

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

3109 SCOMM 143: SENATE SPEC.COMM.ON NATURAL GAS DEV. 2005-2006

the timely development of the project.”²³ Additionally, we are adding a provision to the section which will enable the project sponsor, at the appropriate time in the development of its project and subject to Commission approval, to determine, based on the above criteria, that no further bids can be accepted. We will also revise section 157.34(d)(2) to provide that any bid tendered after the expiration of an open season must contain a good faith showing, including a statement of the circumstances which prevented the bidder from tendering a timely bid, and how those circumstances have changed. This requirement is consistent with the underlying premise of section 157.34(d)(2) in the Final Rule, and should serve to protect against “gamesmanship.” With these revisions and clarifications, we believe that the late bid provision will permit late-developing shippers to obtain capacity after the expiration of the open season, while also providing the prospective applicant the assurance that it will be able to design and develop its project according to its own schedule.

V. Mandatory Pre-Approval

A. The Final Rule - § 157.38

64. Section 157.38 requires that, at least 90 days prior to providing its notice of open season, an applicant must file, for Commission approval, a detailed plan for conducting the open season in conformance with the regulations. The Commission will establish a date by which comments on the request for approval are due, and the Commission, unless it directs otherwise, will act on the request within 60 days of its filing. The Commission concluded in Order No. 2005 that this requirement would allow for the resolution of disputes or dissatisfaction with an open season at the earliest possible time, thereby reducing the risk of having to require a second remedial open season because the first one did not conform to the regulations.

²³ We are retaining the requirement that the prospective applicant must provide a detailed explanation for its rejection, at least until such time as it has determined, subject to Commission approval, that no further late bids can be accepted. We find that, based on the prospective applicant’s position, it is easier for it to evaluate why a late bid cannot be accepted, than it is for a later bidder to explain why its bid can be accommodated.

B. Rehearing/Clarification Requests

65. The North Slope Producers and Enbridge urge the Commission to eliminate the mandatory pre-review process set out in section 157.38, calculating that with the addition of this mandatory review, the open season process will take at least 210 days, instead of the 120-day open season period proposed in the NOPR and established in section 157.34. They state that this additional 90 days does not include further delays that could result from disputes arising during the pre-review process, including the need to consider requests for rehearing of any orders pre-approving an open season or the Commission's inability to adhere to its 90-day window. The result, they claim, is that the open season process will be delayed, not expedited. Enbridge states that the 210-day period is longer than the 180-day open season period which the Commission rejected as inconsistent with Congress' sense of urgency, as well as the Commission's conclusion in Order No. 2005 that "timing is of the essence."

66. The North Slope Producers maintain that the Commission's justification for this requirement is that a successful open season is more likely to occur if issues are identified and resolved at the earliest time. The North Slope Producers disagree, claiming that, instead of reducing the chance of post-bid disputes, this layer of review will provide those who would gain commercial leverage by delaying the open season process "with an additional bite at the apple, first by objecting to the bid package, then by objecting to the results of the open season."

67. Both the North Slope Producers and Enbridge contend that the mandatory pre-review process is unnecessary and duplicative of other protections provided in Order No. 2005, including the transparency and specificity of the open season information, the 30-day prior notice requirement, the prohibition against undue discrimination or preference in rates, terms or conditions of service, and the imposition of Order No. 2004 standards of conduct. They contend that the effects of any delay of the open season can be profound, due to narrow, seasonal windows for environmental studies and preliminary field work, which cannot take place until the open season has been held. These risks, they claim, far outweigh any utility of a mandatory pre-review. In conclusion, the North Slope Producers contend that any pre-review of the open season notice should be voluntary, shortened, and that the Commission decision on the sufficiency should be deemed a pre-decisional, non-reviewable determination, similar to the Commission's action in rejecting a deficient certificate application under section 157.8 of the Commission's regulations.

68. Anadarko defends the mandatory pre-review requirement as striking an "appropriate balance between granting project sponsors flexibility in designing open seasons and providing regulatory supervision to potential bidders by requiring project sponsors to file and obtain approval of the open season plan." Anadarko and the Alaska Legislators state that pre-approval will reduce any risk of having to hold a second open season to correct one done improperly. Anadarko states that this will, as the Commission believes, promote rather than hinder a timely and successful open season. The Alaska Legislators agree with this assessment, contending that adding 90 days to the front end of the open season process, even with the prospect of a rehearing, is better than having an open season called back by an order on rehearing or on appeal from the results of an open season, and then having to hold another open season. Moreover, they state that once the open season is approved, parties may rely on those terms being controlling throughout the bidding and contracting process.

C. Commission Response

69. The North Slope Producers and Enbridge correctly state that, by virtue of the mandatory pre-approval established in section 157.38, the minimum duration of the whole open season process would be 210 days. However, the concept of a mandatory pre-approval and the attendant additional time that such review will add is not inconsistent with our concern that "time is of the essence" that caused us to reject a 180-day open season period, and instead provide for a 120-day open season.²⁴ Our focus in establishing this 120-day period was to arrive at a time period such that all prospective bidders reasonably could review the open season information and evaluate whether to make multi-year capacity commitments, thereby leveling the playing field.

70. When discussing the duration of the whole "open season process," we must consider the potential for delays due to disputes arising during the open season. In this regard, we found in Order No. 2005 that pre-approval of open season procedures would "allow issues to be identified and resolved at the earliest possible time and, ideally, reduce the possibility of dissatisfaction with open seasons, as well as the risk that the

²⁴ The 120 days consists of the 30-day prior notice period (section 157.34(a)), followed by a 90-day open season (section 157.34(d)(1)).

Commission will have to require that deficient open seasons be conducted again.”²⁵ The North Slope Producers’ and Enbridge’s disagreement with this assessment is based on arguments that the transparency and specificity of the information required in the open season and other protections provided in the open season rules render pre-approval unnecessary, and that the pre-approval process itself invites delay.

71. We are not as optimistic as the North Slope Producers and Enbridge that there is little likelihood that disputes might arise over the conduct of an open season and its conformance with the open season rules. While the transparency and specificity of the open season rules might lead to a clearer identification of any issues in dispute, they do not change the fact that in any open season there will be a universe of potential bidders with starkly different, competing needs and interests, and the potential for dispute is real. We continue to believe that getting it right the first time is the best approach.

72. Nonetheless, in revisiting the requirement for mandatory pre-approval as a result of these rehearing requests, we find that it is appropriate to make some changes. First, we are revising section 157.38 to make clear that the plan to be filed by a prospective applicant shall include the information required in a notice of open season under section 157.34. Second, we are eliminating the 30-day prior notice requirement in section 157.34(a). Since the public will have actual notice of a prospective applicant proposed open season notice at least 90 days prior to the open season, there is no reason to provide for an additional prior notice period. By this change, we are reducing the 210-day period to 180 days. It also our conclusion that, given the fact that participants in an open season will have the opportunity to object to the conduct of the open season after a certificate application is filed, as is our current practice, as well as the ability to seek rehearing and obtain appellate review of any Commission certificate orders, orders approving open season procedures will be interlocutory and not subject to rehearing.

V. In-State Study

A. The Final Rule - §157.34(b)

²⁵ Order No. 2005 at P 109.

73. In response to concerns expressed by Alaska entities and in recognition of Congress' mandate that Alaska in-state needs be given due consideration, the Final Rule added in section 157.34(b) a requirement not contained in the proposed regulations that the open season information include an assessment of Alaska's in-state needs and prospective points of delivery within the State of Alaska, based to the extent possible on any available study performed or otherwise approved by an appropriate Alaska governmental entity.

B. Rehearing/Clarification Requests

74. While the North Slope Producers find reasonable a requirement that a study of in-state needs be completed prior to any open season, they object to section 157.34(b)'s requirement that the contents of the open season notice rely on an in-state study, if practicable. They assert that ANGPA does not require a pipeline sponsor's study to "include or consist" of a state-sanctioned study. The North Slope Producers contend that this requirement invites disputes as to whether it is "practicable" to include a state study, or whether "appropriate" state officials were involved. Consequently, the North Slope Producers request that the Commission revise section 157.34(b) to require that a project sponsor consult with the State regarding the study for in-state needs.

75. The Alaska Legislators state that the Commission has avoided the problem of "dueling studies" by deferring the study to the State of Alaska. In this regard, the Alaska legislators advise the Commission that the State of Alaska has undertaken to designate an appropriate agency to conduct or sanction the required study, and the Alaska House of Representatives has passed a resolution urging the Administration to conduct, approve, or sanction the required study prior to the effective date of the opens season rules.

C. Commission Response

76. Section 157.34(b) does not mandate the use of a particular study but rather is premised on the common-sense notion that information provided by the State of Alaska likely will be valuable to potential shippers. We trust that the State and prospective pipeline applicants can agree on the manner in which such information can be provided. If questions arise as to the extent to which it is possible to include a state study, we will resolve them. Our regulations offer several options that the prospective applicant and the State of Alaska could take to ensure the adequate involvement of the State. Accordingly, we will not revise section 157.34(b).

VI. In-State Rates

A. The Final Rule - § 157.34 (c)(8)

77. In addition to the requirement that in-state gas needs be addressed in the open season, the Commission also required, in section 157.34(c)(8), that, based on in-state needs and the delivery points identified in the study, open season information include a proposed in-state transportation rate, based on the costs of providing that service.

B. Rehearing/Clarification Requests

78. The North Slope Producers ask the Commission to clarify that estimating rates for in-state service does not create a requirement to offer such a service at that rate (or at all) if the open season does not yield firm commitments for in-State deliveries. They assert that the ultimate indicator of any market for in-state service is the willingness of shippers to make firm commitments to purchase capacity for in-state use during the open season, not a study. They also request that the Commission clarify that the estimated in-state service rates are merely illustrative and subject to adjustment.

79. Enbridge requests that the Commission make clear that the "estimated transportation rate" referred to in section 157.34 (c)(8) is one based on project sponsor's estimated costs to make in-state deliveries, not upon any rates assumed by the study. Additionally, Enbridge states that the Commission clarify that bids for in-state service should be subjected to the same requirements for creditworthiness, collateral and execution of binding contractual commitments as apply to any other open season bidder.

80. The State of Alaska asks the Commission to clearly state that the in-state rates are to be distance-sensitive in order to ensure that the cost of in-state service is calculated properly.

C. Commission Response

81. During the open season process, qualified bidders must successfully bid upon and arrange to consummate service agreements for transportation service. Projected rates for in-state deliveries must be based on estimates of costs for providing service to the in-state delivery points. While prospective applicants will estimate rates during an open season, the Commission's review of proposed rates will be guided by section 284.10(c)(3) of our regulations, which states in part that "[a]ny rate filed for service ... must reasonably reflect any material variation in the cost of providing the service due to ... the distance over which the transportation is provided."

82. All shippers on any new interstate pipeline have a right to pay only the initial rate on file as approved in the NGA section 7 certificate of public convenience and necessity. Those initial rates, approved under section 7 as part of the certificate, would be paid unless changed under section 4 or 5 of the NGA after appropriate regulatory proceedings and upon the Commission's order. However, under the Commission's negotiated rate policy,²⁶ pipelines and shippers are free to make an agreement to "dispense with cost-of-service regulation" and agree to any mutually agreeable rate. A recourse rate found in the pipeline's tariff would be available for those shippers preferring traditional cost-of-service rates. Thus, if an in-state service is successfully bid upon, filed for and approved, an in-state cost-of-service recourse rate would be set in an Alaskan pipeline's tariff, but in-state shippers would also be free to seek a negotiated in-state rate with an Alaskan pipeline. Negotiated rates can be used to lock in transportation costs and pipeline revenues to the mutual benefit of both the shippers and the pipeline, without the risks of later changes to rates and revenues under the NGA.

83. If there are no successful bids for in-state service, the prospective applicant would nonetheless have to include the in-state service as part of its proposed initial tariff. An opportunity to have in-state service might arise if the pipeline voluntarily accepts a request for it at a later time, or if the Commission acts under section 103(h) of ANGPA and section 5 of the NGA to require the pipeline to make such in-state deliveries. The actual in-state rate for in-state service would be an issue for such future proceedings. Based on the foregoing, we see no need to further clarify the regulations.

VII. Tying Arrangements

A. The Final Rule - §§ 157.34(c)(6), 157.34(c)(10), and 157.35(a)

84. The Commission addressed the matter of tying access to pipeline capacity on an Alaska project to ancillary services in two sections of the Final Rule. First, section 157.34(c)(6) requires that the open season notice must contain an unbundled

²⁶ Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Docket No. RM95-6-000, Regulation of Negotiated Transportation Services of Natural Gas Pipelines, Docket No. RM96-7-000, 74 FERC ¶ 61,076, (Jan. 31, 1996).

transportation rate. Second, section 157.34 (c)(10) prohibits a prospective applicant from requiring prospective shippers to process or treat their gas at any designated facility. We explained elsewhere in Order No. 2005 "that [we] can address any other discriminatory conduct in connection with gas quality requirements or other ancillary services through the provisions of section 157.35 in conjunction with existing Commission policies and procedures." Relevant to this explanation, section 157.35(a) provides that "[a]ll binding open seasons shall be conducted without undue discrimination or preference in the rates, terms, or conditions of service and all capacity awarded as a result of any open season shall be awarded without undue discrimination or preference of any kind."

B. Rehearing/Clarification Requests

85. The State of Alaska states that the Commission should more explicitly explain the prohibition against tying arrangements, and explain how the open season rules will apply to gas treatment plants. The State believes that the open season rules should do more than require an applicant to use an unbundled transportation rate, prohibit tying of capacity on the pipeline to the use of a designated plant or facility, and merely refer to the existing regulations and policies prohibiting undue discrimination or preference. Rather, Alaska states that the open season rules should make clear that any tying arrangements will be subject to an exacting inquiry by the Commission and will require a compelling justification, and even offers recommended language to this end.

86. Alaska also states that since ANGPA includes gas treatment plants in its definition of an Alaska natural gas transportation project,²⁷ treatment plants should be subject to the open season regulations. Alaska points out that the effect of the unbundling requirement of section 157.34(c)(6) is to exclude gas treatment plants from the requirements of the open season. As a possible solution, Alaska suggests that the open season rules be clarified to provide that the applicant must separately offer gas treatment plant capacity and pipeline capacity in the open season notice, and give bidders an opportunity to bid on

²⁷ ANGPA §102(2) defines the term 'Alaska natural gas transportation project' as "any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) ..."

either or both, as they choose. ChevronTexaco contends that because gas treatment plants are jurisdictional facilities,²⁸ Order No. 2005's approach of deferring consideration of any discriminatory conduct as to necessary such ancillary facilities and services to a later day does not satisfy the requirements of the ANGPA. Chevron Texaco maintains that it is particularly important that access to treatment facilities be subject to the same open season, non-discriminatory requirement as the pipeline because pipeline capacity without access to gas treatment facilities that maybe a part of the pipeline system is meaningless.

C. Commission Response

87. The Commission did not intend to preclude the inclusion of jurisdictional natural gas conditioning facilities from the open season. If, pursuant to ANGPA section 103, a project sponsor intends to file an application under section 7 of the NGA for authorization of a project that includes a jurisdictional natural gas conditioning service, we will review the open season plan and notice to ensure that such service is offered in its open season notice, subject to the same requirements as apply to transportation service. However, the prospective applicant must offer a separate rate for the gas treatment service and separate rate for the transportation service. Furthermore, the prospective applicant can neither require bidders to bid on both services, nor evaluate the bids based on whether bidders requested one or both services. Moreover, while the prospective applicant can require specific natural gas quality specifications such as would be met by using the conditioning services of the pipeline, it cannot reject an otherwise qualified bidder that states that it will deliver to the pipeline facilities gas that meets the stated quality specifications.

88. On the other hand, if a prospective applicant is proposing to apply to revise the Alaska Natural Gas Transportation System (ANGTS) application now held in abeyance, then a conditioning service will have to be included as a part of the open season but again, with all services offered priced separately. Specifically, in 1981, President Reagan submitted a Waiver of Law to Congress for the purpose of clearing away certain government-imposed obstacles to the private financing of the ANGTS. The Commission

²⁸ See *Venice Gathering Co.*, 97 FERC ¶ 61,045 at 61,255 (2001) (Treatment of gas to enhance its safe and efficient transportation is subject to Commission jurisdiction).

implemented that portion of the Presidential waiver that required the Commission to include within the ANGTS the gas conditioning plant at Prudhoe Bay.²⁹

VIII. Pre-Subscribed Capacity

A. The Final Rule - §§ 157.33(b) and 157.34(c)(15)

89. Under section 157.33(b), pre-subscription agreements for initial capacity on a proposed Alaska natural gas transportation project are permitted, provided that capacity is offered to all open season prospective bidders at the same rates and on the same terms and conditions as contained in the pre-subscription agreements. In addition, if there is more than one pre-subscription agreement, open season prospective bidders are given the option of selecting the rates, terms and conditions contained in any one of the several agreements. However, section 157.34(c)(15) states that "[i]f capacity is oversubscribed and the prospective applicant does not redesign the project to accommodate all capacity requests, only capacity that has been acquired through pre-subscription shall be subject to allocation on a *pro rata* basis; no capacity acquired through the open season shall be allocated."

B. Rehearing/Clarification Requests

90. The North Slope Producers assert that the provision in section 157.34(c)(15) subjecting only presubscribed capacity to *pro rata* allocation, will dissuade any shippers from signing up for the presubscribed capacity, thereby "wholly negating" the recognized benefits of allowing pre-subscription agreements to facilitate the development of an Alaska natural gas transportation project. They predict that prospective shippers would rather wait for the open season than risk proration. The North Slope Producers maintain that this selective proration unduly discriminates against those shippers who are willing to make early commitments for firm capacity in order to support the project, in violation

²⁹ See *Alaskan Northwest Natural Gas Transportation Co.*, 18 FERC ¶ 61,002 (1982).

of the NGA and Commission policy. They add that since section 157.33(b) allows all open season participants to enjoy the same benefits as contained in the pre-subscription agreements, such discrimination is particularly unjustified. The North Slope Producers add that this is another example where the Commission is attempting to compel the project sponsor to make design changes in order to accommodate all bids.

91. The North Slope Producers also state that the final clause of section 157.34(c)(15) is not consistent with the Commission's presumed intent not to foreclose proration among open season bidders where there is no presubscribed capacity. They suggest that the final clause of that provision, which states "no capacity acquired through the open season shall be allocated," should be clarified.

92. In addition to agreeing that proration renders pre-subscription an unattractive option for prospective shippers, Enbridge adds that the additional requirement that the terms and conditions of any pre-subscription agreements be made public prior to the open season notice renders pre-subscription even less desirable because it put anchors shippers at a competitive disadvantage to open season bidders who would have prior knowledge of the pre-subscription bids. At the same time, Enbridge concedes that it would be highly unlikely that project would not be re-designed to accommodate capacity of all qualified bids at the incipient, open season stage.

93. Enbridge raises again the claim that the "numerous and overlapping protections" of Order No. 2005, in particular the level of information provided in open season notice and measures provided to ensure against discrimination, are sufficient to ensure a fair, open and non-discriminatory open season process. Enbridge also states that the Commission should clarify that open season shippers who in the open season elect to select the terms and conditions of a pre-subscription agreement may not cherry-pick terms and conditions from several agreements but must accept any one agreement in its entirety.

94. The State of Alaska seeks clarification that, in the case of capacity allocation on an oversubscribed pipeline that cannot reasonably be redesigned, both presubscribed capacity and capacity later acquired on the same rates, terms and conditions will be subject to allocation, for the reason that the final words of section 157.34 (c)(15) stating that "no capacity acquired through the open season shall be allocated," suggests otherwise.

95. ChevronTexaco maintains that the Commission failed to consider and provide for the various circumstances that could trigger the pro-rationing of pre-subscribed capacity. ChevronTexaco states that bidders in the open season could outbid pre-subscribing

shippers on the basis of any of the qualifying conditions: for instance, an open season bidder might outbid pre-subscribing shippers whose agreements are at less than maximum rates, or whose agreements are of shorter terms. ChevronTexaco is concerned that pre-subscribing shippers might lose their capacity to open season bidders who outbid them because they know the salient terms of the pre-subscription agreements. Therefore, ChevronTexaco submits that the Commission should expand the requirement of pro-rationing by establishing that all bids eligible to be allocated capacity in an open season where pre-subscribing shippers will be prorated should be treated as having equal value to the pre-subscription precedent agreement for purposes of pro-rationing. In this way, later qualifying bidders would be prevented from outbidding pre-subscribing shippers.

96. In response to the claims on rehearing that the capacity allocation provisions of section 157.34(c)(15) are counterproductive because they will deter potential anchor shippers from entering into pre-subscription agreements, Anadarko contends that the Commission's finding that the North Slope Producers' unique position of control over pipeline design amply justifies putting the consequences of any decision not to redesign pipeline to accommodate all bidders on them. Anadarko also questions the importance placed on pre-subscription agreements in connection with an Alaska pipeline project. According to Anadarko, the only justification for a pre-subscription agreement is to facilitate financing and to provide the project sponsor with assurances that it has the commitments to justify development and construction expenses. However, states Anadarko, there is little doubt that any Alaska natural gas transportation project will be fully committed, even without pre-subscription agreements.

97. The Alaska Legislators support the pre-subscription rules of Order No. 2005, claiming that the rules make sense given the unique nature and circumstances of an Alaska natural gas transportation project and the need to balance concerns "that pre-subscription is essential to finance the pipeline with concerns of those who feared that such arrangements would favor affiliates of the pipeline or otherwise undermine the objectives of conducting public open seasons for capacity."

C. Commission Response

98. Although we allowed pre-subscription agreements in the belief that they could have utility in facilitating the development of an Alaska natural gas transportation project, we cannot quantify how beneficial such arrangements are. Our paramount consideration in allowing pre-subscription was that it should not impact in any way the capacity obtained through the open season process. For this reason, we provided that any capacity acquired by reason of agreements entered into prior to the open season would have to yield to capacity bid for in the open season in the case of oversubscription. We

believe our reasons for this selective proration, as stated in Order No. 2005 and reaffirmed here, are sound.

99. The argument that anchor shippers will be dissuaded from entering into pre-subscription agreements if they risk losing capacity as a result of open season bidding, and that the "recognized benefits" of pre-subscription will be lost, is unpersuasive. The North Slope producers and other potential project sponsors have developed a plethora of information in recent years regarding the viability of an Alaska project. They are fully capable of deciding whether they wish to execute pre-subscription agreements. If they do not, capacity will be allocated in an open season. There has been no showing that an Alaska project cannot be financed, as are many major projects, based on commitments made in an open season. While we have concluded that the public interest permits pre-subscription, under the conditions established by the rule, we do not find that the public interest requires pre-subscription. It does require competition and open-access. We leave it to potential project sponsors and shippers whether pre-subscription makes sense to them.

100. We will, however, clarify section 157.34(c)(15) in two respects, first to eliminate confusion over the last sentence of that section which concludes "no capacity acquired through the open season shall be allocated," and second to make clear that in the event there is more than one pre-subscription agreement, bidders in the open season may not cherry-pick among the provisions of the several agreements. The North Slope Producers contend that the last clause of section 157.34(c)(15) might be read to provide that proration is foreclosed among open season bidders even where there is no subscribed capacity. We will clarify the language of the rule to avoid such a misreading. Capacity bid for in the open season is exempt from allocation only in a case where there is also subscribed capacity, as explained in the text of Order No. 2005. The State of Alaska reads that clause to suggest that capacity acquired by bidders in the open season who elect to acquire their capacity on the same rates, terms and conditions as contained in a pre-subscription agreement will not be subject to pro rata allocation along with the pre-subscription shippers. Such an interpretation also misreads the intent of section 157.34(c)(15), and we will clarify the language of the rule accordingly. Finally, we will clarify section 157.33 to make clear that open season bidders may not cherry pick among the provisions of several precedent agreements, as was our intent in the Final Rule.

IX. Other Issues

101. The North Slope Producers request that the open season rules be clarified in certain respects. First, they request that the Commission clarify the open season

regulations by replacing references to "prospective points of delivery within the State of Alaska" or "delivery points" in several subsections of the regulation with the term "tie-in points."³⁰ The North Slope Producers assert that the term "delivery point" implies an obligation that the pipeline will be finally designed to deliver gas all the way to in-State markets and that ANGPA does not contemplate or impose such an obligation.

102. The Commission understands the terms "prospective points of delivery within the State of Alaska" or "delivery points" to mean those points on the interstate Alaskan pipeline where custody of the gas would be transferred to the facilities of an intrastate pipeline, local distribution company, or end-user whose facilities are not otherwise under the Commission's jurisdiction, assuming that shippers on an Alaska pipeline requested such deliveries. The term "tie-in points" as used only once in ANGPA is used in reference to the study of in-state needs in section 103(g) and as a familiar natural gas industry phrase is not as familiar to the Commission as the terms "points of delivery" or "delivery points."³¹

103. As part of the open season, the prospective applicant is in fact obligated to offer to deliver gas at least at certain prospective in-state delivery points identified in the study of in-state needs. However, the open season notice's initial design of the pipeline need only match the prospective applicant's open season business proposal to deliver at least the amount of gas identified in the study of in-state needs at those prospective in-state delivery points. Bidders may seek alternative delivery points (such as ones closer to their market) as part of their bids, and as part of the open season the prospective applicant may consider building additional facilities to such alternate points, but has no obligation to do so as long as it treats similar requests the same. As discussed above, if the open season ends without any successful bids for in-state deliveries, then there is a continuing obligation for the prospective applicant to leave provision for such in-state service available in its tariff, but it would not have to voluntarily propose such service as part of its initial application. Also, as used in section 157.34, the term "delivery point(s)" also refers to the location at the border between Alaska and Canada where presumably

³⁰ These sections include §§ 157.34(b) and 157.34(c)(1), (2), (3), (6), (8), and (16).

³¹ Although tie-in point is used in some Commission documents, the most common use is to identify the point where a pipeline's loop ties back into the mainline.

prospective bidders will seek to have their volumes delivered. It would be much more confusing if the regulations were revised to refer to "tie-in points" for points inside Alaska and "delivery points" for locations at the border between Alaska and Canada. Therefore, we will not clarify the rules as requested by the North Slope Producers in this regard.

104. Second, the North Slope Producers state that the "catch-all" language in section 157.34(c)(18) was not scaled back enough from the language proposed in the NOPR. Specifically, they state that as written, the final regulation requires a pipeline applicant to provide all bidders, not only with information the applicant has provided to any bidder, but also with information "in the hands of" any bidder. The North Slope Producers claim that the applicant cannot know what information identified in section 157.34(c)(18) is "in the hands of a potential shipper." Moreover, they contend that while the text of Order No. 2005 does not discuss the intent of this subsection, the Commission's press release and the Commission staff's PowerPoint presentation at the February 9, 2005 Commission Open Meeting presentation refer to information that the applicant has in some way made available to a potential shipper, and the regulations should be clarified to be consistent with this intent. The North Slope Producers add that, read literally, this language would call for protected information. Enbridge, on the other hand, claims that section 157.34(c)(18) should be eliminated as unnecessary due to the transparency assured by the rest of the numbered subsections of section 157.34(c).

105. Anadarko objects to this requested clarification, pointing out that the North Slope Producers are likely already to possess relevant project-related information as a result of discussions with other possible project sponsors, and if the North Slope Producers becomes the project sponsor, this information is already in their hands and was not made available to them by an applicant.

106. The "catchall" provision addresses the difficult issue of separation of functions between a prospective applicant and its affiliates who produce, sell or market Alaska gas, and as such are potential bidders for capacity on an Alaska natural gas transportation project. It has been targeted as a problem since it appeared in the NOPR and it was discussed extensively in the Final Rule.³² The North Slope Producers have undertaken

³² See Order No. 2005 at P 72 -83.

millions of dollars of due diligence "homework" on the design, cost, operation and feasibility of an Alaska pipeline. If they are not affiliated with the prospective applicant for an Alaska pipeline, then all that knowledge and information is theirs and, presumably, would give them an informational advantage in the open season bidding. However, if the North Slope Producers are affiliated with the prospective applicant, then the Commission and other potential bidders must be assured that any relevant information about the design, cost, operation and feasibility of an Alaska pipeline that the North Slope Producers transfers to an affiliated prospective applicant is available to everyone. The Commission desires to make this very important part of the Final Rule as clear as possible. Thus, we will revise section 157.34(c)(18) to read as follows:

All information that the prospective applicant has in its possession pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, or that the prospective applicant has made available to, or obtained from, any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;

The Commission understands that the scope of this information is extensive. Therefore, we will not require that the contents of the open season notice to be published by the prospective applicant must contain copies of all the documents which would be covered under section 157.34(c)(18), but that the notice identify a "public reading room" where such information is available, for copying at the reader's expense. Further, as the North Slope Producers point out, dealing with potential "protected information" will have to be addressed as it is in any commercial situation. The Commission expects that all parties will cooperate in dealing with "protected information," but as in all matters pertaining to the open season process, the Commission and its staff stand ready to assist in resolving any disputes.

107. Third, the North Slope Producers request that the Commission clarify the requirement in section 157.35(c) that the project applicant "create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the applicant's Marketing and Energy affiliates." They claim that they intend to create a separate entity to be the project sponsor and to conduct the open season, and that this section would require them to establish yet another separate entity to conduct the opens season, and that section 157.35(c) should be revised to reflect that this is sufficient. Specifically, the North Slope Producers propose to delete from the regulations the language requiring that a project applicant must designate a separate unit

or division to conduct the open season. Anadarko claims that this requested clarification would largely nullify the purpose of section 157.35(c).

108. The Commission denies the North Slope Producers' proposed change to section 157.35(c). However, the Commission will amend the section to take into account situations in which a project applicant is an entity that has been separately created for the purpose of conducting an open season. In such cases, the separate entity would comply with the provisions of section 157.35(c) if that project applicant functioned and operated independently from the project applicant's Marketing and Energy Affiliates, as well as the other divisions of the project applicant. The purpose of section 157.35(c) is to ensure that the project applicant conducting the open season is independent of, and does not favor, its affiliates. If the project applicant was created to comply with section 157.35(c) and does, in fact, comply with the regulation, the project applicant is not required to create a further subdivision to achieve compliance.

109. The North Slope Producers identify several other non-substantive clarifications to the regulatory language that should be made to avoid confusion.³³ These corrections will be made.

110. Enbridge argues that since the open season regulations require that the project design criteria include a requirement that the project be capable of "low-cost expansion,"³⁴ the Commission should explain that the threshold for satisfying the low-cost expansion" standard is any expansion that does not increase rates to initial shippers. However, as Enbridge recognizes, any certificate application for an Alaska natural gas

³³ These include typographical errors in section 157.35(d) (references to sections 258.4(a)(1) and (3) should be to sections 358.4(a)(1) and (3)), Order No. 2005, P 74 (should cite to §§ 358.5(d) and 358.4(e)(3) rather than §§ 358.4(d) and 358.(b)(e)(3)); section 157.34(c)(9) ("proscribed" should be changed to "prescribed"); and section 157.33(b) ("terms, rates, terms and conditions" should be changed to "duration, rates, terms and conditions"). The North Slope Producers also suggest that the term "rate amounts" in section 157.34(c)(9) should be changed to "rates" as the latter term is more commonly used in the industry.

³⁴ See, e.g., Order No. 2005 at P 82; section 157.37.

transportation project might provide detail regarding several expansion scenarios depending on and in response to the results of the open season. The project design review that the Commission will undertake focuses on the proposed project's ability to accommodate the capacity bid for in the open season, as well as the extent to which the project can accommodate "low-cost" expansion. All expansions will involve cost. Obviously, as recognized by virtually all stakeholders, capacity that can be gained by compression alone would typically be the lowest-cost expansion. At the other end of the spectrum would be a pipeline that has no compression-only expansion potential, necessitating the need for looping in the first instance. The operative word in connection with any "low-cost" standard in section 157.37, is the *extent* of the design's expandability, and that standard is not tied to the cost impact of a given expansion. Consequently we will not clarify section 157.37 as requested by Enbridge.

111. ChevronTexaco claims that the Final Rule contains a conflict about how the contract term might be used by the prospective applicant in establishing its methodologies for the evaluation of bids and the allocation of capacity due to oversubscription, should that be necessary. It states that this confusion is caused because contract term is not mentioned in section 157.34(c)(14) regarding evaluation of bids, but is mentioned in section 157.34(c)(15) regarding allocation of capacity due to oversubscription. ChevronTexaco also complains that the Commission's stated intention to rely on after the fact enforcement of issues that might be caused by unusual contract terms, rather than set a cap on contract term for the purpose of bidding and allocation review methodologies, does not satisfy ANGPA's mandate that the Commission's open season rules are fully prescriptive. ChevronTexaco requests that the Commission clarify the open season regulations to require that open season notices to include a cap on the contract term for capacity bids.

112. First, our intention to rely on after-the-fact enforcement of open season issues that might be caused by unusual contract terms, or by any other aspect of the open season process that is not specifically enumerated in the open season regulations, completely satisfies the intent of Congress as stated in ANGPA. Moreover, as explained in Order No. 2005, it is consistent with our existing policy. However, we do agree that the discrepancy in language between section 157.34(c)(14) and section 157.34(c)(15) should be clarified to provide consistency between the methodologies for the evaluation of bids and the allocation of capacity due to oversubscription. To be consistent and avoid confusion, we will delete the phrase "including price and contract term" from section 157.34(c)(15). Furthermore, we will look carefully at this issue in our review of any open season plan and notice under section 157.38.

113. ChevronTexaco claims that the only way to assure that an open season was conducted fairly and in accordance with the open season rules is by making the precedent agreements publicly available. Therefore, ChevronTexaco objects to the provision in section 157.34(d)(4) which provides that all precedent agreements and correspondence with bidders who were not allocated capacity must be filed with the Commission, but that they may be filed under a request for confidential treatment pursuant to section 388.112 of the Commission's regulations. ChevronTexaco claims that since precedent agreements will become agreements that will appear in a pro forma tariff or an effective tariff, there is little chance that the information in the precedent agreements should be confidential for any prolonged period of time, or that any of the information would fall under a Freedom of Information Act exemption. ChevronTexaco states that the precedent agreements could be filed in a public and non-public version in the event parts of the agreements do contain protected information.

114. We deny ChevronTexaco's request. Under section 388.112 of the Commission's regulations, any person submitting a document to the Commission may request privileged treatment by claiming that some or all other information is exempt from the Freedom of Information Act's disclosure requirements. We are not conferring any special confidential status to the agreements. The party requesting privileged treatment must support that claim. It may be, as ChevronTexaco claims, that precedent agreements are not likely to be exempt from disclosure. Neither section 157.35(d)(4) nor section 388.112 predetermines whether privileged treatment will be granted.

Document Availability

115. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

116. From FERC's Home Page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number excluding the last three digits of this document in the docket number field.

117. User assistance is available for FERRIS and the FERC's website during normal business hours from our Help line at (202)502-8222 or the Public Reference Room at

(202) 502-8371 Press 0, TTY (202)502-8659. E-Mail the Public Reference Room at public.referenceroom@ferc.gov

Effective Date

118. These regulations are effective as of the date of publication in the FEDERAL REGISTER.

List of subjects in 18 CFR Part 157

Administrative practice and procedure; natural gas; reporting and recordkeeping requirements

By the Commission.

(S E A L)

Linda Mitry,
Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 157, Chapter I, Title 18, Code of Federal Regulations, as follows.

**PART 157 - APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE
AND NECESSITY AND FOR ORDERS PERMITTING AND
APPROVING ABANDONMENT UNDER SECTION 7 OF THE
NATURAL GAS ACT**

1. The authority citation for Part 157 continues to read as follows:

AUTHORITY: 15 U.S.C. §§ 717 -717w.

**SUBPART B – OPEN SEASONS FOR ALASKA NATURAL GAS
TRANSPORTATION PROJECTS**

2. In section § 157.33, paragraph (b) is revised to read as follows:

§ 157.33 Requirements for Open Seasons.

(a) * * *

(b) Initial capacity on a proposed Alaska natural gas transportation project may be acquired prior to an open season through pre-subscription agreements, provided that in any open season as required in (a) above, capacity is offered to all prospective bidders at the same rates and on the same terms and conditions as contained in the pre-subscription agreements. All pre-subscription agreements shall be made public by posting on Internet websites and press releases within ten days of their execution. In the event there is more than one such agreement, all prospective bidders shall be allowed the option of selecting among the several agreements all of the rates, terms and conditions contained in any one such agreement.

3. In section 157.34, paragraphs (a), (c)(9), (c)(15) and (c)(18), and (d)(2) are revised to read as follows:

§ 157.34 Notice of open season.

(a) Notice. A prospective applicant must provide reasonable public notice of an open season through methods including postings on Internet websites, press releases, direct mail solicitations, and other advertising. In addition, a prospective applicant must provide actual notice of an open season to the State of Alaska and to the Federal

Coordinator for Alaska Natural Gas Transportation Projects.

* * * * *

(c) * * *

(9) Negotiated rate and other rate options under consideration, including any rates and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process prescribed herein;

* * * * *

(15) The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, except that if any capacity is acquired through pre-subscription agreements as provided in §157.33(b) above and the prospective applicant does not redesign the project to accommodate all capacity requests, only that capacity that was acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any one of the pre-subscription agreements shall be allocated on a pro rata basis and no other capacity acquired through the open season shall be allocated.

* * * * *

(18) All information that the prospective applicant has in its possession pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, or that the prospective applicant has made available to, or obtained from, any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;

* * * * *

(d) * * *

(2) A prospective applicant must consider any bids tendered after the expiration of the open season by qualifying bidders and may reject them only if they cannot be accommodated due to economic, engineering, design, capacity or operational constraints, or accommodating the request would otherwise adversely impact the timely development of the project, and a detailed explanation must accompany the rejection. Any bids tendered after the expiration of the open season must contain a good faith showing, including a statement of the circumstances which prevented the late bidder from

tendering a timely bid and how those circumstances have changed. If a prospective applicant determines at any time that, based on the criteria stated above, no further late bids for capacity can be accommodated, it may request Commission approval to summarily reject any further requests.

* * * * *

4. In section 157.35, paragraph (c) is revised to read as follows and paragraph (d), the word "258.4(a)(1)" is removed and the word "358.4(a)(1)" is inserted in its place.

§ 157.35 Undue Discrimination or Preference.

(a) * * *

(b) * * *

(c) Each prospective applicant conducting an open season under this subpart must function independent of the other divisions of the prospective applicant as well as the prospective applicant's Marketing and Energy affiliates as those terms are defined in §§ 358.3(d) and (k) of the Commission's regulations. In instances in which the prospective applicant is not an entity created specifically to conduct an open season under this Subpart, the prospective applicant must create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the project applicant's Marketing and Energy affiliates as those terms are defined in sections 358.3(d) and (k) of the Commission's regulations.

* * * * *

5. Section 157.36 is revised to read as follows:

§ 157.36 Open seasons for expansions.

Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.

6. Section 157.38 is revised to read as follows:

§ 157.38 Pre-Approval Procedures.

No later than 90 days prior to providing the notice of open season required by section 157.34(a), a prospective applicant must file, for Commission approval, a detailed plan for conducting an open season in conformance with these regulations. The prospective applicant's plan shall include the proposed notice of open season. Upon receipt of a request for such a determination, the Secretary of the Commission shall issue a notice of the request, which will then be published in the Federal Register. The notice shall establish a date on which comments from interested persons are due and a date, which shall be within 60 days of receipt of the prospective applicant's request unless otherwise directed by the Commission, by which the Commission will act on the proposed plan.

CHAPTER 83

Natural Gas Transportation

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Scope

The natural gas industry has undergone a radical, albeit evolutionary, transformation since 1985. Culminating in Order No. 636, the effect of this change has been to shift the matter of buying and selling natural gas supplies almost completely into the competitive marketplace, while the focus of much recent regulatory activity has been to ensure that the interstate pipeline system serves as a barrier-free conduit for these transactions.

The discussion that follows begins with a review of the jurisdictional framework for federal natural gas regulation. Following that is a review of the events leading up to and those immediately following the issuance of the FERC's Order No. 436, which was the first major stage in the assault on the bastion of bundled pipeline sales service. Reviewed in some detail after that are the provisions of Order No. 636, the associated regulations and certain of the many orders through which the provisions of Order No. 636 were implemented. That review describes in depth the nature of services under which the natural gas industry is currently operating.

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crediting, distributing or allocating amounts previously collected."

Order No. 528 did not specify a general rule concerning the method to be adopted by individual pipelines, instead allowing individual pipelines and their customers to devise allocation methods suited to the various individual pipeline systems through individual Section 4 proceedings under the National Gas Act.³⁴ Order No. 528 retained Order No. 500's equitable sharing requirement and provided that pipelines must continue to absorb the same amount of costs as they had under Order No. 500. (Pipelines were permitted, however, to file to recover through a volumetric surcharge costs originally included in fixed charges.) In addition, the Commission concluded that, absent agreement of interested parties, it would retain Order No. 500's 50% cap on volumetric surcharge recovery for costs included in prior Order No. 500 filings, but would allow pipelines to seek to recover up to 75% of costs not included in a prior Order No. 500 filing through a volumetric surcharge.³⁵ Further, to mitigate the impact on small customers, the Commission allocated 50% of the costs otherwise allocated to these customers to other, larger customers, noting that small customers are often treated differently than other customers because of their special characteristics.³⁶ The Commission also indicated that the parties should include true-up provisions, and should consider adopting mileage-sensitive volumetric surcharges.

[2] Restructuring Under Order No. 636

[a] Introduction

On April 8, 1992, FERC issued Order No. 636,³⁷ reflecting the latest iteration in FERC's thinking on the nature of

³⁴ Order No. 528 at 61,595-96.

³⁵ Order No. 528-A at 61,299-300.

³⁶ *Id.* at 61,300-01.

³⁷ Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipeline After Partial Wellhead Decontrol*, III F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939, order on reh'g, Order No. 636-A, III F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950 (1992); reh'g denied, Order No. 636-B, 61 F.E.R.C. (CCH) ¶ 61,272 (1992), appeal pending, *Atlanta Gas Light Co. and Chattanooga Gas Co. v. FERC*, No. 94-1171 (D.C. Cir.).

services that interstate pipelines must offer in order to enable consumers to take advantage of the competitive market for natural gas supplies resulting from the Natural Gas Policy Act of 1978,³⁸ the Commission's open-access program under Order No. 436 and the Natural Gas Well-head Decontrol Act of 1979.³⁹

Order No. 636 reflected the logical extension of Order No. 436, that consumer welfare is maximized when the interstate pipeline network provides a conduit for transporting natural gas purchased and sold in an open market. Order No. 636 states:

The Commission must create a regulatory environment in which no gas seller has a competitive advantage over another gas seller. In particular, the Commission must regulate the pipeline transportation system and pipeline sales for resale in a manner that ensures that pipeline control of the transportation system—a natural monopoly—does not give a competitive advantage to pipelines over other sellers in the sale of natural gas.⁴⁰

The Commission further characterized the competitive harm under status quo prior to Order No. 636 as resulting from "an unlawful restraint of trade."⁴¹ According to the Commission:

The bundled, city-gate, firm sales service provides the pipelines with an undue advantage and subjects other gas merchants to an undue disadvantage. It maintains an unreasonable difference in service between classes of service (bundled, city-gate, firm sales and open-access; firm transportation) because the firm transportation embedded within the firm sales is superior in quality. . . . The

³⁸ 15 U.S.C. §§ 3301-3432.

³⁹ 15 U.S.C. § 3331.

⁴⁰ Order No. 636 at 30,393. In a number of cases preceding Order No. 636, parties had litigated, and the Commission had approved settlements addressing, the "comparability of service" between transportation and sales rate schedules. In these cases, parties endeavored to ensure that parties purchasing gas from non-pipeline merchants enjoyed the same features of service, other than the gas itself, offered by pipelines to their bundled sales service customers. See, e.g., *Tennessee Gas Pipeline Co.*, 57 F.E.R.C. (CCH) ¶ 61,360 (1991); *Order on Rehearing Approving Settlement as Modified*, 59 F.E.R.C. (CCH) ¶ 61,045 (1992); *Order on Rehearing*, 59 F.E.R.C. (CCH) ¶ 61,318 (1992); *Transcontinental Gas Pipe Line Co.* went so far as to fully unbundle its sales and transportation services in a settlement approved by the Commission prior to Order No. 636. See *Transcontinental Gas Pipeline Co.*, 55 F.E.R.C. (CCH) ¶ 61,446 (1991).

⁴¹ Order No. 636 at 30,405.

Commission therefore finds and concludes that pipelines' bundled, city-gate firm sales service violates NGA Sections 4(b) and 5(a).

To remedy the harm so identified, the Commission chose from among the suggestions offered in response to its Notice of Proposed Rulemaking in Docket No. RM91-11⁴², the relatively dramatic remedy of prohibiting interstate pipelines from offering their sales service on a bundled basis, thereby requiring all customers to convert their previously bundled sales contracts to transportation and transportation-related services, and to purchase natural gas independently, whether from independent vendors or pipeline suppliers. The Commission provided a basis to allow conversion of each pipeline's bundled city-gate, firm sales service into unbundled firm transportation service.⁴³ In addition, the Commission authorized all interstate pipelines to provide unbundled sales service under new blanket certificates issued under Part 284 of Title 18 of the Code of Federal Regulations.⁴⁴

In an appendix to Order No. 636, the Commission published regulations, now appearing in Part 284 of the FERC regulations,⁴⁵ governing the terms of service with which all pipelines were directed to comply, although the Commission has allowed for a substantial degree of deviation among the features of service across pipelines.

[b] Order No. 636 Implementation

Working under a schedule for filing deadlines imposed in Order No. 636,⁴⁶ all pipelines were required to file their plans for compliance with Order No. 636 not later than the end of December 1992. Compliance filings were to include tariff sheets governing all services and pro forma rates reflecting the service-related changes, along with the rate design changes mandated by Order No. 636⁴⁷ and related

⁴² 56 Fed. Reg. 38,372 (1991).

⁴³ *Id.* at 30,409. The Commission rejected arguments that the remedy prescribed by Order No. 636 required modified certificate authority under § 7 of the Natural Gas Act, an argument upon which certain parties have rested the view that the Commission's Order is unlawful. *Id.* at 30,422.

⁴⁴ *Id.* at 30,409.

⁴⁵ 18 C.F.R. § 284, *et seq.*

⁴⁶ Order No. 636 at 30,462.

⁴⁷ While Order No. 636 addressed pipeline services principally, it raised rate design issues to the extent it required pipelines to implement

regulations under Part 284 of Title 18 of the Code of Federal Regulations (C.F.R.). Preceding these filings, pipelines were required to negotiate the terms of Order No. 636 compliance with their customers and other interested parties in settlement discussions initiated when each pipeline filed a restructuring proposal. Following the compliance filings, completed by December 1992, parties filed responsive comments on issues left unsettled following the negotiations, after which the Commission issued implementation orders governing each pipeline.⁴⁸

[c] Nature of Service Under Order No. 636

[i] The Unbundling Requirement and the Equality Principle

Although the regulations under Order No. 436 required that pipelines provide transportation services on a non-discriminatory basis,⁴⁹ thereby preventing pipelines from favoring their sales customers over transportation customers,⁵⁰ the Commission concluded in Order No. 636 that it was further necessary to prohibit pipelines from providing bundled sales service in order to ensure that customers would have equal access to all natural gas sellers, whether affiliated with a pipeline or independent. Accordingly, the Commission required all pipelines to convert customers' bundled city-gate, firm sales service into unbundled firm transportation service.⁵¹ In addition, the Commission required pipelines to make available so-called "no-notice" transportation, permitting certain customers to transport supplies to meet market needs fluctuating daily, without the need to nominate service or risk incurring a penalty.⁵²

Among the features left open to negotiations in individual pipeline proceedings was the place of unbundling in the

a "straight fixed variable" method for cost allocation and rate design, discussed further below.

⁴⁸ The Commission expressly determined that the record it had created through comments on the NOPR was sufficient in order to require industry-wide restructuring, thus rejecting the arguments of those insisting on evidentiary hearings. Order No. 636-A at 61,528.

⁴⁹ 18 C.F.R. §§ 284.8(b) and 284.9(b).

⁵⁰ Order No. 636 at 30,413.

⁵¹ *Id.* at 30,409.

⁵² *Id.* at 30,410.

pipelines' supply area, downstream of which customers would take control of their transportation services on an unbundled basis.⁵³ The options available to parties in individual proceedings have ranged from systems whereby customers control their transportation service back to the wellhead and those where customers take title to gas at centrally located pooling points, upstream of which suppliers are responsible for transporting supplies.⁵⁴ The Commission also left open to debate in individual proceedings the development of market centers and pooling points, although the Commission encouraged both.⁵⁵

Embodied in Sections 284.8(b)(2) and 284.9(b)(2) of Title 18 of the C.F.R. is the guiding principle behind the Commission's unbundling requirement and its approach to evaluating all pipeline services in the wake of Order No. 636, *i.e.*, that pipelines must offer its transportation services "on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere."⁵⁶ According to the Commission:

This equality principle will ensure that a pipeline cannot impose unreasonable restrictions on a shipper's ability to be served by other gas sellers. Any such restrictions would render transportation of gas sold by the pipeline or an affiliate superior in quality to transportation of gas of other merchants. Such a quality preference would result in undue discrimination under NGA Sections 4 and 5 and is prohibited by the equality principle.⁵⁷

[ii] Transportation Service Terms and Conditions

[A] No-Notice Service

Based on comments received in response to the "Mega-NOPR,"⁵⁸ the Commission concluded that providing customers converting to transportation in pipeline restructuring with so-called "no-notice" transportation service was a key to enabling the customers to replicate in an unbundled environment those services previously enjoyed as part of bundled sales service.⁵⁹ On the central role envisioned by this new service in restructuring, the Commission opined:

⁵³ Order No. 636, at 30,410.

⁵⁴ 18 C.F.R. § 284.283.

⁵⁵ Order No. 636, at 30,027-28.

⁵⁶ Order No. 636, at 30,414.

⁵⁷ Order No. 636, at 30,414.

⁵⁸ 56 Fed. Reg. 38,372 (1991).

⁵⁹ See 18 C.F.R. § 284.8(a)(4). Order No. 636 required pipelines to make this service available in restructuring only to shippers that were firm city-gate bundled sales customers on May 18, 1992, the effective date of Order No. 636, on the theory that only these customers required the new service in order to replicate the service altered through Order No. 636. Pipelines were encouraged to make the service available more widely, if possible. See Order No. 636-B at 62,006.

The requirement that a pipeline provide "no-notice" transportation service will enable a customer to receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices.⁶⁰

The Commission defined no-notice service as the "service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlements on a daily basis without incurring daily balancing and scheduling penalties."⁶¹ In other words, the Commission intended no-notice service to be a surrogate for the sort of service-on-demand previously provided by bundled sales service. In order to ensure that customers had sufficient information to evaluate this more expensive option, as against other options, including storage service and other peak shaving opportunities, the Commission required pipelines to delineate the cost components of the service and to allow customers to nominate the service freely.⁶² Also, the Commission noted that pipelines would have varying operational requirements in order to perform this service, including the retention of a certain amount of system storage and the imposition of operating protocols on the use of unbundled storage.⁶³

Following the D.C. Circuit's remand of Order No. 636, in *United Distribution Cos. v. FERC*,⁶⁴ the Commission issued Order No. 636-C,⁶⁵ determining that pipelines offering no-notice service must offer that service on a non-discriminatory basis to all requesting customers on a prospective basis. The Commission also held that a pipeline offering no-notice service must only do so to the extent the pipeline has capacity available, but such pipelines are not obligated to expand their capacity or acquire additional facilities to provide service.⁶⁶

[B] Flexible Receipt and Delivery Points

Order No. 636 required pipelines to provide customers with the flexibility to take advantage of all receipt and delivery points on a pipeline system, subject to the proviso that customers may transport gas only within the transportation capacity they have under contract and the availability of capacity at the desired points.⁶⁷ Section 284.14(b)(1)(v) of the FERC regulations prescribes new

⁶⁰ Order No. at 636, at 30,424-425.

⁶¹ Order No. at 636, at 30,421.

⁶² Order No. at 636, at 30,421.

⁶³ Order No. at 636, at 30,424.

⁶⁴ 88 F.3d 1105 (D.C. Cir. 1996).

⁶⁵ 78 F.E.R.C. ¶ 61,186 (1997).

⁶⁶ 78 F.E.R.C. ¶ 61,186 (1997).

⁶⁷ Order No. 636, at 30,428-29. Since Order No. 636, pipelines have provided "extended delivery service" outside their contractual path, subject to availability and further payment to account for distance-related costs. See *Tennessee Gas Pipeline Co.*, 66 F.E.R.C. ¶ 61,317 (1994).

procedures for the allocation of receipt and delivery points. As things have developed in individual restructuring proceedings, customers have secured the rights to transport gas on a firm basis through so-called "primary" receipt and delivery points and to use other points on a "secondary," or interruptible, basis.⁶⁸

In *Transcontinental Gas Pipe Line*,⁶⁹ the Commission found that Part 157 shippers that convert to Part 284 service and pay Part 284 rates are entitled to the same flexibility as other Part 284 customers. However, subsequently, in *Tennessee Gas Pipeline Co.*,⁷⁰ the Commission stated that Part 157 shippers are not entitled to flexible receipt and delivery points.

In *Northwest Pipeline Corp.*,⁷¹ the Commission found that shippers may change, without additional payment, their primary receipt and delivery points to other points within their capacity path when capacity at those points is available. According to the Commission, firm shippers may use other points on a secondary basis, without changing their primary point. The Commission also stated that shippers using points on a secondary basis have priority superior to interruptible shippers, but inferior to firm shippers holding that point as a primary point. Additionally, the Commission allowed pipelines to implement right of first refusal (ROFR) and flexible receipt and delivery point procedures that enabled new bidders for capacity under the expiring contracts to have priority for the receipt or delivery points in the contract over existing shippers seeking to change primary receipt or delivery points. As such, the current shippers would be allowed to make receipt or delivery point changes 30 days after the bidding period ends, if no bid is accepted for that capacity.

In *Questar Pipeline Co.*,⁷² the Commission found that a pipeline cannot restrict primary receipt or delivery point changes when capacity becomes available through means other than a contract expiration, unless the change would impair the pipeline's ability to provide firm service to other shippers. Later, in *Questar Pipeline Co.*,⁷³ the Commission clarified that firm shippers receiving discounted rates do not have the right to use alternate receipt and delivery points at the discounted rate, unless their contract so provides. Further, in *Questar Pipeline v. PacifiCorp.*,⁷⁴ the Commission found that if an agreement between a pipeline and shipper is ambiguous, then the pipeline is free to charge the maximum rate.

⁶⁸ See, e.g., *Tennessee Gas Pipeline Co.*, 62 F.E.R.C. ¶ 61,250, at 62,645; *Texas E. Transmission Corp.*, 62 F.E.R.C. ¶ 61,015, at 61,109.

⁶⁹ 73 F.E.R.C. ¶ 61,024 (1995).

⁷⁰ 78 F.E.R.C. ¶ 61,340 (1997).

⁷¹ 66 F.E.R.C. ¶ 61,304 (1994).

⁷² 68 F.E.R.C. ¶ 61,269 (1994).

⁷³ 69 F.E.R.C. ¶ 61,119 (1994).

⁷⁴ 70 F.E.R.C. ¶ 61,328 (1995).

In *Tennessee Gas Pipeline Co., (Tennessee)*,⁷⁵ the Commission found those shippers paying the same zone rate should receive the same priority for secondary points within that zone. However, in Order No. 637-A, the Commission established an equal priority for secondary points within the zone of the shipper's contract path of delivery, thereby reversing the policy established in *Tennessee*.⁷⁶

[C] Abandonment upon Contract Termination and the Right of First Refusal

Resolving a controversy that had been on its doorstep since the court's decision in *AGA II*,⁷⁷ the Commission promulgated in Order No. 636 new Section 284.221(d) of its regulations, revising rules previously providing that pipelines would receive pre-granted, or automatic, abandonment authority terminating their obligation to serve Part 284 transportation customers upon the expiration of their contracts.⁷⁸ With Order No. 636, the Commission replaced its prior regulations with a rule providing customers with transportation contracts⁷⁹ for one year and longer⁸⁰ with the right to renew their contracts upon expiration, so long as they agreed to match the price bid for the capacity by any other interested customer and to sign a contract for as long a term as offered by the competing customer.⁸¹

In Order No. 636, the Commission also clarified that the maximum price customers are required to offer under the regulations in order to take advantage of the protection provided by the rule is the pipeline's maximum lawful price, while in Order No. 636-A, the Commission modified its regulations to require

⁷⁵ 73 F.E.R.C. ¶ 61,399 (1995).

⁷⁶ Order No. 637-A at 31,597.

⁷⁷ *American Gas Ass'n v. FERC*, 912 F.2d 1469 (D.C. Cir. 1990).

⁷⁸ Following the *AGA II* decision, the Commission stayed the operation of former Section 284.221(d), pending reconsideration on remand, in Order No. 500-J. FERC Stats. & Regs. ¶ 30,915 (1991). In *AGA II*, the court determined that the Commission failed to provide adequate protection to customers under Section 7 of the Natural Gas Act by providing pipelines with the authority to abandon customers upon the expiration of their contracts. In view of the court's decision in *AGA II*, the Commission determined in Order No. 636 that customers that converted their bundled sales contracts to transportation following the stay implemented after the *AGA II* remand (February 13, 1991) and prior to the effective date of Order No. 636 would have full abandonment protection. Order No. 636, at 30,452.

⁷⁹ The protection of the revised rules applies also to 18 C.F.R. pt. 284 storage, since the Commission has defined transportation to include storage service. See Order No. 636-A at 30,636.

⁸⁰ Order No. 636-A clarified that the right of first refusal would adhere only to contracts of one year or longer, while in Order No. 637, Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Service, 65 Fed. Reg. 10156 (2/25/00), FERC Stats. & Regs. ¶ 31,091 (2/9/00), the Commission further clarified that this right attached only to contracts for 12 or more consecutive months of service. Order No. 637, at 31,337.

⁸¹ In Order No. 636-A, the Commission clarified that a pipeline would not be required to serve a customer at discounted rates where there were no competing offers driving prices up to levels deemed acceptable by the pipeline. Order No. 636-A at 30,629.

an existing customer to go so far only as to offer a contract term of 20 years in order to take advantage of the new protection.⁸² In Order No. 636-A,⁸³ the Commission further clarified that if customers pay maximum rate, they may renew for any term of their choosing, so long as there are no competitive offers.

In Order No. 637,⁸⁴ the Commission further modified its approach in order to provide that in the limited instance in which a pipeline is fully subscribed, there is an incremental rate schedule providing for firm transportation service above system average rates, and a customer interested in renewing capacity is vying with other shippers for available capacity, the renewing customer may be required to pay up to the incremental rate on the system in order to take advantage of the right of first refusal.⁸⁵

[D] Capacity Release and Buy-Sell Mechanisms

Order No. 636 and Section 284.243 of the FERC regulations provide relatively detailed guidelines on the mechanism pursuant to which the Commission has authorized parties to assign to others the interstate pipeline capacity (transportation and storage) they hold under contract. While the Commission's approach reflects precedent rejecting parties' efforts to broker their capacity,⁸⁶ the Commission's new approach ensures that the parties' efforts to assign capacity remain in full view of the Commission.⁸⁷ Accordingly, while authorizing capacity assignment under the new regulations, the Commission simultaneously amended all previously existing capacity brokering certificates in order to ensure conformity.⁸⁸ In addition, the Commission prohibited parties from entering into

⁸² The Commission left to parties in individual restructuring proceedings the detail of adjudging best offers when faced with offers of varying price and duration. Order No. 636, at 30,451.

⁸³ Order No. 636-A at 30,633.

⁸⁴ Order No. 637, at 31,297.

⁸⁵ Order No. 637, at 31,338-39.

⁸⁶ See *El Paso Natural Gas Co.*, 35 F.E.R.C. ¶ 61,440, at 62,065-66, *reh'g denied*, 38 F.E.R.C. ¶ 61,008 (1987); *Texas E. Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,684 (1986).

⁸⁷ Addressing its need for consistency in these programs in order to preserve its oversight, the Commission opined: "[t]he Commission no longer believes that it can adequately monitor capacity brokering under existing certificates to ensure that all allocations are non-discriminatory. Simply put, there are too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering as it now exists." Order No. 636, at 30,416.

⁸⁸ Order No. 636, at 30,416. See also *Algonquin Gas Transmission Co.*, 59 F.E.R.C. ¶ 61,032 (1992), amending on all capacity brokering certificates existing prior to Order No. 636. The Commission has distinguished capacity brokering from capacity assignment in that brokering has taken place through private arrangements entered into between capacity holders and others, without the involvement of the pipeline or the Commission.

The Commission has, in various orders, rejected arguments that capacity brokering by LDCs is a non-jurisdictional matter equal or akin to local distribution exempt from Commission oversight. See *Texas E. Transmission Corp.*, 51 F.E.R.C. ¶ 61,170, at 61,452. Accordingly, in Order No.

new "buy/sell" arrangements, as of the effective date of the new capacity assignment programs in restructuring.⁸⁰ The Commission grandfathered all such arrangements entered into through the date of restructuring on each pipeline.

In Section 284.243 of the regulations, the defining characteristic of the Commission's rules governing capacity assignment is that available capacity is to be posted for bid on electronic bulletin boards (EBBs) maintained by each of the pipelines.⁸⁰ A pipeline's Part 284 firm shippers⁸¹ may release the capacity to, and the pipeline will thereby be obliged to contract with, bidders extending the best offer for the capacity, up to a ceiling price of the pipeline's maximum transportation rate.⁸²

In *Tennessee Gas Pipeline Co.*,⁸³ the Commission approved net present value (NPV) criteria for evaluating competing bids for capacity available for general subscription. The Commission also found that NPV criteria may be applied to requests for changes in receipt and delivery points. Furthermore, in *Tennessee Gas Pipeline Co.*,⁸⁴ the FERC found that NPV analyses may include revenue from minimum throughput guarantees, provided that the NPV used in such analyses does not exceed the NPV equal to the maximum reservation rate available to recourse shippers, in cases where one or more bidders in an open season is willing to pay only the maximum recourse reservation rate.

Consistent with its rejection of buy-sell arrangements, the Commission has, since the publication of Order No. 436, consistently rebuffed efforts to modify on a generic basis its requirement that shippers must have title to the gas they

636, the Commission issued on a generic basis blanket NGA Section 7 certificates to all shippers holding firm interstate pipeline capacity rights enabling them to assign pipeline capacity pursuant to the new regulations. Order No. 636, at 30,421. See also Order No. 636-A at 30,551-52.

⁸⁰ Order No. 636, at 30,416. See also *El Paso Natural Gas Co.*, 59 F.E.R.C. ¶ 61,031 (1992), issued simultaneously with Order No. 636, in which the Commission addressed existing buy/sell programs. The Commission defined such programs as those whereby an LDC would purchase gas in the production area on behalf of an end user, transport the gas under its transportation contract and sell the gas to the end user at its retail delivery point. Order No. 636, at 30,416. See Carter, *Buy/Sell Transactions in The Natural Gas Industry: What's Prohibited and What Isn't?*, 15 Energy L.J. 427 (1994).

⁸¹ See generally Order No. 636, at 30,418-21. See Mishkin & Adelman, *Gas Industry Standards Board: Legal Considerations in the Standard Setting Process*, 15 Energy L.J. 73 (1994).

⁸² The Commission has expressly excluded shippers under individually certificated Section 7 transportation arrangements to release their capacity. Order No. 636-A at 30,565. These shippers may, however, convert to 18 C.F.R. pt. 284 service.

⁸³ Releasing shippers will remain ultimately liable for reservation charges under original contracts, unless the pipeline agrees otherwise. Usage charges and penalties are solely the responsibility of the replacement shipper. Order No. 636-A at 30,561-62.

⁸⁴ 76 F.E.R.C. ¶ 61,101 (1996), order on reh'g, 79 F.E.R.C. ¶ 61,297 (1997), order on reh'g, 82 F.E.R.C. ¶ 61,008 (1998).

⁸⁵ 82 F.E.R.C. ¶ 61,011 (1998).

ship under an open access transportation agreement.⁹⁵ The Commission again held fast to this "shipper must have title rule" in Order No. 637,⁹⁶ over the objection that it had become antiquated in view of gray market transactions bundling transportation and sales gas that avoid the Commission's capacity release oversight. Nevertheless, waivers of the rule have been granted in limited instances. In *Atlanta Gas Light Co.*,⁹⁷ the Commission waived for one year the "shipper must have title" rule in order to facilitate a retail service unbundling program. The Commission stated that in considering waiver requests the Commission must weigh the need for the waiver to accomplish the unbundling at the state level against any potential negative effect a waiver may have on the interstate gas market. Similarly, in *National Fuel*,⁹⁸ the Commissions temporarily waived the rule for one year in order to implement a unique customer choice program.

In Order No. 637, the Commission removed the price cap for capacity released for a term of less than one year, while retaining the cap for longer-term transactions.⁹⁹ The Commission reasoned that it had already lost meaningful control of the market for released capacity through operation of the "grey" market for bundled sales and transportation service, and that by allowing prices to rise to a market-clearing level would be good economics and competition in the secondary market from regulated pipeline interruptible service would help constrain prices for released capacity.¹⁰⁰

The Commission has further permitted parties to include the length of the assignment to which an assignee will agree as among the factors in determining the best bid.¹⁰¹ The rules further permit releasing customers to specify certain terms governing the release, including provisions limiting the release to those days on which weather conditions permit.¹⁰² In an effort to reflect some of the flexibility certain parties saw in previously existing capacity brokering programs, Order No. 636-A exempted from the requirement for EBB posting the assignment

⁹⁵ See *Texas Eastern Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,684 (1986).

⁹⁶ Order No. 637, at 31,300.

⁹⁷ 84 F.E.R.C. ¶ 61,119, *reh'g denied*, 84 F.E.R.C. ¶ 61,323 (1998).

⁹⁸ 86 F.E.R.C. ¶ 61,179 (1999).

⁹⁹ Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Service, 65 Fed. Reg. 10156 (2/25/00), FERC Stats. & Regs. ¶ 31,091, at 31,279 (2/9/00).

¹⁰⁰ Order No. 637, at 31,281-83.

¹⁰¹ Order No. 636-A at 30,558.

¹⁰² The Commission clarified in Order No. 636-A that releasing shippers may specify minimum acceptable prices. Order No. 636-A at 30,558. The Order further stipulates that all conditions governing releases must be posted and non-discriminatory, and that releasing shippers are prohibited from tying releases to any conditions (such as a requirement that assignees purchase gas from the releasing shipper) unrelated to the capacity to be assigned. Order No. 636-A at 30,559.

of capacity for less than thirty days.¹⁰³ This exemption was subsequently expanded to include transactions for one full calendar month.¹⁰⁴ In addition, the Commission permitted capacity holders to "pre-arrange" capacity releases for specific assignees, provided that these arrangements were posted in advance on the pipelines' EBBs and competing assignees were permitted to extend a superior offer, in the event the capacity were to be released for less than the maximum price.¹⁰⁵

Finally, in regulations implemented with Order No. 637,¹⁰⁶ the Commission has promulgated Section 284.12(c)(1)(ii), providing that purchasers of released capacity, like purchasers of capacity directly from a pipeline, will have the opportunity to submit nominations at the earliest opportunity after consummation of their deal. The regulation is designed to ensure the competitiveness and free substitution of capacity in the secondary market and capacity available directly from a pipeline.¹⁰⁷

[E] Upstream Pipeline Capacity

Section 284.242 of the regulations, promulgated under Order No. 636, requires open-access upstream pipelines to permit capacity under contract to downstream pipelines to be assigned by the downstream pipeline to its customers.¹⁰⁸ The regulations further require downstream pipelines to assign this capacity to their customers, to the extent required, to enable customers converting customers in restructuring to preserve their previous daily entitlements.¹⁰⁹ In Order No. 636-A, the Commission further indicated¹¹⁰ that it would permit downstream pipelines to retain upstream capacity upstream under contract to the extent needed for

¹⁰³ Order No. 636-A at 30,554; 18 C.F.R. § 284.243(h).

¹⁰⁴ Order No. 577, FERC Stats. & Regs. ¶ 31,017 (Mar. 29, 1995).

¹⁰⁵ See generally Order No. 636, at 30,418-20. Individual pipeline tariffs and the Commission's implementation orders on each pipeline must be consulted for specific features of the capacity assignment programs, including details relating to the procedures whereby bidders' offers will be compared in order to determine the best offer. In Order No. 636-A, the Commission clarified that pipeline tariffs must specify objective features by which bids would be evaluated, unless non-discriminatory standards are posted by releasing shippers on pipeline EBBs, along with the release posting. Order No. 636-A at 30,557.

¹⁰⁶ Order No. 637, at 31,343.

¹⁰⁷ Order No. 637, at 31,297.

¹⁰⁸ Order No. 636, at 30,417-18. "Upstream pipelines" are those pipelines which are connected to the supply area and which deliver a substantial portion of the gas transported to so-called "downstream pipelines," rather than to individual customers or distributors. Downstream pipelines do not access directly the market rates, but instead receive gas delivered from upstream pipelines.

¹⁰⁹ Order No. 636-B at 62,004.

¹¹⁰ Order No. 636-A at 30,566-67.

operational management and balancing services and the performance of no-notice service.¹¹¹

In *Texas Eastern Transmission Corp.*,¹¹² the Commission confirmed that Order No. 636 did not create a *per se* rule prohibiting pipelines from entering into contracts for transportation or storage capacity on other interstate pipelines, but rather that the Commission would decide this issue on a case-by-case basis. On rehearing, in *Texas Eastern Transmission Corp.*,¹¹³ the Commission clarified that its analysis would focus on whether the cost impacts of acquiring off-system capacity compared to the benefits to the acquiring pipeline's shippers justifies rolling-in the acquisition costs.

[F] Curtailment

In Order No. 636, the Commission hewed to its prior determination¹¹⁴ that the curtailment priorities stated in Title IV of the Natural Gas Policy Act of 1978 (NGPA)¹¹⁵ only authorize the Commission to apportion gas among a pipeline's sales customers and not its transportation customers.¹¹⁶ With respect to capacity-related curtailments, the Commission adhered to precedent¹¹⁷ approving apportionment among customers on a *pro rata* basis, unless parties in the individual restructuring proceedings agreed to another basis for allocating shortages. The Commission observed that capacity-related curtailments would affect all parties equally, whether pipeline sales customers or not, since after restructuring all customers would become pipeline transportation customers downstream of the point of unbundling.¹¹⁸ It further noted that the NGPA authorized it to apply the statutorily mandated priorities only to shortages of pipeline sales gas, although parties to the restructuring proceedings were encouraged to agree upon protocols that would protect high priority needs in the event of capacity related shortages.¹¹⁹

The clear distinction articulated by the Commission between capacity and supply curtailments was subsequently blurred, however, by the D.C. Circuit's

¹¹¹ The Commission has been fairly rigorous in policing pipelines arguing that they require upstream capacity for this purpose. *CNG Transmission Corp.*, 64 F.E.R.C. ¶ 61,303, at 63,215 (1993).

¹¹² 74 F.E.R.C. ¶ 61,074 (1996).

¹¹³ 78 F.E.R.C. ¶ 61,277 (1997).

¹¹⁴ See, e.g., Order No. 436, at 31,515; Order No. 436-A at 31,652-53; *Sebring Utils. Comm'n v. FERC*, 591 F.2d 1003 (5th Cir. 1979), *cert. denied*, 444 U.S. 879 (1979). See discussion of Order Nos. 436 and 436-A in § 83.03[1].

¹¹⁵ 15 U.S.C. § 3301 *et seq.*

¹¹⁶ Order No. 636, at 30,429; Order No. 636-A at 30,586.

¹¹⁷ See *Texas E. Transmission Corp.*, 37 F.E.R.C. ¶ 61,260 (1986); *Southern Natural Gas Co.*, 41 F.E.R.C. ¶ 61,218 (1987).

¹¹⁸ See *Texas E. Transmission Corp.*, 37 F.E.R.C. ¶ 61,260 (1986); *Southern Natural Gas Co.*, 41 F.E.R.C. ¶ 61,218 (1987).

¹¹⁹ Order No. 636-A at 30,586-94; Order No. 636, at 30,429.

1993 *City of Mesa* decision.¹²⁰ In *City of Mesa*, the court reaffirmed that the traditional NGPA end-use curtailment priorities applied only to supply curtailments, but held that the consumer protection mandate of the NGA requires that the Commission assure that high-priority end-users have continuous access to natural gas, which may require departure from strict *pro rata* capacity curtailments. The court did not rule on a specific mechanism to protect certain end-uses, but rather remanded the case for further explanation and support for the Commission's determination that the pipeline's proposed curtailment provision provided adequate protections. As a result, the precise features of the mechanism necessary to meet the NGA standard are yet to be determined.

[G] Storage Service

Recognizing that a pipeline's control of its storage facilities in order to perform daily and seasonal balancing provided pipeline sales service with an important advantage over competitive service, Order No. 636 also required pipelines to unbundle their storage facilities and to provide storage service on an open-access non-discriminatory basis.¹²¹ Part 284.1(a) of the FERC regulations was amended by Order No. 636 to define transportation to include storage service.¹²² Under Order No. 636, pipelines were permitted to retain part of their storage capacity for system management purposes and to perform no-notice service. Pipelines also were permitted to reserve storage capacity upstream of the point of unbundling in order to perform unbundled sales service, although the Commission further provided that the pipeline must allocate storage between its sales function and other interested parties on a non-discriminatory basis.¹²³

While Order No. 636 refrained from specifying a generic method for allocating storage capacity, leaving that matter to individual restructuring proceedings, the Commission clarified in Order No. 636-A that pipeline sales customers prior to restructuring would have a priority to storage service to the extent needed to preserve their pre-restructuring daily entitlements.¹²⁴ In Order No. 636-B it was held that this priority extended to storage of upstream pipelines, again to the extent necessary to preserve pre-restructuring entitlements.¹²⁵

[H] Capacity Segmentation

Building on earlier decisions,¹²⁶ the Commission made clear in Order No.

¹²⁰ *City of Mesa, Arizona v. FERC*, 993 F.2d 888 (D.C. Cir. 1993).

¹²¹ Order No. 636, at 30,425-27.

¹²² 18 C.F.R. § 284.1(a) defines "transportation" to include "storage, exchange backhaul, displacement, or other methods of transportation."

¹²³ Order No. 636, at 30,427.

¹²⁴ Order No. 636-A at 30,578.

¹²⁵ Order No. 636-B at 62,004.

¹²⁶ See *Texas Eastern Transmission Corp.*, 63 F.E.R.C. ¶ 61,100 (1994), in which the releasing

637 and 637-A that pipelines are required, in the absence of operational infeasibility, to permit customers to segment their capacity in a fashion enabling the original shipper and replacement shippers to employ as severable contractual rights pipeline segments of the pipeline system included within primary receipt and delivery point paths.¹²⁷ Nevertheless, the Commission identified highly reticulated pipeline systems as those on which segmentation may pose particular difficulty. In such cases, the Commission has persisted in requiring segmentation where operations permit.¹²⁸

[I] Capacity Auctions

Building on the Commission's earlier decisions promoting the concept of an auction mechanism for the sale of long-term capacity¹²⁹ the Commission, in Order No. 637 promulgated a series of minimum standards governing auctions for pipeline capacity.¹³⁰ Although the Commission did not insist on any particular auction format for pipelines or third-parties, the Commission set forth some basic principles to which auctions must adhere. In particular, the Commission established six principles:

- The timing of the auction should be predictable, and shippers potentially offering or bidding on capacity should have notice of when the auction will be held and what capacity will be included.
- The auction should be open to all potential bidders on a non-discriminatory basis.
- The auction should be user-friendly with information on the rules and procedures easily accessible to all.
- The bidding procedures as well as the methods for selecting the best bid should be fully disclosed prior to the auction.
- There should be no favoritism in the determination of the winning bidder and mechanisms should be included to permit monitoring of how the

shippers and replacement shippers are treated as separate shippers with separate contract demands. Similarly, in *ANR Pipeline Co.*, 73 F.E.R.C. ¶ 61,288 (1995), customers were permitted to segment capacity and release a portion of its contract path even if the total amount of gas delivered exceeds its total reservation quantity. Segmentation was limited in *Florida Gas Transmission Co.*, 67 F.E.R.C. ¶ 61,008 (1994), in which the Commission allowed a pipeline to refuse a complete segmented release transaction when such a transaction would reduce the firm primary receipt point to firm primary delivery point capacity rights of an existing shipper.

¹²⁷ See Order No. 637, FERC Stats. and Regs. ¶ 31,091, at 31,304 *et seq.*; Order No. 637-A, FERC Stats. and Regs. ¶ 31,099, at 31,590 *et seq.*

¹²⁸ See Order No. 637, FERC Stats. and Regs. ¶ 31,091, at 31,304 *et seq.*; Order No. 637-A, FERC Stats. and Regs. ¶ 31,099, at 31,590 *et seq.*

¹²⁹ See *Natural Gas Pipeline Co. of Am.*, 82 F.E.R.C. ¶ 61,036 (1998).

¹³⁰ See Order No. 637, at 31,296.

selection criteria were applied. This would include methods of verifying any reserve price applied in an auction.

- Transaction information (such as prices, volumes, and receipt and delivery points) should be disclosed so that shippers can ascertain the value of transportation. The names of shippers may not be disclosed or could be disclosed at a later date if the auction results are verifiable and free from potential affiliate favoritism.¹³¹

[iii] Electronic Bulletin Boards

In Order No. 636, the Commission required pipelines to establish Electronic Bulletin Boards (EBBs) upon which parties would post capacity available for release.¹³² The Commission held that the EBBs would be operative as of the effective date of each pipeline's capacity assignment program (generally, the date of restructuring) and further mandated that the terms and conditions governing pipeline EBBs would be included in pipeline tariffs and must be just and reasonable. Further, the Commission expressed a strong preference for having the bulletin boards operate interactively in order to effectuate transactions. In addition, the Commission agreed with those parties arguing that the EBBs should be standardized to facilitate operation and encouraged the industry to work cooperatively in order to implement that goal.¹³³

Operating on the strength of recommendations from the Natural Gas Industry Working Group, convened to consider industrywide protocols for standardizing the operation of the EBBs, the Commission issued Order No. 563, requiring pipeline compliance with specified standard EBB procedures.¹³⁴ In Order No. 563, the Commission adopted the Working Group's recommendations for developing a common code database that would identify pipeline transaction points, including receipt and delivery points. Additional modifications to the Commission's approach were made upon further recommendations of the Working Group in Order No. 563-C.¹³⁵

¹³¹ See Order No. 637, FERC Stats. and Regs., ¶ 31,091, at 31,304 *et seq.*; Order No. 637-A, FERC Stats. and Regs. ¶ 31,099, at 31,590 *et seq.*

¹³² Order No. 636, at 30,419. See Mishkin & Adelman, *Gas Industry Standards Board: Legal Considerations in the Standard Setting Process*, 15 Energy L.J. 73 (1994).

¹³³ Order No. 636-A at 30,549-50.

¹³⁴ Standards for Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations, [Regulations Preambles] III FERC Stats. & Regs. ¶ 30,988 (1993), *order on reh'g*, Order No. 563-A, [Regulations Preambles] III FERC Stats. & Regs. ¶ 30,994, *reh'g denied*, Order No. 563-B, 68 F.E.R.C. ¶ 61,002 (1994).

¹³⁵ 68 F.E.R.C. ¶ 61,362 (1994).

[iv] Standardization of Business Practices

In Docket No. RM96-1-000,¹³⁶ the Commission solicited proposals designed to standardize business practices for all interstate pipelines in order to facilitate interstate transactions. Building on the outline of priorities for standardization identified by the Natural Gas Industry Working Group (*see* § 83.03[2][c][iii]), the Commission sought comments in the following areas: nominations; confirmations; allocated gas flows; customer and contract imbalances; gas flow at metered points; transportation invoices; pre-determined allocation methodologies; gas payment remittance statements; gas sales invoices; and uploads of capacity release prearranged deals.

[d] Transition Costs Under Order No. 636**[i] Introduction**

Order No. 636 recognized that pipelines were likely to incur certain transition costs as a result of the move to restructured services. The Commission identified four basic categories of these costs:

- (1) gas supply realignment (GSR) costs;
- (2) costs associated with the elimination of the purchase gas adjustment (PGA) mechanism;
- (3) costs associated with unneeded upstream capacity; and
- (4) stranded facilities costs.¹³⁷

Under Order No. 636 pipelines are authorized to file a separate Section 4 proceeding to recover these costs, while parties opposing recovery of such costs are permitted to challenge the eligibility and prudence of the costs in the individual Section 4 cases.

[ii] Gas Supply Realignment (GSR) Costs

GSR costs are costs which result from the pipelines having to reform their existing supply contracts as a result of the implementation of Order No. 636. In order to recover contract reformation costs as GSR costs, pipelines must satisfy a two-part test specified by Order No. 636. First, the costs must be found to be eligible as costs that are attributable to the implementation of Order No. 636.¹³⁸ The test for eligibility is that the pipeline must determine that realignment costs are directly attributable to the implementation of Order No. 636 and not a result of events which occurred independently of Order No. 636.¹³⁹ Elaborating

¹³⁶ 73 F.E.R.C. ¶ 61,104 (1995).

¹³⁷ *See* Order No. 636, at 30,457-62.

¹³⁸ Order No. 636, at 30,459.

¹³⁹ Order No. 636, at 30,459. *See also* Texas E. Transmission Co., 62 F.E.R.C. ¶ 61,015, at 61,124 (1993).

on this standard in Order No. 636-A, the Commission stipulated that pipelines only are permitted to recover as GSR costs, those costs incurred to reform gas supply contracts in response to customer purchasing decisions during restructuring.¹⁴⁰ Second, all eligible costs must have been prudently incurred. Order No. 636 provided that the pipeline requesting recovery bears the burden of proof with regard to both the eligibility and prudence of its GSR costs.

Building on the basic eligibility criteria established in Order Nos. 636, *et al.*, the Commission further held in *Texas Eastern Transmission Corp.*¹⁴¹ that:

Eligibility depends on the facts of each case but certain standards of eligibility must be met under any circumstance:

(1) prior to the issuance of Order No. 636, the contracts must have been part of an overall gas supply portfolio that was commensurate with the pipelines' merchant obligation; (2) the cost must have been incurred after the issuance of Order No. 636 on April 8, 1992; (3) the pipeline's contract sales obligations must have decreased as a result of Order No. 636 restructuring, thus necessitating the reduction or elimination of gas supplies under contract; (4) the cost must be known and measurable.

In addition, some pipelines, such as Texas Eastern, had GICs under which they were to recover gas contract reformation costs. To prevent pipelines from recovering transition costs twice, the Commission will also apply a fifth eligibility standard in all cases in which a pipeline had a GIC: if the obligation to pay contract reformation costs was incurred during the effectiveness of a GIC, such obligation cannot be recovered as GSR costs. *Texas Eastern Transmission Corp.*, 65 FERC ¶ 61,608 (1993).

On a case-by-case basis, the Commission has determined that the parties have raised sufficiently serious eligibility and prudence issues to warrant full evidentiary hearings.¹⁴² For example, Columbia Gas Transmission Corporation's (Columbia) request for GSR cost recovery was rejected by the Commission on eligibility grounds.¹⁴³ Columbia argued for the recovery as GSR costs of liability it accrued prior to restructuring as a result of having rejected its gas supply contracts while it was in bankruptcy. The Commission dismissed Columbia's

¹⁴⁰ Order No. 636-A at 30,642.

¹⁴¹ 65 F.E.R.C. ¶ 61,246 (1994).

¹⁴² See *Texas E. Transmission Corp.*, 65 F.E.R.C. ¶ 61,363 (1993); *Tennessee Gas Pipeline Co.*, 66 F.E.R.C. ¶ 61,029 (1994).

¹⁴³ *Columbia Gas Transmission Corp.*, 64 F.E.R.C. ¶ 61,060, at 61,572 (1993). The Commission stated, "Thus, while the Commission has not determined eligibility in other restructuring cases, the Columbia case is unique." *Id.*

arguments and stated that the costs in question were associated with the bankruptcy proceedings and ineligible for recovery of GSR costs.¹⁴⁴

In addition to contract reformation costs, pipelines also have been permitted to recover so-called "pricing differential" costs as GSR costs. A pricing differential is calculated by taking the difference between the price of gas purchased under above-market contracts and a price established by an objective index of spot market prices. In the Commission's view, the pricing differential mechanism holds out the hope that it may be less expensive for a pipeline to continue purchasing gas under certain contracts, even at above-market levels, than to buy out the supply, at least for some interim period of time.¹⁴⁵ Consequently, in order for a pipeline to use a pricing differential, it must demonstrate that the potential costs incurred can be minimized on the competitive market rather than continuing to purchase gas under existing contract prices.¹⁴⁶ Moreover, the Commission has held that to be recoverable through a pricing differential mechanism, pipelines must also demonstrate that they have met the Commission's eligibility and prudence standards.¹⁴⁷ To enable the Commission to evaluate the pricing differential mechanism, the Commission has required pipelines using the pricing differential mechanism to identify specific contracts, keep strict accounting, and separate costs by contract.¹⁴⁸ Further, in *Tennessee Gas Pipeline Company (Tennessee)*,¹⁴⁹ the Commission required Tennessee to make quarterly filings that would identify costs that are known, measurable, and actually incurred in the previous quarter. The Commission approved pricing differential costs for a period of two years, three months prior to the expiration of which Tennessee would have to show support for the continuation of using the pricing differential mechanism or use an alternate mechanism.¹⁵⁰

¹⁴⁴ 64 F.E.R.C. at 65,582. Columbia argued that these contracts were entered into in anticipation of Order No. 636 and renegotiated during its restructuring proceedings. The Commission rejected this argument and stated that: (1) Columbia could have had "no meaningful knowledge of the effect of Order No. 636 on its system or what actions its customers would take"; (2) Columbia previously attempted to make these contracts marketable under its Global Settlement and failed; (3) a § 4 filing was unnecessary since Columbia's arguments for recovery raised a legal question, and the Commission had all the facts necessary to make a determination. As for Columbia's argument that it had been penalized for realigning these contracts early, the Commission has consistently held that even though a contract is terminated during restructuring, the pipeline still bears the burden of proving that the termination was attributable to the implementation of Order No. 636. *Id.*

¹⁴⁵ Texas E. Transmission Corp., 62 F.E.R.C. ¶ 61,015, at 61,124 n.130 (1993).

¹⁴⁶ See Texas E. Transmission Corp., 63 F.E.R.C. ¶ 61,100 (1993).

¹⁴⁷ Thus, the pipeline must prove that: (1) it negotiated in good faith to reduce or terminate contracts; and, (2) transition costs were minimized by vigorous arms-length negotiations with suppliers. 63 F.E.R.C. ¶ 61,100, at 61,507. See Texas E. Transmission Corp., 63 F.E.R.C. ¶ 61,100 (1993). See also *Tennessee Gas Pipeline Co.*, 64 F.E.R.C. ¶ 61,020 (1993).

¹⁴⁸ Texas E. Transmission Corp., 63 F.E.R.C. ¶ 61,100 (1993).

¹⁴⁹ 64 F.E.R.C. ¶ 61,020 (1993).

¹⁵⁰ *Tennessee Gas Pipeline Co.*, 62 F.E.R.C. ¶ 61,250 (1993).

As to the prudence criterion for recovering GSR costs, the Commission has stated that it will follow traditional prudence standards,¹⁵¹ examining such questions as:

- (1) whether contract terms are reasonable in light of the market conditions when contract negotiated, renegotiated or terminated;
- (2) whether the contract realignment costs resulted from vigorous arm's length negotiations; and
- (3) whether there was a bona fide effort on the part of both parties to the contract to arrive at settlement.¹⁵²

Ninety percent of the eligible costs may be recovered from Part 284 firm shippers, whether through a reservation fee, a surcharge or an exit fee, while ten percent of the costs can be recovered from interruptible transportation customers.¹⁵³ The Commission specifically exempted, from the obligation to fund GSR costs, transportation services under individual Section 7(c) certificates, on the theory that these services are not directly affected by Order No. 636.¹⁵⁴

[iii] Account No. 191

In Order No. 636, the Commission permitted pipelines to direct bill positive purchase gas adjustment (PGA) balances left in Account No. 191¹⁵⁵ as of July 31, 1991, to their former firm sales customers, whether or not they continued as firm sales customers. However, direct billed customers were granted the right to challenge the prudence of any related gas contracts.¹⁵⁶ The Commission restricted recovery of Account No. 191 costs to the costs that a pipeline had incurred prior to the issuance of the Notice of Proposed Rulemaking (NOPR) of Order No. 636 on July 31, 1991, reasoning that the NOPR established adequate notice for the pipelines to plan for the changing market.¹⁵⁷

Although the Commission left the allocation of Account No. 191 costs to determination of the individual restructuring proceedings, it indicated in Order

¹⁵¹ Order No. 636, at 30,459.

¹⁵² Order No. 636, at 30,459. The Commission later added that if pipelines had collected GIC charges, these costs would be precluded as transition costs. An exception would be made if the pipeline could prove that certain transition costs were anticipated and not recovered in designing the GIC. Order No. 636-A at 30,654.

¹⁵³ Order No. 636, at 30,458; Order No. 636-A at 30,641. Order No. 636-B at 62,032. The Commission noted that if a pipeline cannot recover 10% of its GSR costs from interruptible customers because it has no interruptible customers or a *de minimis* level, the Commission would consider in a § 4 filing, a request for another form of recovery. Order No. 636-B at 62,034.

¹⁵⁴ Order No. 636-A at 30,650.

¹⁵⁵ Account No. 191 refers to certain unrecovered gas costs. See Order No. 636, at 30,457-58.

¹⁵⁶ Order No. 636, at 30,458.

¹⁵⁷ For purposes of determining the date on which costs were deemed incurred, the Commission required use of the date on which the associated gas was taken.

No. 636 that commodity costs could be allocated based upon customers' gas purchases for the 12 months preceding the effective date of service under the pipeline's unbundled sales certificates. The Commission further indicated that demand costs could be allocated upon relative contract entitlements on the day preceding the effective date of service under the pipeline's unbundled sales certificate.¹⁵⁸ The Commission also directed the pipeline to flow through any over-recoveries to its customers.¹⁵⁹ In *Columbia Gas Transmission Corp.*,¹⁶⁰ the Commission rejected Columbia's effort to allocate all Account No. 191 costs based on customers' contract demand.

Customer payments to the pipeline may be made in a lump sum, over a 12-month period or any reasonable period of time at the customer's discretion.¹⁶¹ If the customer chooses to pay the assessment over time, however, the Commission permits the pipeline to collect carrying charges on the unrecovered balance.¹⁶² Thus, for example, in Texas Eastern's initial restructuring filing the pipeline determined its customers' liability for Account No. 191 costs on a *pro rata* basis, according to each buyer's total annual sales contract demand level to the aggregate sales annual contract demand level on the Texas Eastern system. Texas Eastern's methodology, while not in strict accord with the Commission's guidelines, was determined to be consistent with the Commission's overall policy goals. Furthermore, the Commission stated under Order No. 636, parties can suggest alternate consistent methodologies.¹⁶³ In subsequent restructuring orders, the Commission upheld Texas Eastern's methodology, but clarified that only "costs that are known and measurable" may be direct billed as transition costs subject to Commission approval.¹⁶⁴

[iv] Stranded Investment Costs

The third type of cost that drew Commission concern under the new competitive market proposed by Order No. 636 is stranded investment costs. These costs eligible for recovery are those incurred by a pipeline after implementation of Order No. 636 in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services. The Commission suggested that these costs may entail retention of unclaimed or unneeded

¹⁵⁸ Order No. 636, at 30,458.

¹⁵⁹ Order No. 636, at 30,458.

¹⁶⁰ 64 F.E.R.C. ¶ 61,060, at 61,564 (1993). The Commission reiterated this holding in subsequent Columbia restructuring orders, insisting that Columbia disregard its use of AENs and base demand costs on those costs that are actually billed and to account for commodity costs as well. 64 F.E.R.C. ¶ 61,365, at 63,574 (1993).

¹⁶¹ Order No. 636, at 30,458.

¹⁶² Order No. 636-A at 30,652.

¹⁶³ 62 F.E.R.C. ¶ 61,015 (1993).

¹⁶⁴ 63 F.E.R.C. ¶ 61,100 (1993).

upstream capacity, unbooked open-access, and contract storage beyond contract needs for balancing and system management,¹⁶⁵ as well as costs associated with unneeded gathering facilities.¹⁶⁶

The Commission directed pipelines to file a general rate filing under Section 4 of the NGA to recover stranded investment costs, upon which the Commission indicated it would make case-by-case determinations.¹⁶⁷ Further, the pipelines were required to meet eligibility and prudence criteria, as with GSR cost recovery. Pipelines must prove that the facilities for which they are seeking stranded cost recovery were "used and useful" before restructuring, but are no longer as a result of the implementation of Order No. 636.¹⁶⁸

[v] Facilities Costs

Facilities costs are defined as those capital costs and other costs incurred for and in connection with new facilities needed to implement Order No. 636.¹⁶⁹ Costs associated with stranded facilities costs are typically capital costs associated with the installation of electronic data exchanges, electronic meters, and other equipment needed to function in the competitive market.¹⁷⁰

For a pipeline to recover stranded facilities costs it must make a Section 4 filing and justify the prudence in which these costs are incurred.¹⁷¹ As of December 1994, Tennessee sought recovery of an estimated \$10-20 million for the installation of electronic meter and communications systems.¹⁷² Although Texas Eastern did not estimate any particular dollar amounts, it reserved the right to recover any new facilities costs incurred under a general Section 4 case.¹⁷³

However, Columbia's request for facilities costs warranted Commission criticism when it claimed that its costs would be highly speculative and it requested permission to build these costs into its rate base with an amortization period of five years.¹⁷⁴ The Commission denied Columbia's request to amortize

¹⁶⁵ Order No. 636, at 30,460.

¹⁶⁶ Order No. 636-A at 30,662 (explaining that certain facilities may no longer be needed in the restructured market as a result of capacity reallocation).

¹⁶⁷ Order No. 636, at 30,460.

¹⁶⁸ Order No. 636-A at 30,662. *See, e.g.*, Trunkline Gas Co., 66 F.E.R.C. ¶ 61,158 (1994).

¹⁶⁹ 62 F.E.R.C. ¶ 61,015 (1993).

¹⁷⁰ 62 F.E.R.C. ¶ 61,015 (1993).

¹⁷¹ 62 F.E.R.C. ¶ 61,250 (1993).

¹⁷² 62 F.E.R.C. ¶ 61,250 (1993).

¹⁷³ 62 F.E.R.C. ¶ 61,015, at 61,217. The Commission replied to Texas Eastern's request stating that "Order No. 636 anticipates such section 4 filings to recover costs associated with new facilities" and the Commission "will not prejudge Texas Eastern's right to recover such costs until Texas Eastern files a section 4 case to recover facility costs." *Id.*

¹⁷⁴ 64 F.E.R.C. ¶ 61,060, at 61,565.

these costs and directed Columbia to file for cost recovery in a general Section 4 rate case after the costs are actually incurred.¹⁷⁵

[3] Interconnection Policy

Responding to the court's remand in *Panhandle Eastern Pipe Line Co. v. FERC*,¹⁷⁶ the Commission announced in *Panhandle Eastern Pipe Line Co.*,¹⁷⁷ a new set of generic rules requiring pipelines to provide applicants with physical interconnection upon application. Reinforced by its decision in *ANR Pipeline Co.*,¹⁷⁸ the Commission held that its authority under NGA Section 5 to remedy undue discrimination is sufficient to mandate interconnection when the following five conditions are met:

- (1) the applicant must agree to bear the cost of interconnection;
- (2) the interconnection must not adversely affect existing operations;
- (3) the proposed interconnection must not diminish existing service;
- (4) the proposed interconnection must not cause the pipeline to be in violation of applicable environmental or safety laws or regulations; and
- (5) the proposed interconnection must not cause the pipeline to be in violation of its right of way agreements or other contractual obligations.

§ 83.04 Transportation Rate Issues

[1] Introduction

Considered below are several rate issues of interest in connection with transportation service. Issues of more general interest in connection with pipeline ratemaking, including a review of cost of service rate setting, and other rate design and cost allocation principles are reviewed elsewhere in this treatise.

[2] Incremental Versus Rolled-In Rates

The Commission's approach to the question of whether the cost of new facilities and service should be treated on an incremental basis, and thereby assessed to new customers individually, or rolled into general pipeline system rates is the subject of the decision in *TransCanada Gas Pipeline v. FERC*.¹ In *TransCanada*, the court remanded to the Commission for further consideration the decision in *Great Lakes Transmission L.P.*² In *Great Lakes*, the Commission

¹⁷⁵ 64 F.E.R.C. ¶ 61,060, at 61,565.

¹⁷⁶ 196 F.2d 1273 (D.C. Cir. 1999).

¹⁷⁷ 91 F.E.R.C. ¶ 61,037 (2000).

¹⁷⁸ 91 F.E.R.C. ¶ 61,066 (2000).

¹ 24 F.3d 305 (D.C. Cir. 1994).

² 57 F.E.R.C. ¶ 61,140, 61,512 (1991) (Opinion 367), *reh'g denied*, 62 F.E.R.C. ¶ 61,101, 61,713

had adopted a "commensurate benefits" test for determining whether the cost of new facilities should be rolled into system rates. Under this test, as explained by the Commission, parties seeking to roll the cost of new facilities into system rates must demonstrate that the benefits accruing to system customers are at least commensurate with costs. Of the showing made by the proponents seeking roll-in in the *Great Lakes* case, the Commission stated:

Even assuming, arguendo, that all those systemwide benefits asserted by the parties advocating rolled-in pricing have or will come to fruition, based on our review of the record, the new facilities were not needed to ensure continued service to existing customers at the same level of reliability. In return for these benefits, existing customers would, under the rolled-in methodology, pay significantly higher rates for the same service. This result would be inequitable based upon the record evidence in these proceedings . . . Simply put, existing customers would not, under rolled-in pricing, receive system-wide benefits "commensurate with the increase in rates."³

In *TransCanada*, the court faulted the Commission for failing adequately to explain its reliance on the commensurate benefits test, in preference to the approach taken in other precedent holding that the cost of new facilities would be rolled into system rates upon a showing that the facilities are integrated with the existing system and that the facilities would produce systemwide benefits.⁴ Importantly, the *TransCanada* decision does not prejudice the outcome of the Commission's reconsideration, instead it requires the Commission to rethink its approach and provide further explanation for its departure from precedent.⁵

Responding to the *TransCanada* remand, and perhaps because not all hands at the Commission are fully supportive of the approach in *Great Lakes*, the Commission issued on August 3, 1994, a Notice of Public Conference in Docket No. PL94-4 seeking industrywide comments on an appropriate approach for handling the incremental/rolled-in issue.⁶

(1993) (Opinion 367-A); *Great Lakes Gas Transmission L.P.*, 57 F.E.R.C. ¶ 61,141, 61,534 (1991) (Opinion 368), *reh'g denied*, 62 F.E.R.C. ¶ 61,102, 61,731 (1993) (Opinion 368-A). See Spulber, *Pricing and the Incentive to Invest in Pipelines After Great Lakes*, 15 *Energy L.J.* 377 (1994).

³ 57 F.E.R.C. ¶ 61,141, at 61,541-52 (citing *Colorado Interstate Gas Co.*, 56 F.E.R.C. ¶ 61,015, at 61,074 (1991)).

⁴ See *Battle Creek Gas Co. v. FPC*, 281 F.2d 42 (D.C. Cir. 1960).

⁵ Of relevance is the court's decision in *Algonquin Gas Transmission Corp. v. FERC*, 948 F.2d 1305 (D.C. Cir. 1991). There, the court held that in order to support a decision authorizing the roll-in of the cost of new facilities, the Commission must at least: (1) define and address the cost impact, and (2) describe with reasonable particularity the specific benefits provided by the facilities. 948 F.2d at 1313, 1315.

⁶ Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines, 68 F.E.R.C. ¶ 61,140 (1994).

Following a public conference on November 4, 1994, the Commission issued in May 1995 its long-awaited policy statement addressing the question whether the cost of new facilities should be treated on a rolled-in or an incremental basis.⁷ The Policy Statement signals the Commission's preference for rolled-in pricing, especially for projects that evidence a cost impact on existing customers of five percent or less. The Policy Statement establishes a presumption favoring rolled-in rate treatment in cases where the rate impact on existing customers of rolling in new facilities is no more than five percent and the pipeline makes a "showing of system benefits." Opponents of roll-in may overcome this presumption only if they demonstrate that "the benefits [of the new service] are so insignificant that rolled-in rates are not justified." In cases where the rate impact exceeds five percent, pipelines proposing to roll-in the costs of new facilities must show that the rate impact on existing customers is "proportionate" to the claimed benefits. The Policy Statement offers a detailed listing of potential operational and financial benefits, and wisely discounts so-called societal benefits. The Commission notes that it will not permit pipelines to break projects into small increments simply to qualify for the presumption applicable to projects with an impact smaller than five percent.

To provide greater rate certainty at the time new facilities or services are designed and placed in service, the Policy Statement provides that the Commission will reflect its pricing determination in a declaratory order to be issued in the Section 7 certificate proceeding together with the certificate authorizing construction. The initial pricing determination contained in the declaratory order will be controlling in the pipeline's next-filed rate case absent a showing of changed circumstances.

The mechanics of the five percent threshold are unclear. The Policy Statement explains that to determine the rate impact of a proposed roll-in "the pipeline should calculate the effect on revenue responsibility for each Firm Rate Schedule under its currently effective rate design and under the pipeline's preferred rolled-in rate design." The Policy Statement does not explain, however, how to address cases where the rate impact exceeds five percent for some customers but not for others. Moreover, the Policy Statement does not consider cases in which the initial estimate of costs may be less than five percent, and thereby qualify for the presumption, while the actual costs may exceed the threshold. Further, while the Policy Statement admonishes applicants against splitting larger projects into smaller parts to stay below the five percent threshold, it offers no mechanism for preventing such abuses. Indeed, the very existence of the threshold encourages such gaming of the system.

In a separate order on remand of the *TransCanada* case, the Commission declined to apply the new policy statement, instead holding that the pricing

⁷ Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines, Docket No. PL94-4-000, 71 F.E.R.C. ¶ 61,241 (1995).

treatment of the project should be determined on the basis of the traditional *Battle Creek* policy in place when Great Lakes initially planned its expansions. The Commission asserted it would be inappropriate to apply retroactively its new pricing policy, whose "hallmark is up-front assurance at the certificate stage" to facilities certificated years prior to the issuance of the Policy Statement. Applying *Battle Creek*, the Commission concluded that the new additions satisfied both prongs of the test and ordered rolled-in rates.

The Commission changed course yet again with the issuance of a new Statement of Policy in Docket No. PL93-3-000 on September 15, 1999.⁹ Reversing altogether its presumption favoring rolled-in rates where the rate impact of the proposed new facilities is less than 5%, the Commission now indicates that it will require proposals for new service be predicated upon incremental rates, unless incremental rates would be below the generally applicable Part 284 rate, or projects are designed to improve existing services. The Commission explained that a policy encouraging incremental pricing for facilities (1) sends the proper price signals to the market; (2) leaves the pipeline responsible for the costs of new capacity that is not fully utilized; and (3) obviates the need for an "at risk" condition because it accomplishes that same purpose. To implement this policy, the Commission established a two-part test for determining whether proposed NGA Section 7(c) projects serve public convenience and necessity by requiring an applicant to show that: (1) its proposal can proceed without financial subsidies, and (2) that the balance of benefits outweighs the adverse impacts to all relevant interests associated with the proposal.¹⁰

Under the Commission's new policy, to establish that a project serves public convenience and necessity, an existing pipeline must demonstrate that it is prepared to financially support the project without relying on subsidization from its existing customers.¹⁰ In addition, the Commission's public convenience and necessity analysis requires the certificate applicant to show that its proposed project will produce public benefits in excess of the adverse effects to all the relevant interests. The Commission identified three major interests that must be balanced: (1) the interests of the applicant's existing customers, (2) the interests of competing existing pipelines and their captive customers, and (3) the interests

⁹ Certification of New Interstate Natural Gas Pipeline Facilities, 88 F.E.R.C. ¶ 61,227 (1999) (Statement of Policy).

¹⁰ 88 F.E.R.C. at 61,745-46.

¹⁰ The Commission noted that projects designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility, are for the benefit of existing customers. As such, increasing rates of existing customers to pay for these improvements is not a subsidy. Under the Commission's current policy, these kinds of projects are permitted to be rolled-in and are not covered by the presumption of the current pricing policy. See *Great Lakes Gas Transmission Ltd. Partnership*, 80 F.E.R.C. ¶ 61,105 (1997) (pricing policy statement not applicable to facilities constructed solely for flexibility and reliability).

of landowners and surrounding communities. The Commission stated that, in this balancing step, it will consider all relevant factors reflecting on the need for the project, including but not limited to, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.¹¹ In *Williston Basin Interstate Pipeline Co.*,¹² one of the first cases decided under the Commission's new Policy Statement, the Commission permitted rolled-in rates upon a showing that the project would likely produce revenues exceeding costs, and that public benefits were provided through the addition of new gas supply sources. Similarly, in *Tennessee Gas Pipeline Co.*,¹³ the Commission granted NGA Section 7(c) authority and roll-in of costs under the new Policy Statement on the ground that the project would not be subsidized by Tennessee's existing customers because project revenues would exceed costs, and would not cause adverse impacts. The Commission also required the pipeline to execute firm contracts equal to the project shippers' committed capacity prior to commencing construction of the project. In *Transwestern Pipeline Co.*,¹⁴ the Commission also ordered rolled-in rate treatment under the new Policy Statement because such treatment would effectuate a rate decrease to existing customers.

In a theme elaborated upon in Order No. 637,^{14.1} a shipper exercising a right of first refusal in renewing a long-term contract would be required to match a competing shipper's bid rate for the same capacity in the event the pipeline system is fully subscribed and an incremental rate has been previously approved for the system. The incremental rate caps the required matching price.^{14.2}

[3] Market-Based Rates

While the Commission has yet to issue a decision approving a proposal for market-based transportation rates, it has approved several proposals for market-based storage rates.^{14.3} For example, in *Avoca Natural Gas Storage*,^{14.4} the

¹¹ 88 F.E.R.C. at 61,747-49.

¹² 89 F.E.R.C. ¶ 61,021 (1999).

¹³ 89 F.E.R.C. ¶ 61,129 (1999).

¹⁴ 90 F.E.R.C. ¶ 61,032 (2000).

^{14.1} See discussion at § 83.03[2][c][ii][C]; see also discussion of Order No. 637 in § 83.04[8].

^{14.2} 88 F.E.R.C. at 61,646.

^{14.3} See, e.g., *Avoca Natural Gas Storage*, 68 F.E.R.C. ¶ 61,045 (1994); *Koch Gateway Pipeline Co.*, 66 F.E.R.C. ¶ 61,385 (1994); *Bay Gas Storage Co., Ltd.*, 66 F.E.R.C. ¶ 61,354 (1994); *Petal Gas Storage Co.*, 64 F.E.R.C. ¶ 61,190 (1993); *Richfield Gas Storage Sys.*, 59 F.E.R.C. ¶ 61,316 (1992). See also *Koch Gateway Pipeline Co.*, 72 F.E.R.C. ¶ 61,216 (1995) (The Commission set for hearing a proposal to establish market-based rates for firm and interruptible transportation services. The Commission commented that the outcome of the litigation would be made subject to the guidelines it expected to issue in generic docket no. RM95-6-000).

^{14.4} 68 F.E.R.C. ¶ 61,045 (1994).

Commission granted an application to provide market-area storage services at negotiated, market-based rates. The Commission concluded that market-based rates were appropriate because Avoca lacked "market power" in its market.

Of relevance to the Commission's authority to implement market-based storage and transportation rates is *Elizabethtown Gas v. FERC (Transco)*.^{14.5} There, the court upheld a Commission order approving a settlement under which a pipeline would offer unbundled sales at market-based rates, opining that the Commission was within its statutory authority in relying on the competitive market in order to establish just and reasonable rates under the Natural Gas Act.^{14.6} In *Elizabethtown*, the court specifically rejected petitioners' claim that the NGA mandates that the Commission approve only cost-based rates:

[T]he Supreme Court "has repeatedly held that the just and reasonable standard does not compel the Commission to use any single pricing formula . . .," and we have indicated that when there is a competitive market the FERC may rely upon market-based prices in lieu of cost-of-service regulation to assure a "just and reasonable" result.

In *New York State Electric & Gas Corp. (NYSEG)*,^{14.7} the Commission approved a request for market-based rates for interstate storage services, applying its Alternative Rate Policy Statement^{14.8} for evaluating proposals for market-based rates.^{14.9} The Alternative Rate Policy Statement requires finding either (1) that there is a lack of market power because customers have sufficient good alternatives or (2) that market power has been mitigated.^{14.10} The Commission indicated its three-step analysis required it to: (1) define the relevant markets; (2) measure a firm's market share and market concentration; and (3) evaluate other relevant factors.^{14.11} Relying on *Avoca Natural Gas Storage (Avoca)*,^{14.12} and *Steuben Gas Storage Co. (Steuben)*,^{14.13} the Commission held that NYSEG's market share of 0.3 percent for working gas capacity and 1.44 percent for deliverability was relatively small compared to the overall market which has 339 times the capacity, and 70 times the deliverability of NYSEG.^{14.14} While the Commission found that market concentration was high in the market areas served

^{14.5} 10 F.3d 866 (D.C. Cir. 1993).

^{14.6} 10 F.3d at 870-71.

^{14.7} 81 F.E.R.C. ¶ 61,020 (1997).

^{14.8} Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 F.E.R.C. ¶ 61,076 (1996), *reh'g denied*, 75 F.E.R.C. ¶ 61,024 (1996).

^{14.9} 81 F.E.R.C. ¶ 61,132.

^{14.10} 76 F.E.R.C. ¶ 61,230.

^{14.11} 76 F.E.R.C. ¶ 61,231.

^{14.12} 68 F.E.R.C. ¶ 61,045 (1994).

^{14.13} 72 F.E.R.C. ¶ 61,102 (1995).

^{14.14} 72 F.E.R.C. ¶ 61,102 (1995).

by NYSEG (4692 HHIs for working gas capacity and 4196 for deliverability), the Commission stated that this was mitigated for the following factors: (1) NYSEG's market share for working gas capacity and deliverability are too small to permit an exercise of market power; (2) NYSEG could not exercise market power as a new entrant that must offer better deals to obtain customers; (3) there was ease of entry and anticipation of many new entrants in the market; (4) rates of existing interstate storage providers in New York and Pennsylvania are regulated.^{14.15}

[4] Straight-Fixed Variable Rate Design

While the Commission in Order No. 636 concerned itself largely with unbundling and service-related issues, in one significant departure from that rule it required on a generic basis the implementation of a straight-fixed variable (SFV) format for rate design and cost allocation purposes, allowing for only limited deviations.^{14.16} Under SFV, pipelines are required to include all fixed costs in demand charges and to limit the costs included in commodity rates to variable costs.^{14.17} In contrast, most pipelines have employed a modified-fixed variable format, whereby the pipelines' revenue requirement associated with return to equity and taxes was assigned to commodity rates.^{14.18}

In the Commission's view in its adoption of SFV, it was necessary to level pipeline commodity rates across various

(Text continued on page 83-59)

^{14.15} 72 F.E.R.C. ¶ 61,136-137. See NE Hub Partners, L.P., 83 F.E.R.C. ¶ 61,043 (1998); CNG Transmission Corp., 81 F.E.R.C. ¶ 61,031 (1997); CNG Transmission Corp., 83 F.E.R.C. ¶ 61,134 (1998); Clear Creek Storage Co., 84 F.E.R.C. ¶ 61,210 (1998); Petal Gas Storage Co., 86 F.E.R.C. ¶ 61,224 (1999).

^{14.16} Order No. 636, at 30,431-37.

^{14.17} See 18 C.F.R. § 284.8(d).

^{14.18} See Natural Gas Pipeline Co. of Am., 25 F.E.R.C. ¶ 61,176 (1983), *order on reh'g*, 26 F.E.R.C. ¶ 61,203 (1984), *aff'd in part*, Northern Ind. Pub. Serv. Co., 782 F.2d 730 (7th Cir. 1986).

pipeline systems in order to eliminate deviations in pipeline costs as a factor in determining which supplies to purchase.¹⁵ According to the Commission:

Under MFV, or any method other than SFV, pipeline usage charges vary depending upon the amount of fixed costs recovered in the usage charge. If customers can choose to take gas from two or more pipelines, they will minimize their transportation costs by baseload-ing the pipeline with the lowest usage rate and swinging on pipelines with higher usage rates. . . . Producers whose gas moves to market over pipelines with low usage charges would be able to have higher sales and/or higher prices than otherwise equally efficient producers whose gas moves over pipelines with higher usage charges. Equally efficient producers whose gas gets to market on pipelines with equal total cost would not be on an equal footing because of the differing rate designs of the pipelines. This is inefficient and creates artificial barriers to the production of gas from one basin as compared to another.¹⁶

The Commission left open the potential for limited exceptions to the application of its general rule by providing that it would consider allowing parties to individual cases to agree upon alternative rate design methodologies. In cases where such deviation was agreed to by the pipeline but opposed by other parties, the Commission provided that parties advocating a departure from SFV would bear a "heavy burden of persuasion."¹⁷ In addition, the Commission stated that it would require pipelines to mitigate the impact of the cost shifts among pipeline services due to SFV implementation, where parties demonstrated that historic customers (those existing as of the effective date of Order No. 636) experienced an increase in cost responsibility greater than 10%.¹⁸ In such cases, the Commission stated it would require pipelines to implement measures to phase in the implementation of SFV over a period not longer than four years, using methodologies tailored to individual cases.¹⁹

¹⁵ Order No. 636-A at 30,596.

¹⁶ *Id.*

¹⁷ Order No. 636 at 30,434.

¹⁸ While the Commission first chose to measure the impact on customer classes, in Order No. 636-B, it clarified that it would look to the impact on individual customers. Order No. 636-B at 62,016.

¹⁹ Order No. 636 at 30,435-36.

[5] Interruptible Transportation Rate Design and Revenue Crediting

[a] Rate Design

It has been the Commission's practice to establish maximum rates for interruptible transportation (IT) based on the rate for firm transportation. Prior to the issuance of the Commission's 1989 Statement of Policy on Rate Design,²⁰ the Commission routinely calculated the IT rate as a 100% load factor derivative of the firm transportation (FT) rate. That is to say, IT volumetric rates were set by adding to the FT commodity rate a derivative of the firm demand rate based on the assumption that transportation was moved on a 100% load factor. This practice was upheld by the Court of Appeals for the D.C. Circuit in *Elizabethtown Gas Company v. FERC*.²¹ Responding to the argument of the parties that the 100% IT load factor rate overvalued the service, the court commented that this was a misconception, since IT rates only would equal firm rates in circumstances when firm customers moved their gas at a 100% load factor, i.e., at their maximum entitlement, 365 days each year. According to the court, the argument of the opponents of the 100% load factor rate "proceeds on the erroneous premise." In the court's view, firm customers:

are in fact charged a higher rate than interruptible customers. . . reflecting the cost and quality differentials between the two classes of customers. The 100% load factor is only the lowest per unit rate that a firm customer can in principle pay, i.e., if it takes 100% of its demand entitlements. Because many firm customers do not take all of their entitlements, firm customers overall end up paying a greater load factor than interruptible customers, who never pay more than the 100% load factor.²²

Picking up a thread of doubt the Commission had earlier raised over the propriety of the 100% IT load factor rate,²³ the Commission in the Policy Statement on Rate Design

²⁰ Policy Statement Providing Guidance With Respect to the Designing of Rates, 47 F.E.R.C. (CCH) ¶ 61,295 (1989); Order on Rehearing and Clarifying Policy Statement Providing Guidance with Respect to the Designing of Rates, 48 F.E.R.C. (CCH) ¶ 61,122 (1989).

²¹ 10 F.3d 866 (D.C. Cir. 1993).

²² *Id.* at p. 873.

²³ See, e.g., Transcontinental Gas Pipe Line Corp., 46 F.E.R.C. (CCH) ¶ 61,364, at 62,143 (1989).

invited parties to debate in individual proceedings whether the rate should be reduced through the imputation of a higher load factor.²⁴ The Commission focused its concern principally on whether the 100% load factor rate yielded a rate too high to maximize throughput and, in the Commission's view, allocate capacity efficiently. The Commission further made clear that it would consider this issue only in the context of individual cases. According to the Commission:

The issue is whether the 100 percent load factor rate yields a maximum interruptible rate which is too high to efficiently maximize throughput and is therefore an inefficient allocation of costs or revenue responsibility to interruptible service. The answer depends on an analysis of the pipeline's package of rates and services and not merely on an examination of the 100% load factor method by itself. For example, the 100% load factor method may be an appropriate way to set a maximum rate which acts as a cap on a pipeline's market power where it is efficiently discounting to maximize throughput or where the pipeline is using peak and off-peak rates.²⁵

In addition, the Commission commented that it would judge the appropriate level of rates in view of the relative quality of the services.²⁶

In the many pipeline rate cases following the issuance of the Policy Statement, the parties considered the application of the Commission's stated predilection for altering its approach to setting IT rates, in the context of individual proceedings. These cases were, by and large, settled on the basis of agreements reached by the parties in which IT rates were generally decreased, in varying degrees. In, for example, *CNG Transmission Corp.*,²⁷ the Commission approved a settlement establishing IT rates for the winter season set on a 110% load factor basis, while summer rates were set on a 150% load factor basis. Taking a somewhat different tack in *Tennessee Gas Pipeline Company*,²⁸ the

²⁴ Consistent with applicable precedent, the Commission clarified in its Order on Rehearing of the Policy Statement, the Statement did not shift the burden or proof away from parties seeking to change the status quo on individual pipelines, although it plainly suggested the Commission's sympathy would be with those parties seeking to do so. See *Order on Rehearing and Clarifying Policy Statement Providing Guidance with Respect to the Designing of Rates*, 48 F.E.R.C. (CCH) ¶ 61,122 at 61,444.

²⁵ 47 F.E.R.C. at 62,058.

²⁶ *Id.* at 62,059.

²⁷ 55 F.E.R.C. (CCH) ¶ 61,189 at 61,628 (1991).

²⁸ 59 F.E.R.C. (CCH) ¶ 61,045 at 61,194 (1992).

Commission approved a settlement establishing a 125% load factor rate for IT service.

In what may be a general shift in direction, the Commission in *South Georgia Natural Gas Company*,^{28.1} approved an initial decision rejecting a proposal to reduce the pipeline's IT rate from one set on a 100% load factor to 125%, holding that the 100% load factor rate would best ration capacity, while protecting customers. The Commission further noted that decreasing the IT rate would provide it with a price advantage over released capacity. Similarly, in *Southern Natural Gas Company*,^{28.2} the Commission approved a settlement implementing a 100% load factor IT rate, rejecting claims that the rate failed to recognize the inferior quality of IT service. Nevertheless, the Commission approved a reduced maximum IT rate for certain production area transportation subject to intense competition.

[b] Revenue Crediting

In Order No. 636-A, the Commission recognized that the implementation of its capacity release program would create a great deal of uncertainty over the level of IT service that a pipeline would perform after restructuring. Responding to comments arguing that establishing a representative level of throughput for IT service in order to allocate costs in this environment would be a difficult task, the Commission encouraged parties to consider some type of revenue crediting mechanism in lieu of the traditional mechanism for allocating costs.²⁹

In the restructuring cases following the Commission's comments, many pipelines have implemented revenue crediting mechanisms for IT service. In general, these mechanisms call for crediting to firm services 90% of the revenues derived from IT throughput once a pipeline has recovered a specified level of cost associated with an assumed level of IT throughput.³⁰ Pipelines have generally been allowed to retain ten percent of these revenues as an incentive to perform this service. For example, in *Viking Gas Transmission Corp.*,³¹ the Commission approved

^{28.1} 72 F.E.R.C. (CCH) ¶ —, Dec. 20, 1995.

^{28.2} 72 F.E.R.C. (CCH) ¶ 61,322, *mimeo* at 28, *et seq.* (1995).

²⁹ Order No. 636-A at 30,563.

³⁰ See, e.g., *Paiute Pipeline Co.*, 63 F.E.R.C. (CCH) ¶ 61,189 (1993); *Colorado Interstate Gas Co.*, 63 F.E.R.C. (CCH) ¶ 61,101 (1993).

³¹ 65 F.E.R.C. (CCH) ¶ 61,058 at 61,463-64.

a 90/10 IT revenue crediting system, once the pipeline recouped costs associated with a designated level of throughput. Explaining the interplay between the revenue crediting mechanism and the attribution of costs to IT service, the Commission commented,

Viking is required to credit excess interruptible revenues, but only to the extent that Viking's allocation of costs to interruptible service is less than the revenues it receives from interruptible service. The crediting requirement does not apply to situations where Viking's allocation of costs to interruptible service equals or exceeds the revenues from interruptible service.³²

In *CNG Transmission Corporation*,³³ the Commission permitted a modest departure from the 90/10 rule, authorizing the pipeline in approving the parties' settlement to retain twenty percent of IT revenues in excess of allocated costs. Similarly, in *Southern Natural Gas Company*,³⁴ the Commission approved a settlement allowing the pipeline to retain 25% of its IT revenues.

In a series of more recent orders, the Commission has authorized the elimination of the 90/10 interruptible revenue crediting mechanism, at least in certain circumstances. The Commission has stated it will permit a pipeline to eliminate the IT revenue crediting if the pipeline has had substantial actual post-Order No. 636 experience representative of the full range of annual operating conditions and allocated a representative percentage of its fixed cost of service to interruptible transportation service.³⁵ Previously, the Commission had rejected pipeline requests to eliminate the 90/10 mechanism, noting that the pipelines had not had sufficient operating experience to be able to make known and measurable projections of interruptible service levels and had not allocated a sufficient portion of fixed costs to interruptible service.³⁶ Elimination of the 90/10 crediting was approved where the pipeline had at least twelve months of operating experience post-Order No. 636, had supplied sufficient support through data and testimony for its projected interruptible transportation levels, and

³² *Id.* at 61,464-65. See also, *Tennessee Gas Pipeline Co.*, 62 F.E.R.C. (CCH) ¶ 61,250 at 62,654 (1993); *Order on Rsh'g*, 64 F.E.R.C. (CCH) ¶ 61,020 at 61,226 (1993).

³³ 66 F.E.R.C. (CCH) ¶ 61,144 (1994).

³⁴ 72 F.E.R.C. (CCH) ¶ 61,322, *mimeo* at 28, *et seq.* (1995).

³⁵ See *Transcontinental Gas Pipe Line Corp.*, 70 F.E.R.C. (CCH) ¶ 61,384, at 62,130 (1995); *KN Interstate Gas Transmission Co.*, 66 F.E.R.C. (CCH) ¶ 61,138, at 61,253 (1994).

³⁶ See *ANR Pipeline Co.*, 66 F.E.R.C. ¶ 61,335, at 62,105 (1994); *KN Interstate*, 66 F.E.R.C. at 61,253 (1994).

had demonstrated that a sufficient portion of fixed costs would be allocated to interruptible service.³⁷

[6] Transportation Rate Discounts

Section 284.7(d) of the Commission's Regulations, 18 C.F.R. § 284.7(d) (1995), permits pipelines operating under Part 284 open access blanket certificates to discount transportation rates to a level not less than average variable cost. Through a variety of methodologies, pipelines have generally projected their level of discounted service and allocated the cost shortfall between the discounted rate and maximum rate to remaining customers.³⁸ Although, in *Associated Gas Distributors v. FERC*,³⁹ the court appeared generally to approve the Commission's Order No. 436 regulations permitting discounting for Part 284 service in order to meet competition, the court recently suggested in *Mississippi Valley Gas Co. v. FERC*⁴⁰ that selective discounting to meet "gas-on-gas" competition between pipelines may be discriminatory. The controversy in that case was nevertheless dismissed for lack of ripeness.

³⁷ See *Ozark Gas Transmission Sys.*, 73 F.E.R.C. ¶ 61,129 (1995) (IT revenue crediting mechanism eliminated because pipeline no longer has any firm shippers); *Questar Pipeline Co.*, 72 F.E.R.C. (CCH) ¶ 61,195, at 61,928 (1995) (IT crediting mechanism eliminated because pipeline had over one and one-half years' post-636 operating experience and provided testimony and exhibits to support its projected IT throughput); *Transcontinental*, 70 F.E.R.C. at 62,130 (IT revenue crediting mechanism eliminated where pipeline had 12 months' operating experience and sufficiently explained IT throughput levels in its filing); *Florida Gas Transmission Co.*, 70 F.E.R.C. (CCH) ¶ 61,116, at 61,306 (1995) (pipeline's analysis of IT throughput comparing test period volumes to total entitlements sufficient to permit elimination of crediting mechanism); *High Island Offshore Sys.*, 66 F.E.R.C. (CCH) ¶ 61,378, at 62,269 (1994) (revenue crediting mechanism eliminated where pipeline allocated 93% of total cost of service to IT service and IT projection based on expiration of firm contracts); *U-T Offshore Sys.*, 66 F.E.R.C. (CCH) ¶ 61,377, at 62,264 (1994) (revenue crediting mechanism eliminated where pipeline allocated 53% of costs to IT service and projections of interruptible service levels based on expiring firm contracts).

³⁸ See *Interstate Natural for Pipeline Rate Design*, 47 F.E.R.C. (CCH) ¶ 61,295, at 62,056-58, *reh'g*, 48 F.E.R.C. ¶ 61,122 (1989).

³⁹ 824 F.2d 981 (D.C. Cir. 1987).

⁴⁰ D.C. Cir. No. 94-1486, issued Oct. 20, 1995.

[7] Allocation of Costs Associated with "turned-back" Capacity

In a series of recent orders, the Commission has been grappling with the cost allocation issues arising when long-term firm contracts are not renewed at the end of the contract term and the pipeline is unable to secure replacement shippers. In the clearest signal of its approach to date, in *Natural Gas Pipeline Co.*,⁴¹ the Commission rejected the pipeline's proposal to reallocate costs that would have been recovered from the departing customers from the remainder of the pipeline system. The Commission commented that it would "not permit a pipeline losing customers simply to shift the costs of resulting unsubscribed capacity to the remaining customers without regard to the adverse effects on those customers."⁴² Accordingly, the Commission rejected the pipeline's alternative proposals to reallocate its costs or to book the excess costs for subsequent recovery.

The decision in *Natural Gas Pipeline Co.* builds on prior decisions in *El Paso Natural Gas Co.*⁴³ and *Transwestern Gas Pipeline Co.*⁴⁴ In *El Paso*, the Commission rejected the pipeline's proposal to institute an exit fee allocating system capacity costs to customers failing to renew or substantially maintain their contract entitlements. The Commission found that such an exit fee would violate its exit fee policy set forth in Order Nos. 636 and 636-A.⁴⁵ In *Transwestern*, the Commission approved a settlement including a mechanism for sharing costs associated with departing customers between shareholders and customers. The settlement provided that the pipeline's firm customers pay a demand surcharge equal to approximately thirty percent of the costs associated with the capacity relinquished for five years. In approving the settlement, the Commission expressed the hope that its structure would serve as a model on other systems.

In a related development, in *Southern Natural Gas Co.*,⁴⁶ the Commission approved a settlement agreement requiring the pipeline to accept prospective demand reductions in two circumstances: (1) where elected by local distribution company customers in response to a public service commission order to reduce interstate pipeline capacity; and (2) where the reduction is necessitated by loss of the LDC's market due to pipeline bypass. The Commission rejected challenges that these provisions were discriminatory and anti-competitive, in the context of a settlement.

⁴¹ 73 F.E.R.C. ¶ 61,050 (1995).

⁴² 73 F.E.R.C. at 61,129.

⁴³ 72 F.E.R.C. ¶ 61,083 (1995).

⁴⁴ 72 F.E.R.C. ¶ 61,085, *reh'g denied*, 72 F.E.R.C. (CCH) ¶ 61,089 (1995).

⁴⁵ The Commission rejected the pipeline's argument that such a unilateral fee was appropriate in light of the FERC Electric Utility Open Access Rulemaking (RM95-8) where exit fees were one of the Commission's proposed methods of dealing with electric utility stranded costs.

⁴⁶ 72 F.E.R.C. (CCH) ¶ 61,322 (1995).

[8] Order No. 637

In Order No. 637,⁴⁷ the Commission promulgated a series of changes governing released capacity, peak and off-peak pricing and term-differentiated rates for pipeline services, voluntary auctions for pipeline capacity, proposals for imbalance service, and the right of first refusal for firm contract holders upon expiration of their contract terms. Contained here is a report on the Commission's new provisions on peak and off-peak pricing, term-differentiated rates, auctions, imbalance services and a review of the Commission's thinking on negotiated terms and conditions of service.⁴⁸

[a] Peak and Off-Peak Rates

Order No. 637 invites interstate pipelines to file proposals for varying rates for peak and off-peak service that would enable the price of peak service to rise toward a market clearing level. The Commission asserts that such seasonally differentiated rates will serve the dual goals of more efficiently allocating a scarce service during peak periods to the highest valued uses, while providing a pool of additional revenues available to reduce the rates for captive long-term customers.⁴⁹ The Commission has further indicated that it will be receptive to a variety of proposals for seasonal pricing, but has commented: (1) that it will allow peak rates to rise on a "value of service" basis, and will not reject such pricing based on arguments that such rates are not cost-based; and (2) that it will require reductions to off-peak prices corresponding to increases for peak pricing in order to keep revenues within a filing pipeline's approved revenue requirement.⁵⁰

Pipelines have been permitted to file for approval of such pricing either in the context of a general section 4 rate case, or through the implementation of *pro forma* tariff sheets. In the event the latter mechanism is used, the Commission has required pipelines to propose a mechanism for sharing increased peak revenues with long-term customers. Pipelines are further required to file within 15 months of implementing peak and off-peak rates a cost/revenue study, following which the Commission comments it will determine whether further rate adjustments are necessary prospectively.⁵¹

⁴⁷ *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Service*, 65 Fed. Reg. 10156 (2/25/00), — FERC Stats. & Regs. ¶ 31,091 (2/9/00).

⁴⁸ A discussion of the provisions in Order No. 637 governing capacity release and the right of first refusal is found at § 83.03[2][c][ii][C] and [D], respectively.

⁴⁹ Order No. 637, at 31,287-90.

⁵⁰ Order No. 637, at 31,290-91.

⁵¹ Order No. 637, at 31,290-91.

[b] Term-Differentiated Rates

Order No. 637 also permits pipelines to apply in a Section 4 rate proceeding for authority to implement term-differentiated rates designed to increase rates for shorter-term transactions, while extending offsetting decreases to customers entering into longer-term transactions.⁵² The Commission has commented that it believes pipelines are justified in charging more for short term, rather than for longer-term transactions, on the ground that longer-term shippers assume more financial risk than their shorter-term counterparts and provide an assured source of revenues for the pipeline. As with seasonally differentiated rates, the Commission has determined to limit rates in the aggregate to the pipeline's revenue requirement.⁵³

[c] Auctions

Retreating from a proposal in the NOPR for mandatory auctions of available pipeline capacity, the Commission has promulgated in Order No. 637 a series of basic principles governing procedures for auctions the Commission is now encouraging on a voluntary basis, both by pipelines and third parties. The guidelines governing such auctions include that:

- (1) the timing of the auctions be predictable and provide sufficient notice to bidders;
- (2) the auctions should be open to all potential bidders on a non-discriminatory basis;
- (3) the auctions be user friendly with information on the rules and procedures easily accessible;
- (4) the bidding procedures, as well as methods for selecting the best bids should be fully disclosed prior to the auctions;
- (5) there should be no favoritism in the determination of the winning bidders;
- (6) transaction information be disclosed so that shippers may determine the value of the transportation.⁵⁴

Within these guidelines, the Commission is encouraging experimentation that may include auctions of capacity establishing a transportation path over a series of pipelines in a given region.⁵⁵

[d] Imbalance Services, Operational Flow Orders and Penalties

Concerned that the existing regulatory approach to the imposition of penalties upon shippers for exceeding their contractual rights has encouraged shippers to

⁵² Order No. 637, at 31,292-94.

⁵³ Order No. 637, at 31,292-94.

⁵⁴ Order No. 637, at 31,294-96.

⁵⁵ Order No. 637, at 31,294-96.

engage in service arbitrage across pipeline system and to commit intentional violations of service restrictions as a means of managing imbalances,⁵⁶ the Commission has promulgated new rules in three areas. First, through new Section 284.12(c)(2)(iii) of its regulations, the Commission has required pipelines to provide, to the extent practicable, a new range of services enabling shippers to manage their imbalances more efficiently. Such services may include parking and lending, and the creative provision of additional storage rights, and must include provision for imbalance trading and netting in order to enable customers to minimize their imbalances. Further, the new regulation requires that provision must be made to enable third party vendors to provide such services, and that transportation customers will be treated on a non-discriminatory basis when they employ such third-party suppliers.⁵⁷

Second, through new Section 284.12(c)(2) of the regulations, the Commission has required pipelines to take all reasonable steps to minimize the impact and issuance of Operational Flow Orders (OFOs) and to set forth in their tariffs standards governing the circumstances in which OFOs will issue and when they will end. Pipelines are further obligated to provide timely information to shippers enabling them to minimize the adverse impact of an OFO. These new measures are designed to provide a level of predictability in the issuance of OFOs and to minimize their incidence.⁵⁸

Finally, new Section 284.12(c)(2)(v) of the Commission's rules requires that: (1) a pipeline may include penalties in its tariff only to the extent necessary to prevent the impairment of reliable service; (2) pipelines must credit penalty revenues to shippers' rates; and (3) pipelines must provide shippers as much information as is available on the status of their imbalances and overruns in order to assist them in avoiding penalties. The aim of these new regulations is to minimize the imposition of penalties and to remove any incentive for pipelines to assess penalties where they may otherwise assist customers in managing their imbalances.⁵⁹

[e] Negotiated Terms and Conditions of Service

Rejecting a proposal made in the earlier NOPR, the Commission decided in Order No. 637 not to extend blanket authority to pipelines to enter into negotiations with customers over the terms and conditions of their service.⁶⁰ While the Commission previously granted permission to pipelines to negotiate

⁵⁶ Order No. 637, at 31,307-09.

⁵⁷ Order No. 637, at 31,310.

⁵⁸ Order No. 637, at 31,312-13.

⁵⁹ Order No. 637, at 31,314-19.

⁶⁰ Order No. 637, at 31,342-43.

rates,⁶¹ the Commission refrained from extending this authority to features of natural gas transportation service other than rates, including provisions regarding scheduling, imbalances or operational obligations. The Commission has indicated an interest in continuing to discuss this concept in connection with what it anticipates will be an ongoing dialogue with the natural gas industry over the potential for two-track regulation, with one track reserved for services directed to traditional captive pipeline markets, with another track permitting individuated agreements aimed at customers with a range of service options.⁶² Pending that discussion, the Commission comments that it will continue to permit pipelines to submit non-conforming, negotiated agreements that will be subject to review on an individual basis against claims of discrimination or preferential treatment.⁶³

§ 83.05 Conclusion

With the FERC's issuance of Order Nos. 636, *et al.*, the natural gas industry may have reached a relatively stable stage in which natural gas supplies are purchased and sold freely in an open market. Looking to the future, the Commission has yet to resolve a host of issues relating to, among other things, the rate treatment for capacity built to serve new markets and the challenges raised by those recommending the application of market-based rates to transportation service. The Commission also has not put to bed issues relating to the transition costs resulting from industry restructuring under Order No. 636. What further issues arise will very much depend on the durability of the competitive framework engineered by the Commission.

⁶¹ See *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipeline*, 74 F.E.R.C. ¶ 61,076 (1996).

⁶² Order No. 637, at 31,343.

⁶³ Order No. 637, at 31,343.

Access to Alaska Gas Pipeline and "Basin Control"

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1

ACCESS AND BASIN CONTROL OVERVIEW

- Alaska Gas Pipeline ("AGP") will be a tightly regulated "open access" pipeline
- Pipeline operations must be legally separate from marketing affiliates – the law requires gas and pipeline transportation to be sold separately
- Affiliate restrictions enforced by new, heavy penalties
- FERC reviews competitive issues including size and expandability as part of its approval process
- FERC has unique powers to mandate expansion of this pipeline to protect unaffiliated explorers and shippers
- AGP will be the most scrutinized pipeline in the U.S. over its life

2

ACCESS AND BASIN CONTROL PRODUCER PIPELINE OWNERSHIP

- Past efforts to prohibit producer ownership of AGP were counter-productive
- Congress did not prohibit producer ownership of AGP when it enacted Alaska Natural Gas Pipeline Act ("ANGPA")

3

ACCESS AND BASIN CONTROL RELATIONSHIP OF GAS, PIPELINE, AND CAPACITY OWNERS

Order 636 and following orders changed dramatically how pipelines and producers conduct their business:

- After Order 636, pipeline companies do not own or sell gas; they just sell transportation services
- Separate companies -- affiliated or not -- sell gas
- Owning the pipeline no longer gives the owner transportation (capacity) rights
 - pipeline owner must put out for bid all capacity
 - pipeline affiliates may bid on the capacity but have no assurance of winning
- Likewise, owning the gas in the basin connected to the pipeline does not entitle a producer to capacity absent a winning bid

4

ACCESS AND BASIN CONTROL

THE PERVASIVE NATURE OF FERC REGULATION OF INTERSTATE GAS PIPELINES

- FERC reviews and approves all aspects of an interstate pipeline
 - Permitting
 - Design of facilities
 - Size of facilities
 - Access to facilities
 - Open seasons
 - Tariff rates
 - Operations
 - Expansions
 - Abandonment
- This will be especially so for AGP. For example,
 - FERC will consider how the project design considers the capacity needs of initial and future shippers (18 CFR § 157.36)
 - AGP must even consider any bids tendered after the expiration of the open season and can only reject them if economic, engineering or operational constraints do not allow the pipeline to accommodate the bids (18 CFR § 157.34 (d)(2))
 - As stated by FERC: "Our expectation is that an Alaska gas transportation project will be designed and built, to the extent possible, to accommodate all qualified shippers who are ready to sign firm transportation agreements" (Order 2005-A at ¶ 34)

5

ACCESS AND BASIN CONTROL

THE LEGAL FRAMEWORK

- Natural Gas Act of 1938 ("NGA")
- Natural Gas Policy Act of 1978 ("NGPA")
- Alaska Natural Gas Policy Act of 2004 ("ANGPA")
- Energy Policy Act of 2005 ("EPAAct")
- FERC Orders
 - Order 436 (1985)
 - Order 636 (1992)
 - Order 637 (2000)
 - Order 2004, 2004-A-D (2003)
 - Order 2005, 2005-A (2005)
 - Order 670 (2006)

6

ACCESS AND BASIN CONTROL

PHASES OF FERC REGULATION

1. Open Season
2. FERC Application process that results in a certificate
3. Pipeline construction
4. Pipeline operations

7

PART II

EVOLUTION OF FERC'S AFFILIATE/SEPARATION OF FUNCTIONS REGULATIONS

8

NATURAL GAS RESTRUCTURING – OPEN ACCESS/ORDER 436

- FERC's issuance of Order 436 in 1985:
 - Required interstate pipelines that offer transportation services to do so on an open-access, nondiscriminatory basis
 - Pipeline customers could now contract directly with producers for gas supply and transport it on the pipelines
 - Pipelines were encouraged to provide transportation to those customers who requested it

NATURAL GAS RESTRUCTURING – ORDER 636/UNBUNDLING

- FERC's issuance of Order 636 in 1992:
 - Required interstate pipelines to unbundle their commodity gas sales from transportation and storage services
 - Services were defined in new tariffs
 - Pipelines were given blanket sales certificates to allow for the unbundled sale of gas at market-based rates
 - However, such gas sales generally performed by marketing affiliates
 - Market Centers quickly evolved for gas trading

NATURAL GAS RESTRUCTURING – ORDER 636/CAPACITY

- Provided terms and structure for a capacity release program whereby capacity holders could release their un-utilized pipeline capacity to replacement shippers
- FERC requires a capacity release mechanism with open-access bidding, rather than assignment provisions, so as to foster open, competitive markets

NATURAL GAS RESTRUCTURING – ORDER 637

FERC's issuance of Order 637 enhanced Order 636:

- Increased informational reporting requirements for interstate pipelines
 - More stringent standards of conduct information
 - Enhanced information for firm, interruptible, storage, and capacity release transactions and for the Index of Customers
 - Enhanced scheduling provisions
 - Enhanced capacity segmentation rights
 - Mandatory provision of imbalance services
 - Encouragement of new rate forms for services
 - Peak and off-peak rates
 - Term-differentiated rates

PART III

FERC'S ENFORCEMENT POWERS DURING PIPELINE OPERATIONS

13

MONITORING OF NATURAL GAS DEREGULATION – ORDER 2004/STANDARDS OF CONDUCT

Order 2004 and Orders 2004-A-D, released in 2003-04:

- Set Standards of Conduct designed to ensure open access and competition by non-affiliated customers
- Barred undue preferential treatment by providers to their marketing affiliates:
 - Required provider's transmission function employees to operate independently from marketing employees or other energy affiliates (18 CFR 358.4(a))
 - Provider's sales and marketing units, energy affiliates, and potential merger partners must be posted on its website (18 CFR 358.4(b))
 - Ensure that non-affiliated customers have equal access to information about transmission, operations, price (18 CFR 358.5(a))
- Recognized post-unbundling market expansion that included growth of physical and financial transactions by marketing and non-marketing gas pipeline affiliates

14

FERC'S ORIGINAL ENFORCEMENT TOOLS UNDER NGA (1938) AND NGPA (1978)

- Can order disgorgement of unjust profits
- Can condition, suspend or revoke
 - Market-based rate authority
 - Certificate authority
 - Blanket certificate authority
- Minor penalty provisions
 - Both the NGA and NGPA had minor penalty provisions in the \$500 to \$5000 range

EX-456710

15

FERC'S NEW ENFORCEMENT TOOLS UNDER EPAc

- EPAc granted FERC greatly enhanced authority to assess civil and criminal penalties
 - Congress extended FERC's civil penalty authority to cover violations of the NGA or any rule or regulation imposed under NGA authority (EPAc section 314(b))
 - Congress increased the maximum civil penalty under the NGA and NGPA to \$1 million per violation for each day the violation continues (EPAc section 314(b))
 - Congress increased the maximum criminal fine under the NGA and NGPA to \$1 million and the maximum imprisonment time to 5 years (EPAc section 314(a))

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FERC'S ENFORCEMENT TOOLS UNDER EPAct...cont.

- FERC's October 2005 Policy Statement on enforcement listed several factors it would consider in determining the appropriate penalties. Among those:
 - What harm was caused
 - Was the harm widespread across markets or customers
 - What efforts did the company make to remedy the violation in a timely manner
 - Was the conduct fraudulent; was it the result of manipulation, deceit or artifice
 - Did the wrongdoer act in concert with others
 - Was this a repeat offense
 - How long did the wrongdoing last
 - Was the wrongdoing related to actions by senior management and was there any cover-up
 - Did management impede any inquiry into the wrongdoing
 - What effect would the penalties have on the financial viability of the company

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CONCLUSION

In FERC's own words: "Entities subject to the Commission's jurisdiction should expect firm but fair enforcement in the future, including the use, as appropriate, of the substantial new civil penalty authority provided by EPAct 2005."

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ORDER 670: PROHIBITION OF ENERGY MARKET MANIPULATION

- In January 2006 FERC issued regulations pursuant to its new EPCA authority
- Order bars energy market manipulation by "any entity" (not just jurisdictional entities)
- If the entity's conduct is "in connection with" a jurisdictional transaction, it is subject to FERC's anti-manipulation authority
- Order makes it unlawful for any entity in connection with gas and transportation purchases and sales to
 - Defraud using any device, scheme or artifice,
 - Make any untrue statement of material fact or omit a material fact, or
 - Engage in any act, practice, or course of business that operates as a fraud or deceit

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ORDER 670: PROHIBITION OF ENERGY MARKET MANIPULATION...cont.

- Fraud is defined to include "any action, transaction, or conspiracy for the purpose of impairing, obstructing or defeating the honest functioning of the market."
- There also must be a showing of intent to deceive or defraud, that is, "scienter" as established under securities law.

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PART IV

THE ALASKA OPEN SEASON REGULATIONS

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OPEN SEASON REGULATIONS FOR THE ALASKA PIPELINE OVERVIEW

- ANGPA directed FERC to issue regulations governing the conduct of open seasons, the first such regulations ever issued by it
- Comprehensive regulations were issued in 2005 (Orders 2005 and 2005-A) that cover procedures for the allocation of capacity and criteria for and timing of any open season
- FERC's stated goals are an open season process that
 - provides economic certainty to support the building of the pipeline
 - promotes competition in the exploration, development and production of Alaska natural gas
 - prevents unduly discriminatory behavior and limits the ability of a project applicant to unduly favor its affiliate -- hence, Order 2004 Standards of Conduct apply
- Regulations apply to any initial capacity or voluntary expansion capacity
- In sum, regulations provide FERC with an additional tool over and above its other enforcement tools to actively and closely police all capacity related conduct for the Alaska pipeline.

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OPEN SEASON REGULATIONS FOR THE ALASKA PIPELINE

OVERVIEW...cont.

- FERC will review the open season notice in advance of its publication
- At least 30 days' notice must be given of start of open season
- The open season must remain open for at least 90 days once precedent agreements are signed, they must be disclosed and filed with FERC
- Open season notice will contain extensive information about the project, including a proposed tariff and technical data
 - See 18 CFR 157.34 (reproduced in appendix)

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INFORMATION AVAILABILITY

18 CFR 157.34

- “(18) All information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;”

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CERTIFICATION BY SALES AND MARKETING UNITS
18 CFR 157.34

- “(21) A statement that any officers and directors of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska named in paragraph (c)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season.”

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UNDUE DISCRIMINATION OR PREFERENCE
PROHIBITIONS
18 C.F.R. 157.35

- “(a) All binding open seasons shall be conducted without undue discrimination or preference in the rates, terms or conditions of service and all capacity allocated as a result of any open season shall be awarded without undue discriminations or preference of any kind.
- (b) Any complaint filed pursuant to §385.206 of this chapter alleging non-compliance with any of the requirements of this subpart shall be processed under the Commission's Fast Track Processing procedures contained in §385.206 (h).

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**UNDUE DISCRIMINATION OR PREFERENCE
PROHIBITIONS**

18 C.F.R. 157.35...cont.

- (c) Each project applicant conducting an open season under this subpart must create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the project applicant's Marketing and Energy affiliates as those terms are defined in §385(d) and (k) of this chapter."
- (d) The relevant Order 2004 Standard of Conduct provisions apply
 - Separation of transmission function employees from marketing and energy affiliate employees
 - Information access for marketing and energy affiliate employees that is only what the transmission employees provide to their transmission customers
 - Information disclosure that does not favor marketing and energy affiliate employees
 - No preferences to affiliates for transmission service
 - Discounts that must be completely transparent

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**UNDUE DISCRIMINATION OR PREFERENCE
PROHIBITIONS**

18 C.F.R. 157.35...cont.

- (e) The Mainline LLC will have to post on its internet website written procedures describing how it will comply with Order 2004
- (f) The Mainline LLC will also have to designate a Chief Compliance Officer and train its employees on the open season requirements
- (g) As FERC concluded: "The application of some of the non-discrimination requirements of Order No. 2004 will broadly prohibit discrimination by a project applicant conducting an open season and limiting its ability to unduly favor a Marketing Energy Affiliate."

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