disagree. Commission policy requires that for an NGA section 7 proceeding certificating new facilities, incremental rates should be designed to reflect only the incremental costs associated with the new facilities and should not reflect the reallocation of costs related to existing facilities or other common costs." Citing *Transcontinental Gas Pipe Line Co. L.L.C.*, 141 FERC ¶61,091, at P 27 (2012) ( *Transco*), FERC noted that issues "related to the allocation of reserved capacity costs are appropriately addressed in the pipeline's next NGA section 4 general rate proceeding." FERC concluded that the pipeline "was correct to exclude costs associated with the reserved existing capacity." *Tennessee Gas Pipeline Co. L.L.C.*, 161 FERC ¶61,265 (2017).

   FERC "recognizes that in the *Transco* proceeding the Commission accepted the pipeline's proposal to include the costs of reserved capacity in the calculation of the incremental rates. However, in that proceeding, such a rate treatment was not protested and the Commission approved the rates as proposed." *Tennessee Gas Pipeline Co. L.L.C.*, 161 FERC ¶61,265 (2017).

   The protestors also argued that the cost and revenue analysis used by the pipeline to justify its proposal for a predetermination that it may roll the costs of the project into its recourse base rates in a future NGA section 4 general rate case was flawed because it did not include the cost of the existing capacity reserved for the project. FERC found that the pipeline's exclusion of the cost of reserved capacity from its cost and revenue analysis was proper and consistent with FERC policy. *Tennessee Gas Pipeline Co. L.L.C.*, 161 FERC ¶61,265 (2017).

   The protestors cited *Florida Gas Transmission Co.*, 154 FERC ¶61,256 (2016) ( *Florida Gas*) to support its argument that FERC policy requires the elimination of all revenues related to new service that can be provided through the pipeline's existing facilities from the cost and revenue analysis. FERC said the *Florida Gas* proceeding "is inapposite. In *Florida Gas*, the pipeline was capable of providing an incremental portion of the project service using only existing capacity, without construction of any of the proposed project facilities. Indeed, pursuant to its agreement with the shipper, Florida Gas intended to provide such service prior to the construction of the project facilities. Under those circumstances, the Commission found that the applicant improperly included 'revenues generated using the contract volumes for both the service being provided using the capacity made available by the project facilities and the service [Florida Gas] is able to provide using only existing capacity.' In contrast to *Florida Gas*, the new project facilities proposed by [the pipeline] are integral to enabling the existing capacity to be used to serve the project shipper. As confirmed by Commission staff's engineering review the additional capacity created by the new facilities is necessary to allow the reserved unsubscribed capacity to be utilized to meet the demands of the project shipper. Therefore, we dismiss [the] protest and conclude that [the pipeline] appropriately included revenues associated with the reserved capacity in its cost/revenue analysis." *Tennessee Gas Pipeline Co. L.L.C.*, 161 FERC ¶61,265 (2017).

   FERC denied rehearing of *Tennessee Gas Pipeline Co. L.L.C.*, 161 FERC ¶61,265 (2017). "The arguments presented in Indicated Shippers' rehearing request conflate the Commission's determinations to first set an initial recourse rate for the project, followed by a predetermination of rolled-in rate treatment. ... [T]he Commission's determination to approve the use of a pipeline's general system rate is based on whether an illustrative incremental rate is higher than the general system rate (not whether projected costs of the proposed service exceed projected revenues). Upon a determination that the general system rate should be used for the expansion project because it is greater than the illustrative incremental rate, the Commission then determines whether it is appropriate to grant a predetermination that the expansion project costs can be rolled-in to the system rates in a future NGA section 4 or 5 rate proceeding. If the projected revenues exceed the costs of the proposed project, the Commission will grant the predetermination. We note that these are two distinct determinations." *Tennessee Gas Pipeline Co. L.L.C.*, 165 FERC ¶61,217 (2018).

   For integrated mainline expansions, "where capacity is added to the existing pipeline system through the addition of looping or compression, the Commission permits a pipeline to charge an incremental rate when it is greater than the applicable general system rate. Commission policy with regards to the development of an illustrative incremental rate is that the rate includes only the costs of the new facilities being constructed. On the other hand, if the illustrative incremental rate for the expansion project is lower than the pipeline's applicable general system rate, the Commission requires the pipeline to charge the expansion shippers its applicable general system rate." *Tennessee Gas Pipeline Co. L.L.C.*, 165 FERC ¶61,217 (2018).

   The fact that the pipeline has reserved capacity for the expansion project "does not change the appropriateness of the Commission's 'higher of' policy or require [the pipeline] to include the costs of the reserved capacity in the calculation of the illustrative incremental rate. For integrated expansions of existing pipeline systems such as this, where capacity is added through some combination of increased compression or pipeline looping, the gas being transported for the expansion shippers will invariably be transported through some existing pipeline facilities; however, the Commission's incremental rate policy does not require that the costs of any system capacity utilized in the project be allocated to the incremental rate shipper in designing the incremental rate as those costs are already recovered in [the pipeline's] system rates." The pipeline's existing maximum reservation rate is designed to recover the full fixed costs associated with the capacity path, and thus, "includes costs associated with transportation on the existing capacity ... that was reserved for the project. ... Because the existing maximum rate is designed to recover the costs of the entire zone to zone transaction, no additional charge is needed to permit [the pipeline] to recover its cost of service for the capacity reserved for the project. Under these circumstances, where the illustrative incremental rate is lower than the existing ... reservation rate, establishing the existing ... reservation rate for service on the project is consistent with the no-subsidy rule of the Certificate Policy Statement, [the pipeline's] zone rate structure, and cost causation principles." *Tennessee Gas Pipeline Co. L.L.C.*, 165 FERC ¶61,217 (2018).

   For an expansion project where FERC approves the use of the pipeline's applicable system rate, FERC examines whether granting a predetermination of rolled-in rate treatment for the expansion project is appropriate. To receive approval for a predetermination, "a pipeline must show that the incremental revenues of an expansion project will exceed the incremental costs of the project. In such a situation, granting a predetermination that the pipeline can roll in the costs of the expansion into its system-wide rates in the next general rate case is appropriate because it will not result in cross-subsidization of the project's costs by the pipeline's existing shippers, consistent with the Certificate Policy Statement. It is not appropriate to include the embedded cost of existing capacity reserved for the project ... because those costs are already included in [the pipeline's] current rates and are not relevant to this analysis. Thus, we find that the [underlying] Order appropriately granted a predetermination of rolled-in rate treatment based on [the pipeline's] comparison in Exhibit N, which showed that incremental revenues of the project using actual contract volumes and the maximum recourse rate exceeded the incremental costs of the project." *Tennessee Gas Pipeline Co. L.L.C.*, 165 FERC ¶61,217 (2018).

**Use of most recently approved rate of return**. Over the objections of two state commissions, FERC approved the pipeline's proposal to design its recourse rates for an expansion project using the pre-tax rate of return from its most recent general NGA section 4 rate case in which a return was specified, approved 16 years ago, adjusted for the current corporate tax rate. FERC's "policy in NGA section 7 certificate proceedings is to require that a pipeline's cost-based recourse rates for incrementally priced expansion capacity be designed using the rate of return from its most recent general rate case approved by the Commission under section 4 of the NGA in which a specified rate of return was used to calculate the rates. The recourse rates we are approving comply with this policy, and provide the necessary check on the potential market power of the pipeline." *Transcontinental Gas Pipe Line Co. LLC*, 169 FERC ¶61,051 (2019).

   In NGA section 7 certificate proceedings, FERC "reviews initial rates for service using proposed new pipeline capacity under the public convenience and necessity standard, which is a less rigorous standard than the just and reasonable standard under NGA sections 4 and 5. The Commission develops the recourse rate for expansion capacity based on the project's estimated cost-of-service. The initial NGA section 7 rates are 'a temporary mechanism to protect the public interest until the regular rate setting provisions of the NGA come into play.' [ *Mo. Pub. Serv. Comm'n v. FERC*, 601 F.3d 581, 583 (D.C. Cir. 2010) (internal quotation omitted).] Using a previously-approved rate of return allows the Commission to complete requests for NGA section 7 facilities and service in a timely manner, while 'hold[ing] the line' until just and reasonable rates are adjudicated under section 4 or 5 of the NGA. [ *Atlantic Refining Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 392 (1959) ( *CATCO*).]" *Transcontinental Gas Pipe Line Co. LLC*, 169 FERC ¶61,051 (2019).

   FERC disagreed that its reliance on *CATCO* is misplaced, even though that decision was issued prior to the advent of negotiated rates. "The less exacting standard of review used in a section 7 certificate proceeding is intended to mitigate the delay associated with a full evidentiary rate proceeding, and the Commission has discretion to approve initial rates that will 'hold the line' while awaiting the adjudication of just and reasonable rates. ... [T]hat *CATCO* was decided prior to the development of negotiated rates does not detract from the applicability of the Supreme Court opinion to this proceeding. Whether the initial rates in question are recourse rates, serving as a check against the exercise of market power by pipelines with negotiated rate authority, or the rates actually charged to shippers, the Commission retains the discretion to protect the public interest while preventing the delays that can accompany full evidentiary proceedings." *Transcontinental Gas Pipe Line Co. LLC*, 169 FERC ¶61,051 (2019).

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