135 FERC ¶ 61,208
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Tennessee Gas Pipeline Company Docket No. RP11-1566-000

ORDER ON TECHNICAL CONFERENCE

(Issued May 31, 2011)

Paragraph Numbers

1. On December 29, 2010, in the captioned docket, the Commission issued a Suspension Order that, among other things, directed Commission Staff to convene a technical conference to examine the non-rate issues in Tennessee Gas Pipeline Company's (Tennessee) Natural Gas Act (NGA) section 4 rate filing.[1] On February 15 and 16, 2011, Commission Staff convened a technical conference. In the instant order, the Commission reviews all of the non-rate tariff proposals discussed at the technical conference. As discussed below, the Commission accepts several proposals outright, accepts other proposals subject to conditions, and rejects certain proposals. Where, as detailed in the body of this order, the Commission accepts Tennessee's NGA section 4 tariff proposals outright or subject to conditions, those tariff records are effective on June 1, 2011, as requested. The Commission is also, pursuant to NGA section 5, requiring Tennessee to modify its existing tariff provisions concerning reservation charge credits during non-*force majeure* periods and its authority to waive tariff provisions or explain why it should not be required to modify those provisions. Any changes the Commission requires in those tariff provisions will not take effect until after the Commission acts on Tennessee's filing to comply with this order. The Commission directs Tennessee to submit its compliance filing within 30 days of the date that this order issues.

I. <u>Background</u>

2. Tennessee's currently effective rates are the result of a settlement that the Commission approved in a October 30, 1996 order, resolving all cost of service, cost classification, cost allocation, and rate design issues from Tennessee's last NGA section 4 general rate case and establishing Tennessee's base tariff rates (1996 Settlement).[2] In its Initial Filing, Tennessee proposed rate changes reflecting a rate base of over $2.6 billion, up from less than $1.5 billion under the 1996 Settlement, and a total cost of service of approximately $1.05 billion, up from approximately $700 million under the 1996 Settlement.

3. Tennessee also proposed numerous non-rate changes to its tariff, including the following:

- Elimination of Rate Schedules PAT and IT-X from its tariff.
- Modifications to the general waiver language of Tennessee's tariff which currently requires notice of one business day prior to the effective date of a waiver to require notice as soon as practicable under the circumstances.

[1] *Tennessee Gas Pipeline Co*., 133 FERC ¶ 61,266 (2010) (Suspension Order).

[2] *Tennessee Gas Pipeline Co*., 77 FERC ¶ 61,083 (1996).

- Reduction of the notice period for operational flow order (OFO) – Action Alerts from 48 hours to 24 hours.
- Changes to balancing services provided under Rate Schedules LMS-PA (Load Management Service – Production Area) and LMS-MA (Load Management Service – Market Area).
- Elimination of unutilized balancing options: Third Party Provider (TPP) and Downstream Storage Swing Option (DSSO) (both for TPP Shippers and FS Storage Contract Holders) under Rate Schedule LMS-MA.
- Changes to its cashout and imbalance provisions, including addition of two more market area pricing points to the pooling and market area pricing indices used to determine cashout prices and to carry forward the positive Net Cashout Balances up to $4 million and to apply carrying charges to both positive and negative imbalances.
- Addition to Tennessee's General Terms and Conditions (GT&C) of a provision that addresses how Tennessee may seek a discount-type adjustment for certain negotiated rate agreements.
- Changes to when Tennessee may hold an open season to sell capacity.
- Changes to scheduling priorities.
- Changes related to Tennessee's pooling services under Rate Schedule SA, including modifications to the location of existing pooling points.
- Addition of a provision to Rate Schedule FS that would impose a charge on firm storage customers who do not cycle 70 percent of their total inventory by withdrawing stored gas by the end of the winter heating season (April 1 of every year).

4. Public notice of Tennessee's Initial Filing was issued on December 1, 2010. There were a large number of intervenors who protested and requested that the Commission convene a technical conference on Tennessee's Initial Filing. On December 29, 2010, the Commission issued the Suspension Order directing Commission Staff to convene a technical conference on the non-rate issues.

5. The technical conference was convened on February 15 and 16, 2011. Based on the comments, questions, and concerns raised by the parties and Commission Staff, Tennessee agreed to submit Preliminary Comments clarifying some of the issues discussed at the technical conference on March 14, 2011. All parties also agreed to submit Initial Comments on the technical conference by April 4, 2011, and Reply Comments by April 20, 2011. New England LDCs submitted both Initial and Reply Comments at the appropriate time. On April 25, 2011 however, they filed what they termed further Reply Comments, which were not provided for at the technical conference. The Commission did not rely on this extra-procedural filing in rendering its determination herein. The list of parties who submitted comments on the technical conference is appended to the end of this order.

6. In filings after the technical conference, Tennessee agreed to or submitted *sua sponte* a number of changes to its Initial Filing's non-rate proposals in this proceeding to address the concerns of the parties. The Commission generally accepts Tennessee's non-rate tariff proposals, as revised after the technical conference, except for certain rejections and conditional acceptances that are detailed below. Where necessary, Tennessee should file actual tariff records to replace the *pro forma* records filed in its Preliminary Comments to the technical conference.

II. Open Season

A. Proposal

7. Article XXVI, Section 5.1 of Tennessee's GT&C at tariff sheet No. 380 governs open seasons, including the conditions under which Tennessee may or must hold an open season. That section requires Tennessee to post available capacity on its PASSKEY system. "When a Shipper expresses interest in available capacity for a period greater than 92 days," Tennessee must conduct an open season to receive bids for forward haul or backhaul capacity. Section 5.9 of Tennessee's GT&C permits it to enter into a pre-arranged service agreement for capacity that has been posted on PASSKEY. Section 5.9 requires that Tennessee post the terms of the prearranged service agreement in order to give other parties an opportunity to acquire the capacity by submitting a bid with a higher net present value. The prearranged shipper would then have an opportunity to match the third party's bid.

8. In its Initial Filing,[3] Tennessee proposed to remove the requirement in section 5.1 that it hold an open season when a shipper requests service for more than 92 days, leaving only the requirement that Tennessee must post available capacity via its PASSKEY system. Under the proposal, Tennessee will have the option of holding an open season for available capacity when it believes an open season would maximize bidding. Tennessee proposes a corresponding change to section 5.9, eliminating the requirement that it post pre-arranged deals for third party bids and instead simply giving Tennessee the option to post such prearranged deals. Tennessee contends that holding open seasons in some situations results in no bids, unnecessarily delaying transactions. Tennessee claims that out of 87 open seasons triggered by prearranged deals since September 2008, Tennessee claims that there were only two instances where an entity submitted competitive bids for capacity at rates higher than those pre-arranged with another shipper. Tennessee argues that it has the incentive to obtain the highest value for

[3] Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 380, Service Requests Credit Evaluation Award Available Capacity, 3.0.0 (Third Revised Sheet No. 380).

generally available capacity, and thus will continue to voluntarily conduct open seasons whenever the capacity at question might be valued more by other shippers.

9. In its Preliminary Comments, Tennessee revised its proposal in order to address the concern that capacity may not have been posted as generally available for a sufficient period of time for shippers to act upon the posting. Under the revised proposal, Tennessee would only have tariff authority to dispense with an open season for the sale of capacity that (1) is for a term of 92 days or less, or (2) has been posted as generally available on PASSKEY for at least five days.

B. Comments

10. Several commenters continue to urge the Commission to reject Tennessee's open season modifications, arguing that it would harm transparency.[4] For instance, Atmos posits that when Tennessee observes the posted release rate (or bids) submitted in response to a releasing shipper's posting of a capacity release Tennessee could easily offer capacity directly to the interested bidder at lower rates and circumvent the capacity release mechanism.[5] Indicated Shippers explain that under Tennessee's current posting policy, "[w]hen Tennessee posts point and mainline capacity on its website as available, the posting does not automatically mean that any combination of those points and that mainline capacity are available. Moreover, while entering into a large-quantity contract at a discounted rate may provide the best return for Tennessee, it may mean that more valuable portions of that capacity are not available to the market."[6] Similarly, Anadarko urges the Commission not only to reject Tennessee's proposal, but also to require Tennessee to provide additional transparency in its postings, by requiring it to post capacity on a segment-by-segment basis. Sequent also notes that Tennessee's proposed changes in its Preliminary Comments are "not germane to the issue, since they do not preserve shippers' current ability to evaluate and potentially bid upon prearranged deals before the capacity is awarded."[7]

11. The New England LDCs and Northeast Customer Group conditionally support Tennessee's proposal. Both groups urge that Tennessee further revise its proposed tariff language to clarify how the five-day posting requirement would work, but recommend mutually opposing language. The New England LDCs urge that the five-day posting

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[4] Anadarko, Atmos, Cabot, Indicated Shippers, Piedmont, and Sequent.

[5] Atmos Initial Comments at 6.

[6] Indicated Shippers Initial Comments at 12.

[7] Sequent Initial Comments at 8.

should be “*during* the 60 days prior to the award of the capacity,”[8] while the Northeast Customer Group urge that the five-day posting should be “*at least* sixty (60) days prior to [Tennessee]’s awarding of the capacity.”[9]

12. In its Reply Comments, Tennessee states that it understands both the New England LDCs and the Northeast Customer Group to be requesting that the five-day posting requirement must occur at some point during the 60 day period preceding the award of capacity. Based on this understanding, Tennessee states the request is reasonable and it agrees to incorporate that change into its proposal.

C. Commission Decision

13. The Commission accepts Tennessee’s proposal to remove the requirement that it hold an open season if a shipper requests capacity for more than 92 days, and instead make the holding of an open season to sell available capacity optional, subject to the condition discussed below. The Commission has not required pipelines to sell existing capacity solely through open seasons. Rather, so long as the pipeline posts all available firm capacity, it may sell that capacity on a first come, first served basis.[10] As we explained in *Northern Natural Gas Co*., although the Commission:

> favors placing capacity in the hands of those that value it most highly, it also assumes that the pipeline will always seek the highest possible rate from non-affiliated shippers, since it is in its own economic interest to do so. Accordingly, the Commission has not required pipelines to implement allocation mechanisms utilizing methodologies such as the Net Present Value (NPV) process, which would allocate firm capacity (such as at issue here), to the shipper bidding the highest amount to the pipeline. Rather, the Commission has permitted pipelines to implement such an allocation methodology to the extent it believes such methodologies are necessary on its system in order to allocate scarce capacity to the highest valued use. Consistent with this policy,

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[8] New England LDCs Initial Comments at 30 (emphasis added).

[9] Northeast Customer Group Initial Comments at 15 (emphasis added).

[10] *Northern Natural Gas Co.*, 110 FERC ¶ 61,361, at P 10 (2005), *cited in, e.g., Promotion of a More Efficient Capacity Release Market*, Order No. 712, FERC Stats. & Regs. ¶ 31,271, at P 136 n.131 (2008), *order on reh’g,* Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh’g*, Order No. 712-B, 127 FERC ¶ 61,051 (2009).

> Northern's tariff permits it to hold open seasons for capacity but does not require the use of such a methodology.[11]

14. Section 5.1 of Tennessee's GT&C requires Tennessee to post available capacity on its PASSKEY system. Its proposal to require capacity to be posted as available for at least five days before it awards the capacity to a shipper for more than 92 days without an open season should in theory ensure that all shippers have an opportunity to request the capacity. However, it is unclear from Tennessee's comments how the five-day posting requirement would operate in practice. Accordingly, we accept Tennessee's open season proposal, as revised in its Reply Comments, subject to further review. We direct Tennessee to file actual tariff language that clarifies whether and how a shipper could offer a competing bid or trigger an open season during this five-day period, along with a narrative explanation of the tariff language, effective the date Third Revised Sheet No. 380 is moved into effect.

III. Scheduling Priority

15. In the Initial Filing, Tennessee proposed several changes to Article IV, section 3 of the GT&C of its tariff, which provides the scheduling priorities among Tennessee's various services.[12] Specifically, Tennessee proposed (1) to elevate the scheduling priority for firm transactions from a secondary receipt point to a primary delivery point to the same level as primary to primary point in-the-path transactions when a restriction is within the shipper's primary capacity path; (2) to schedule secondary point transactions where a restriction is outside the shipper's capacity path on an economic basis, where capacity will be allocated first to the contract paying the highest transportation rate; and (3) to collapse the current priority tiers for below secondary out-of-the-path level services to four levels. According to Tennessee, the proposed changes streamline the scheduling priority section by eliminating some redundant provisions and provide a more equitable and efficient way of allocating capacity by prioritizing services for shippers that pay higher rates over services for shippers that pay lower rates. For the reasons discussed below, we reject Tennessee scheduling priority proposals (1) and (2) above because Tennessee has not shown them to be just and reasonable, and accept proposal (3) as just and reasonable.

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[11] *Northern Natural Gas Co.*, 118 FERC ¶ 61,053, at P 51 (2007). *Tuscarora Gas Transmission Co.*, 120 FERC ¶ 61,022, at P 11 n.6 (2007). *Tennessee Gas Pipeline Co.*, 121 FERC ¶ 61,149, at P 23 (2007).

[12] Initial Filing at 12.

A. Scheduling Priority Based on Shipper's Path

1. Proposal

16. Tennessee states that its proposal to increase the scheduling priority for secondary receipt to primary delivery point transactions[13] recognizes that such transactions are using capacity within a shipper's primary capacity path and should thus be afforded the highest priority.[14] Tennessee acknowledges that it is seeking this revision to address the concerns of its northeastern customers about the primacy of city gate delivery points in meeting the needs of essential gas customers. Tennessee asserts that the priority increase is warranted because it intends to promote the flexibility of its pooling services while providing the most reliable service possible to LDCs at their city gates.[15] Tennessee further asserts that the proposal is consistent with what it calls the Commission's "'within-the-path' scheduling policy," which Tennessee claims is that "'all shipper nominations … for which the affected mainline is within the shipper's primary path shall receive equal priority.'"[16] According to Tennessee, its proposal "reasonably expands" this policy.

2. Comments

17. Several parties, mainly Tennessee's customers in its northeast market area who are the admitted impetus for Tennessee's proposed change, filed in favor of the increased priority for deliveries to primary points.[17] Those commenters contend the proposal provides recourse rate shippers with the highest level of reliability while permitting them to obtain the least cost supplies along their contract path. They state that while LDCs historically obtained supply from the Gulf of Mexico, and thus were able to transport their gas reliably to their city gates on primary point to primary point transactions, changes to Tennessee's pooling services and supply sources have altered the manner in which these customers access and transport gas. They state that as Tennessee's pooling

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[13] Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 316, , 2.0.0, and Sheet No. 317, , 1.0.0.

[14] Initial Filing at 12.

[15] Tennessee Reply Comments at 40.

[16] Tennessee Initial Comments at 25 (*quoting Ozark Gas Transmission LLC*, 125 FERC ¶ 61,113, at P 27 (2008) (*Ozark*)).

[17] *See, e.g.*, Nicor Initial Comments, Northeast Customer Group Initial Comments, Northeast State Coalition Initial Comments.

services evolved, LDCs shifted from using Tennessee's interruptible Rate Schedule SA to transport gas to the production pools to using primary receipt points to ensure reliability. According to the commenters, moving their primary receipt points to the production pools results in a shortening of the shipper's capacity path when its primary receipt points are upstream of the pool. They further stated that Tennessee has added several interconnects with pipelines that provide access to shale production supplies in the Barnett, Haynesville, and Marcellus shale basins. They note that while there are now numerous supply options on Tennessee's system for a shipper looking to provide least cost supplies to its customers, the LDCs in the situation described above must weigh the advantages of the alternative supply options against the risk of having to ship at a lower out-of-the-path priority. These entities state that Tennessee's proposal will allow them to access these new, and often less costly, supply sources on a reliable basis.[18]

18. Opponents of Tennessee's proposed scheduling priority increase for service to primary delivery points focus on two major criticisms. First, they claim that the proposal violates the Commission's "firm is firm" policy, which to the opponents means that a service transaction from a primary point to a primary point must have priority over any transaction involving a secondary point.[19] Second, protesters assert that the proposal discriminates against producers and marketers who need flexibility to obtain reliable service at secondary delivery points.[20] Many of these parties request that Tennessee extend the scheduling priority increase to secondary in-the-path transactions from primary receipt points to secondary delivery points.

19. Several parties assert that Tennessee's proposal should be rejected because it essentially eliminates the distinction between primary in-the-path and secondary-in-the-path scheduling priorities for many of its customers. They contend that the Commission's paradigm for priority of service has focused on the primacy of firm transactions from primary receipt points to primary delivery points, which are established by the shipper's contract defining the shipper's rights to firm transportation capacity. They contend that the Commission's facilitation and development of a secondary capacity release market and flexible point rights was never intended to degrade a shipper's contractual primary firm rights in favor of secondary rights. They assert the proposal should be rejected as it reduces the rights of primary firm shippers to receive the

[18] Northeast Customer Group Initial Comments at 17-22.

[19] *See, e.g*., Cabot Initial Comments, EMUS/IOGA/JPMVEC Initial Comments, Piedmont Initial Comments.

[20] *See, e.g.*, Anadarko Initial Comments, Chesapeake Initial Comments, Repsol Initial Comments, North American Marketers Initial Comments.

capacity for which they paid and would increase the likelihood that a primary to primary nomination would be cut or prorated on an equivalent basis with secondary shippers.[21] Others echo those concerns, asserting that a firm transportation customer nominating within its path from primary receipt meters to primary delivery meters should always have an absolute priority over secondary in-the-path customers.[22] They argue that the change would substantially alter the understanding with which firm transportation contracts were entered into with Tennessee, that a shipper would have the highest priority to deliver gas to one's primary delivery point when shipping from one's primary receipt point. They claim that the proposal represents nothing more than a derogation of shippers' primary capacity rights at the same time Tennessee seeks to nearly double the cost of that capacity.[23]

20. Some opponents argue that the proposal violates the Commission's policy established in Order No. 636, as clarified by Order No. 637, that "shippers seeking to move to receipt points within their path should generally have higher priority for mainline capacity than shippers moving to receipt points outside their path."[24] They contend that because Tennessee's proposal would provide a higher priority to a shipper moving its receipt point downstream within its path than to a shipper moving its delivery point upstream in its path, the proposal violates Order No. 637's requirement that both these shippers be treated equally for scheduling purposes.

21. Commenters also argue that the proposal discriminates against producers and marketers. They note that Tennessee admits the impetus for the proposed change came from LDCs in Tennessee's market area seeking to obtain reliable service to their city gates from new supply sources. They claim that producers and marketers holding firm transportation rights on Tennessee also have reliability issues and they should not be discriminated against in favor of the market area customers. Accordingly, they request

[21] Piedmont Initial Comments at 6-7.

[22] Cabot Initial Comments at 5.

[23] *Id*.

[24] EMUS/IOGA/JPMVEC Initial Comments at 3 (citing *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, Order No. 637-B, 92 FERC ¶ 61,062, at 61,170 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *aff'd sub nom. American Gas Ass'n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005)).

that Tennessee extend its proposal to place transactions from primary receipt points to primary delivery points on the same priority level as secondary receipt to primary delivery points.[25] In its Reply Comments, Tennessee declined to modify its proposal as requested by the producers and marketers.

3. <u>Commission Decision</u>

22. The Commission rejects Tennessee's proposal to elevate the scheduling priority for firm transactions from a secondary receipt point to a primary delivery point to the same priority as firm transactions from a primary receipt point to a primary delivery point when the point of constraint is within the shipper's capacity path. The Commission finds that Tennessee has not shown that its proposal is just and reasonable. Further, the Commission finds that the proposal is inconsistent with Commission policy that primary point to primary point transactions must be afforded the highest scheduling priority.

23. When firm shippers contract with Tennessee for firm service, their contracts specify the receipt and delivery points to which the shipper will have primary rights. The shipper then has a guaranteed firm right to ship gas from primary receipt points listed in its contract to primary delivery points.[26] While Order No. 636 required pipelines to permit firm shippers to use other points within the rate zones for which they were paying, Order No. 636-B required that pipelines give a scheduling priority for primary to primary point services when there is a capacity constraint.[27] In *Tennessee Gas Pipeline Co.*,[28] the Commission explained:

> A shipper pays reservation charges based on primary points not on secondary points. The secondary rights to delivery points are based on Commission regulations and are by

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[25] *See* North American Marketers Initial Comments at 5-7, Anadarko Initial Comments at 13.

[26] *Tennessee Gas Pipeline Co*., 94 FERC ¶ 61,097, at 61,402 (2001).

[27] *See, e.g., El Paso Natural Gas Co.*, 64 FERC ¶ 61,265, at 62,825 & n.55 (1993) (denying protester's request to require pipeline to grant a higher priority for primary receipt to alternate (secondary) delivery point transactions than for alternate secondary receipt point to primary delivery point transactions) (quoting *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* Order No. 636-B, 61 FERC ¶ 61,272, at 62,013 (1992)).

[28] *Tennessee Gas Pipeline Co.*, 73 FERC ¶ 61,083, at 61,206 (1995).

> definition inferior to primary point rights. The reservation charge a customer pays is based on its contract with the pipeline for receipt and delivery of gas at particular primary points, . . . The contract does not guarantee the same level of security if other points are used; rather the Commission's regulations require [a pipeline] to provide service to those other points if it can.

24. Tennessee's attempts to show that the Commission has since abrogated or modified that policy are unavailing. First, we disagree with Tennessee's claim that its proposal is merely a reasonable extension of the Commission's "in-the-path" scheduling priority policy. That policy, which was established in Order No. 637-A, was limited to requiring pipelines to establish a higher scheduling priority for secondary in-the-path transactions over secondary out-of-the-path transactions.[29] Moreover, Tennessee is mistaken that *Ozark* established a different policy for primary receipt and delivery points and in-the-path mainline capacity that would warrant the scheduling elevation of secondary receipt to primary delivery transactions proposed here. As we stated there, in rejecting a protester's contention that secondary in-the-path service should have the same mainline capacity priority as primary firm service, "[a]ll secondary service has a lower priority than primary service."[30] Tennessee's proposal is inconsistent with this policy, and nothing in *Ozark* implies that a mainline constraint in the shipper's primary path should elevate the priority of that shipper's secondary point rights to a priority equal with primary in-the-path rights.

25. Further, paragraph 27 of the *Ozark* order, on which Tennessee relies for its contention that all nominations within a shipper's primary path should receive equal scheduling priority, addresses curtailment priorities once volumes are scheduled, and is inapplicable to scheduling priorities. There, the Commission was reaffirming our policy that once scheduled, firm is firm and thus all scheduled firm transactions, whether primary or secondary, must be curtailed on a *pro rata* basis.[31] Pursuant to this policy, a scheduled secondary firm transaction cannot be bumped by a primary firm transaction.[32]

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[29] *See* Order No. 637-A, FERC Stats. & Regs. ¶ 31,099 at 31,596-99.

[30] *Ozark*, 125 FERC ¶ 61,113 at P 26.

[31] Tennessee's existing and proposed revised tariff complies with this policy. Article IV, section 4 of the GT&C of Tennessee's tariff provides that in the event Tennessee has to curtail firm services, it will curtail its firm customers on a *pro rata* basis.

[32] Tennessee's existing tariff is consistent with this policy. *See* Article IV, section

(continued…)

26. Further, we reject Tennessee's arguments concerning the distinction between the priority that should be afforded to primary delivery points and that afforded to primary receipt points. Tennessee asserts that this difference is justified because the Commission "favors flexible supply aggregation and pooling services that facilitate shippers' ability to avail themselves of different supply sources."[33] The fact that the Commission promotes the facilitation of shippers obtaining access to diverse sources of supply does not in any manner imply that therefore primary delivery points should be afforded a higher priority than primary receipt points.

27. Tennessee's argument that the Commission should approve its proposal because it is just and reasonable regardless of the fact that other methods may also be just and reasonable is likewise lacking. As noted above, we find that Tennessee has not shown its proposal to be just and reasonable. The proposal violates Commission policy regarding the primacy of primary to primary point transactions. Further, Tennessee's proposal discriminates against shippers that seek to schedule through a primary path constraint from a primary receipt to a secondary delivery point by not providing those shippers with the same elevated priority. Moreover, the proposal would derogate the value of other customers' primary in-the-path capacity by potentially affecting their ability to transport gas in their capacity path from their primary receipt point to their primary delivery point.

B. Scheduling Priority Based on Price

1. Proposal

28. Tennessee proposes to revise Article IV, section 3 of the GT&C of its tariff to schedule firm transactions using a secondary receipt or secondary delivery point outside of a shipper's primary capacity path, where there is an allocation of capacity outside the shipper's capacity path, by price, allocating capacity first to the contract paying the highest transportation rate.[34] Tennessee proposes to use "transportation rate inclusive of all applicable fees and surcharges agreed upon by the Transporter and Shipper ('Confirmed Price') to the route being scheduled such that higher rates are allocated

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2.(f) of the GT&C of Tennessee's tariff, which states that except in one limited circumstance, Tennessee "shall not schedule an Intra-day Nomination Change or an Hourly Nomination Change, if the result of scheduling such nomination would be to bump flowing and/or scheduled transportation under any firm primary or secondary service."

[33] Tennessee Reply Comments at 39-40.

[34] Initial Filing at 12. *See also* Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 318, , 1.0.0.

before those paying lower rates" for scheduling capacity under primary contracts.[35] According to certain commenters, Tennessee explained at the technical conference that it would calculate the Confirmed Price by taking the sum of the transportation rate (both reservation and commodity components) and all applicable fees and surcharges, except for fuel.[36] Tennessee will calculate the reservation charge as a 100 percent load factor rate and the commodity rate will be determined by nomination zone of receipt to zone of delivery. Thus, Tennessee is proposing to schedule secondary out-of-the-path transactions according to the rate a customer pays, without consideration of the duration of the contract.[37]

29. For capacity releases, Tennessee proposes to schedule according to the replacement shipper's Confirmed Price for non-index based capacity releases and the Index-Based Release Rate Floor (NAESB 1.9) in the Confirmed Price calculation for capacity releases based on index prices.[38] In both the primary sale and capacity release situations, Tennessee proposes to schedule on the basis of the amount paid by the replacement shipper and would not take into account any payments by the releasing shipper. For shippers paying the same rate, Tennessee proposes to allocate capacity on a *pro rata* basis. Based on comments made at the technical conference, Tennessee proposed to modify its original changes to allow a shipper paying a rate less than maximum rate to upgrade its scheduling priority by paying the maximum rate for the entire day.[39] Tennessee also proposed in the Preliminary Comments to use the releasing shipper's Confirmed Price for capacity releases under asset management arrangements and state retail access programs.

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[35] Proposed GT&C Article IV, section 3(c).

[36] *See* BG Energy Initial Comments at 4-5.

[37] Scheduling by absolute price, or actual rate paid, may be contrasted with scheduling according to a percentage of maximum rate. Scheduling according to absolute price on an additive zone system such as Tennessee's generally favors long haul shippers who pay more because they are transporting gas over a longer distance and thus they pay more than a shipper transporting gas for only a short distance. Scheduling by a percentage of maximum rate alleviates the discrimination against short haul shippers because a short haul shipper paying the same percentage of the maximum rate as a long haul shipper will receive the same scheduling priority.

[38] Proposed GT&C Article IV, section 3(c).

[39] Tennessee Preliminary Comments, *pro forma* Sheet No. 318.

2. **Comments**

30. According to Tennessee, the scheduling of firm capacity by price is just and reasonable and consistent with the Commission's policy of allocating capacity to the party that values it the most.[40] Tennessee asserts that no party at the technical conference opposed this basic premise.

31. The protests to this part of Tennessee's proposal generally focus on two issues: (1) the use of absolute price, and (2) the use of the replacement shipper's rate as the Confirmed Price in scheduling released capacity.

32. Protests concerning the use of an absolute price contend that the Confirmed Price that Tennessee proposes to use to schedule secondary-out-of-the-path transactions is discriminatory because long haul shippers will automatically trump short haul shippers.[41] They note that firm recourse rate short haul shippers could be disadvantaged with respect to long haul shippers paying a discounted rate, because the proposal could schedule a secondary out-of-the-path contract at maximum rate for intra-zone service behind a discounted multi-zone contract.[42] Commenters also claim that Tennessee's proposal compares apples to oranges, and that long haul shippers do not value their capacity any more than short haul shippers; they are each paying for separate services.[43]

33. Certain protesters challenge Tennessee's contention that scheduling secondary out-of-the-path transactions by absolute price promotes allocative efficiency. They argue that the mechanism does not allocate capacity to the one that values it the most because it does not take into consideration the value of the capacity on the day for which the shipper is seeking to schedule an out-of-the-path transaction. According to the commenters, the value of the capacity to the party that originally purchased the capacity from the pipeline has no bearing whatsoever on that shipper's valuation of secondary receipt capacity

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[40] Tennessee Initial Comments at 28 (citing *Trunkline Gas Co.*, 64 FERC ¶ 61,141, at 62,124-25 (1993); *Colorado Interstate Gas Co.*, 95 FERC ¶ 61, 321, at 62,118 (2001)).

[41] *See, e.g.*, BG Energy Initial Comments at 4.

[42] Chesapeake Initial Comments, Indicated Shippers Initial Comments, Nicor Initial Comments, Repsol Initial Comments, North American Marketers Initial Comments.

[43] Statoil/South Jersey Initial Comments.

during a scarcity event. The shipper could not, at the time of original contracting, plan to schedule around an unknown future constraint.[44]

34. Louisville claims that it is inappropriate to rank the order of shippers that have committed to firm service contracts, and objects to the proposal as irrational and fatally flawed. It states that a primary goal of economic allocation is to maximize revenues to the pipeline. Louisville asserts that Tennessee's proposal would not accomplish this goal because the primary component of the Confirmed Price will be reservation charges, which represent sunk costs to the shipper that the shipper cannot avoid or recoup if Tennessee rejects a shipper's nomination.

35. Further, Louisville notes that allocating by price is supposed to award capacity to the customer that values it the most. It points out that an inherent assumption of Tennessee's proposal is that average daily reservation charges are a measure of how each customer values secondary out-of-the-path capacity, and argues that assumption is inaccurate because reservation charges are calculated on an annual basis and billed monthly. Thus, the average daily reservation charge is not a fair measure of how a customer values capacity on a particular day; rather reservation charges are a measure of how, on an annual basis, a customer values peak day service. Louisville further argues that Tennessee's proposal in the Preliminary Comments to allow a discounted rate shipper to bid maximum rate to elevate the priority of its secondary out-of-the-path transaction demonstrates Tennessee's true objective, namely to increase revenues to the pipeline at the expense of firm customers. Louisville states that firm shippers, who have already committed to support the system through the payment of reservation charges, should not have to bid again for that capacity.[45]

3. <u>Reply Comments</u>

36. With regard to the use of an absolute price to determine scheduling priority, Tennessee contends that the Commission has addressed this issue numerous times and with the exception of the *Panhandle* case cited by the protesters, in each instance the Commission found that scheduling on the basis of absolute price is consistent with allocative efficiency goals.[46] Tennessee argues the Commission has approved the scheduling of service according to absolute price for interruptible service, done essentially the same in approving allocation methodologies based on net present value (NPV), and rejected arguments that secondary firm capacity must be allocated on the

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[44] Sequent Initial Comments, Piedmont Initial Comments.

[45] Louisville Initial Comments at 4-6.

[46] Tennessee Reply Comments at 46.

basis of a percentage of maximum rate instead of the highest rate paid in approving a priority scheduling methodology for secondary firm service for El Paso Natural Gas Company.[47]

37. Tennessee asserts the use of the replacement shipper's rate as the confirmed price in the scheduling calculation for capacity releases is appropriate. According to Tennessee, the issue boils down to which rate, the releasing shipper's rate or the replacement shipper's rate, best reflects the value of capacity for purposes of scheduling the released capacity. Tennessee claims that the relevant time period for determining the scheduling priority is when the replacement shipper nominates service, not when the releasing shipper first entered into the contract. Thus, Tennessee concludes, the best indicator of the value of the released capacity for scheduling purposes is the replacement shipper's rate, which is determined in most instances through a competitive bidding process.[48]

38. Tennessee states that the opposition to use of the replacement shipper rate as proposed is based on misconceptions by the opponents regarding the effect of the proposal on the value of released capacity and Tennessee's ability to potentially collect more than its maximum rate or double collect, and that the proposal will not provide Tennessee with a competitive advantage in selling its capacity as opposed to released capacity. Tennessee claims that the proposal will increase the value of capacity because contrary to the opponent's claims that the proposal would allow Tennessee to exceed its maximum rate, Tennessee will credit any additional reservation charges received as a result of an increased replacement shipper's rate to the releasing shipper. Thus, according to Tennessee, it would not benefit from an increase in the replacement shipper's rate but the releasing shipper would benefit by way of an increased credit. Tennessee also states that because the goal of allocative efficiency is to allocate to the shipper who values the capacity the most – determined by who is willing to pay the most – the original value of the capacity to the releasing shipper is irrelevant.[49]

39. Tennessee also claims that it will not be given an advantage over the sale of released capacity under its proposal because the rate zones where the opposing shippers are located are fully subscribed, and thus there would be no competition from the pipeline attempting to sell firm in the path capacity in those zones. The only competition would be interruptible and secondary out-of-the-path services. Tennessee argues that it allows all secondary out-of-the-path to compete on a level playing field, and thus it is only the

[47] *Id*. (citing *El Paso Natural Gas Co*., 114 FERC ¶ 61,305 (2006)).

[48] Tennessee Reply Comments at 42-43.

[49] *Id*. at 44.

releasing shipper that stands to benefit from an increased replacement shipper rate through increased credits.[50]

4. Commission Decision

40. The Commission rejects Tennessee's proposal to allocate secondary out-of-the-path transactions according to price. As demonstrated by several of the commenters, Tennessee's proposal is based on a flawed economic premise. Tennessee proposes to schedule secondary out-of-the-path transactions according to the transportation rate that the shipper agreed to at the time it entered into its original contract with the pipeline, based on the claim that such methodology allocates the capacity to the shipper who values it the most. As Tennessee itself notes, however, the value to the original capacity holder of the point capacity to which the shipper wants to move on a secondary out-of-the-path basis is irrelevant to that shipper's current valuation of that point capacity.[51]

41. Further, Tennessee's proposal would not allocate capacity to the customer that valued it the most because it is based on the erroneous presumption that a shipper's average daily demand charges are an accurate measure of how that shipper values secondary out-of-the-path capacity. A shipper's reservation charge is a sunk cost to reserve primary capacity for an annual period that the shipper will pay regardless of whether Tennessee schedules the shipper's nomination.[52] Accordingly, demand charges are not a fair measure of how a shipper values capacity on a particular day, but more accurately represent the value, on an annual basis, that a shipper places on receiving reliable peak day service.

42. Tennessee's proposal attempts to tie the price that the shipper is currently paying for the capacity path for which it originally contracted to the market value of secondary point capacity at a different time. As discussed above, such a methodology does not allocate the currently available secondary point capacity to the shipper who values it the most because the value that a shipper placed on capacity when it executed its contract with the pipeline for that capacity (i.e. the reservation charge) bears no relation to the value the shipper places on a secondary point outside its capacity path. Thus, Tennessee's proposal is not consistent with allocating capacity to the highest valued use.

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[50] *Id*.

[51] *Id*. at 43.

[52] For this reason, Tennessee's proposal would not maximize revenue to the pipeline.

43. Tennessee's attempts to analogize its proposal to other situations where the Commission has approved the allocation of capacity by price – interruptible transportation service and allocations based on NPV[53] – also fail. In those circumstances, the price the shipper pays does reflect that shipper's current valuation of the capacity. For allocations based on NPV, a shipper bids in an open season an amount that reflects that shipper's value of the capacity being sold in the open season. The same holds true for a shipper seeking interruptible transportation service on a particular day. Moreover, allocating capacity according to price in both those instances maximizes the revenue the pipeline will receive for that capacity.

44. Because Tennessee's proposal is based on a flawed economic premise, it has not shown its proposal to economically allocate firm secondary out-of-the-path transactions to be just and reasonable. Therefore, we do not need to address the issues raised relating to released capacity, as Tennessee's contentions there are based on the same flawed analysis.

45. Accordingly, for the reasons discussed above, the Commission rejects Tennessee's proposals to modify the scheduling priority provisions in Article IV, section 3 of the GT&C of its tariff, as contained on the tariff records noted in footnotes 13 and 34 above.

C. Priorities Below Secondary Out-of-Path Service

1. Proposal

46. In the Initial Filing, Tennessee proposed to simplify the priority of services below secondary out-of-path by reducing the total number of tiers from eight to four. Tennessee's proposed revised priority levels (from highest to lowest) are: (1) services that pay a reservation-type charge; (2) services related to mid-month make-up quantities; (3) authorized overrun under firm storage between a shipper's maximum daily injection quantity and maximum daily withdrawal quantity; and (4) all other services. Tennessee states further allocations within each service level would be based on price such that shippers paying higher rates would be restricted after shippers paying lower rates. Tennessee asserts that these changes, along with those proposed above, would recognize that both across and within services, Tennessee would schedule shippers paying higher rates before those paying lower rates.[54]

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[53] *See* Tennessee Reply Comments at 46.

[54] Initial Filing at 12.

2. Comments

47. There was only one substantive comment regarding Tennessee's proposal for reducing the secondary out-of-path priorities in its tariff. The New England LDCs assert that mid-month make-up volumes should have the highest priority in this category because "mid-month rights are critical to firm service and permit firm shippers to avoid imbalance penalties."[55]

48. In reply, Tennessee states that the New England LDCs do not cite to any Commission policy supporting a higher priority for make-up volumes and that under Tennessee's proposal mid-month make-up volumes remain in the second category of the below secondary out-of-path tiers. Tennessee also states that pursuant to its proposal, the priority for mid-month make up volumes is just below "Rate Schedule PAL-Term Rate," which has a reservation charge component. Tennessee claims that mid-month make-up volumes, for which there is no charge and which already receives a higher priority than all other commodity based services, should not have a higher priority than a service for which shippers pay reservation charges.[56]

3. Commission Decision

49. The Commission accepts Tennessee's proposal to streamline the priority tiers for below secondary out-of-path services. As noted by Tennessee, the proposal is largely unopposed. As to the New England LDCs' request to place mid-month make-up volumes at the highest scheduling priority, we find that the mid-month make-up service, for which shippers pay no charge, should not be placed above the PAL-Term service for which shippers pay a reservation charge.

50. We also approve Tennessee's proposal to allocate the below secondary out-of-path services by price. Unlike Tennessee's proposal to schedule firm secondary out-of-path nominations by price, these below secondary out-of-path services are interruptible services for which a shipper would pay an additional fee on the day that it wanted to use the service. Thus the Confirmed Price a shipper would pay does represent that shipper's valuation of the service at the time it wants to use that service, and would maximize revenue to the pipeline.

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[55] New England LDC Initial Comments at 33.

[56] Tennessee Reply Comments at 41.

IV. Reservation Charge Credit for Curtailments

A. Proposal

51. Tennessee did not propose any changes to its reservation charge crediting provisions. Tennessee's rate schedules for its FT-A (Firm Transportation Service), FT-BH (Firm Transportation Backhaul Service), FT-G (Small Customer Transportation Service), and FT-IL (Incremental Lateral Service) firm services include provisions requiring it to provide credits against the shippers' reservation charges during periods when service can not be provided because of a non-*force majeure* event.[57]

52. However, Tennessee's rate schedules for its firm services provide that it is not obligated to provide firm shippers reservation charge credits during periods when it cannot provide service due to a *force majeure* event. In Opinion No. 406-A,[58] the

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[57] For example, section 7, Failure of Transporter, of Rate Schedule FT-A provides that:

> If Transporter fails to tender for delivery during any one or more days the quantity of natural gas which Shipper has scheduled for delivery, taking into consideration an allowable variation of 2%, up to the maximum quantity which Transporter is obligated by the transportation contract to deliver to Shipper, then the demand charge as otherwise computed hereunder shall be reduced by an amount equal to the applicable Daily Demand Rate per dth times the difference between the quantity of natural gas tendered for delivery during said day or days and the quantity of natural gas scheduled by Shipper for delivery at Primary Delivery Points during said day or days; provided that if Transporter's failure to perform is due to a force majeure event described in Article XII of the General Terms and Conditions of Transporter's FERC Gas Tariff, Transporter will not be obligated to reduce Shipper's demand charges, in the manner described above, for failure to tender delivery at Shipper's primary or secondary delivery point(s).

Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 81, , 0.0.0. Section 7 of Rate Schedules FT-BH, FT-G, and FT-IL contains identical language.

[58] *Tennessee Gas Pipeline Co.*, Opinion No. 406-A, 80 FERC ¶ 61,070, at 61,200 (1997) (Opinion No. 406-A).

Commission held that Tennessee need not include in its tariff a provision for reservation credits during *force majeure* events, because a settlement had changed Tennessee's rate design to include certain fixed costs in its usage charges. The Commission found that the new rate design accomplished the Commission's goal of ensuring a sharing of the risk associated with a *force majeure* interruption. During such an interruption, Tennessee would not recover the fixed costs included in the usage charge, while the shippers would continue to pay the reservation charge with no credit. In this rate case, Tennessee has proposed to return to a Straight Fixed Variable (SFV) rate design.

B. ***Force Majeure* Events**

1. **Comments**

53. In their protests to Tennessee's filing, several parties argued that Tennessee's existing tariff provision regarding reservation charges for *force majeure* events must be revised because Tennessee's proposal to return to an SFV rate design will eliminate the risk sharing inherent in the existing Modified Fixed Variable (MFV) rate design. Tennessee asserts that a consensus on a *pro forma* tariff provision to resolve the issue was not achieved in the technical conference and proposes that this issue be considered in the settlement discussions and hearing in this proceeding. Tennessee argues that it has not proposed to change its *force majeure* provision and, therefore, any change must be implemented under NGA section 5. Tennessee further argues that any change to the existing *force majeure* provision depends on final approval of the contested SFV rate design.

54. While some parties either support or do not oppose Tennessee's proposal to defer the issue, some parties request that Tennessee be required to change its tariff to provide partial reservation charge credits for *force majeure* outages when the proposed SFV rate design goes into effect, subject to refund, on June 1, 2011. Several parties assert that the Commission can change the provision because Tennessee's proposed SFV rate design has altered the operation of the existing *force majeure* provision. North American Marketers request that Tennessee be required to make a new crediting mechanism effective on June 1, 2011, subject to the condition that if the SFV rate design is rejected any reservation charges credited to firm shippers be repaid to Tennessee with interest. Tennessee contends that refunds cannot be ordered for reservation charge credits without a section 5 determination. Tennessee asserts that it is not aware of any provision of the NGA that authorizes a requirement that pipelines provide payments subject to pay back by customers.

2. **Commission Decision**

55. The Commission recently explained its reservation charge credit policy in an order on a petition by various industry associations requesting that the Commission take action to enforce its reservation charge crediting policy, *Natural Gas Supply Assn., et al.*,

135 FERC ¶ 61,055 (2011) (*NGSA*) and contemporaneously-issued decisions in *Southern Natural Gas Co.*, 135 FERC ¶ 61,056 (2011) (*Southern*) and *Kern River Gas Transmission Co.*, 135 FERC ¶ 61,050 (2011). As these orders state, Commission policy requires that pipelines and shippers share the risk of *force majeure* service interruptions, because such service interruptions are no-fault occurrences. The risk sharing is accomplished by the pipeline providing partial reservation charge credits for all scheduled gas not delivered due to a *force majeure* event.

56. Before Order No. 636 required pipelines to shift to an SFV rate design, the risk of a *force majeure* service interruption was automatically shared between the pipeline and its shippers. A non-SFV rate design places some portion of the pipeline's fixed costs in the usage charge.[59] Therefore, in the event of an interruption in service due to *force majeure,* the pipeline would be at risk for the fixed costs included in the usage charge, since the customer would not have to pay any costs in the usage charge. However, under an SFV rate design, the pipeline does not share any risk because all of its fixed costs are included in the reservation charge.

57. After Order No. 636, the Commission first addressed the issue of how to accomplish a sharing of the risk of *force majeure* service interruptions on pipelines with an SFV rate design in Opinion No. 406, issued in a Tennessee rate case.[60] At the time of Opinion No. 406, Tennessee had shifted to an SFV rate design as required by Order No. 636, yet its tariff still contained a provision excusing it from providing any reservation charge credits during a *force majeure* service interruption. Opinion No. 406 held that a continuation of that tariff provision would be unjust and unreasonable, because the SFV rate design required Tennessee's shippers to bear all of the risk of a *force majeure* service interruption, absent reservation charge credits. Accordingly, the Commission affirmed the Administrative Law Judge's decision requiring Tennessee to adopt what has become known as the No-Profit method of determining a partial reservation charge credit. Under that method, the pipeline provides partial refunds commencing on the first day of the interruption in service, covering the portion of the pipeline's reservation charge that represents the pipeline's return on equity and associated income taxes. Opinion No. 406 also pointed out that in other cases the Commission had approved a different method of providing partial reservation credits, the Safe Harbor method. Under that method,

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[59] For example, under the MFV rate design generally being used before Order No. 636, the pipelines' return on equity and associated income taxes were in the usage charge.

[60] *Tennessee Gas Pipeline Co*., Opinion No. 406, 76 FERC ¶ 61,022 (1996) (Opinion No. 406), *opinion and order on reh'g*, Opinion No. 406-A, 80 FERC ¶ 61,070.

reservation charges must be credited in full to the shippers after a short grace period without a crediting requirement (i.e., 10 days or less).[61]

58. On rehearing of Opinion No. 406, the Commission reaffirmed the policy adopted in that opinion. However, the Commission found that circumstances on the Tennessee system had changed since Opinion No. 406, because a settlement had modified Tennessee's rate design to include certain fixed costs in the usage charge so that Tennessee no longer utilized the SFV rate design. Opinion No. 406-A held that Tennessee's new non-SFV rate design accomplished the Commission's goal of ensuring that the risk of *force majeure* service interruptions be shared, because Tennessee would share the risk by not collecting the costs recovered in the usage charge while the shippers would continue to pay the reservation charge.[62] Therefore, the Commission allowed Tennessee to retain its tariff provision excusing it from providing reservation charge credits during *force majeure* service interruptions.

59. In this proceeding, Tennessee has proposed to return to an SFV rate design. Accordingly, the holdings of Opinion No. 406 once again apply. The interaction between Tennessee's section 4 proposal to use an SFV rate design and its existing tariff provision excusing credits during *force majeure* service interruptions "will *create* results that are unjust or unreasonable under *existing* Commission policy as it applie[d] to" Tennessee at the time of its filing of this section 4 rate case.[63] The Commission accordingly finds that NGA section 4 provides the Commission the authority to require Tennessee to implement partial reservation charge credits for *force majeure* service interruptions at the same time it implements its section 4 proposal to change its rate design to SFV. Tennessee must provide its shippers with the partial reservation charge credits for *force majeure* events required by Commission policy for pipelines with an SFV rate design as of the June 1, 2011 effective date of its proposed SFV rate design. The Commission will not direct which of the two partial credit methods the Commission has approved Tennessee must choose. The Commission would also consider another method provided it results in the same type of risk-sharing. Therefore, Tennessee is directed to file revised tariff records to be effective the date Tennessee motions its base rates into effect, which are consistent

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[61] *See, e.g., Texas Eastern Transmission Co.*, 62 FERC ¶ 61,015 (1993). *Natural Gas Pipeline Company of America*, 106 FERC ¶ 61,310, at P 20-24, *order denying reh'g*, 108 FERC ¶ 61,170, at P 10-11 (2004).

[62] Opinion No. 406-A, 80 FERC ¶ 61,070, at 61,200.

[63] *East Tennessee Natural Gas Co. v. FERC*, 863 F.2d 932, 943 (D.C Cir. 1988) (emphasis in original) (clarifying *Cities of Batavia v. FERC*, 672 F.2d 64, 76-77 (D.C. Cir. 1982)).

with Commission policy regarding reservation charge credits for outages due to *force majeure* events.

C. Non-*Force Majeure* Events

60. Tennessee's existing tariff provides for reservation charge credits during non-*force majeure* service interruptions. The tariff provides generally that, if Tennessee fails to deliver the quantity of natural gas which the shipper scheduled for delivery at its primary points, taking into consideration an allowable variation of two percent, then Tennessee will provide a reservation charge credit equal to the difference between the quantity actually delivered and the quantity scheduled by the shipper.

61. Several parties object that Tennessee's current tariff provisions concerning reservation charge credits for non-*force majeure* events conflict with Commission policy and request appropriate Commission action pursuant to NGA section 5. Tennessee asserts that it has not proposed to make any change to its existing reservation charge credit provision and that only the issue of reservation charge credits for *force majeure* events was set for the technical conference. Tennessee asserts that any resolution of these issues should either be by consensus or at the hearing so that a tariff provision can be placed into effect at the appropriate time.

62. The Commission requires full reservation charge credits during non-*force majeure* events regardless of a pipeline's rate design. Therefore, unlike the situation with respect to the reservation charge credits during *force majeure* events discussed above, Tennessee's section 4 proposal to shift to an SFV rate design does not affect the justness and reasonableness of its tariff provisions concerning reservation charge credits during non-*force majeure* events. Accordingly, the Commission must act under NGA section 5 to modify those provisions. The Commission finds that Tennessee's shippers can raise these non-*force majeure* event reservation charge crediting issues for section 5 determinations in this section 4 proceeding, even though Tennessee has not proposed to change those provisions. While we generally discourage parties from raising unrelated issues in section 4 proceedings, the Commission may use its discretion to act under section 5 of the NGA when it is made aware of a tariff provision that is clearly contrary to Commission policy[64] consistent with our explanation of this issue in our recent decision in *Southern*.[65] Furthermore, in *NGSA*, the Commission determined that, in the interest of obtaining pipeline compliance with our longstanding reservation charge crediting policy, we will permit parties to raise the issue in any section 4 proceeding filed

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[64] *Wyoming Interstate Gas Co., Ltd.*, 129 FERC ¶ 61,022, at P 11 (2009).

[65] 135 FERC ¶ 61,056 at P 12-17.

by a pipeline.[66] As discussed in the following sections of this order, the Commission finds that certain aspects of Tennessee's existing reservation charge credit provisions for non-*force majeure* events are contrary to established Commission policy. Therefore, pursuant to section 5 of the NGA, the Commission directs Tennessee either to file revised tariff records, consistent with the discussion below or explain why it should be permitted to retain the provisions which are contrary to Commission policy.

D. 98 Percent Requirement

1. Comments

63. Tennessee provides reservation charge credits for non-*force majeure* outages in its firm rate schedules if it is unable to make deliveries of at least 98 percent of the shipper's scheduled volumes.[67] Northeast Customer Group, Tennessee Customer Group, PGC, and Anadarko argue that Tennessee must remove this two percent tolerance as in conflict with the Commission's requirement of full reservation charge credits for non-*force majeure* outages. Tennessee agrees that these parties have cited cases where the Commission has stated that the 98 percent requirement would improperly require customers to bear the risk associated with interruption of service within the pipeline's control.[68] However, Tennessee contends that, in these cases, the Commission has misapprehended the reason for this two percent tolerance because the Commission stated such limitations would improperly require customers to bear the risk of interruption of service within the pipeline's control. Tennessee asserts that the two percent tolerance reflects the commonly accepted fact in the industry that gas flow cannot be precisely measured and that there is typically a two percent meter error inherent in gas measurement.[69] Tennessee further asserts that a two percent variance between the amount of gas scheduled and delivered is not within the pipeline's control, and pipelines should not be required to provide credits for these types of measurement discrepancies.

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[66] *NGSA*, 135 FERC ¶ 61,055 at P 13.

[67] Section 7 of Rate Schedules FT-A, FT-BH, FT-G, and FT-IL.

[68] *Citing Petal Gas Storage, L.L.C.*, 126 FERC ¶ 61,199, at P 25 (2009) (*Petal Gas*); *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 63 (2006) (*Rockies Express*).

[69] *Citing, e.g., Panhandle Eastern Pipe Line Co.*, 82 FERC ¶ 61,163, at 61,597 (1998) (*Panhandle*).

2. Commission Decision

64. Tennessee's 98 percent requirement conflicts with the Commission's current policy regarding non-*force majeure* or planned maintenance events that where gas is not delivered the shipper should receive the full reservation charge credit for the undelivered amount.[70] The Commission established its current policy on the 98 percent requirement in *Rockies Express*, where the Commission rejected a provision similar to that at issue here. The Commission explained:

> The Commission's policy regarding reservation charge adjustments is that where scheduled gas is not delivered due to a non-*force majeure* or planned maintenance event, there must be a full reservation charge adjustment as to the undelivered amount. This is because the failure was due to the pipeline's conduct and was within its control. We agree with BP that Rockies Express' proposal not to provide reservation charge credits when it schedules at least 98 percent of a shipper's nominations in non-*force majeure* situations does not adequately comply with Commission policy. We acknowledge that we accepted a similar proposal in *Tennessee* [Opinion No. 406], but in that case the Commission did not specially address the merits of that provision. Upon consideration here, we find that Rockies Express' proposal is unjust and unreasonable because it requires its customers to bear the risk associated with interruption of service within the pipeline's control.[71]

In subsequent cases, the Commission has consistently followed the holding in *Rockies Express*.[72]

65. Therefore, the Commission finds that Tennessee's 98 percent threshold for reservation charge credits is unjust and unreasonable and inconsistent with the Commission's reservation charge credit policy because it requires customers to bear the

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[70] *Rockies Express*, 116 FERC ¶ 61,272 at P 63.

[71] *Id.*

[72] *See Petal Gas*, 126 FERC ¶ 61,199 at P 25-26; *Orbit Gas Storage, Inc.*, 126 FERC ¶ 61,095, at P 69 (2009); *SG Resources Mississippi*, *L.L.C.*, 122 FERC ¶ 61,180, at P 6 (2008).

risks associated with the interruption of service within the pipeline's control.[73] Tennessee's reliance on the two percent measurement error does not establish that the failure to deliver this amount was not within the pipeline's control.[74] Tennessee cites the *Panhandle* case in which the Commission denied requests for a penalty tolerance level higher than the pipeline's proposed two percent tolerance level before imposing a penalty on unauthorized overruns of contract demand. The Commission noted that "[t]he reasonableness of the two percent tolerance is underscored by the fact that they regard the 2 percent as customary meter error for the industry."[75] However, the determination of whether a pipeline should provide reservation charge credits in connection with service provided during a particular period is part of determining what amount the pipeline should bill shippers for the service provided during that period. Reservation charge credits do not entail penalties for shipper conduct adversely affecting the system. When a pipeline bills for service provided, it bills for an exact amount of service provided, regardless of what meter error may be inherent in the measurement of the service provided. If the amount of service measured by the meters for billing purposes is less than the scheduled deliveries, then it is appropriate for the pipeline to be required to provide reservation charge credits for the under-delivered amount.

66. Tennessee's existing tariff does not provide credits for the undelivered amount of service when the two percent limitation is not met and, therefore, conflicts with Commission policy that full reservation charge credits must be provided for non-*force majeure* events. Accordingly, pursuant to NGA section 5, the Commission directs Tennessee to submit a compliance filing within thirty days of the date of this order either (1) eliminating the 98 percent requirement and revising its tariff to provide reservation charge credits when it does not provide 100 percent of scheduled service consistent with Commission policy, as discussed above, or (2) providing a further explanation why that policy should not be applied to it.

E. <u>Secondary Points</u>

67. Tennessee's tariff only provides for reservation charge credits when it fails to make scheduled deliveries at a shippers primary delivery points.

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[73] *Rockies Express*, 116 FERC ¶ 61,272 at P 63.

[74] *Southern*, 135 FERC ¶ 61,056 at P 21.

[75] *Panhandle*, 82 FERC ¶ 61,163 at 61,597. The Commission also noted that the 2 percent penalty tolerance level under consideration in that case would be subject to review based on actual experience.

1. Comments

68. Anadarko contends that reservation charge credits must be provided for interruptions to secondary points. Tennessee argues that credits should be required only for service to primary points.

2. Commission Decision

69. Anadarko is in error. Commission policy concerning reservation credits is related to primary firm service, not secondary service or the scheduling priority of such service.[76] The Commission requires pipelines to provide reservation charge credits during non-*force majeure* situations, because such outages result in the pipeline failing to meet its contractual obligation to provide service to that shipper for reasons within its control. A firm shipper has such a guaranteed firm contractual right to service only at its primary points. Therefore, pipelines need not provide reservation charge credits when they fail to provide service at secondary points.[77]

F. Measurement of Reservation Charge Credits

70. Tennessee's tariff provides that it will provide reservation charge credits during non-*force majeure* outages based on "the difference between the quantity of natural gas tendered for delivery during said day or days and the quantity of natural gas scheduled by Shipper for delivery at Primary Delivery Points during said day or days."

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[76] *See Tennessee Gas Pipeline Co.*, 73 FERC ¶ 61,083, at 61,206 (1995), where the Commission stated that:

> A shipper pays reservation charges based on primary points not on secondary points. The secondary rights to delivery points are based on Commission regulations and are by definition inferior to primary point rights. The reservation charge a customer pays is based on its contract with the pipeline for receipt and delivery of gas at particular primary points, and corresponding reservation charge credits should ordinarily be given when the pipeline fails to provide service to those particular points. The contract does not guarantee the same level of security if other points are used; rather the Commission's regulations require [a pipeline] to provide service to those other points if it can. If a customer wants to be able to receive reservation charge credits for service at a particular point, then that customer should reserve that point as a primary point.

[77] *Southern*, 135 FERC ¶ 61,056 at P 40.

1. Comments

71. Northeast Customer Group asserts that this provision improperly bases reservation charge credits on the volumes Tennessee agrees to schedule, rather than the volumes the shipper nominates to be scheduled. Northeast Customer Group further asserts that this use of scheduled volumes would conflict with the Commission's requirement of reservation charge credits for scheduled maintenance during non-*force majeure* outages. Northeast Customer Group is concerned that, if Tennessee does not schedule service because of planned maintenance, it would not provide reservation charge credits. Anadarko asserts that Tennessee should clarify that customers are not required to nominate their Maximum Daily Quantity (MDQ) to receive reservation charge credits. Anadarko contends that Tennessee should be required to provide credits for the difference between the quantity of gas actually delivered and the higher of the shipper's nomination on the Gas Day or the immediately preceding Gas Day. Nicor asserts that reservation charge credits should be given based on the level of curtailment regardless of the level of the shipper's nomination. Some parties raise the issue of reservation charge credits associated with outages for scheduled maintenance. For example, Northeast Customer Group states that the Commission should either direct Tennessee to modify its tariff to provide such reimbursement or permit the parties to explore this issue at the hearing.

72. Tennessee argues that its tariff is consistent with Commission policy which requires reservation charge credits when scheduled gas is not delivered.[78] Tennessee asserts that Anadarko's proposal would allow shippers to game the system by nominating 100 percent of their maximum entitlement every day after the declaration of a *force majeure* event to increase their credit. Tennessee further asserts that Nicor's proposal would provide an unjustifiable windfall to shippers because Tennessee would incur the costs that reservation charges are designed to recover while providing credits for an interruption of service that did not happen. Tennessee states that it would be willing to address any perceived distinction between nominated and scheduled quantities at the appropriate time. Tennessee states that it does not oppose addressing the issue of scheduled maintenance along with all issues concerning reservation charge credits at the hearing.

2. Commission Decision

73. Tennessee's measurement of the reservation charge credits to be provided in non-*force majeure* service interruptions is consistent with Commission policy as we found in

[78] *Citing, e.g.*, *Entrega Gas Pipeline LLC*, 114 FERC ¶ 61,326, at P 13 (2006).

Opinion Nos. 406 and 406-A, except with respect to the 98 percent requirement where there has been an express change of policy since those decisions, as discussed above.

74. As explained in *Southern,*[79] the amount of reservation charge credits a pipeline must give in the non-*force majeure* situation is measured by the amount of service which the shipper nominated to be scheduled but the pipeline was unable to deliver. The reservation charge credit is not measured by a shipper's contractual entitlement for service. The Commission interprets the term "the quantity of natural gas which Shipper has scheduled for delivery" in Tennessee's tariff to mean nominated amounts the shipper nominates to be scheduled by the pipeline consistent with the Commission policy discussed above. A shipper's scheduling nominations are often referred to as amounts the shipper "scheduled," despite the fact that technically only the pipeline "schedules" service.

75. With respect to scheduled maintenance, consistent with our interpretation that Tennessee uses nominated volumes to calculate the reservation charge credits, Tennessee's tariff language complies with the Commission's crediting policy regarding scheduled maintenance. As Northeast Customer Group notes,[80] the Commission found in *Tennessee Gas Pipeline Co.*, 133 FERC ¶ 61,191, at P 17 (2010):

> section 7 of [Tennessee's] Rate Schedules FT-A, FT-BH, and FT-G, FT-IL requires it to provide demand charge credits whenever it is unable to schedule service for firm shippers because it is performing maintenance.

76. Accordingly, Tennessee's tariff provision is consistent with Commission policy requiring the pipeline to provide reservation charge credits for amounts not delivered during non-*force majeure* events including scheduled maintenance.[81]

77. With regard to Tennessee's concern about shippers gaming their nominations, the Commission recognizes that pipelines may give advance notice of the unavailability of service, i.e., due to an outage or scheduled maintenance, before shippers have submitted scheduling nominations for the day (or days) of the outage. In that circumstance, shippers' scheduling nominations may not accurately reflect what they would have scheduled without advance knowledge that the scheduling nominations would not be

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[79] *Southern*, 135 FERC ¶ 61,056 at P 32-34.

[80] Northeast Customer Group Comments at 56.

[81] *See Southern*, 135 FERC ¶ 61,056 at P 24-27.

accepted. Therefore, in *Southern*,[82] the Commission found that in those circumstances, it is reasonable for a pipeline to calculate the reservation charge credits based on an appropriate historical average of usage as a substitute for use of actual scheduled amounts, i.e., the shipper's prior seven days utilization of firm capacity when the pipeline has given such advance notice. Accordingly, in order to address its concern about gaming, Tennessee may, as part of the compliance filing directed by this order, propose tariff language using an appropriate historical average consistent with the decision in *Southern*.

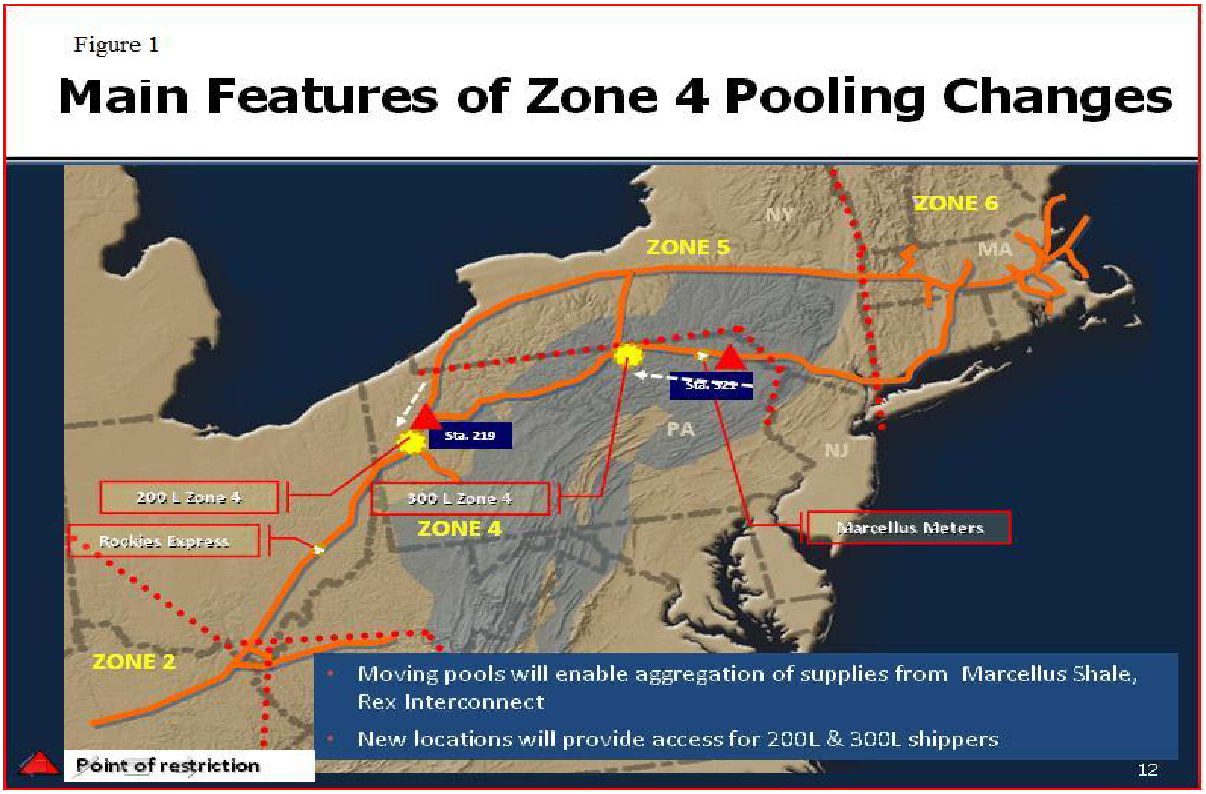
V. Changes to Pooling Points

A. Proposal

78. Tennessee filed tariff changes related to its pooling services under Rate Schedule SA. In response to operational issues responsible for restrictions on Tennessee's system due to increased Marcellus shale gas, volumes received into the Tennessee system from the REX Pipeline in Zone 4, and increased production in the Haynesville region, Tennessee proposes to modify the location of existing pooling points. In Zone 4, Tennessee proposes to move the 200 Line Pool upstream to the suction side of Station 219 and to move the 300 Line Pool upstream to the discharge side of Station 313. (See Figure 1 below.)[83] In Zone 1, Tennessee has filed to move the Zone 1 100 Leg pool further upstream to MLV 43. In addition, Tennessee proposes to allow supplies that enter the Tennessee system near the terminus of Zone 1 at Station 87 to be aggregated into the Zone 1 500 leg pool.

[82] *Southern*, 135 FERC ¶ 61,056 at P 34.

[83] Tennessee's *2-16-11 Tech Conf Presentation by S. Neck - Open Season Pool Schedule*, filed February 18, 2011, at 12.



B. <u>Comments</u>

79. The Northeast State Coalition filed comments in support of Tennessee's changes to its pooling services. The Northeast Customer Group notes that the location of Tennessee's proposed Zone 4 pooling points should facilitate receipts of Marcellus shale gas. However, Northeast Customer Group requests that Tennessee's proposal be modified to allow shippers to avoid incurring fuel, transportation, and usage charges to deliver gas from the Station 313 pooling point to other pipeline interconnects or to an interconnection with Tennessee's storage facilities, in order to avoid inhibiting the creation of a market center at Station 313. Tennessee, addressing Northeast Customer Group concerns in its Reply Comments, indicates that there will be no change in the rates applied to services using a Zone 4 pool. Tennessee states that it does not charge for transportation into a pool, but does charge for transportation from the pool, and that billing approach will not change as the result of moving the Zone 4 pool locations.

80. Indicated Shippers argue that because Tennessee has virtual pooling points, movement of its Zone 4 Pooling Points may be unnecessary. Indicated Shippers also state that because Tennessee has not provided adequate information regarding the mainline capacity at the constraint point at Station 219 or the combined mainline flow on the 200 Line, the impact of Tennessee's proposal to relocate pooling receipts to a point upstream of a constraint point cannot be determined. In addition, Indicated Shippers list several of Tennessee's proposed expansion projects, and question if those expansions would alleviate some of the congestion on Tennessee's system, eliminating the need to

move the Zone 4 pooling points. Indicated Shippers request that the Commission require Tennessee to address the potential impact of those expansions before allowing it to move its Zone 4 pooling point. Indicated Shippers also request that the issue be set for hearing to address its objections discussed above.

C. **<u>Commission Decision</u>**

81. The Commission finds that Tennessee has provided sufficient justification for redefining its pooling areas and finds that its proposals are just and reasonable, and denies the request to set the issues for hearing.

82. The Commission's determination in *El Paso*[84] recognized the need for pools to reflect operational considerations. In examining El Paso's proposal, the Commission stated that "[o]nce physical pools are established, the Commission has determined that a showing of operational need is necessary prior to allowing modification to pooling areas."

83. No party protests Tennessee's proposed changes to the Zone 1 pools. With regard to the Zone 4 pool, Tennessee is changing the location of its pooling points to address changing operational conditions. For example, Tennessee states that it currently receives approximately 30percent of its receipts from the middle of its system in Zone 4, up from 5percent in 2009. Tennessee attributes the changes in receipts to increased Marcellus shale gas and volumes received into the Tennessee system from the REX pipeline.[85] In addition, Tennessee states that Zone 4 has several operational constraint points.[86] Figure 1 above shows Zone 4's points of constriction, and Tennessee's proposed relocation of the 200 and 300 Leg Pools. Tennessee states that moving the 200 Line pool upstream to Station 219 (shown by a white arrow on Figure 1) will reduce the likelihood of a restriction on moving gas into the pool on the 200 Line as it will eliminate the need for gas to flow through a constrained segment of pipe downstream of Station 219 in order to reach the pool.[87] Similarly Tennessee states that moving the 300 Line pool from Station 325 upstream to Station 313 (shown by a white arrow on Figure 1) will reduce the likelihood of a restriction on moving supplies into the pool, particularly during peak

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[84] *El Paso Natural Gas Co.*, 99 FERC ¶ 61,244, at 62,014 (2002) (*El Paso*). *See also Gulf South Pipeline Company, LP*, 132 FERC ¶ 61,199, at P 54 (2010) (*Gulf South*).

[85] Tennessee Ex. TGP-132 at 18:12-20 and 20:1-3.

[86] Tennessee Ex. TGP-132 at 17:12-18:2, and Ex. TGP-134.

[87] Tennessee Ex. TGP-132 at 17:1-6, and Ex. TGP-141 at 47:11-18.

winter periods, as transportation to the pool will be a backhaul as opposed to a forward haul on an historically constrained portion of the 300 Line.[88]

84. The Indicated Shippers note that Tennessee has several expansion projects in the northeast either in construction or awaiting Commission certification. They question the need for Tennessee to change the Zone 4 pooling points in light of all of this activity, and request that the Commission set the issue for hearing. The Commission denies the Indicated Shippers' request. First, as noted by the Indicated Shippers, the projects in question are either under construction or are still pending before the Commission for Commission approval. Any examination would consist of a considerable number of hypothetical situations that would not necessarily provide meaningful guidance. Nor does Tennessee need to wait to implement a pooling approach to see whether such projects will come to fruition or will be sufficient to alleviate the constraint.[89] Second, even if the capacity constraints were to disappear, Tennessee indicates that the operational changes that have resulted in significant increases in Zone 4 gas receipts are a factor in moving the location of the pools. The Commission gives deference to pipelines' operational experience and provides pipelines with reasonable discretion to manage their own systems. This is particularly true when the change will not result in significant increased revenue to the pipeline. Tennessee has presented evidence that these changes exist and evidence supporting its assertion that they will continue to exist. The Commission finds that in this instance, the pipeline's reaction to scheduling concerns as a result of the location of constraints and significant changes in the pattern of gas receipts on the pipeline's system easily falls within the allowable discretion.[90] Third, Order No. 587 requires pipelines to offer at least one pooling point.[91] In Zone 4, Tennessee offers and will continue to offer two pools, and thus it is in satisfaction of this Commission requirement. If other parties wish to establish a pool elsewhere in Zone 4, including the

[88] Tennessee Ex. TGP-141 at 47:11-18.

[89] *Gulf South*, 132 FERC ¶ 61,199 at P 60.

[90] *Id.* P 63.

[91] *Standards for Business Practices of Interstate Natural Gas Pipelines,* Order No. 587, FERC Stats. and Regs., Regulations Preambles July 1996-December 2000 ¶ 31,038 (1996), wherein the Commission required pipelines to offer pooling and also adopted North American Energy Standards Board (NAESB) Standard 1.3.17, providing that if requested by a shipper or supplier on a transportation service provider's system, the transportation service provider should offer at least one pool.

current locations, they may do so, as Tennessee is prohibited from inhibiting such a development.[92] The Indicated Shippers' request is denied.

85. Northeast Customer Group's request for modification of the pool to permit deliveries from the pool directly to other pipeline interconnects and/or storage facilities is denied. Tennessee does not propose any change to the applicable rates for gas transported through a pool. Further, Tennessee's pools are physical points. Northeast Customer Group's request to permit deliveries from the pool directly to other pipeline interconnects and/or storage facilities would convert the pool to a Zone 4 virtual pool. Northeast Customer Group makes no argument, much less demonstrate, that Tennessee's physical pooling point model is no longer just and reasonable, and it has not shown why its proposal is just and reasonable.

VI. OFO Notice Period

A. Proposal

86. Tennessee filed to reduce the notice period for Operational Flow Order (OFO) Action Alerts.[93] Under Tennessee's existing tariff, an OFO Action Alert requires a minimum notice period of 48 hours. Tennessee proposed to revise the notice period to require a minimum notice of 24 hours. Tennessee states in its Initial Filing that without a shorter notice period, it must issue a potentially more onerous OFO that would subject shippers to a higher penalty than Action Alerts for violations of the OFO.

87. Tennessee's current tariff contains several different levels of OFOs, which differ in severity and notice period. These include: Action Alerts, Critical Days, and Balancing Alerts. In the event that action is necessary to avoid a situation in which Tennessee's system integrity is jeopardized or its ability to render firm service is threatened, it may issue an Action Alert to forestall development of the situation.[94] If an Action Alert is insufficient, Tennessee can issue a Critical Day One or Critical Day Two OFO. Tennessee is required to give notice for a Critical Day One OFO no later than 10:00 p.m.

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[92] *Tennessee Gas Pipeline Co.*, 128 FERC ¶ 61,032, at P 35 (2009).

[93] NAESB Business Practices and Standards Version 1.9 Section 1.2.6 states that an Operational Flow Order is an order issued to alleviate conditions, which threaten or could threaten the safe operations or system integrity, of the transportation service provider's system or to maintain operations required to provide efficient and reliable firm service.

[94] An Action alert carries a penalty charge of $.2198 per dekatherm for which it deviates from the requirements of the OFO.

for the Critical Day One to be effective by 9:00 a.m. the following gas day. In the event that Tennessee determines that it must issue a Critical Day Two OFO, it can call a Critical Day Two to be effective no earlier than 9:00 a.m. for the gas day following the gas day that Critical Day One was in effect. A Critical Day One OFO carries a penalty of $5 plus the applicable regional spot price of gas per dekatherm for which it deviates from the requirements of the OFO. A Critical Day Two OFO carries a penalty of $10 plus the applicable regional spot price of gas per dekatherm for which it deviates from the requirements of the OFO. In the event that Action Alerts and Critical Day OFOs are not sufficient, Tennessee can issue a Balancing Alert. Balancing Alerts must be issued a minimum of eight hours before the action required by the OFO. A Balancing Alert OFO carries a penalty of $15 plus the applicable regional spot price of gas per dekatherm by which it deviates from the requirements of the OFO. If neither Action Alerts, Critical Days, nor Balancing Alerts are sufficient to correct a system problem, or if there is insufficient time to carry out the procedures of the OFO, Tennessee reserves the right to take unilateral action, including the curtailment of firm service, to maintain the operational integrity of its system.[95]

88. After the technical conference and negotiations with various interested parties, Tennessee, in its Preliminary Comments, proposed to change the notice period to 27 hours instead of its originally proposed 24 hours. In addition, Tennessee re-inserted into the tariff language concerning the expectation that the recipient of an OFO will assist Tennessee in avoiding a system problem, and noted that conformance with the OFO instructions is mandatory.

B. <u>Comments</u>

89. Indicated Shippers and the New England LDCs filed comments generally in support of the proposed 27 hour notice period. Statoil/South Jersey and Piedmont filed comments that support the 27 hour notice period for weekdays. However, they state that during weekends and holidays the 27 hour notice period is inadequate and request that the 48 hour notice period be maintained on weekends and holidays.

90. Cabot filed comments opposing the 27 hour notice period proposed by Tennessee, stating that the change is not operationally necessary and that reducing the notice period would place the need for shipper action in response to an alert day closer to circumstances that might warrant a more onerous OFO. In addition, Cabot also states that the 27 hour notice period is inadequate because it places an undue burden on parties

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[95] Sheet No. 357, Action Alerts, 0.0.0, Sheet No. 358, Action Alerts Critical Days, 0.0.0, Sheet No. 360, Critical Days Balancing Alerts, 0.0.0, Sheet No. 361, Balancing Alerts, 0.0.0 to FERC NGA Gas Tariff, TGP Tariffs.

particularly during weekends or extended holidays, and does not allow sufficient time for suppliers to take corrective action. Thus, Cabot requests that the 48 hour notice period be maintained in order for suppliers and their markets to coordinate potential adjustments.

91. In its post-technical conference comments, Tennessee asserts that its proposal to reduce the notice period from 48 to 27 hours enables the pipeline to make a more informed decision on whether to declare an OFO Action Alert based on updated accurate information such as weather patterns.[96] Tennessee also reiterates its claim that the reduced notification period may prevent the issuance of a more onerous OFO. Tennessee explains that because the events that trigger the issuance of an OFO Action Alert are beyond its control, so is Tennessee's ability to issue advance notice.[97] Thus, claims Tennessee, if it is precluded from issuing an OFO Action Alert on a weekend or holiday because it cannot give 48 hours notice, then it will have no choice but to issue a more onerous Critical Day 1 OFO, which carries a penalty of $5.00 plus the spot price of gas per Dth, as opposed to the penalty of $0.0128 per Dth for an OFO Action Alert.[98] With regard to Cabot's claim that the reduced noticed period is not operationally necessary, Tennessee states that OFO Action Alerts are by their very nature operationally necessary as they are used to protect system integrity and Tennessee's ability to provide firm service.[99]

C. <u>Discussion</u>

92. The Commission accepts Tennessee's proposal to shorten the OFO Action Alert notice period in its tariff. Several commenters assert that 27 hours is not enough time to address an OFO Action Alert on weekends or holidays. However, pipeline operations, including receipts and deliveries of shippers' gas, are a 24-hour a day, 7-day a week operation. Tennessee's tariff requires shippers, their agents, point operators, and balancing agreement holders to designate one or more persons for Tennessee to contact on operating matters on a 24-hour a day, 365 day a year basis, and it also requires that such designee have adequate authority and expertise to deal with operating matters.[100] Further, Tennessee's hourly nomination cycles provide opportunities to adjust scheduled

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[96] Tennessee Initial Comments at 13.

[97] Tennessee Reply Comments at 18.

[98] *Id*.

[99] *Id*.

[100] Sheet No. 356, Pressure Gas Delivery OFO, 0.0.0 to Tennessee's FERC NGA Gas Tariff, TGP Tariffs.

quantities of gas whether an Action Alert falls on a business day or non-business day. Thus, Tennessee shippers must be staffed to address potential operating issues at all times, including weekends and holidays, and Tennessee's hourly nomination procedures provide shippers ample opportunities to change their nominations in a timely fashion when necessary.

93. We reject Cabot's argument. Cabot comments that the change to a 27 hour notice period is not operationally necessary. As Tennessee points out, however, the purpose of an OFO is system integrity,[101] and thus OFO Action Alerts are by their nature operationally necessary as determined by pipeline in its role as operator of the system. If necessary, Tennessee is authorized to issue an OFO upon short notice in order to maintain system integrity or even to take unilateral action.[102] Despite this authority, however, Tennessee attempts to project system operations and identify potential operational problems that may affect system integrity or continuity of service as early as possible. Based on these projections, Tennessee offers several different levels of OFOs with different notice periods in order to give customers time to respond and to ensure that they are not needlessly penalized. Tennessee's proposed OFO Action Alert notice period allows Tennessee to issue an OFO with out potentially having to issue a more onerous OFO such as a Critical Day or Balancing Alert, which carries with it a much higher penalty charge. In addition, the proposed notice period provides shippers advance notice of an OFO Action Alert while taking into account the gas day, allows Tennessee to maintain system integrity, and adheres to the applicable NAESB standards and is thus reasonable.

VII. Regional Daily Imbalance Charge

A. Proposal

94. Tennessee proposes to continue to impose a daily imbalance charge under Rate Schedules LMS-PA (Load Management Service-Production Area) and LMS-MA (Load Management Service-Market Area). Those imbalance charges currently apply only on days on which the net pipeline imbalance position is greater than plus or minus five percent of scheduled quantities and apply only to a balancing party with an imbalance greater than 10 percent of scheduled volumes in the same direction as the net pipeline position.[103] The imbalance charge is two times the Rate Schedule PAL rate for

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[101] *Tennessee Gas Pipeline Company*, 108 FERC ¶ 61,177, at P 2 (2004).

[102] Sheet No. 361, Balancing Alerts, 0.0.0 to FERC NGA Gas Tariff, TGP Tariffs.

[103] The daily imbalance charge under Rate Schedule LMS-PA applies to the difference between scheduled and actual receipts at the balancing party's receipt point. The daily imbalance charge under Rate Schedule LMS-MA applies to the difference

(continued…)

imbalances greater than 10 percent and less than or equal to 20 percent, and four times the Rate Schedule PAL rate for imbalances greater than 20 percent. Tennessee provides on PASSKEY a continuous notice detailing the pipeline's net imbalance position. Tennessee credits revenues collected pursuant to this mechanism to balancing parties with an imbalance that is within plus or minus five percent of scheduled volumes. According to Tennessee, the daily imbalance charge thus (1) rewards parties that stay within 5 percent of scheduled volumes; (2) is only applied to parties who exceed the 10 percent tolerance; and (3) is only charged when the system is stressed by being more than five percent out of balance.

95. In this proceeding, Tennessee proposes that, instead of applying the net pipeline position across all zones as is the current practice, it will utilize a regional approach by establishing two regional net pipeline positions: one for Zones 0 and 1, and another for Zones 2-6. If the regional net pipeline position for any region is greater than plus or minus five percent, balancing parties in that region and in the same direction as the regional net pipeline position will be assessed the same charge as currently in effect for net pipeline position. Tennessee claims that these changes are designed and intended to change shipper behavior and to help to better manage imbalances on the Tennessee system in a manner that more fairly focuses on assessing penalties on those parties that are actually causing harm to the system. Tennessee further claims that the regional net pipeline position approach should help to minimize the need for Operational Flow Orders.

96. In its Preliminary Comments, Tennessee made two clarifications and revisions to its regional net pipeline position proposal. Tennessee proposes (1) to exempt application of the Daily Imbalance Charge for deliveries at or below 1,000 Dth; and (2) to ensure that credits will be provided based on Daily Imbalance Charges collected in each region.

B. <u>Comments</u>

97. The Indicated Shippers claim that Tennessee has not demonstrated that system operations and customer behavior require a change to the currently effective daily system-wide imbalance calculation. Indicated Shippers point out that Tennessee admits that, as the result of its proposed change, the Daily Imbalance charge will likely be imposed more often than in the past. The Indicated Shippers speculate that, while Tennessee does post system balance information, shippers do not really monitor their and Tennessee's imbalance positions over the course of the gas day. Notwithstanding, the

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between scheduled quantities and actual quantities accepted at the balancing party's delivery point.

Indicated Shippers state that, while they do not agree with Tennessee's proposal, they do not oppose the proposal as revised by Tennessee's Preliminary Comments.

98. Sequent claims that Tennessee has not provided operational evidence in support of its need for two Daily Balancing regions. Sequent claims that Tennessee continues to operate its pipeline as a single system. Sequent believes that Tennessee's proposal manufactures a spurious need to impose balancing charges when, in fact, Tennessee's system needs no balancing. Sequent requests that the Commission reject Tennessee's proposal.

C. Commission Decision

99. For the reasons discussed below, the Commission finds that Tennessee has shown that applying its daily imbalance charge on a regional basis is reasonable. However, its proposed tariff language does not actually implement its intended regional approach to determining daily imbalance charges. Accordingly, the Commission rejects Tennessee's proposal, without prejudice to Tennessee re-filing its proposal in a separate limited section 4 filing consistent with the discussion below.

100. Tennessee's proposed Preliminary Comments revisions, to (1) exempt application of the Daily Imbalance charge for deliveries at or below 1,000 Dth; and (2) ensure that credits will be provided based on Daily Imbalance Charges collected in each region, appear to have satisfied most of the adverse December 2010 comments. While the Indicated Shippers do not agree with Tennessee's proposal, they do not oppose it. As for Sequent, it continues to oppose it on the grounds that Tennessee has failed to support its proposal, noting that Tennessee still operates its pipeline as a single system. The Commission believes that Tennessee has shown that a regional determination of daily imbalance charges is reasonable. While Tennessee operates its pipeline as a single system, a regional approach better identifies where and when imbalances may adversely affect system operations and services, because of changed and projected changes in shipper utilization of its system.

101. Notwithstanding, the Commission rejects Tennessee's proposal, because the proposed tariff language fails to carry out its intent to determine daily imbalance charges on a regional basis. Tennessee states that its proposal would establish two regions upon which to calculate Daily Imbalances. At Ex. TGP-131, it purports to show examples of how the Daily Imbalance calculations would appear if its proposal were applied to historical data. The implication of Tennessee's testimony and Ex. TGP-131 is that Daily Imbalances will be calculated on a regional basis. However, Tennessee did not propose to change the tariff provisions governing the calculation of Daily Imbalance charges:

> … Transporter shall calculate ~~the~~ each regional net pipeline position by dividing the sum of the total positive or negative cumulative imbalances at all points covered by this Rate

> Schedule and the total positive or negative cumulative imbalances at all points under Rate Schedule LMS-PA by the sum of the total scheduled quantities at all points covered by this Rate Schedule and the total scheduled quantities at all points covered by Rate Schedule LMS-PA. The resulting % imbalance is the regional net pipeline position.[104]

102. Thus, according to this tariff language, regional net pipeline positions will be calculated on the basis of *total* imbalance data from both Rate Schedules LMS-MA and LMS-PA for the entire system. Because the same system-wide imbalance data will be used to calculate the pipeline's regional net pipeline position for each region, the net pipeline imbalance positions for each region will always be the same as that of the other region. The end result would appear to be that Tennessee would impose exactly the same daily imbalance charges as if it had never made the instant proposal. Therefore, we reject Tennessee's proposal located on the tariff records noted in footnote 104 above.

103. This rejection is without prejudice to Tennessee re-filing its proposal in a separate proceeding, modifying the Daily Imbalance calculation consistent with its proposal, and demonstrating that its imbalance calculation description will generate the expected results.

VIII. Cashout Modifications

A. Pricing Points

1. Proposal

104. In its Initial Filing, Tennessee proposed several other changes to its mechanism for cashing out monthly imbalances, including the addition of two market area pricing points to the pooling and marketing area pricing indices used to determine cashout prices.[105] Specifically, Tennessee is proposing to add the Appalachia and New England pricing points from Natural Gas Week's Gas Price Report. Tennessee asserts that the Appalachia point is reflective of the price of gas traded in Tennessee's Zones 2-4, and the New England point reflects the price of gas in Tennessee's Zones 5-6.[106] Tennessee states that

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[104] Rate Schedule LMS-MA, section 7(a)(ii) located at Tennessee Gas Pipeline Company's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 248, , 1.0.0. Redline/strike as provided by Tennessee. Similar language is located in Rate Schedule LMS – PA at section 5(b), Sheet No. 264, , 1.0.0.

[105] Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 266, , 1.0.0.

[106] Initial Filing at 10 (citing Moran Test., Ex. TGP-130, at 19).

the additional market area pricing points are necessary to reflect recent changes in supply sources on its system and to more accurately reflect the price of gas transported by Tennessee due to the increase in Marcellus shale gas on its system and from its interconnection with Rockies Express Pipeline, LLC (REX). Therefore, monthly imbalances arising in the Zones 2-4 region will be cashed out at the Appalachia price and imbalances arising in the Zones 5-6 region will be cashed out at the New England price.

2. Comments

105. The Northeast LDCs and the Northeast Customer Group support Tennessee's proposal to add the new pricing points.[107] Cabot challenges Tennessee's continued use of Natural Gas Week indices instead of Gas Daily indices in its cashout calculations, on the basis that the natural gas market overwhelmingly relies on and uses the Gas Daily indices while the Natural Gas Week is outdated. Cabot claims that, because of the dominant position in the industry of Gas Daily indices, they are likely more reliable in terms of establishing the market prices in a particular region.[108] Cabot also comments that Tennessee should consider a pricing point that more accurately tracks Marcellus Shale production in Appalachia. Anadarko questions Tennessee's proposal to include Natural Gas Week's Gas Price Report for Dominion North in its calculations for Zones 2-4, which are associated with the proposed Appalachia region. Anadarko claims that Dominion North does not represent the value that should be associated with Zones 2-4, and therefore should not be included in the Appalachia pricing calculations.[109]

106. In reply, Tennessee claims that the Appalachia pricing point it proposes is reflective of the price of gas traded in Tennessee's Zones 2-4, and thus does accurately track the price of gas transported by Tennessee as a result of increased Marcellus shale gas and its interconnection with REX. Tennessee also notes that the New England point it proposes is reflective of the price of gas traded in Tennessee's Zones 5-6.[110]

107. Moreover, in response to Anadarko's comment on the inclusion of the Dominion North pricing point, Tennessee states that pricing point includes deliveries in Tennessee's Zone 4, including deliveries by Tennessee to points of interconnection with Dominion Transmission that are included in the Dominion North Price Point. Tennessee asserts that

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[107] Northeast LDCs Initial Comments at 9, Northeast Customer Group Initial Comments at 10.

[108] Cabot Initial Comments at 3.

[109] Anadarko Initial Comments at 6.

[110] Tennessee Reply Comments at 12.

Dominion North is thus an appropriately representative value for imbalance calculations within the Appalachia region.

108. In response to Cabot's suggestion that Tennessee use the Gas Daily indices instead of Natural Gas Week, Tennessee states that the publications in question all provide similar prices based on the same set of data. Tennessee further asserts that Natural Gas Week's report is preferable because it organizes and weighs the prices in precisely the same manner as used in Tennessee's tariff. Tennessee contends that Cabot has not shown that Tennessee's use of the Natural Gas Week index is less reliable or unjust or unreasonable and thus the Commission should approve the proposal.

3. Commission Decision

109. The Commission finds that Tennessee's proposal to add two pricing points in its cashout calculation is just and reasonable as a means of reflecting the price of gas transported on Tennessee from new supply sources. As Tennessee states, the Appalachia Point reflects gas prices traded in Tennessee's Zones 2-4, where it receives new supply from the Marcellus Shale and REX. Cabot has not shown why this point does not accurately track Marcellus shale production in Appalachia. Similarly, Anadarko does not provide an explanation as to why the Dominion North point does not represent the value of gas traded in Tennessee's Zones 2-4. As explained by Tennessee, that pricing point includes deliveries made in Zone 4 by Tennessee.

110. As to the appropriate price index for Tennessee to use in its monthly cashout mechanism, the Commission finds that Tennessee's continued use of Natural Gas Week's indices is just and reasonable. Cabot's request for alternative indices does not show that Tennessee's approach is unjust and unreasonable, particularly when Tennessee is not proposing a change in this regard.

B. Cashout Threshold Proposal

1. Proposal

111. In its Initial Filing, Tennessee proposed to carry forward the positive Net Cashout Balances up to $4 million, and to apply carrying charges to both positive and negative imbalances for an annual cashout period. Tennessee stated that this will reduce the administrative burden associated with making refunds. Tennessee states that its proposal will be more equitable given that negative balances are not returned to Tennessee but rather are rolled over to the next year regardless of the size of the balance. Tennessee also notes that it proposes to apply carrying charges to any balances, both positive and negative, that are rolled over to the following year. Tennessee states that this change is needed to eliminate an inequity in the current tariff provisions by keeping both Tennessee and shippers/operators whole during the time money is owed to them.

112. To implement its proposal Tennessee proposes the following redline revisions to its tariff:

> To the extent that the Net Cashout Balance in any Annual Cashout Period results in a positive balance greater than $4 million, Transporter shall refund such balance, plus accrued interest determined in accordance with section 154.501 of the Commission's regulations to shippers and OBA [operational balancing agreement] point operators subject to the cashout provisions of Rate Schedules LMS-MA and LMS-PA. To the extent the positive balance is $4 million or less, then such balance shall be carried forward and applied to the next annual determination of the Net Cashout Balance.
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> * * *
>
> To the extent that the Net Cashout Balance in any Annual Cashout Period results in a negative balance, such balance plus accrued interest determined in accordance with section 154.501 of the Commission's regulations shall be carried forward and applied to the next annual determination of the Net Cashout Balance.[111]

2. Comments

113. In its Preliminary Comments, Tennessee proposes that positive Net Cashout Balances will be refunded only if such balance exceeds $4 million in any year, and that interest would accrue on both negative and positive balances. However, Tennessee states that in exchange for support for this proposal, Tennessee would agree to reduce the refund threshold to $2 million.

114. Subsequently, in its Initial Comments Tennessee states that under its existing tariff, negative net cashout balances are carried forward to the next annual period, while positive net cashout balances must be refunded and Tennessee states that this is inequitable. Tennessee stated that originally it proposed to add a $4 million threshold before any refunds are made, and to include a carrying charge on any positive or negative net cashout balances that are carried forward. Interest would be calculated in accordance with Commission regulations pertaining to refunds. Tennessee asserts that at the technical conference, some parties contended that a $4 million threshold was too high so

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[111] Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 256, , 1.0.0, redline/strikeout as provided by Tennessee.

Tennessee agreed to reduce the refund threshold to $2 million in exchange for support for this proposal.

115. In its Initial Comments New England LDCs supports Tennessee's proposal. However, the Indicated Shippers state that Tennessee's proposal is potentially unduly discriminatory and preferential. They argue that cash-out over-recoveries from one year may ultimately be refunded to different balancing parties in a different year. Indicated Shippers submit that Tennessee has not justified the proposed revision to its cash-out refund mechanism but argue that if the Commission approves this proposal, such approval must be made subject to Tennessee's proposal to revise the refund floor to $2 million.

116. Northeast Customer Group argues that Tennessee has not shown that it is just and reasonable to establish a $2 million threshold, or any minimum dollar threshold of whatever kind, before refunds of net cashout balances are made in any year. The Northeast State Coalition argues that although Tennessee asserts that its $2 million dollar threshold is necessary in order for Tennessee to "reduce the administrative burden" associated with refunds, Tennessee also provided the same rationale with respect to a $4 million dollar threshold it originally proposed. Northeast Customer Group questions why the administrative burden, once previously unduly burdensome for net cashout balances less than $4 million, is now bearable for cashout balances from $2 million to $4 million. In addition, Northeast State Coalition argues that only once in the past ten years has a positive net cashout balance fallen below $2 million, so it is not persuaded that establishing a threshold would affect Tennessee's administrative burden.

117. Sequent argues that the Commission should reject Tennessee's proposal, even as revised from a $4 million threshold to a $2 million threshold. Sequent argues that Tennessee is unable to offer a compelling reason that it now be permitted to "bank" positive cashout revenues. Sequent asserts that net cashout revenue balances are monies belonging to shippers, not Tennessee, and, as such, there is no reason to allow Tennessee to retain these dollars at its shippers' expense. Sequent also asserts that in *Texas Gas,*[112] the Commission rejected a request by a pipeline for a $2 million dollar crediting threshold.

118. Anadarko states that Tennessee's proposal is unclear concerning whether Tennessee intends to apply a $2 million threshold to each regional net pipeline position separately or whether Tennessee intends to apply a $2 million threshold in the aggregate. Anadarko suggests that Tennessee employ a $1 million refund threshold for each regional

[112] *Texas Gas Transmission Corp.*, 64 FERC ¶ 61,083, at 61,814 (1993) (*Texas Gas*).

net pipeline position. Anadarko asserts that because Tennessee proposes to track imbalances and assess imbalance charges separately for each of its two proposed regional net pipeline positions, any refund threshold for positive net cashout balances should be similarly applied to each regional net pipeline position separately.

119. In its Reply Comments, the Indicated Shippers maintain that Tennessee's contention that equitable considerations require modification of the current cash-out mechanism are without basis. The Indicated Shippers maintain that nothing in the history of the operation of the cash-out suggests that the mechanism is inequitable.

120. In its Reply Comments, Tennessee states that it circulated its proposal to reduce its threshold to $2 million to see if it was agreeable to the parties and requested that they inform Tennessee if they opposed the modification. Tennessee states that because no party indicated any opposition to this proposal, as modified, Tennessee included it in its Preliminary Comments "in exchange for support" of the proposal. Tennessee states that as noted by Indicated Shippers, this proposed compromise was conditional on resolving the issue. Tennessee states that as a result of the rejection of its proposed compromise shown in the comments by several parties, Tennessee continues to support its proposed $4 million threshold.

121. Tennessee maintains that the commenters argue two main points. One that Tennessee has not justified the proposal, and two that carrying forward any amounts owed could result in refunds ultimately being paid to different balancing parties. In response Tennessee repeats that it is inequitable to require Tennessee to refund all positive cashout balances while not allowing Tennessee to collect negative balances. Further, Tennessee asserts that the relatively small amounts that would need to be refunded on a customer-by-customer basis do not justify the administrative burden of making such refunds. Tennessee notes that the parties express the desire to be paid sooner rather than later, no party has explained why it is equitable for Tennessee to be required to refund all amounts due regardless of amount, while amounts shippers owed to Tennessee are always carried forward. Moreover, Tennessee argues that with respect to the potential for different shippers to get the refunds, that is always the case with amounts that are carried forward from year-to-year, and is currently true in connection with Tennessee's carry forward of cashout losses.

122. Tennessee states that there is no Commission cashout refund threshold. Tennessee asserts the issues surrounding a cashout threshold is how much of a threshold is reasonable in light of the size of the pipeline, the number of shippers on the pipeline, and

the potential number and amount of potential refunds.[113] Tennessee submits that in its 2008 Cashout Report filed in Docket No. RP09-116-000, Tennessee's positive cashout balance was a little over $4 million. Tennessee points out that this required Tennessee to send refunds to 301 customers, 105 of which received refunds of less than $100. Tennessee adds that over half of the refunds were for less than $500. Tennessee, asserts that this $4 million refund equated to less than three tenths of a cent per dekatherm over the 1.64 billion dekatherms upon which it was allocated, at a time when the average cashout price exceeded $8.00 per dekatherm.

3. Commission Decision

123. The Commission finds that Tennessee's proposal to carry forward to the next annual cashout period positive net cashout balances up to $4 million, and to apply carrying charges to both positive and negative imbalances for an annual cashout period is just and reasonable. Tennessee has shown that this will ease its administrative burden and supported its contention with figures from its 2008 Cashout Report which shows a refund of $4 million resulting in numerous small payments. While parties argue that net cashout revenue balances are monies belonging to shippers, this point is not in dispute. Tennessee is not proposing to keep the funds but merely to wait until the payout will result in an amount that will require a meaningful payment and thus reduce the administrative burden associated with refunds. This does not, as argued, allow Tennessee to retain these dollars at its shippers' expense; rather, Tennessee must pay interest to the shippers on any retained amounts until refunds are made.

124. Moreover, the Commission cannot find, as suggested by the parties, that concerns related to intergenerational payments require rejection of the instant proposal. While it is true that under Tennessee's proposal some payments may not go to the shippers on the system when the benefits were incurred, this is a function of any delayed payment or situation where amounts are carried forward from year-to-year. In these circumstances, the Commission cannot find that this factor should negate the administrative convenience sought by Tennessee.

125. Sequent's argument that the Commission rejected Texas Gas' request for a $2 million dollar crediting threshold is not on point. Parties to that proceeding argued that Texas Gas should not be permitted to use up to $2 million dollars of shippers' money without paying interest on the retained amounts.[114] However, unlike Texas Gas,

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[113] Tennessee Reply Comments at 15 (citing *Gulf South Pipeline Co.*, 113 FERC ¶ 61,212, at P 5 & n.1 (2005) (citing a $400,000 payout threshold for Discovery Gas Transmission, LLC)).

[114] *Texas Gas*, 64 FERC ¶ 61,083 at 61,814.

Tennessee proposes to pay interest on the retained amounts. Therefore, the rejection of Texas Gas' proposal did not establish a Commission policy against thresholds before a pipeline must refund a positive balance or, given the differences between the proposals, require that the Commission reject the instant proposal.

126. Anadarko states that Tennessee's proposal is unclear concerning whether Tennessee intends to apply a $2 million threshold to each regional net pipeline position separately or whether Tennessee intends to apply a $4 million threshold in total. The Commission does not find the subject proposal to be unclear. Tennessee's proposal is to provide for a $4 million threshold amount applicable to the monthly imbalance cashout mechanism. Tennessee's proposal to establish regional net pipeline imbalance position is only for purposes of determining what shippers are subject to daily imbalance penalties. That proposal thus has no applicability to the monthly imbalance cashout mechanism at issue here.

127. Lastly, several parties argue that if the Commission accepts Tennessee's proposal to establish a threshold amount before refunds are made, it should set the threshold amount at $2 million. The Commission declines to take the action under section 5 of the NGA that would be required to direct Tennessee to choose a particular, arbitrary dollar amount. While Tennessee did offer a $2 million threshold amount in comments filed after the technical conference, Tennessee withdrew this offer as parties continued to oppose its proposal. In any event, the Commission finds that Tennessee has adequately supported its proposal for a $4 million threshold.

IX. Storage Cycling

A. Proposal

128. Tennessee proposes to add a provision to Rate Schedule FS that would impose a charge on firm storage customers who do not cycle their inventory by withdrawing stored gas by the end of the winter heating season. Tennessee proposes to require that storage customers reduce the amount of gas they have in storage to no more than thirty percent of their Maximum Storage Quantity (MSQ) by April 1 of each year. Tennessee's proposed charge is a reduction of the Shipper's Storage Balance by a quantity equal to the applicable fuel and gas loss rate for every Dth greater than thirty percent of Shipper's MSQ. However, the charge will not be assessed if the storage balances as of April 1 at each storage service point are less than or equal to thirty percent of the contracted MSQ.

B. **Comments**

129. Many parties[115] recommend that the Commission summarily reject Tennessee's storage cycling proposal as not supported,[116] not just, not reasonable, and unduly preferential to Tennessee (and its storage field partners, as the cycling requirement would not apply to their capacity). Most of these parties question Tennessee's standing to make such a proposal as Tennessee shares storage facilities with other pipelines, and is not the operator of most of these storage facilities. To the extent that Tennessee is relying on claims that the storage fields' geologic limitations require storage cycling, parties question why Tennessee, and not the storage fields' operators, is proposing the operational requirement, and whether pipelines sharing storage capacity with Tennessee are under the same cycling requirements Tennessee claims are necessary. They also question why Tennessee provided operational data for only one field when it utilizes several fields to provide storage services. The Indicated Shippers, Atmos, and Piedmont also note that Tennessee attempts to support its storage cycling proposal on the basis of system requirements. However, they contend that Tennessee also fails to support that rationale.

130. Tennessee, in its Reply Comments, contends that it provides adequate support of its storage fields' operational limitations. Tennessee believes that its proposal is further supported by changed storage shipper cycling behavior in response to operational changes on its transmission system as the result of the introduction of gas into the Tennessee system in the market area from REX pipeline and the Marcellus Shale. Tennessee further believes its proposal is supported by the fact that other pipelines have storage cycling requirements in their tariffs.

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[115] Anadarko, Atmos, BG Energy, ETG, Eastman, Elizabethtown Gas, Indicated Shippers, New England LDCs, NJR, Northeast Customer Group, Northeast State Coalition, Piedmont, Repsol, Sequent, and Tennessee Customer Group.

[116] Tennessee Customer Group notes that Tennessee filed with the Commission a presentation it made at the Technical Conference (*2-16-11 Tech Conf Presentation by A. Johnson - Storage Cycling*, filed February 18, 2011). Tennessee Customer Group requests that the Commission reject what Tennessee Customer Group characterizes as an attempt by Tennessee to supplement its deficient record. The Commission rejects Tennessee Customer Group's request as premature. The Commission, below, is setting the issue of storage cycling for hearing before an ALJ. If Tennessee decides to introduce this document into the record, it will be the ALJ's decision as to whether it should be made part of the record and the weight it deserves.

C. Commission Decision

131. Tennessee supports its storage cycling proposal on three bases: (1) certain storage fields have geologic characteristics that require Tennessee to cycle gas at the levels proposed; (2) Tennessee's pipeline operations have changed which, in turn, have modified how customers utilize their storage capacity and Tennessee's system requirements for storage; and (3) other pipelines have storage cycling requirements.

132. Parties have raised numerous questions of fact as to whether Tennessee's storage facilities require the cycling proposed, whether Tennessee has standing to impose such cycling requirements on the basis of storage field operational requirements that have not been imposed on Tennessee or others in the fields, and whether the proposed solution would address the alleged problems or provide Tennessee or others an undue preference. These parties request that the Commission reject Tennessee's storage cycling proposal.

133. These questions are largely focused on Tennessee's first basis of support, that the storage fields' geologic limitations required storage cycling. The geological limitations of the storage fields is a factual issue which is properly addressed at hearing. Moreover, even if the Commission were to agree with the protesting parties and find Tennessee's geologic arguments unconvincing, it would not be enough to warrant summary rejection of Tennessee's proposal without a hearing. Tennessee may be able to demonstrate at hearing that its pipeline operations require the storage cycling, or that other pipelines' storage cycling requirements affect Tennessee's pipeline operations in such a manner as to require storage cycling. Therefore the Commission will set Tennessee's storage cycle for hearing before an ALJ.

134. If Tennessee moves the proposed storage cycling provision into effect and charges the proposed fuel and gas loss retention rate, this rate has been accepted subject to refund should the Commission ultimately reject the storage cycling proposal or reject or reduce the rate.

X. Eliminating Disused Services

A. Proposal

135. Tennessee proposes to eliminate four services that it states were rarely or never used in the past several years, namely: (1) the Preferred Access Transportation (PAT) Rate Schedule, (2) the Interruptible Transportation-X (IT-X) Rate Schedule, (3) the Third Party Provider Swing Storage Option (TPP SSO), and the Downstream Swing Storage Option (DSSO).

136. Pursuant to Rate Schedule PAT, Tennessee provides preferred interruptible transportation service during the winter such that if Tennessee determines capacity is available, Rate Schedule PAT shippers would have priority over all other interruptible

services provided by Tennessee.[117] Under Rate Schedule IT-X, Tennessee provides an interruptible transportation service with hourly scheduling flexibility under certain conditions.[118]

137. The swing storage options in Tennessee's tariff generally provide balancing parties under Rate Schedule LMS-MA[119] with access to storage contracts on Tennessee's system, or with access to third party storage services, to use those contracts or third party services to resolve daily imbalances. The TPP SSO allows customers to use swing storage options provided by third party provider facilities that are directly connected to Tennessee's system, and the DSSO allows the same for third party provider facilities not directly connected to Tennessee.

B. <u>Comments</u>

138. In support of its proposal, Tennessee states that Rate Schedule PAT has never been used and that Rate Schedule IT-X has been used by only one customer in the past two years. Tennessee states that Rate Schedule IT-X was initially developed in response to requests from electric generators desiring service on short notice to meet fluctuating peak load requirements. Tennessee states that the utility of Rate Schedule IT-X diminished with the requirement that pipelines provide for intra-day nominations for all open access services, which allowed shippers to get comparable service for a higher priority at a lower rate. Tennessee argues that it should not have to spend the $100,000 to $200,000 annually that it currently spends to support these underutilized services.[120]

139. With regard to the TPP SSO service, Tennessee notes that service was developed as part of a two month pilot program beginning in September 1996. Tennessee states that as no customers utilized the option during the original two months, Tennessee extended it until June 1997. Tennessee states that the DSSO balancing option was also offered pursuant to a two month pilot program to three customers, though no customer used the service after the pilot program ended. Tennessee notes that it filed to eliminate the TPP

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[117] *See* Tennessee's currently effective FERC NGA Gas Tariff, TGP Tariffs, First Revised Sheet Nos. 201-204.

[118] *See* Tennessee's currently effective FERC NGA Gas Tariff, TGP Tariffs, First Revised Sheet Nos. 152-154.

[119] "Balancing parties" are delivery point operators on Tennessee's system that have executed operational balancing agreements. *See* Tennessee's currently effective FERC NGA Gas Tariff, TGP Tariffs, Original Sheet No. 246.

[120] Tennessee Initial Comments at 1-3.

SSO option in 1997 when no customers participated in the pilot program but the Commission required certain modifications and an opportunity for customers to utilize the service as revised. Tennessee states that to date no customer has used either of these services, and thus that it is reasonable to eliminate them from its tariff as these services are apparently not valued in the marketplace.[121]

140. The Northeast State Coalition opposes elimination of the PAT and IT-X rate schedules. The Northeast State Coalition argues that Rate Schedule IT-X should be kept because eight customers have contracted for IT-X service, even if they have not exercised their contractual rights to nominate under IT-X. The Northeast State Coalition argues that Rate Schedules PAT and IT-X may become desirable services for certain shippers in the future, even though those shippers may not have used those rate schedules in recent years.[122] No other commenters oppose the elimination of these two rate schedules, although some argue that Tennessee should quantify the cost savings of eliminating Rate Schedules PAT and IT-X and include them in its rate calculations.

141. Several commenters[123] oppose the proposed elimination of the two third party swing storage options. Most of the opposing comments argue that while these swing storage options have not been used in recent years, they may become useful in the near future as market conditions evolve. Preserving these services, commenters argue, is worth the presumably modest expense, which they claim Tennessee has failed to quantify. Louisville raises an additional argument, stating, "Tennessee's proposal is anticompetitive; it … would deny competitive TPP storage operators, like Louisville, the opportunity to compete to provide imbalance management services to customers on Tennessee's pipeline system."[124] Thus, Louisville argues, Tennessee's proposal violates § 284.12(b)(2)(iii) of the Commission's regulations.[125]

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[121] *Id*. at 5.

[122] Northeast State Coalition Initial Comments at 11-12.

[123] Louisville, New England LDCs, Northeast Customer Group, Northeast State Coalition, Statoil/South Jersey, and TVA.

[124] Louisville Initial Comments at 2.

[125] "A pipeline with imbalance penalty provisions in its tariff must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances. A pipeline also must provide its shippers the opportunity to obtain similar imbalance management services from other providers and shall provide those shippers using other providers access to transportation

(continued…)

C. Reply Comments

142. In its Reply Comments, Tennessee states that no customers expressed opposition in Initial Comments to the elimination of Rate Schedules PAT and IT-X. Tennessee notes that the only party to oppose elimination in its post-technical conference comments is the Northeast State Coalition, whose members are state commissions that do not receive service from Tennessee. Tennessee contends that the fact that not one customer has opposed the elimination of these rate schedules should weigh heavily in favor of approving its proposal over speculation that they may become useful at some point in the future.[126]

143. With regard to the TPP SSO and DSSO balancing options, Tennessee counters the argument that the changing natural gas market may make these options useful in the future by arguing that these mooted market changes have already occurred, and customers still are not using these swing storage options. Tennessee states that it experienced dramatic surges in monthly receipts from the Marcellus shale in 2010 and that its interconnection with REX has been operating at nearly full capacity for roughly a year. Tennessee states that despite these significant market shifts, customers still are not using the TPP SSO or DSSO balancing options. Tennessee further notes that none of the parties opposing its proposal have provided any specifics as to what changes in market conditions would entice them to use the services in the future.

144. Tennessee also argues that the elimination of the TPP SSO and DSSO is not anticompetitive, as is supported by the fact these services have not been used in fourteen years. Tennessee claims that it is not required by Commission precedent or section 284.12(b)(2) of the Commission's regulations to provide these services, and that the regulation requires only that pipelines not discriminate against parties using imbalance services offered by a third party. Tennessee also states that it will discuss with any customers in the future how they may use other services and options on Tennessee to best achieve results similar to those achievable under the eliminated sections. Finally, Tennessee states that it quantified the costs of retaining these unused services in its Initial Comments, namely \$100,000 to \$200,000 annually, plus an additional \$250,000 to \$400,000 to integrate these into its new information technology system.[127]

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and other pipeline services without undue discrimination or preference." 18 C.F.R. § 284.12(b)(2)(iii) (2010).

[126] Tennessee Reply Comments at 2.

[127] Tennessee Reply Comments at 7.

D. Commission Decision

145. We find Tennessee's proposal to eliminate Rate Schedules PAT and IT-X, and its TPP SSO and DSSO services, to be just and reasonable. While several parties speculated about a possible need for these services in the future, in practice these services have been almost or entirely unused in the sixteen years since Tennessee's last rate case, even as the natural gas transportation market has evolved. Thus, in practice, it appears that customers are finding other services from Tennessee or third parties to be not only adequate, but superior substitutes for the services being eliminated.

146. We reject Louisville's claim that Tennessee's proposal violates section 284.12(b)(2)(iii) of our regulations. That section requires pipelines with imbalance penalties in its tariff to provide imbalance management services, such as park and loan, to the extent operationally practicable, and also requires pipelines to provide shippers the opportunity to obtain such services from third parties without discriminating against shippers who do so. As we clarified in Order No. 637-A, section 284.12(b)(2)(iii) was intended to require pipelines to include their own imbalance management services as part of their tariff, not the third party's services. Further, pipelines cannot include in their tariffs any "unnecessary restrictions that prevent third-party imbalance providers from competing with the pipeline."[128]

147. Under its proposal Tennessee will continue to offer imbalance management services, including park and loan service and the use of the storage swing option on Tennessee storage agreements, and those services will remain in Tennessee's tariff. Further, the elimination of the TPP SSO and DSSO services from Tennessee's tariff will not create any unnecessary restrictions on the ability of shippers to obtain imbalance management services from a third party. As Tennessee states in its Reply Comments, Tennessee's shippers may obtain balance management services from third parties and will receive equal treatment whether they obtain those services from Tennessee or a third party.[129] Accordingly, Tennessee's proposal does not violate section 284.12(b)(2)(iii) of our regulations.

148. Tennessee proposes to eliminate rate schedules and services that all parties agree have not been used in many years or were never used at all. The proposal is consistent with our regulations and none of the arguments made by protesters compel us to require Tennessee to retain these unutilized services. Thus, we approve Tennessee's proposal on this issue as it is just and reasonable.

[128] Order No. 637, FERC Stats. & Regs. ¶ 31,091, 65 Fed. Reg. 35,706, 35,737 (2000).

[129] Tennessee Reply Comments at 6.

XI. General Waiver Provision

A. Proposal

149. Tennessee proposes to modify the general waiver language in section 31 of its GT&C.[130] As originally filed, Tennessee proposed to significantly expand its ability to waive any provision of its tariff unilaterally, by both striking a clause limiting that ability to situations that are "related to shipper obligations for a particular transaction" and also striking a clause requiring Tennessee to give advance notice before the effective date of the waiver.

150. Since Tennessee's Initial Filing generated substantial criticism, Tennessee modified its proposal. In its Preliminary Comments, Tennessee proposed the following revised section 31; changes marked are in comparison to the currently effective section 31 of its GT&C:

> Transporter may waive any provisions of its effective FERC Gas Tariff related to Shipper obligations ~~for a particular transaction~~ and shall not be obligated to file notice with, or seek approval from, the FERC for any waiver that is uniformly applicable to all Transporter's affected customers~~;~~<u>.</u> ~~if~~ Transporter <u>shall post a</u> ~~provides~~ notice of such waiver ~~by posting~~ on PASSKEY <u>as soon as practicable under the circumstances but no later than three business days from the date of the waiver</u>~~one business day prior to the effective date of the waiver~~.[131]

151. In its Initial Comments after the Technical Conference, Tennessee argues that the latter, revised version of the change to its waiver language is no longer opposed, is just and reasonable, and should be approved.

B. Comments

152. The New England LDCs and the Northeast Customer Group each state that they would support the latter version of the proposed waiver language, subject to one additional modification regarding the posting of notice. They express concern that in

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[130] Tennessee's FERC NGA Gas Tariff, TGP Tariffs, Sheet No. 388, Periodic Report Incorp GTC Rate Schedules Contracts Waiver, 1.0.0

[131] Pro Formal [sic] Sheet No. 388, Periodic Report Incorp GTC Rate Schedules Contracts Waiver, 1.0.0 to Tennessee's FERC NGA Gas Tariff, TGP Tariffs.

practice the notice of waivers on Tennessee's Electronic Bulletin Board (EBB) are difficult to find. Accordingly, they argue that Tennessee should notify its customers by email or display notice of waivers in a more prominently marked section of its EBB.

C. **Commission Decision**

153. Tennessee's proposed discretionary waiver provision is overly broad and therefore is inconsistent with the Commission's policy set forth in *Discovery Gas.*[132] Tennessee proposes that it may waive any provisions of its effective FERC Gas Tariff related to Shipper obligations. In *Discovery Gas*, the pipeline proposed language stating that "Transporter may waive any of its rights hereunder or any obligations of shipper on a basis that is not unduly discriminatory."[133] The Commission stated that this broad waiver provision had the potential for unduly discriminatory application. The Commission stated that it had previously held that pipelines should only use such waiver provisions to waive past occurrences, not to waive a broad range of tariff provisions for mutual benefit in the context of a transportation agreement.[134]

154. On rehearing, the Commission set forth its policy concerning general waivers and stated that such waiver provisions would be permitted in a pipeline's tariff to address specific past defaults. Further, the Commission reviewed the arguments of the parties that there is a distinction between on-going waivers that would result in non-conforming contract provisions that the Commission prohibits, and advance waivers that are needed to prevent interruption of services. The Commission stated that its intent in prohibiting such advance waivers was to prevent negotiations for service agreements that reflect permanent waivers of tariff terms and conditions of service which may result in undue discrimination among shippers, not to prohibit waivers that apply to temporary periods for operational reasons on a case-by-case basis.[135]

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[132] *Discovery Gas Transmission L.L.C.*, 111 FERC ¶ 61,377 (2005) (*Discovery Gas*). *See CenterPoint Energy Gas Transmission Co.*, 104 FERC ¶ 61,281, at P 49 (2003) (rejecting pipeline's interpretation of a tariff provision that would authorize non-conforming material deviations without seeking Commission approval) (*CenterPoint*). *See also El Paso Natural Gas Co.*, 114 FERC ¶ 61,305, at P 348-349 (2006).

[133] *Discovery Gas*, 111 FERC ¶ 61,377 at P 3.

[134] *Id.* P 4 (citing *Northern Border Pipeline Co., LLC*, 110 FERC ¶ 61,203 (2005); and *CenterPoint*, 104 FERC ¶ 61,281).

[135] *Id.* P 14.

155. Accordingly, the Commission stated,

> while we continue to find that broad waiver language of the type Discovery initially proposed in this proceeding is inappropriate, we will permit pipelines to include in their tariffs provisions not only permitting waiver of the tariff to address past defaults but also permitting advance waivers to address specific, short-term operational problems.[136]

156. Neither Tennessee's proposal nor its currently effective tariff limit its waiver authority consistent with Commission policy as set forth in *Discovery Gas*. Neither version of section 31 of its GT&C limits Tennessee's waiver authority to (1) waivers of past defaults, or (2) advance waivers to address specific, short-term operational problems. Therefore, the Commission rejects Tennessee's proposed modification of section 31 of its GT&C located at the tariff record identified in footnote 130 above. In addition, pursuant to section 5 of the NGA the Commission directs Tennessee either to file revised tariff language consistent with this discussion or explain why it should not be required to modify existing section 31 of its GT&C consistent with the Commission's policy set forth in *Discovery Gas.*[137]

157. Lastly, the New England LDCs and the Northeast Customer Group urge further modification of the proposed waiver language that would let Tennessee provide notice of any waivers of the tariff on PASSKEY no later than three business days from the date of the waiver. We find Tennessee's notice proposal to be reasonable, subject to one condition. In Order No. 717, the Commission stated that the "blanket requirement to post all waivers and exercises of discretion goes beyond what is needed to alert customers and others to possible acts of undue discrimination or preferences in favor of an affiliate."[138] As a result, section 358.7(i) of the Commission's regulations provides that pipelines are

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[136] *Id.* P 14.

[137] For example, in the subsequent compliance order following *Discovery Gas*, the Commission approved the following provision: "Transporter may waive any of its rights hereunder or any obligations of Shippers as to any specific default that has already occurred, or case-by-case in advance as to any specific, temporary operational problem, on a basis that is not unduly discriminatory." *See Discovery Gas Transmission L.L.C.*, Docket No. RP05-180-003 (July 15, 2005) (unpublished letter order).

[138] *Standards of Conduct for Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280, at P 214 (2008), *order on reh'g*, Order No. 717-A, FERC Stats. & Regs. ¶ 31,297, *order on reh'g*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh'g*, Order No. 717-C, 131 FERC ¶ 61,045 (2010).

required to post waivers granted to affiliates within twenty-four hours of the occurrence, but contains no similar requirement with respect to waivers granted to non-affiliates. Accordingly, any proposal by Tennessee for a three-day notice period must contain an exception requiring a one-day period for waivers granted to affiliates. Finally, no commenters have alleged that Tennessee's EBB is deficient under NAESB standards. Accordingly, we decline to require Tennessee to modify its EBB as sought by the New England LDCs and the Northeast Customer Group.

XII. Discount Adjustment Provision

158. Tennessee proposed to include a new provision in Section XXVII of its GT&C to set forth the burden of proof Tennessee must satisfy in a general section 4 rate case in order to obtain a discount-type adjustment of the volumes used to design its maximum recourse rates in connection with negotiated rate agreements. The proposed tariff provision requires Tennessee to meet the standards required to obtain a discounts adjustment for discounts granted to affiliates. The Commission has consistently held that, in order to obtain a discount adjustment in connection with a discount provided to an affiliate, "the pipeline has a heavy burden to show that competition required discounts to affiliates."[139]

159. Tennessee must also demonstrate that any discount type adjustment does not have an adverse impact on recourse rate shippers by: (1) showing that, in the absence of Tennessee's entering into such negotiated rate agreements, Tennessee would not have been able to contract for such capacity at any higher rate(s) or that recourse rates would otherwise be as high or higher than recourse rates which result after applying the discount adjustment; or (2) making another comparable showing that the negotiated rate contributes more to fixed cost recovery to the system than could have been achieved without the negotiated rate. Tennessee states that it must show that its customers are protected from inappropriate cost shifting caused by a claimed discount adjustment for a negotiated rate.[140]

160. In its Preliminary Comments, Tennessee stated that it intended its tariff proposal to follow the language the Commission has accepted in other recent cases. Therefore, in its Preliminary Comments, Tennessee proposed to add the word "only" to its proposed

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[139] *Trunkline Gas Co.*, 90 FERC ¶ 61,017, at 61,087 and 61,096 (2000) (describing the type of evidence the pipeline must submit to satisfy this burden).

[140] *See generally* Statement P, H. Milton Palmer Test. at 43-44.

tariff language to make it "essentially identical" to the provision recently accepted by the Commission in *Columbia Gulf*.[141]

161. Secondly, in its Reply Comments, Tennessee stated that several parties pointed out that Tennessee replaced the word "and" with the word "or" in subpart (1) of the tariff language. Tennessee stated that this change from "and" to "or" was inadvertent and that it would correct the oversight.

162. In pertinent part, with Tennessee's modifications as set forth above in bold, proposed Section XXVII of Tennessee's GT&C now reads:

> A discount adjustment to recourse rates for negotiated rate agreements shall **only** be allowed to the extent that Transporter can meet the standards required of an affiliate discount type adjustment including requiring that the Transporter shall have the burden of proving that any discount granted is required to meet competition.
>
> Accordingly, Transporter shall be required to demonstrate that any such discount type adjustment does not have an adverse impact on recourse rate shippers by:
>
> (1) Demonstrating that, in the absence of Transporter's entering into such negotiated rate agreement, Transporter would not have been able to contract for such capacity at any higher rate(s) **and** that recourse rates would otherwise be as high or higher than recourse rates which result after applying the discount adjustment; or
>
> (2) Making another comparable showing that the negotiated rate contributes more to fixed costs recovery to the system than could have been achieved without the negotiated rate.[142]

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[141] *Citing Columbia Gulf Transmission Co.*, 133 FERC ¶ 61,078 (2010) (*Columbia Gulf*), *citing Wyoming Interstate Company, Ltd.*, 117 FERC ¶ 61,150 (2006) (*WIC*).

[142] Pro Forma Sheet No. 387 (emphasis added).

A. Initial Comments

163. In its Initial Comments, Tennessee noted arguments that its proposal was unclear or that it would not allow consideration of facts that were relevant to whether such an adjustment should be permitted. Tennessee asserts that parties also argue that its proposal is contrary to Commission policy. Tennessee asserts that the fact that the Commission has recently accepted provisions specifying the circumstances under which discount adjustments will be allowed for negotiated rate agreements refutes any argument that they are contrary to Commission policy. Tennessee argues that the Commission has never implemented a *per se* ban on discount adjustments in connection with negotiated rate agreements, and its policy has always been to consider these issues on a case-by-case basis.[143] In response to arguments that its tariff language may limit arguments parties may wish to make with respect to a proposed discount adjustment, Tennessee states that in *Columbia Gulf* the Commission addressed similar arguments and found that the specific application of the proposed language was best addressed in Columbia Gulf's general section 4 rate proceeding.[144]

164. AGA argues that tariff provisions such as those proposed in the instant proceeding and in *Columbia Gulf*, would allow discount adjustments for negotiated rate agreements in circumstances beyond what was originally contemplated in the Commission's *Alternative Rate Policy Statement*.[145] AGA asserts that there the Commission explained that the fundamental predicate for permitting a pipeline with market power to charge a negotiated rate is that capacity must be available from the pipeline at a cost-based recourse rate and that under its negotiated rate program customers electing the recourse rate should be no worse off as a result of a pipeline's use of negotiated rates.

165. AGA asserts that the Commission initially denied discount-type adjustments to negotiated rate agreements except under limited conditions. AGA argues that in *NorAm*, the Commission reiterated that customers electing recourse rates must be no worse off as

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[143] *Citing Southern Natural Gas Co.*, 95 FERC ¶ 61,038, *order on reh'g*, 95 FERC ¶ 61,364 (2001).

[144] *Citing Columbia Gulf*, 133 FERC ¶ 61,078 at P 15.

[145] *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *reh'g and clarification denied*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066 (1996); *pet. for review denied, Burlington Resources Oil & Gas Co. v. FERC, Nos. 96-1160, et al.*, 1998 U.S. App. LEXIS 20697 (D.C. Cir. July 20, 1998).

a result of the use of negotiated rates.[146] The Commission explained that while it was not promulgating a *per se* rule against discount-type adjustments to recourse rates to reflect negotiated rates, it would require that a pipeline's negotiated rate proposal protect the recourse rate-paying shippers against inappropriate cost-shifting. AGA states that the Commission denied NorAm its discount type adjustment and rejected other efforts by pipelines to seek discount-type adjustments for their negotiated rate agreements.[147] AGA points out that the Commission also rejected a similar proposal by Tennessee at that time,[148] stating that "[i]n order to ensure that risks involved in Tennessee's negotiated rates do not fall on its recourse shippers, no discount-type adjustment will be allowed for negotiated rates in Tennessee's next rate case."[149]

166. AGA asserts that the Commission permitted discount type adjustments in *Northwest*, where the pipeline proposed that it would not seek discount adjustments to demand-charge billing determinants under a newly negotiated rate in future rate cases unless the rate had already been discounted in the initial Part 284 contract, and that the adjustment would be based on the greater of the negotiated rate revenues received or the discounted recourse rate revenues that would have been received if the contract had not been converted to a negotiated rate agreement.[150] The Commission concluded that in such a situation its concerns about the allocation of capacity between recourse rate and negotiated rate shippers were not present. AGA states that the Commission did require Northwest to bear the higher standard for affiliates when seeking discount-type adjustments for negotiated rate agreements, i.e., the Commission imposed on Northwest the burden of proving that any discount reflected in the negotiated rate is required to meet competition. AGA also noted that the Commission stated that it would use the information that Northwest was required to file in its general rate case to closely scrutinize the negotiated rate transactions and ensure that any discount-type adjustment does not have an adverse impact on recourse rate shippers.

167. AGA asserts that the Commission was particularly concerned that no inappropriate cost-shifting take place and that the Commission required additional measures to ensure

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[146] *NorAm Gas Transmission*, 81 FERC ¶ 61,204, at 61,872 (1997) (*NorAm*).

[147] *See Koch Gateway Pipeline Co.*, 81 FERC ¶ 61,205 (1997); *Columbia Gulf Transmission Co.*, 81 FERC ¶ 61,206 (1997); *CNG Transmission Corp.*, 80 FERC ¶ 61,401 (1997).

[148] *See Tennessee Gas Pipeline Co.*, 81 FERC ¶ 61,207 (1997).

[149] *Id*. at 61,881.

[150] *See Northwest Pipeline Corp.*, 84 FERC ¶ 61,109 (1998) (*Northwest*).

that a pipeline's negotiated rates would not be used to shield it from market risks by inappropriately shifting resulting costs to recourse shippers. AGA points out that the Commission believed that Northwest's proposal protected recourse shippers against inappropriate cost shifting because Northwest had limited both the shippers with whom it would negotiate and the amount of any discount adjustment to recourse rates. AGA states that the Commission concluded that there could be no harm to recourse shippers from Northwest's negotiated rates below the maximum recourse rate.[151]

168. AGA asserts that the Commission has diverted from its initial policy in *WIC* where it accepted tariff provisions that go beyond what it permitted in *Northwest*.[152] AGA recognizes that in *WIC*, the Commission reiterated that it does not have a *per se* prohibition on discount-type adjustments with respect to negotiated rates, and that in order for a pipeline to be able to seek such adjustments it must include in the negotiated rate provisions of its tariff a protective mechanism that will ensure that its negotiated rate agreements will not cause inappropriate cost-shifting. AGA asserts that in *WIC*, unlike *Northwest*, the pipeline's tariff provisions did not limit both the shippers with whom it would negotiate or the amount of any discount adjustment to recourse rates. AGA states that the only significant protection for recourse shippers offered by WIC was that it proposed to be bound by the standard required of an affiliate discount-type adjustment, i.e., that WIC would bear the burden of proving that any discount reflected in the negotiated rate is required to meet competition.

169. AGA asserts that the Commission has accepted tariff provisions with similar lax requirements for discount-type adjustments for negotiated rate agreements in *Columbia Gulf* and in *Kinder Morgan Interstate Gas Transmission*, FERC Docket No. RP11-1542-000 (Letter Order dated December 15, 2010). AGA argues that the Commission cannot continue with this new interpretation of the *Alternative Rate Policy Statement* without subjecting its new policy interpretation to notice and comment procedures under the Administrative Procedures Act (APA). AGA states that the Courts have found that "Once an agency gives its regulation an interpretation, it can only change that interpretation as it would formally modify the regulation itself; through the process of notice and comment rulemaking."[153] AGA states that under the APA, agencies are required to engage in notice and comment rulemaking procedures before formulating regulations and while courts will generally show substantial deference to an agency's

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[151] *Id*.

[152] *Wyoming Interstate Co., Ltd.*, 117 FERC ¶ 61,150 (2006) (*WIC*).

[153] *Paralyzed Veterans of Amer., et al. v. D.C. Arena LP*, 117 F.3d 579, 586 (D.C. Cir. 1997).

interpretation of its own regulations, an agency must follow notice and comment procedures when it substantially changes its interpretation. AGA argues that "To allow an agency to make a fundamental change in its interpretation of a substantive regulation without notice and comment obviously would undermine those APA requirements."[154]

170. AGA does not suggest that the Commission must comply with all of the requirements of the APA to revise its Alternative Rate Policy Statement. Rather, AGA contends that the Commission need only employ the same kind of generic notice and comments procedures that it has used in the past when it has revised its negotiated rate program.[155] Moreover, AGA does not dispute that the Commission may proceed to make policy through adjudication rather than in a generic proceeding. However, it adds that under the APA, the Commission must vet its policy changes with those that will be affected by them and, therefore the Commission may not accept Tennessee's proposed tariff provisions on the grounds that it is simply following its precedent in *WIC and Columbia Gulf.*

171. AGA contends that because of the significant policy implications involved in accepting Tennessee's tariff provisions, the Commission must institute a generic proceeding and afford all interested persons notice and an opportunity to be heard. AGA argues that the Commission should provide generic guidance on its policies before it permits any more pipelines to seek discount-type adjustments for negotiated rate agreements.

172. Elizabethtown Gas state that they are members of AGA and that they support AGA's position on this issue. They assert that Tennessee's proposal does not protect shippers from the unfairness of subsidizing below-max negotiated rates while gaining no benefit from above-max negotiated rates. Nor has Tennessee demonstrated that its new tariff provision should be eligible for retroactive effect. The Northeast Customer Group states that it agrees with AGA that the Commission may be obligated, as a matter of law, to conduct a generic proceeding to address this matter. The Northeast Customer Group assert that a generic proceeding culminating in a policy statement or rulemaking could

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[154] *Id. See, also Alaska Professional Hunters Ass'n, et al. v. FCC*, 177 F.3d 1030, 1034 (D.C. Cir. 1999) ("When an agency has given its regulation a definitive interpretation, and later significantly revises that interpretation, the agency has in effect amended its rule, something it may not accomplish without notice and comment.")

[155] *See e.g., Natural Gas Pipeline Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 FERC ¶ 61,134 (2003), *order on reh'g and clarification*, 114 FERC ¶ 61,042 (2006), *order dismissing reh'g denying clarification*, 114 FERC ¶ 61,304 (2006).

provide comment opportunities for entities not in the instant proceedings and help to clarify and rationalize the Commission's discount adjustment policy.

173. Piedmont and Atmos argue that Tennessee proposes language to allow it to seek recovery of negotiated losses in a manner similar to which it is now able to seek recovery of discounted losses. Piedmont, Atmos, and Northeast State Coalition argue that the Commission has previously ruled that it is not appropriate to allow discount-type adjustments for negotiated contracts where the pipeline's proposal does not adequately protect recourse shippers from the risks associated with negotiated rates agreements. There, the Commission also ruled that the risks involved in Tennessee's negotiated rate agreements cannot be transferred to its recourse rate shippers and that no discount adjustment would be allowed for negotiated rates in Tennessee's next (this) rate case.[156] Similarly, Northeast State Coalition argues that market participants may have relied upon the Commission's decision in *Tennessee* when deciding whether to intervene and potentially protest the negotiated rate agreements filed by Tennessee since this order. It asserts that the Commission should reject Tennessee's proposal and prohibit it from taking discount adjustments for any of its negotiated rate agreements.

174. Piedmont and Atmos also argue that Tennessee's proposal should be rejected because its mandatory language allows for an automatic right to recover discount type adjustments for negotiated rate agreements without an adequate opportunity for the examination of the relevant facts. Moreover, Piedmont and Atmos argue that permitting discount treatments for negotiated rate agreements raises the specter of an after-the-fact indirect subsidization of incremental negotiated rate capacity by recourse shippers.

175. The Indicated Shippers argue that the proposed discount adjustments undermine the protection of the recourse rate and that it should be rejected. Moreover, Indicated Shippers maintain that the proposed language includes an inappropriate legal test binding on the Commission's decision in the tariff. Indicated Shippers argue that if a tariff provision is necessary to enable a pipeline to seek a discount adjustment for a negotiated rate contract in a rate proceeding, the tariff provision should be limited solely to that purpose, and not state a legal test to govern the outcome of the rate proceeding. The Indicated Shippers maintain that if the Commission permits Tennessee to include such a provision, it should clarify that it will only apply prospectively only to contracts entered into and effective after the provision has become effective. Northeast State Coalition also argues that if the Commission accepts Tennessee's proposal, it should make clear that those revisions do not apply to agreements negotiated prior to the effective date of those revisions because market participants have had no opportunity to protest the potential

[156] Piedmont Initial Comments at 5 (citing *Tennessee Gas Pipeline Co.*, 81 FERC ¶ 61,207 (1997) (*Tennessee*)).

impact of those agreements on system rates. Northeast State Coalition also argues that allowing Tennessee to seek discount adjustments for pre-existing negotiated rate agreements without applicable tariff procedures in place would create the potential for inappropriate cost shifting.

176. Northeast Customer Group argues that if the Commission opts to accept Tennessee's proposal the Commission should require several revisions to those tariff modifications to protect recourse rate shippers. Northeast Customer Group asserts that allowing Tennessee to take discount adjustments for negotiated rate contracts executed before the conclusion of the test period would create the potential for abuse. Therefore, Northeast Customer Group asserts that Tennessee must revise its proposed tariff modifications to state that discount adjustments cannot be taken for negotiated rate agreements executed before June 1, 2011. Second, Northeast Customer Group asserts that Tennessee must explain how it determines whether a negotiated rate may exceed the maximum rate and the Commission should require Tennessee to make clear that it may not take a discount adjustment for any negotiated rate contract that could exceed the maximum rate at some point in its term. Third, Northeast Customer Group argues that Tennessee should be required to revise its tariff to explain how it will separately account for the costs and revenues of its negotiated rate agreements and regularly report such amounts to the Commission. Fourth, Northeast Customer Group argues that Tennessee's proposed tariff provisions must track those in accepted in *Columbia Gulf* and *WIC.*

177. Northeast Customer Group argues that the Commission should find that Tennessee must meet all conditions set forth in *Columbia Gulf*, for the allowance of discount adjustments, including the fact that a pipeline must meet the higher affiliate discount type standards for receiving discount adjustments for negotiated rates. Lastly, Northeast Customer Group argues that Tennessee must revise its tariff to make clear that discount adjustments may only be taken for negotiated rate agreements in which other terms and conditions have not been modified.

178. The New England LDCs assert that the Commission should reject Tennessee's proposal to take a discount-type adjustment to its recourse rates for certain negotiated rate agreements. They assert that Tennessee's proposal is based upon the Commission's decision in *WIC* which reversed the Commission's determination to preclude such adjustments without adequate explanation. The New England LDCs assert that by changing this rule in *WIC*, the Commission deprived the natural gas industry of the opportunity to be heard in a generic rulemaking proceeding. The New England LDCs argue that the Commission should not further revise its policies disfavoring discount adjustments by extending the *WIC* precedent to the instant case.

179. The New England LDCs assert that if the Commission accepts Tennessee's proposal it must require Tennessee to modify the proposed tariff language to make clear that the tariff will not be applicable to the instant proceeding. They assert that this is

Tennessee's first general rate proceeding since the *Tennessee* decision which prohibited Tennessee from taking a discount-type adjustment in its next general rate proceeding. The New England LDCs, state that they have relied on this prohibition. Second, the New England LDCs argue that the *WIC* decision requires pipelines seeking discount adjustments for negotiated rates to have provisions in their tariffs protecting recourse ratepayers from inappropriate cost shifts and they point out that Tennessee has no such provision. They argue that Tennessee's assertion that it may seek a discount adjustment in the absence of the required tariff provision is specious and that the Commission is clearly empowered to impose limitations on a pipeline's ability to adjust recourse rates.

B. Reply Comments

180. Piedmont and New England LDCs argue that in *Tennessee* the Commission ruled that it is not appropriate to allow discount-type adjustments for negotiated contracts where the pipeline's proposal does not adequately protect recourse shippers from the risks associated with negotiated rate agreements. Piedmont and New England LDCs argue that in that order Tennessee was informed that no discount adjustment would be allowed for negotiated rates in Tennessee's next (this) rate case. They assert that because Tennessee's proposal seeks what was specifically prohibited the Commission should reject Tennessee's proposal. However, Piedmont joins the Indicated Shippers and the Northeast State Coalition and asserts that if the Commission accepts the proposal it should state that the proposal will apply only to negotiated rate agreements entered into after approval of this mechanism. Lastly, Piedmont and Northeast Customer Group support suggestions made by several other parties that the Commission should consider the issue of permitting discount adjustments for negotiated rates in a generic proceeding.

181. In its Reply Comments, Tennessee argues that several parties claim that the Commission has reversed its policies with regard to discount adjustments for negotiated rates and that such action was improper absent notice and comment in a rulemaking proceeding. Tennessee also asserts that several parties have requested that if the Commission accepts Tennessee's provision it should clarify that the tariff provision should not be applied to negotiated rate agreements that pre-date Commission approval of this provision. Tennessee argues that these arguments are a collateral attack on the *WIC* and *Columbia* orders and should be rejected for that reason alone.

182. Secondly, Tennessee argues that the tariff provision does not itself make any determination of whether the specific adjustments proposed in this case will or will not be permitted, and all parties are free to make any arguments they wish at the hearing. Moreover, Tennessee argues that the parties that argue that the tariff should be applied only prospectively because of their reliance upon prior Commission policy ignore several Commission pronouncements which made clear that there was no *per se* ban on discount adjustments. Finally, Tennessee argues that the parties opposing its instant provision assume that allowing a discount adjustment in connection with a negotiated rate

agreement would necessarily result in inappropriate cost-shifting or adversely affect recourse rate shippers. Tennessee asserts that, for purposes of determining the propriety of a discount adjustment, a rate in a negotiated rate agreement that is below a pipeline's maximum recourse rate is no different than a discounted rate, provided that both rates were provided to meet competition. Absent the pipeline discounting the rate, the pipeline would lose business and there would be less billing determinants over which to spread fixed costs. The only difference is that the pipeline may have other negotiated rates in excess of the maximum rate, which may or may not need to be considered in connection with any discount adjustment. Tennessee asserts the excess over the maximum rate is a matter that Commission precedent in *WIC* states should be determined in a rate proceeding.

183. Tennessee also asserts that the comments of Atmos and Piedmont regarding what they refer to as the mandatory language of the tariff which precludes an appropriate examination of Tennessee's request for a discount adjustment is without merit. Tennessee points out that the discount adjustment "shall" be allowed if Tennessee can meet the standards set forth in the tariff provision. Tennessee argues that if it meets the standards set forth in its tariff language, a discount adjustment is appropriate and should be allowed. Lastly, Tennessee states that Northeast Customer Group's request that Tennessee's tariff provision be modified to allow discount adjustments only for negotiated rate agreements "in which other terms and conditions have not been modified" is overbroad and should be rejected.

C. Commission Decision

184. The Commission accepts Tennessee's proposed Section XXVII of Tennessee's GT&C, subject to the revisions Tennessee agreed to make in its post-technical conference filings. As revised, Tennessee's proposed tariff language is consistent with the tariff language we approved in both *WIC* and *Columbia Gulf*. The proposed tariff language does not guarantee Tennessee the right to make a discount-type adjustment, but only establishes the burden of proof Tennessee must satisfy in order to obtain a discount-type adjustment for negotiated rate transactions in a section 4 rate case. The Commission finds that the burden set forth in Tennessee's proposed tariff language provides an appropriate framework for considering the issue of discount-type adjustments for negotiated rates in section 4 rate cases, consistent with our longstanding concern that negotiated rate transactions not cause inappropriate cost-shifting to recourse rate-paying shippers.

185. Before addressing the contentions of the parties, we first describe the origins of, and reasons for, our policy of permitting billing determinants associated with discounted rate transactions to be adjusted downward for purposes of determining rate design volumes in section 4 rate cases. We then review the Commission's past holdings concerning the burden pipelines must satisfy to obtain a discount adjustment for

negotiated rates. Next, we discuss why we are unwilling to impose a blanket prohibition on such adjustments for negotiated rate transactions as requested by AGA and other commenters, and find that Tennessee's proposed tariff language provides a reasonable framework for considering whether to allow a discount adjustment for negotiated rates in a section 4 rate case.

1. <u>Discount Adjustment Policy</u>

186. As part of Order No. 436, which commenced the transition to open access transportation in 1985, the Commission adopted regulations permitting pipelines to engage in selective discounting based on the varying demand elasticities of the pipeline's customers.[157] Under these regulations, the pipeline is permitted to offer discounts from its maximum transportation rates, on a nondiscriminatory basis, in order to meet competition. In Order No. 436, the Commission explained that these selective discounts would benefit all customers, including customers that did not receive the discounts, because the discounts would allow the pipeline to maximize throughput and thus spread its fixed costs across more units of service. The Commission further found that selective discounting would protect captive customers from rate increases that would otherwise ultimately occur if pipelines lost volumes through the inability to respond to competition.[158]

187. In *Associated Gas Distributors v. FERC (AGD I)*,[159] the court upheld the regulations permitting selective discounting adopted in Order No. 436. In doing so, the court addressed an argument presented by some pipelines that the Commission's policy might lead to the pipelines under-recovering their costs. The court set forth a numerical example showing that the pipeline could under-recover its costs, if, in the next rate case after a pipeline obtained throughput by giving discounts, the Commission nevertheless designed the pipeline's rates based on the full amount of the discounted throughput, without any adjustment. However, the court found no reason to fear that the Commission

[157] *Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,665, at 31,543-45 (1985).

[158] *See Interstate Natural Gas Pipeline Rate Design*, 47 FERC ¶ 61,295, at 62,056-57, *order on reh'g*, 48 FERC ¶ 61,122, at 61,448-49 (1989), and *Policy for Selective Discounting By Natural Gas Pipelines*, 111 FERC ¶ 61,309 (Policy Reaffirmance Order), *order on reh'g*, 113 FERC ¶ 61,173, at P 3-4 (2005) (Policy Reaffirmance Rehearing Order).

[159] 824 F.2d 981, 1010-12 (D.C. Cir. 1987).

would employ this "dubious procedure,"[160] and accordingly rejected the pipelines' contention.

188. Consistent with *AGD I*, the Commission held in its 1989 Rate Design Policy Statement[161] that it would allow adjustments to discounted volumes in section 4 rate cases. The Commission explained that, if a pipeline must assume that the previously discounted service will be priced at the maximum rate when it files a new rate case, there may be a disincentive to pipelines discounting their services in the future to capture marginal firm and interruptible business. Therefore, in section 4 rate cases, pipelines may reduce the discounted volumes used to design its rates so that, assuming market conditions require it to continue giving the same level of discount when the new rates are in effect, the pipeline will be able to recover 100 percent of its cost of service. That reduction in the volumes used to design a pipeline's rates in a section 4 rate case is known as a "discount adjustment."

189. Since the *Rate Design Policy Statement*, pipelines have proposed discount adjustments in numerous section 4 rate cases.[162] While the pipeline has the ultimate burden of showing that its discounts were required to meet competition in order to obtain such an adjustment, the Commission has developed a policy in those cases of distinguishing between the burden of proof the pipeline must meet depending upon whether a discount was given to a non-affiliate or an affiliate. In the case of discounts to non-affiliated shippers, the Commission has stated that it is a reasonable presumption that a pipeline will always seek the highest possible rate from non-affiliated shippers, because

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[160] *Id*.

[161] *Interstate Natural Gas Pipeline Rate Design*, 47 FERC ¶ 61,295, *order on reh'g*, 48 FERC ¶ 61,122 (1989).

[162] *See, e.g*., *Southern Natural Gas Co*., 65 FERC ¶ 61,347, at 62,829-62,833 (1993), *reh'g denied*, 67 FERC ¶ 61,155, at 61,456-61,460 (1994); *Williston Basin Interstate Pipeline Co*., 67 FERC ¶ 61,137, at 61,377-61,282 (1994); *Panhandle Eastern Pipe Line Co*., 71 FERC ¶ 61,228, at 61,866-61,871 (1995) (Opinion No. 395); *Northwest Pipeline Corp*., 71 FERC ¶ 61,253, at 62,007-61,009 (1995); *Panhandle Eastern Pipe Line Co*, 74 FERC ¶ 61,109, at 61,399-61,408 (1996) (Opinion No. 404); *Williams Natural Gas Co*., 77 FERC ¶ 61,277, at 62,205-61,207 (1996*), reh'g denied*, 80 FERC ¶ 61,158, at 61,189-61,190 (1997); *Iroquois Gas Transmission System, L.P*., 84 FERC ¶ 61,086, at 61,478 (1998), *reh'g denied*, 86 FERC ¶ 61,261 (1999); *Williston Basin Interstate Pipeline Co*., 84 FERC ¶ 61,266, at 61,401-61,402(1998); *Northwest Pipeline Corp*., 87 FERC ¶ 61,266, at 62,077 (1999); and *Trunkline Gas Co*., 90 FERC ¶ 61,017, at 61,084-61,096 (2000).

it is in its own economic interest to do so. Therefore, once the pipeline has explained generally that it gives discounts to non-affiliates to meet competition, parties opposing the discount adjustment have the burden of producing evidence that discounts to non-affiliates were not justified by competition. To the extent those parties raise reasonable questions concerning whether competition required the discounts given in particular non-affiliate transactions, then the burden shifts back to the pipeline to show that the questioned discounts were in fact required by competition.[163]

190. In contrast to its treatment of non-affiliate discounts, the Commission has consistently held that "the pipeline has a heavy burden to show that competition required discounts to affiliates."[164] Thus, in *Panhandle Eastern Pipe Line Co.*,[165] the Commission held that the pipeline had not met its burden to show that its discounts to its affiliates were required by competition. While the pipeline did show that it had granted some non-affiliates similar discounts, the Commission held that this was not sufficient. Rather, the Commission stated that the pipeline should have identified the specific competitive alternatives the affiliate had, which required giving the discount. In addition, in *Williams Natural Gas Co.*[166] and *Trunkline Gas Co.*,[167] the Commission disallowed discount adjustments in connection with a discount to an affiliate on similar grounds.

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[163] While the Commission has generally permitted a discount adjustment with respect to non-affiliate transactions, the Commission has held that, when a pipeline gives a long-term discount to non-affiliated firm shippers, it would expect that the pipeline would make a thorough analysis whether competition required such a long-term discount. In two cases, the Commission held that the pipeline had failed to present any evidence of such an analysis. *Iroquois Gas Transmission System, L.P.*, 84 FERC ¶ 61,086, at 61,476-61,478 (1998), *reh'g denied*, 86 FERC ¶ 61,261 (1999) and *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,092-95 (2000).

[164] *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,087 and 61,096 (describing the type of evidence the pipeline must submit to satisfy this burden).

[165] 74 FERC ¶ 61,109, at 61,401-61,402 (1996).

[166] 77 FERC ¶ 61,277, at 62,206-61,207 (1996), *reh'g denied*, 80 FERC ¶ 61,158 (1997).

[167] 90 FERC ¶ 61,017 at 61,096.

2. The Commission's Past Treatment of Discount-Type Adjustments for Negotiated Rates

191. The Commission adopted its negotiated rate program in its 1996 *Alternative Rate Policy Statement*.[168] Under that program, the Commission permits pipelines to negotiate individualized rates which, unlike discounted rates,[169] are not constrained by the maximum and minimum rates in the pipeline's tariff.[170] However, pipelines must permit shippers to opt for use of the traditional cost-of-service "recourse rates" in the pipeline's tariff, instead of requiring them to negotiate rates for any particular service. The Commission relies on the availability of the recourse rates to prevent pipelines from exercising market power by assuring that the customer can fall back to the just and reasonable tariff rate if the pipeline unilaterally demands excessive prices or withholds service.[171]

192. While the Commission's discount adjustment policies had been fully developed by 1996, the *Alternative Rate Policy Statement* did not address the issue of whether similar adjustments would be permitted for negotiated rate transactions in future pipeline rate cases. Instead the Commission stated,

> Issues regarding the appropriate allocation of costs between recourse rate shippers and negotiated rate shippers will be addressed fully in the pipeline's section 4 rate cases. At that time, the Commission will consider issues related to cross subsidization and interested parties will be able to raise any concerns they have regarding the proper allocation of costs. Therefore, the Commission does not intend to review a pipeline's negotiated rates at the time filed.[172]

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[168] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *reh'g denied*, 75 FERC ¶ 61,024 (1996).

[169] *See* 18 C.F.R. § 284.10(c)(5) (2010) ("any rate schedule filed under this section must state a maximum and a minimum rate.")

[170] *See Northern Natural Gas Co.*, 105 FERC ¶ 61,299 (2003) (clarifying the distinction between discounted and negotiated rates).

[171] *Alternative Rate Policy Statement*, 74 FERC ¶ 61,076 at 61,238-61,242.

[172] *Id*. at 61,242.

In denying rehearing of the *Alternative Rate Policy Statement*, the Commission again set forth its intention to address issues related to the use of negotiated rates on a case by case basis.[173]

193. In the fifteen years since the *Alternative Rate Policy Statement*, the issue whether to grant a discount-type adjustment for negotiated rates has not arisen in any actual pipeline section 4 rate case until the recent section 4 rate case filings by Tennessee and Columbia Gulf Transmission Co. However, when individual pipelines began filing tariff language authorizing them to negotiate rates, some pipelines indicated that they reserved the right to in subsequent section 4 rate cases to seek such an adjustment. While the Commission initially stated that issue should be addressed in individual section 4 rate cases,[174] the Commission subsequently modified that determination. In a series of orders issued in November 1997, the Commission explained its policy on this issue as follows:

> The Commission's policy with respect to negotiated rates is that "customers electing the recourse rates will be no worse off as a result of the use of negotiated rates." Although the Commission is not promulgating a *per se* rule against discount-type adjustments to recourse rates to reflect negotiated rates, the Commission does require that a pipeline's negotiated rate proposal protect the recourse rate-paying shippers against inappropriate cost-shifting.
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> Pipelines assert that there may be times when negotiated rates could benefit recourse rate shippers. However, such instances

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[173] As the Commission explained in denying rehearing of the policy statement:

> The purpose of the Policy Statement was to provide the industry with guidance by stating the criteria the Commission will consider when evaluating the proposals for alternative ratemaking methodologies. … **The Commission intends to evaluate the specific proposals based on the facts and circumstances relevant to each applicant and to address any concerns regarding the application of the criteria on a case-by-case basis.** In general, objections to statements of policy are not directly reviewable. Rather, such review must await implementation of the policy in a specific case.

75 FERC ¶ 61,024, at 61,076 (1996) (emphasis supplied).

[174] *See, e.g.*, *NorAm Gas Transmission Co*., 75 FERC ¶ 61,091 (1996).

> are hypotheticals that lack any certainty or mechanism to ensure that such negotiated rate transactions would be beneficial and not harmful to recourse rate shippers. Since the inception of the Commission's negotiated rate policy, the Commission has made clear its intention to keep recourse shippers from being adversely affected. Thus, without protective measures in place, the Commission will not permit discount adjustments for negotiated rates.
>
> While retaining and attracting new load is an important goal, the Commission considers that this goal must be achieved in manner that adequately protects existing shippers. Negotiated rates are a new voluntary option available to pipelines that does not preclude the pipeline discounting rates to attract or retain load. However, when a pipeline chooses to use the new authority to negotiate new rate forms (such as index rates or non-SFV rates), the Commission must be assured that no harm will occur to the shippers still taking service using the existing form of rates. NorAm has not provided this assurance regarding its negotiated rates program. Thus, the Commission continues to hold that in order to ensure that the risks involved in NorAm's negotiating rates do not fall on its recourse shippers, no discount-type adjustment will be allowed for negotiated rates in NorAm's next rate case. [175]

194. Subsequent to its actions in *NorAm* and related cases, that Commission found in *Northwest* that the pipeline had provided adequate assurances to protecting the recourse rate shipper and the Commission, therefore, accepted Northwest's proposal to include in its tariff a mechanism under which it could seek a discount-type adjustment in a future section 4 rate case for negotiated rate transactions.[176] Under Northwest's proposal, it was not permitted to seek a discount adjustment in a future rate case for a negotiated rate, unless it first discounted the recourse rate and then subsequently converted the discount to a negotiated rate. The discount adjustment would then be based on the higher of the

[175] *NorAm*, 81 FERC ¶ 61,204 at 61,872 (internal citations omitted). *See also Wyoming Interstate Co., Ltd.*, 90 FERC ¶ 61,220, at 61,720 (2000); *CNG Transmission Corp.*, 81 FERC ¶ 61,401, at 62,328 (1997); *Tennessee Gas Pipeline Co.*, 81 FERC ¶ 61,207, at 61,880 (1997); *Columbia Gulf Transmission Co.*, 81 FERC ¶ 61,206, at 61,876 (1997); *Koch Gateway Pipeline Co.*, 81 FERC ¶ 61,205, at 61,874 (1997).

[176] *Northwest Pipeline Corp.*, 79 FERC ¶ 61,416 (1997), *order on reh'g*, 84 FERC ¶ 61,109 (1998).

negotiated rate revenues actually received by Northwest or the discounted recourse rate revenues that would have been received absent the conversion to a negotiated rate contract. Moreover, Northwest would be required to show that competition required the discount without the benefit of any presumption that the discount was given to meet competition.

195. In 2000, in *Southern*, the Commission addressed another proposed tariff provision setting forth the conditions under which a pipeline could seek a discount-type adjustment for negotiated rates in a future section 4 rate case. The Commission rejected that proposal, holding that it failed to provide protections for recourse rate shippers comparable to those provided by the pipeline in *Northwest*.[177] However, the Commission stated that:

> the proper place to review whether recourse rate customers have in fact been protected is in a section 4 rate proceeding. All parties will be free to argue whether the pipeline has adequately protected the recourse rate customers. That is the fairest way to accommodate the interests of all concerned, including the pipeline. **Upon reflection of the various orders heretofore entered by the Commission, it is clear that this course of action better serves the ends of just and reasonable rates and practices than does a predetermination, not based on facts, whether a given plan is adequate.** Therefore, we affirm our holding in the April 12 Order that Southern's proposed plan is inadequate, and we also affirm our determination that Southern may seek discount-rate adjustments in a future rate case where all the facts are available for reasoned decision on whether there has in fact been a cost-shifting. The burden of proof, of course, will be Southern's to show that such a shifting has not occurred.[178]

196. The Commission next addressed the issue of permissible tariff provisions permitting a pipeline to seek discount adjustments for negotiated rates in a future rate case in *WIC*. In that case, the Commission pointed out that in the *NorAm* series of orders in November 1997, quoted above, the Commission had stated that, although it was not promulgating a *per se* rule against discount-type adjustments to recourse rates to reflect

[177] *Southern Natural Gas Co.*, 94 FERC ¶ 61,063 (2001); 95 FERC ¶ 61,038, *order on reh'g*, 95 FERC ¶ 61,364 (2001).

[178] 95 FERC ¶ 61,364 at 62,379 (emphasis added).

negotiated rates, the Commission required that a pipeline's negotiated rate proposal protect the recourse rate-paying shippers against inappropriate cost-shifting. The Commission stated that this remained the Commission's policy, summarizing the policy as follows:

> Thus, the Commission does not have a *per se* prohibition on discount-type adjustments with respect to negotiated rates. However, in order for a pipeline to seek such a discount adjustment in its next rate case, the pipeline must include in the negotiated rate provisions of its tariff a protective mechanism that will ensure that its negotiated rate transactions will not cause any inappropriate cost shifting to the recourse rate shippers. [179]

197. In both *WIC* and the more recent *Columbia Gulf* cases, the Commission reviewed proposed tariff provisions, which were essentially the same as Tennessee has proposed in this case and concluded that those provisions would properly protect recourse rate customers. The Commission emphasized that the tariff language adequately protected recourse rate shippers by requiring the pipelines to satisfy the same heavy burden pipelines must bear with respect to affiliate discounts to show that competition required the discount. In addition, the tariff language specifically requires the pipelines to demonstrate that any discount-type adjustment "does not have an adverse impact on recourse rate shippers," and specifies the showings the pipeline must make to satisfy that burden. The Commission also pointed out that, when the pipeline files its next general section 4 rate proceeding, shippers will have the opportunity to fully evaluate all of the pipeline's cost and revenue data and make any arguments as to whether the pipeline has satisfied its heavy burden of proof and shown that recourse rate shippers are not adversely affected. Among other things, shippers can raise the issue whether any proposed discount-type adjustment is consistent with the policy that "pipelines should not be able to shift the cost of below maximum rate discounts to the recourse rate shippers, while keeping the profits from above maximum rate transactions for themselves."[180]

3. <u>Approval of Tennessee proposal</u>

198. The Commission finds that Tennessee's proposed section 27 to its GT&C is just and reasonable. That proposed tariff language does not guarantee Tennessee the right to make a discount-type adjustment, but only establishes burden of proof Tennessee must satisfy in order to obtain a discount-type adjustment consistent with the policy in *WIC*

[179] *WIC*, 117 FERC ¶ 61,150 at P 11. *Columbia Gulf*, 133 FERC ¶ 61,078 at P 14.

[180] *WIC*, 117 FERC ¶ 61,150 at P 15. *Columbia Gulf*, 133 FERC ¶ 61,078 at P 15.

and *Columbia*. The Commission finds that the burden set forth in Tennessee's proposed tariff language provides an appropriate framework for considering the issue of discount-type adjustments for negotiated rates in Tennessee's section 4 rate cases, including this case.

199. The Commission recognizes that its policy concerning the burdens a pipeline must satisfy in order to obtain a discount-type adjustment for negotiated rates has evolved over the fifteen years since the negotiated rate program was established. In the *Alternative Rate Policy Statement*, the Commission stated its intent that "customers electing the recourse rates will be no worse off as a result of the use of negotiated rates,"[181] and the Commission has consistently reiterated that goal. However, the Commission's statements in individual cases concerning how to accomplish that goal have varied. In the November 1997 *NorAm* series of orders, the Commission reconsidered its initial policy of simply allowing the issue of how to allocate costs between recourse rate and negotiated rate shippers to be addressed at hearing in section 4 rate cases. While the Commission stated it "was not promulgating a *per se* rule against discount-type adjustments to recourse rates to reflect negotiated rates," the Commission held that, unless a pipeline's negotiated rate tariff provisions included protections assuring that recourse rate-paying shippers would not be subject to inappropriate cost-shifting, the Commission would not permit discount-type adjustments for negotiated rates in the pipeline's next rate case. As several commenters point out, one of the November 1997 series of orders involved Tennessee. In that order, the Commission reaffirmed its earlier holding that Tennessee's negotiated rate tariff provisions did not provide adequate protections and therefore no discount-type adjustment would be allowed for negotiated rates in Tennessee's next rate case.[182]

200. Some commenters interpret the *NorAm* line of cases as establishing a nearly blanket prohibition on pipelines seeking discount adjustments for negotiated rates in section 4 rate cases.[183] However, as the commenters also recognize, in later cases, including the *Southern*, *WIC*, and *Columbia Gulf* orders described above, the Commission has not imposed such a stringent burden. After further considering the matter in response to the comments on following the technical conference in this case, the Commission continues to find that the approach it has taken in the *WIC* and *Columbia Gulf* cases provides the most balanced and reasonable method of addressing this issue.

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[181] 74 FERC ¶ 61,076 at 61,242.

[182] *Id*. at 61,881.

[183] The only exception from the prohibition would be for negotiated rate transactions converted from discounted rate transactions, as permitted in *Northwest.*

201. The Commission finds that a blanket prohibition on discount adjustments for negotiated rates is too extreme, because it fails to recognize that pipelines may use negotiated rates to obtain additional shippers who would not contract for service at the pipeline's recourse rates. Such negotiated rate transactions can benefit the maximum rate recourse rate shippers in the same manner as discounted rate transactions by enabling the pipeline's fixed costs to be spread over more units of services. In those circumstances, the considerations underlying our discount adjustment policy for discounted rate transactions, as set forth in the 1989 *Rate Design Policy Statement* and subsequent cases permitting discount adjustments, would also apply to negotiated rate transactions.

202. However, unlike discounted rates, negotiated rates may exceed the maximum recourse rate. This fact raises the possibility that a pipeline may enter into some negotiated rate transactions for reasons other than lowering the rate below its maximum recourse rate in order to meet competition and attract shippers who would not otherwise contract for service on the pipeline. For example, a pipeline may enter into a negotiated rate transaction using a formula rate based on gas price differentials, because it believes that the market value of its capacity as reflected in those pricing differentials during the term of the negotiated rate agreement may be higher than its maximum recourse rate. For that reason, the Commission has been concerned that pipelines should not be granted discount adjustments for below-maximum rate negotiated rate agreements without taking into account projected revenues from above-maximum rate negotiated rate agreements. As we stated in *WIC*:

> [B]ecause negotiated rates, unlike discounted rates, can be above, as well as below, the maximum recourse rate, pipelines should not be able to shift the cost of below maximum rate discounts to the recourse rate shippers, while keeping the profits from above maximum rate negotiated rate transactions for themselves.[184]

203. Therefore, in *WIC*, the Commission provided pipelines a choice. We clarified that, if a pipeline chooses not to include in its tariff a provision permitting a discount adjustment for negotiated rates, "there is no requirement for the pipeline to flow-through to recourse rate shippers any revenue the pipeline receives under a negotiated rate agreement in excess of recourse rate levels."[185] In other words, in a section 4 rate case, the pipeline's rates would be designed based on the assumption that all its negotiated rates were at the maximum recourse rate, even if during the test period the pipeline's negotiated rate revenues exceeded its maximum recourse rates. As the Commission

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[184] *WIC*, 117 FERC ¶ 61,150 at P 13.

[185] *Id*. P 15.

explained, “Where there is no tariff provision permitting a discount adjustment, the risk of cost shifting does not exist; therefore, pipelines are entitled to keep the profits from negotiated rates above the maximum recourse rate.”[186]

204. However, if the pipeline includes in its tariff a provision permitting discount adjustments for negotiated rates of the type approved in *WIC* and *Columbia Gulf*, then a pipeline may obtain a discount adjustment for negotiated rate transactions, if it satisfies the burden of proving that the negotiated rates were required to meet competition and that the adjustment does not have an adverse impact on recourse rate shippers. As part of considering the effect of the adjustment on recourse rate shippers, parties may raise the issue “whether or not the pipeline should be allowed to keep negotiated revenues in excess of the recourse rate.”[187] In other words, if during the test period in a section 4 rate case, the rates for some negotiated rate transactions were in excess of the maximum recourse rate, the volumes associated with those transactions may be adjusted upward to allocate costs to those transactions based on the actual revenues received. In this way, the pipeline would not be able to shift the costs of below maximum rate negotiated rate transactions to the recourse rate shippers, while keeping the profits from above maximum rate negotiated rate transactions for itself.

205. Thus, the tariff language approved in *WIC* and *Columbia Gulf* provides a pipeline an opportunity to obtain a discount adjustment for negotiated rate transactions entered into for the same purpose as the discounted rate transactions for which the Commission permits discount adjustments: to meet competition and thus benefit the maximum rate recourse rate shippers by enabling the pipeline’s fixed costs to be spread over more units of services. At the same time, the *WIC* and *Columbia Gulf* tariff language protects recourse rate shippers from unreasonable costs shifts in several ways.

206. First, in order to show that it gave the discount to meet competition, the pipeline must satisfy “the standards required of an affiliate discount-type adjustment.” The Commission has consistently held that, in order to obtain a discount adjustment in connection with a discount provided to an affiliate, “the pipeline has a heavy burden to show that competition required discount to affiliates.”[188] Thus, in order to obtain a discount adjustment for a negotiated rate, the pipeline will have to provide detailed evidence concerning the competitive circumstances which required it to offer a negotiated rate that was lower than its maximum recourse rate, including the competitive

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[186] *Id*.

[187] *Id*. P 14.

[188] *Trunkline Gas Co*., 90 FERC ¶ 61,017 at 61,087 and 61,096 (describing the type of evidence the pipeline must submit to satisfy this burden).

alternatives the negotiated rate shipper had.[189] Moreover, most negotiated rate transactions are for long-term firm service. As with long-term firm discounted rate transactions, the Commission would expect that at the time of offering a below-maximum rate negotiated rate, the pipeline would make a thorough analysis whether competition required such a long-term commitment to a negotiated rate below the maximum recourse, and the Commission would expect that in a rate case seeking a discount adjustment for such a transaction, the pipeline would present evidence showing that it did make such an analysis.[190]

207. Second, the tariff language specifically requires the pipeline to demonstrate that any discount-type adjustment "does not have an adverse impact on recourse rate shippers." As part of considering whether the pipeline has satisfied that burden, the parties should evaluate all of the pipeline's cost and revenue data, including revenue from all its negotiated rate transactions. The analysis should not focus solely on the particular negotiated rate transactions for which the pipeline has sought a discount adjustment. Parties should also consider whether the pipeline obtained above-maximum rate revenues from other negotiated rate transactions which offsets the below-maximum rate revenues from the negotiated rate transactions for which the pipeline seeks a discount adjustment.[191] If so, there should be a corresponding reduction in any proposed discount adjustment. If the pipeline's overall negotiated rate revenues exceeded its maximum recourse rates, parties may, as stated in *WIC*, raise the issue whether costs should be allocated to the negotiated rate transactions based on the full revenues received in those transactions during the test period.

208. For these reasons, the Commission concludes that the tariff language approved in *WIC* and *Columbia Gulf* provides a reasonable framework for considering in a general section 4 rate case whether to permit a discount adjustment for a pipeline's negotiated rate transactions. That tariff language accommodates the interests of all concerned, including the pipeline and its customers. At the hearing in the section 4 rate case, all

[189] *See Panhandle Eastern Pipe Line Co.*, Opinion No. 404, 74 FERC ¶ 61,109 at 61,401-61,402, holding that the pipeline had not met its burden to show that its discounts to its affiliates were required by competition, because it has not identified the specific competitive alternatives the affiliate had, which required giving the discount. *See also Williams Natural Gas Co*., 77 FERC ¶ 61,277 at 62,206-61,207, and *Trunkline Gas Co*., 90 FERC ¶ 61,017 at 61,096.

[190] *Iroquois Gas Transmission System, L.P.*, 84 FERC ¶ 61,086 at 61,476-61,478, and *Trunkline Gas Co*., 90 FERC ¶ 61,017 at 61,092-61,095.

[191] *Columbia Gulf*, 133 FERC ¶ 61,078 at P 15 (citing *WIC* 117 FERC at P 15).

parties will be free to present evidence and argue whether the pipeline has adequately protected the recourse rate customers. This should bring before the Commission all the facts about the relevant transactions for reasoned decision on whether the negotiated rate transactions benefitted the recourse rate shipper or whether a discount adjustment would cause unreasonable cost-shifting. Such an approach better serves the ends of just and reasonable rates and practices than does a nearly blanket prohibition on any discount adjustments for negotiated rate transactions.[192] Therefore, the Commission reaffirms the policy adopted in *WIC* and *Columbia Gulf*. Because Tennessee's proposed tariff language tracks the language approved in *WIC* and *Columbia Gulf*, we accept Tennessee's proposal.

4. Whether Approval of Tennessee's Proposal Constitutes a Change in Policy Requiring a Rulemaking

209. The Commission rejects assertions by the commenters that the Commission must subject its policy regarding discount adjustments for negotiated rate transactions to notice and comment procedures under the APA or provide for generic proceedings.[193] Contrary to the contentions of the commenters, the Commission has consistently developed its policy on this issue in case-by-case adjudications. As described above, the *Alternative Rate Policy Statement* adopting the negotiated rate program did not establish any rule prohibiting or limiting discount adjustments for negotiated rate transactions. Rather, that policy statement stated that the Commission would consider issues regarding the appropriate allocation of costs between recourse rate shippers and negotiated rate shippers in individual pipeline section 4 rate cases. In denying rehearing of the *Alternative Rate Policy Statement*, the Commission again set forth its intention to address issues related to the use of negotiated rates on a case by case basis.[194]

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[192] *See Southern Natural Gas Co.*, 95 FERC ¶ 61,364, at 62,379 (2001).

[193] *See Michigan Wis. Pipe Line Co. v. FPC*, 171 U.S. App. D.C. 352, 520 F.2d 84, 89 (D.C. Cir. 1975) ("There is no question that the Commission may attach precedential, and even controlling weight to principles developed in one proceeding and then apply them under appropriate circumstances in a *stare decisis* manner."); *Transcontinental Gas Pipe Line Corp*., 77 FERC ¶ 61,270, at 62,134 (1996) (Any litigated proceeding before the Commission may serve as a vehicle for precedential decisions).

[194] As the Commission explained in denying rehearing of the policy statement:

> The purpose of the Policy Statement was to provide the industry with guidance by stating the criteria the Commission will consider when evaluating the proposals for alternative

(continued…)

210. In cases regarding the implementation of negotiated rate authority, the Commission specifically rejected arguments that it must conduct a rulemaking proceeding in this matter. Specifically, in *NorAm*, in regard to arguments that the Commission could not allow negotiated rate to take effect immediately, without following the APA rulemaking requirements, the Commission stated:

> [I]t is well established that the choice between rulemaking and case-by-case adjudication "lies primarily in the informed discretion of the administrative agency." The Commission exercised its discretion in this instance and chose to implement its negotiated rate program on a case-by-case basis. Thus, the Commission issued the Alternative Rate Policy Statement to serve as guidance to the industry on the parameters within which non-cost-of-service-based rate proposals should fall, but the Commission has chosen to evaluate the particulars of each program presented on a case-by-case basis.[195]

211. Further, in reaffirming its discount adjustment policy for selective discounting, the Commission explained:

> While the permission given by the Commission to pipelines to discount their rates between a minimum and maximum rate was promulgated in Order No. 436 and adopted in a regulation, **the adjustment in throughput to recognize discounting is not a rule, but is a policy that was adopted**

> ratemaking methodologies. … **The Commission intends to evaluate the specific proposals based on the facts and circumstances relevant to each applicant and to address any concerns regarding the application of the criteria on a case-by-case basis.** In general, objections to statements of policy are not directly reviewable. Rather, such review must await implementation of the policy in a specific case.

75 FERC ¶ 61,024 at 61,076 (emphasis supplied).

[195] *NorAm*, 81 FERC ¶ 61,204 at 61,039 (citing *SEC v. Chenery Corp*., 332 U.S. 194, 203, 67 S. Ct. 1575, 91 L. Ed. 1995 (1947)). *See also Panhandle Eastern Pipe Line Co.*, 81 FERC ¶ 61,234, at 61,971 (1997); *KN Interstate Gas Transmission Co*., 81 FERC ¶ 61,221, at 61,940 (1997); *Columbia Gulf Transmission Co.*, *et al*., 81 FERC ¶ 61,206, at 61,887 (1997).

> **by the Commission in the [1989] Rate Design Policy Statement. Therefore, in individual rate cases, the parties are free to develop a record based on the specific circumstances on the pipeline to determine whether the discounts given were beneficial to captive customers.** The pipeline has the burden of proof under section 4 of the NGA in a rate case to show that its proposal is just and reasonable. If there are circumstances on a particular pipeline that may warrant special considerations or disallowance of a full discount adjustment, those issues may be addressed in individual proceedings. Parties in a rate proceeding may address not only the issue of whether a discount was given to meet competition, but also issues concerning whether the discount was a result of destructive competition and whether something less than a full discount adjustment may be appropriate in the circumstances.[196]

212. Accordingly, the Commission has, since the beginning of this issue determined to examine the issues concerning discount adjustments on a case by case basis rate case where all the facts related to the specific case are available in order to arrive at a reasoned decision. The Commission cannot find that a generic proceeding related to this issue would help it reach a more accurate or reasonable decision in the case of a particular pipeline proposal.

5. <u>Retroactive vs. Prospective Application of Policy</u>

213. Finally, commenters argue for various reasons that if the Commission permits Tennessee to include such a provision, it should clarify that it will only apply prospectively only to contracts entered into and effective after the provision has become effective because market participants have had no opportunity to protest the potential impact of those agreements on system rates. The Commission will not so restrict the negotiated rate contracts subject to adjustments. The Commission has previously encountered these types of arguments in the context of its selective discounting program. In these cases, the Commission determined that, because the subject agreement had no

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[196] *Interstate Natural Gas Pipeline Rate Design*, 47 FERC ¶ 61,295, *order on reh'g*, 48 FERC ¶ 61,122 (1989) (1989 Rate Policy Statement). *See Policy for Selective Discounting By Natural Gas Pipelines*, 111 FERC ¶ 61,309 (Policy Reaffirmance Order), *order on reh'g*, 113 FERC ¶ 61,173, at P 22 (2005) (Policy Reaffirmance Rehearing Order), *pet. dismissed*, *Illinois Municipal Gas Agency v. FERC*, 2007 U.S. App. LEXIS 26296 (D.C. Cir., Nov. 27, 2007).

effect on the rate that a customer other than the customer paying the discounted rate, no customer was affected by the subject discount until the rate case in which the rate was adjusted to account for any discount. During the rate case shippers on the system would be free to argue against the necessity of the discount and or the discount adjustment. As stated by the Commission:

> the discounts in the subject agreements have no effect on the rates that [Shipper] or any other customer other than the discounted customer currently pays. [Pipeline's] maximum rates will remain those approved in its last general section 4 rate case, until such time as [Pipeline] proposes to change them in a new section 4 filing. Because the record in [Pipeline's] last section 4 rate case did not, and could not, reflect the discounts [Pipeline] is providing in the instant agreements, those rates do not include any discount adjustment with respect to the instant agreements. [197]

214. The same reasoning applies to negotiated rates. To permit discount adjustments for negotiated rate transactions has no effect on other shippers until the pipeline files a new section 4 rate case proposing a discount adjustment for those negotiated rate transactions. This is because the rate they pay is the same until the rate case in which the discount adjustment is sought. At that time they may have "an opportunity to challenge the [negotiated rate] and to seek discovery regarding the purpose and level of any [negotiated rate]."[198]

215. Moreover, the Commission also rejects any argument by the shippers to the extent that they argue that they could have taken some action at the time of the execution of the negotiated rate contract had they known that a discount adjustment would ultimately be sought by the pipeline for the negotiated rate contract. In the *Alternative Rate Policy Statement*, the Commission stated that it "does not intend to review a pipeline's

[197] *Northern Natural Gas Co*., 113 FERC ¶ 61,188, at P 22 (2005). In *Northern Natural Gas Co*., 113 FERC ¶ 61,119, at P 26 (2005), the Commission stated that "[T]he pipeline is at risk for service provided at prices below those projected in the setting of its rates" (citing 1989 Rate Policy Statement, 48 FERC ¶ 61,122 at 61,449) and found that at least until the pipelines' next rate case, its other customers can in no way be considered to be subsidizing the discounts given to the discounted customers.

[198] *Northern Natural Gas Co*. 113 FERC ¶ 61,188 at P 25; *Northern Natural Gas Co*., 113 FERC ¶ 61,119 at P 25 ("the Commission finds it most efficient to address the discount adjustment issues in whatever Section 4 rate case [the Pipeline] proposes to make such a discount adjustment, rather than here.").

negotiated rates at the time filed."[199] Because a discount adjustment for negotiated rates does not affect shippers until the pipeline files a section 4 rate case, there is no reason to consider discount adjustment issues until such a rate case is filed. That approach is consistent with the Commission's discount policies and accompanying precedent that the Commission would not address whether the pipeline should be granted a discount adjustment for discounted rate transactions, unless and until the pipeline filed for a discount adjustment in a general section 4 rate proceeding.[200]

216. Last, several commenters have raised concerns regarding the specific application of Tennessee's proposed language or argued that certain specific provision must be included in the proposed language. Such issues are, as discussed in *Southern* and *Columbia Gulf* above, best resolved at hearing.

XIII. Hurricane Recovery

A. Proposal

217. Tennessee proposes a new hurricane cost recovery mechanism to recover eligible costs incurred by Tennessee as a result of named hurricanes and windstorms. In the pre-conference comments on Tennessee's Initial Filing, several parties requested that the Commission summarily reject this hurricane surcharge mechanism, arguing that the surcharge is unnecessary, unsupported, speculative, and contrary to prevailing policies disfavoring trackers. In the Suspension Order, the Commission briefly summarized its policy on hurricane trackers, stating that the Commission has allowed pipelines to establish a hurricane cost recovery mechanism via a limited section 4 filing, or to have in place a mechanism to recover future hurricane-related costs incurred prior to its next general section 4 rate case. The Commission then rejected the requests for summary dismissal, and set for hearing "the issues set forth in the protests and not resolved above."[201]

B. Comments

218. In the comments to the technical conference, the Northeast State Coalition and the Tennessee Customer Group continue to object to the proposed hurricane tracker. The

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[199] *Alternative Rate Policy Statement*, 74 FERC ¶ 61,076 at 61,242.

[200] *Northern Natural Gas Co.*, 113 FERC ¶ 61,119 at P 25-33; *Northern Natural Gas Co.*, 110 FERC ¶ 61,321, at P 32 (2005); *Northern Natural Gas Co.*, 111 FERC ¶ 61,379, at P 17-21 (2005); *Northern Natural Gas Co.*, 113 FERC ¶ 61,188 at P 22-25.

[201] Suspension Order, 133 FERC ¶ 61,266 at P 23.

Tennessee Customer Group argues that, based on its understanding of Tennessee's proposed discount adjustment provision, Tennessee's tariff would obligate the pipeline to discount its hurricane surcharge before it discounts base rates. The Tennessee Customer Group requests that the Commission clarify that this issue is one that the Commission has set to be resolved in the evidentiary hearings. In the alternative, the Tennessee Customer Group urges that the Commission reject this aspect of the hurricane tracker outright, so that extraordinary hurricane costs are allocated to all customers, not just maximum rate customers.[202] The Northeast State Coalition argues that while Tennessee has cited cases in which the Commission has authorized hurricane trackers, those cases are distinguishable, so the hurricane tracker should be denied.[203] In the alternative, Northeast State Coalition argues that the Commission should set issues related to the hurricane trackers for hearing.[204]

C. Commission Decision

219. In the Suspension Order, the Commission affirmed that the proposed hurricane tracker should not be rejected summarily, but set all other objections to the hurricane tracker raised in the protests for hearing. We reaffirm that parties shall discuss the hurricane tracker at hearing, including its justness and reasonableness as applied to Tennessee's specific circumstances and its proposed tariff.

XIV. Fuel Tracker

A. Proposal

220. In its Initial Filing, Tennessee proposed to recover fuel and LAUF gas through a new fuel tracker and true-up mechanism. Tennessee proposed to file quarterly to revise its fuel retention percentages, with the Initial Filing to be made thirty days prior to its effective date on June 1, 2011. As stated in its transmittal letter, Tennessee proposed to make the fuel tracking mechanism effective upon motion following the suspension of its proposed base rates. Tennessee also explained its intent to file tariff records to place reduced fuel retention percentages into effect contemporaneously with the effectiveness of the base rates proposed in the filing. While Tennessee submitted indicative fuel

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[202] Tennessee Customer Group Initial Comments at 25-26.

[203] Northeast State Coalition Initial Comments at 10.

[204] Northeast State Coalition Initial Comments at 11.

retention percentages based on base period data,[205] Tennessee did not propose tariff records with new fuel and LAUF gas retention percentages.

221. In the Suspension order, the Commission accepted and suspended the fuel tracker for five months, to be effective June 1, 2011, subject to refund. The Commission declined certain parties' request to suspend the tracker for the minimal suspension period and set all issues relating to the tracker for hearing.[206]

B. Comments

222. Sequent comments that while it supports the concept of a fuel tracker with a true-up, it opposes Tennessee's proposal to update its fuel and loss percentages on a quarterly basis.[207] Sequent contends that such filings should be made on an annual basis with the potential for out-of-cycle filings to address any unexpected events affecting fuel on its system. According to Sequent, the natural contracting unit for long term service is yearly not quarterly, and in its experience, quarterly fuel filings are disruptive and increase administrative and contracting costs. Sequent also claims that Tennessee fails to provide compelling operational evidence for the necessity of a quarterly fuel adjustment filing.

223. In its Reply Comments, Tennessee notes that the Commission set the fuel tracker mechanism for hearing, in part based on protests regarding how often Tennessee should adjust its fuel retention percentages.[208] Tennessee thus argues that it would be inconsistent with that order to act summarily, without a hearing, to approve Tennessee's proposal conditioned on it filing annual, not quarterly, adjustments.

C. Commission Decision

224. As noted by Tennessee, the Commission set the fuel tracker mechanism and all related issues for hearing. Sequent may raise any issues it has concerning the frequency of Tennessee's fuel adjustment filings in that forum. Thus, Sequent's request for the Commission to rule on that issue here is denied.

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[205] Exs. TGP-159 and TGP-160.

[206] Suspension Order, 133 FERC ¶ 61,266 at P 36 and P 38.

[207] Sequent Initial Comments at 6.

[208] Tennessee Reply Comments at 61.

XV. Uncontested and Miscellaneous Tariff Provisions

225. Tennessee proposed additional tariff revisions that were not contested or otherwise discussed above in this order. The Commission approves these uncontested tariff revisions effective June 1, 2011.

The Commission orders:

(A) Where, as detailed in the body of this order, the Commission accepts an NGA section 4 proposal outright or accepts it subject to conditions, those tariff records are accepted effective on June 1, 2011, as requested.

(B) Where, as detailed in the body of this order, the Commission rejects an NGA section 4 proposal, the corresponding tariff records are rejected.

(C) Within 30 days of the date of this order, Tennessee shall file the revised tariff records required by Ordering Paragraphs (A) and (B), to be effective on the date Tennessee moves its suspended records into effect.

(D) Within 30 days of the date of this order, Tennessee shall file revised tariff records concerning reservation charge credits during non-*force majeure* events and its waiver of tariff provisions consistent with the discussion in this order or explain why it should not be required to do so.

(E) The Presiding Administrative Law Judge previously designated in this proceeding is authorized to conduct further proceedings in accordance with the issues set for hearing in the body of this order. The Presiding Administrative Law Judge shall have discretion over the scheduling and phasing-in of these additional proceedings, in accordance with the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

List of Commenters and Abbreviations

Commenter	Abbreviation
American Gas Association	AGA
Anadarko Energy Services Company	Anadarko
Atmos Energy Corporation	Atmos
BG Energy Merchants, LLC	BG Energy
Cabot Oil & Gas Corporation	Cabot
Chattanooga Gas Company and Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas	Elizabethtown Gas
Chesapeake Energy Marketing, Inc.	Chesapeake
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.	Con Ed
East Tennessee Group	ETG
Eastman Chemical Company	Eastman
Enbridge Marketing (U.S.) L.P., Independent Oil & Gas Association of West Virginia, Inc., and JPMorgan Ventures Energy Corporation	EMUS/IOGA/JPMVEC
Apache Corporation; BP Energy Company and BP America Production Company; Chevron U.S.A. Inc.; ConocoPhillips Company; ExxonMobil Gas & Power Marketing Company, a division of Exxon Mobil Corporation; Hess Corporation; Noble Energy Inc.; Shell Energy North America (US), L.P. and Shell Offshore Inc.	Indicated Shippers
Louisville Gas and Electric Company	Louisville
New England Local Distribution Companies	New England LDCs
Nicor Gas	Nicor
NJR Energy Services Company	NJR
The Brooklyn Union Gas Company d/b/a National Grid NY; KeySpan Gas East Corporation d/b/a National Grid; Boston Gas Company and Colonial Gas Company d/b/a National Grid; Energy North Natural Gas, Inc. d/b/a National Grid NH; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid	Northeast Customer Group
Massachusetts Attorney General, Pennsylvania Office of Consumer Advocate, Maine Public Utilities Commission, New York State Public Service Commission, Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, Connecticut Department of Public Utility Control, Connecticut Office of Consumer Counsel, Rhode Island Attorney General, Rhode Island Division of Public Utilities and Carriers, New Hampshire Public Utilities Commission,	Northeast State Coalition

Vermont Department of Public Service, and New York State Consumer Protection Board.	
Piedmont Natural Gas Company, Inc.	Piedmont
Process Gas Consumers Group	PGC
Repsol Energy North America Corporation	Repsol
Selkirk Cogen Partners, L.P.	Selkirk
Sequent Energy Management, L.P.	Sequent
Statoil Natural Gas LLC and South Jersey Resources Group, LLC	Statoil/South Jersey
Talisman Energy USA Inc., Encana Marketing (USA) Inc., Tenaska Marketing Ventures, and MGI Supply Ltd.	North American Marketers
CenterPoint Energy; City of Clarksville Gas and Water Department, City of Clarksville; City of Corinth Public Utilities Commission; Delta Natural Gas Company, Inc.; Greater Dickson Gas Authority; Hardeman Fayette Utility District; Henderson Utility Department; Holly Springs Utility Department; Humphreys County Utility District; Town of Linden; Morehead Utility Plant Board; Portland Natural Gas System, City of Portland; Savannah Utilities; Springfield Gas System, City of Springfield; City of Waynesboro; West Tennessee Public Utility District; Athens Utilities; City of Florence, Alabama; Hartselle Utilities; City of Huntsville, Alabama; Municipal Gas Authority of Mississippi; North Alabama Gas District; Tuscumbia Utilities and Sheffield Utilities	Tennessee Customer Group
Tennessee Gas Pipeline Company	Tennessee
Tennessee Valley Authority	TVA