The Commonwealth of Massachusetts

DEPARTMENT OF
TELECOMMUNICATIONS AND ENERGY

June 6, 2005

D.T.E. 04-1

Investigation by the Department of Telecommunications and Energy on its own motion regarding the assignment of interstate pipeline capacity pursuant to Natural Gas Unbundling, D.T.E. 98-32-B (1999).

TABLE OF CONTENTS

I. INTRODUCTION . . . . . Page 1

A. Procedural Background . . . . . Page 1

B. Historical Background . . . . . Page 2

II. SCOPE OF PROCEEDING . . . . . Page 4

A. Position of the Commenters . . . . . Page 4

B. Analysis and Findings . . . . . Page 6

III. CAPACITY ASSIGNMENT . . . . . Page 8

A. Position of the Commenters Favoring Voluntary Assignment . . . . . Page 8

1. Preconditions for a Fully Competitive Market . . . . . Page 10

2. FERC Initiatives and Interstate Pipeline Developments . . . . . Page 12

3. Current Status of the Market . . . . . Page 13

B. Analysis and Findings . . . . . Page 15

1. Introduction . . . . . Page 15

2. Developments at FERC . . . . . Page 17

3. Number of Marketers . . . . . Page 22

4. Number of Transportation Customers . . . . . Page 24

5. Conclusion . . . . . Page 26

IV. METHOD OF CAPACITY ASSIGNMENT: SLICE VERSUS PATH . . . . . Page 27

A. Position of the Commenters . . . . . Page 27

B. Analysis and Findings . . . . . Page 34

V. OTHER ISSUES . . . . Page 39

A. Monthly Recall and Release Process . . . . Page 39

1. Position of the Commenters . . . . Page 39

2. Analysis and Findings . . . . Page 41

B. Non-Daily Metered Algorithms . . . . Page 42

1. Position of the Commenters . . . . Page 42

2. Analysis and Findings . . . . Page 44

C. Monthly True-ups for Non-Daily Metered Customers . . . . Page 45

1. Position of the Commenters . . . . Page 45

2. Analysis and Findings . . . . Page 46

D. Operational Flow Order Imbalance Penalties . . . . Page 47

1. Position of Commenters . . . . Page 47

2. Analysis and Findings . . . . Page 49

E. Synchronization of Nomination Deadlines and Procedures . . . . Page 51

1. Positions of the Commenters . . . . Page 51

2. Analysis and Findings . . . . Page 52

VI. CONCLUSION . . . . Page 52

I. INTRODUCTION

A. Procedural Background

On January 12, 2004, the Department of Telecommunications and Energy ("Department") opened a proceeding, docketed as Capacity Assignment, D.T.E. 04-1, to determine whether to modify the existing mandatory method for capacity assignment established by Natural Gas Unbundling, D.T.E. 98-32-B at 35, 40-42 (1999). The Department requested two rounds of comments in this investigation to address the following issues: (1) initiatives by the Federal Regulatory Commission ("FERC") regarding the upstream capacity market; (2) the number of marketers; (3) the number of transportation customers; and (4) the percentage of the market that has converted to transportation service (both in volume and number of customers).

Ten local gas distribution companies ("LDCs") and four marketers, including a trade association, submitted initial comments: Bay State Gas Company ("Bay State"); The Berkshire Gas Company ("Berkshire"); Blackstone Gas Company ("Blackstone"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); KeySpan Energy Delivery[1] ("KeySpan"); New England Gas Company[2] ("New England"); NSTAR Company ("NSTAR"); Amerada Hess Corporation ("Hess"); Energy East Solutions, Inc. ("Energy East"); Select Energy, Inc ("Select"); and National Energy Marketers Association ("NEM").

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1 KeySpan commented on behalf of Boston Gas Company, Colonial Gas Company, and Essex Gas Company.

2 New England commented on behalf of Fall River Gas Company and North Attleboro Gas Company.

Six LDCs filed reply comments: Bay State; Berkshire; Blackstone; KeySpan; New England; and NSTAR. Four marketers replied: Direct Energy/Centrica North America ("Direct Energy"); Hess; Select; and Energy East. One interstate pipeline filed reply comments: Algonquin Gas Transmission Company.

The Attorney General of the Commonwealth ("Attorney General") filed initial and reply comments.[3] Finally, the commenters[4] responded to four sets of information requests by the Department.[5]

B. Historical Background

On February 1, 1999, the Department issued its Order regarding the assignment of upstream capacity held by the LDCs. D.T.E. 98-32-B at 10-35, 40-42. In that Order, the Department envisioned a fully competitive gas market in which all customers would have the option to purchase both gas commodity and transportation capacity from a wide range of providers, operating in a competitive market. Id. at 7. In such a fully competitive market for commodity and capacity, the LDCs' obligations would be limited to the transportation and

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3 The Department granted Dominion Transmission Inc. limited participant status in the proceeding.

4 The LDCs, marketers, pipeline, and Attorney General are referred to collectively as commenters.

5 The Department enters into the record as evidence the commenters' responses to the Department's information requests. 220 C.M.R. §1.10. The responses to the Department's information requests will be identified by the name of the entity or entities, the information request set number, and the actual question number. For example, KeySpan's response to the Department's first question in our third set of information requests will be referred to as "KeySpan 3-1."

delivery of supplies brought to the citygate by competitive third-party suppliers. Id. Under these circumstances, the Department stated that the LDCs' traditional obligation to procure and transport gas on behalf of all existing customers would have to be modified. Id. The Department reasoned that if LDCs would no longer be required to serve as gas merchants to all customers downstream of the citygate, they would no longer be in a position to ensure reliable and least-cost gas-sales service to distribution customers collectively. Id.

As a precondition to modifying the LDCs' role in procuring and transporting gas, however, the Department stated that a workably competitive upstream capacity market would have to exist to ensure the availability of reliable and reasonably priced capacity resources. Id. The Department concluded, in 1999, that the conditions that characterize a fully competitive market structure for interstate pipeline and storage capacity did not yet exist. Id. at 8, 25-35. Therefore, the Department required LDCs to continue planning for and procuring upstream pipeline capacity to serve all firm customers for a transition period of at least three to five years. Id. at 40. The Department found that assigning capacity to marketers on a mandatory, slice-of-system method would enable converting customers to gain access to capacity, while maintaining reliability, and would avoid improper transfer of cost responsibility, until the upstream market could become workably competitive. Id. at 35, 40.

Nonetheless, the Department acknowledged that a number of factors, including FERC initiatives, might move the upstream market closer to full competition. Id. at 41-42. Therefore, the Department stated that mandatory assignment would be subject to review after competition in the upstream capacity market had the opportunity to develop. Id. at 41. In addition to developments at FERC and the number of alternative contract holders with firm rights to interstate pipeline capacity, the Department indicated that this review would include consideration of the number of marketers, the number of transportation customers, and the percentage of the market that has converted to transportation service. Id. at 27, 42. The Department stated that this review would take place after the third year of the five-year unbundling transition period. Rulemaking Regarding Unbundling, D.T.E. 98-32-E at 4 (2000); D.T.E. 98-32-B at 27-29, 41. The five-year period commenced in November 2000 with the Department's approval of final terms and conditions for the ten LDCs operating in Massachusetts. D.T.E. 98-32-E at 4.

II. SCOPE OF PROCEEDING

A. Position of the Commenters

The Attorney General requests that the Department expand the current investigation into the competitiveness of the gas market in Massachusetts to include broader issues (Attorney General Comments at 1, 3-4). The Attorney General suggests that the expanded investigation should examine the following issues: (1) how the market can bring choice to customers who have none; (2) how LDCs plan, procure, manage, and optimize their resource portfolio; and (3) how to mitigate price volatility in the natural gas market (id. at 1, 3).[6]

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[6] In the alternative, the Attorney General requests the Department to expand its inquiry, he also suggests that the Department reconvene the Massachusetts Gas Collaborative to address LDCs' gas supply procurement and pricing options for small customers (Attorney General Reply at 2).

The Attorney General states that because LDCs are obligated to serve customers at least cost, it is necessary that LDCs plan and contract for sufficient resources to meet the needs of customers within their service territory (id. at 3). The Attorney General suggests that the Department investigate the ability of LDCs to serve returning load, and how they plan to recover the costs of serving this load from customers, before making a decision on whether or not to continue with mandatory capacity assignment (id.). According to the Attorney General, the investigation should also address LDCs' asset management and optimization strategies in a changing gas industry (Attorney General Comments at 4).

Further, the Attorney General states that the Department discouraged LDCs from entering into fixed price or long-term contracts extending beyond the end of the transition period in Natural Gas Unbundling, D.T.E. 98-32-B (id. at 4). The Attorney General claims that, as a result, customers have been exposed to volatile natural gas prices in recent years (id. at 4-5). The Attorney General recommends that the Department review spot or indexed pricing and implement policies, such as fixed price options, that will result in stable prices for customers (id. at 4-5). The Attorney General also suggests that the Department investigate why LDCs other than Keyspan have not yet proposed dollar cost averaging program for their customers (id. at 5, citing KeySpan Gas Purchasing Practices, D.T.E. 03-85 (2003)).

Energy East responds to the Attorney General by stating the market should evolve more fully before considering the Attorney General's request to broaden the scope of the investigation (Energy East Reply at 2). KeySpan responds to the Attorney General's request to expand the scope of the proceeding to price volatility and planning practices by stating that these matters are addressed in other proceedings (KeySpan Reply at 18). NSTAR responds to the Attorney General's request to investigate the LDCs ability to meet future growth by stating that such concerns are met within each LDC's terms and conditions (NSTAR Reply at 11-12; see also Hess Reply at 9).

B. Analysis and Findings

The Department has considered the comments of Attorney General, who requested that the Department perform a full investigation into issues broader than the competitiveness of the natural gas market in Massachusetts. When we issued our decision in D.T.E. 98-32-B, we intended that the scope of this proceeding be limited only to a review of whether the market is sufficiently competitive to modify the existing mandatory capacity assignment. The issues that the Attorney General requests that we investigate in this docket are not narrowly tailored to the competitiveness of the natural gas market in Massachusetts and have been or are being addressed in other filings. See, e.g., Bay State Gas Company, D.T.E. 02-75-A at 5-6 (2004).

For example, in Bay State Gas Company, D.T.E. 02-75-A at 5-6, the Department addressed the issue of modifying its current policies regarding LDCs' obligation to serve transportation customers returning to firm sales service. In the Order, we noted that the obligation of the LDCs to serve returning load is addressed in the LDCs' current terms and conditions. Id. Similarly, there is no need to review in this proceeding how LDCs plan and procure their gas supply resources because this issue is reviewed in separate company-specific filings. See, e.g., Fitchburg Gas and Electric Company, D.T.E. 03-52 (2004); Bay State Gas Company, D.T.E. 02-74 (2004). Likewise, the LDCs' asset management and optimization strategies are reviewed in LDC-specific filings. See, e.g., Berkshire Gas Company, D.T.E. 04-47 (2004); Keyspan Energy Services, D.T.E. 04-9 (2004); Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.T.E. 99-76 (1999). Further, we established a method to review how LDCs mitigate price volatility in Risk Management Techniques to Manage Natural Gas Price Volatility, D.T.E. 01-100 (2001).

We disagree with the Attorney General's assertion that, in D.T.E. 98-32-B, the Department discouraged the LDCs from entering into long-term contracts extending beyond the end of the transition period. Rather, the Department indicated that all LDCs must continue to plan and procure necessary upstream capacity to serve all firm customers. D.T.E. 98-32-B at 41-42. Indeed, subsequent to D.T.E. 98-32-B, the Department approved proposals by LDCs to enter into long-term capacity contracts (ten years). See, e.g., New England Gas Company, D.T.E. 02-39 (2002); Algonquin Gas Company/Keyspan Energy, D.T.E. 02-18 (2002).

Finally, the Attorney General claims that no LDC other than KeySpan has proposed dollar cost averaging programs. The Attorney General, however, ignores our approval of NSTAR's identical proposal in NSTAR, D.T.E. 04-63 (2004).

In conclusion, the Attorney General has not justified any expansion of the scope of this proceeding. We find that it is appropriate to review market conditions to determine whether a workably competitive marketplace exists. Therefore, we will now review the comments on that issue and whether the Department should continue with mandatory assignment of capacity.

III. CAPACITY ASSIGNMENT

A. Position of the Commenters Favoring Voluntary Assignment

Hess states that several major changes have occurred in the New England market since the Department issued D.T.E. 98-32-B. These changes include the importation of greater volumes of natural gas, the increase in the number of marketers, and a revaluation of the delivered prices to New England so that the prices no longer reflect a New York-delivered price plus transportation (Hess Comments at 10-18).

Four marketers, Direct Energy, Hess, Select, and NEM, contend that Massachusetts must adopt voluntary capacity assignment if the state wants to achieve the objective of a fully competitive gas market (Direct Energy Reply at 2; Hess Comments at 15; Select Comments at 2; NEM Comments at 2). Hess states that mandatory capacity assignment is an overwhelming structural barrier that makes it difficult for many marketers to enter the Massachusetts market (Hess Comments at 15). According to Hess, the few marketers that have been able to enter the market are only sustained by a substantial number of customers that have been exempt from mandatory capacity assignment (id.).

Direct Energy and Select agree with Hess that the mandatory capacity assignment in Massachusetts is a structural barrier to competition (Direct Energy Reply at 7; Select Comments at 2). According to Select, mandatory capacity assignment places the cost structure of LDCs on customers of marketers, defeating the very purpose of competition in Massachusetts (Select Comments at 2).

Direct Energy and Hess suggest that the Department undertake a gradual transition to a voluntary capacity assignment program (Direct Energy Reply at 2; Hess Comments at 18). Hess argues that the transition should coincide with (1) the expiration of key LDC capacity contracts and (2) the time LDCs need to contract for capacity to meet incremental load growth behind their system (Hess Comments at 18-24). Hess states that each time an LDC's capacity contract is nearing its expiration date, the LDC could allow marketers to discontinue taking assigned capacity from any new contract, and instead give marketers the opportunity to purchase their own capacity from the market in lieu of the amount assigned from the LDC contract (id. at 19-20). The LDC could then reduce its new capacity contract by a corresponding amount (id. at 19-20). Similarly, when an LDC requires capacity to meet its growth requirements, the LDC could allow marketers to turn back assigned capacity to the LDC to use for its own growth instead of purchasing new capacity on the open market (id. at 20-21). The marketer could then purchase capacity in the open market to replace the assigned capacity it returned to the LDC (id. at 20-21). Hess recommends that capacity purchased and held by marketers to substitute for LDC-assigned capacity must meet reliability requirements to be established jointly by LDCs, marketers, and the Department (id. at 18-19).[7] Hess believes that such a gradual shift to a voluntary capacity assignment system will allow

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[7] According to Hess, New York accepts an affidavit from the marketer that its capacity is primary to the LDC's citygate during the winter months, a practice which has served New York well for the last six years (Hess Comments at 19).

marketers to begin to substitute capacity purchased and held by them for assigned capacity from LDCs (Hess Comments at 18-19).[8]

B. Position of the Commenters Favoring Mandatory Assignment

1. Preconditions for a Fully Competitive Market

Five LDCs comment that the Department's stated pre-conditions for a fully competitive market still do not exist in Massachusetts and therefore no change in the mandatory capacity assignment policy is warranted (Bay State Comments at 2; Berkshire Comments at 3; KeySpan Comments at 6-7; New England Comments at 2; NSTAR Comments at 3). For the same reason, the LDCs reject a gradual transition to voluntary assignment as well (Bay State Reply at 1-3; KeySpan Comments at 1-7; New England Reply at 1-2; NSTAR Comments at 3-9).

Bay State claims that it is not mandatory capacity assignment that has hindered the development of competitive markets (Bay State Comments at 27-28). According to Bay State, prices in the market have become highly volatile and the number of marketers has diminished considerably due to consolidations, failures, and more stringent creditworthiness standards (id. at 8, 11, 15). Bay State asserts that the LDC must continue to design its resource portfolio in a way that ensures the reliability of gas supply on its system until the market becomes

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8 Hess claims that in New Jersey, where there is no capacity assignment, there are at least sixteen marketers working on each of that state's four LDCs' systems as compared to seven in Massachusetts (Hess Comments at 15-16). Also, in New York, where capacity assignment is limited to areas served by a single pipeline, there are at least sixteen marketers working on each upstate New York LDC's system compared to seven in Massachusetts (id. at 16-17).

sufficiently robust (id. at 8-9). Bay State contends that mandatory assignment avoids the potential reliability and cost risks of voluntary assignment (id. at 32).

KeySpan argues that despite increased imports of LNG and the completion of the 1999 Maritimes and Northeast Pipeline ("M&NE") interconnect at Dracut, these increases to capacity merely offset the increased use of gas, primarily from gas-fired power generation (Keyspan Reply at 4). Berkshire cites the experience of electricity generators in cold weather to emphasize that entities without firm, long-haul capacity entitlements are at great risk of not meeting demand during peak periods (Berkshire at 7-8; see also NSTAR Comments at 5-7).

KeySpan takes issue with Hess's comparisons of Massachusetts with New York and New Jersey, which do not have mandatory capacity assignment (KeySpan Reply at 7). KeySpan emphasizes that those states have more diverse pipeline delivery options that are not capacity-constrained (id.). KeySpan contends that the marketers in New York are required to contract for upstream capacity so that the effective result is very similar to the mandatory capacity assignment in Massachusetts (id. at 8). Finally, KeySpan contends that Hess is simply wrong that competition is thriving in other Northeast states, and argues that Massachusetts has had more migration to transportation service for commercial and industrial ("C&I") customers than New York in percentage terms (id.).[9]

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[9] KeySpan indicates that 46 percent of KeySpan, 55 percent of Berkshire, 25 percent of Bay State, and 27 percent of NSTAR's load has migrated in 2002; in New York, the migration rate was 32 percent (KeySpan Reply at 8).

2. FERC Initiatives and Interstate Pipeline Developments

Bay State, KeySpan, and NSTAR state that FERC, in Order No. 637,[10] temporarily removed price caps on short-term capacity releases of less than a year, but reimposed them at the end of the experimental period on September 30, 2002 (Bay State Comments at 19; KeySpan Comments at 5; NSTAR Comments at 6-7). They contend that the reimposition of price caps indicates that the upstream market is not competitive (Bay State Comments at 19; KeySpan Comments at 5; NSTAR Comments at 6-7).

NSTAR states that while FERC has taken some initiatives to facilitate capacity-related transactions on interstate pipelines, these initiatives, such as capacity segmentation,[11] have little practical effect on Massachusetts given the limited physical nature of the pipeline system into Massachusetts (NSTAR Comments at 8-9). Also citing capacity segmentation, New England argues that FERC's policies have not resulted in increased competition in the capacity market (New England Comments at 3).

Bay State Gas indicates that pipelines often require a ten-year commitment on new or renewed contracts, and primary capacity rights are concentrated among those willing to enter into such long-terms contracts (Bay State Comments at 12-13). Previously, primary capacity holders, mainly LDCs, in renewal considerations, only had to match a competing bid for a

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10 Regulation of Short-Term Natural Gas Transportation Services, Docket No. RM98-10-000 and Regulation of Interstate Natural Gas Transportation Services, Docket No. RM98-12-000 (February 9, 2000) and respective orders on rehearing, Order 637-A (May 19, 2000) and Order 637-B (July 26, 2000).

11 Capacity segmentation allows shippers to divide pipeline capacity into segments with each segment equal to the total contract demand of a contract.

five-year period (id. at 19-20). FERC dropped the five-year requirement, according to Bay State, thereby creating additional contracting risks for LDCs who may have to contract for longer periods to ensure winning the bid (id. at 20). Unitil also raises the issue of longer-duration contracts being necessary for the LDC to ensure that its bid is a winner and notes that the longer term could conflict with the Department's goal to transition the market to competition (Unitil Comments at 2-3).

Berkshire acknowledges that a number of regional pipeline or supply projects are being considered that may address the capacity constraints in the future (Berkshire Comments at 8). However, Berkshire notes that many of these projects will not benefit Berkshire directly since it is served only by Tennessee Gas Pipeline (id. at 8-9). Berkshire notes, moreover, that many of these projects will not be in place for at least three to five more years (id. at 9).

Finally, KeySpan, New England, and NSTAR indicate that pipeline companies have tightened creditworthiness standards making market entry more onerous (KeySpan Comments at 5; New England Comments at 3; NSTAR Comments at 9-10;). NSTAR further alleges that the FERC's current rulemaking on creditworthiness standards will directly affect the number of upstream market participants (NSTAR Comments at 9-10).

3. Current Status of the Market

KeySpan indicates that since 1999 the number of marketers in its service territories has dropped from twenty-one to eleven (KeySpan Comments at 6). KeySpan indicates that residential transportation service is virtually non-existent and the percentage of C&I customers on transportation rates has steadily declined (id. at 12-13). KeySpan acknowledges that the volume of transportation sales is steady at around 40 percent of total sales, and has shown a slight upward trend since 1999 (id. at 13).

KeySpan argues that while Hess claims the number of marketers has increased, Hess inappropriately includes marketers serving other New England states and New York (KeySpan Reply at 4). KeySpan contends that the actual number of marketers serving Massachusetts has declined and there is no significant increase in the amount of firm pipeline capacity held by these marketers (id. at 7). Therefore, according to KeySpan, there is no basis for shifting from mandatory capacity in the absence of a fully competitive market and given the continuing FERC controls on transmission pricing (id.).

According to Berkshire, eight marketers currently serve its territory and that number has not changed much over time, though the identity of the marketers has changed dramatically (Berkshire Comments at 6). Residential customers on transportation service represent less than one percent of sales volumes (id. at 7). Thirteen percent of C&I customers, representing 55 percent of C&I sales volumes, are transportation customers (id.).

NSTAR states that the number of marketers in its area has declined steadily from eleven to seven since the beginning of 2001 (NSTAR Comments, Appendix C). NSTAR reports that the percentage of its throughput delivered to transportation-only customers has remained stable on a yearly average (id.)

Bay State reports that the number of marketers in its service territory has dropped from 32 in 1998 to nine in February 2004 (Bay State Comments at 8). Further, according to Bay State, several marketers have gone out of business and there has been significant marketer turnover (id. at 8). Bay State claims that marketers have not demonstrated a long-term commitment to the market by acquiring firm upstream capacity (id. at 24). Finally, Bay State reports that the marketers in its area have failed to deliver on several occasions and Bay State had to make up the shortfall (id. at 7)

Unitil reports that, at the end of 2003, it had 22 transportation-only customers, down from a monthly high of 48; all were C&I customers (Unitil Comments at 1). Fifty-two customers who migrated later returned to firm service (id.). Unitil indicates that, in August 2001, 25.38 percent of sales were transportation customers, and at the end of 2003, only 6.33 percent were transportation customers (id. at 2). Unitil explains that five marketers operated in Unitil's service territory in 1999 (id.). According to Unitil, as of February 2004, three still operate, but one is about to cease operating (id.).

B. Analysis and Findings

1. Introduction

In D.T.E. 98-32-B at 26-27, the Department concluded that mandatory capacity assignment was the appropriate mechanism to assign upstream capacity in Massachusetts to ensure the continued deliverability and reliability of gas at reasonable prices. In addition, the Department was concerned that a voluntary assignment of upstream capacity could result in stranded capacity costs which the LDCs would have to recover from non-migrating customers. Id. at 29. The Department noted that this shifting of costs would violate the Department's long-established policy on cost allocation, i.e., that cost responsibility must follow cost incurrence. Id.

The Department found in D.T.E. 98-32-B at 27 that the upstream capacity market was not workably competitive and that Massachusetts remained capacity-constrained, given that only two primary pipelines directly serve it. The Department concluded that, for us to regard the upstream capacity market as fully competitive, (1) the FERC-imposed price controls on interstate pipeline capacity had to be lifted, and (2) the number of alternative contract holders with firm rights to the interstate pipeline capacity serving Massachusetts must increase. Id. at 27. In addition, the Department would consider a number of factors including, but not limited to, the number of marketers, the number of transportation customers, and the percentage of the market that has been converted to transportation service, to determine whether the upstream capacity market was workably competitive. Id. at 42. Further, the Department was concerned that, absent a significant increase in the upstream capacity resources serving Massachusetts, a system of voluntary capacity assignment could result in the diversion of the limited interstate pipeline capacity serving firm customers to serve markets outside the Commonwealth or non-traditional customers within the state, such as gas-fired electric generation facilities. Id. at 8.

Based on these considerations, the Department concluded that, absent a workably competitive upstream capacity market serving Massachusetts, reliability could be jeopardized if LDCs relinquished their obligation to plan for and procure sufficient upstream capacity to serve firm customers. Id. at 27. The Department, however, noted that, with proper market conditions, voluntary assignment would be the most expeditious way to achieve the Department's long-range objective of a fully competitive gas industry in which all customers would have the option to purchase gas commodity and transportation capacity from a wide range of providers, including third-party marketers, operating in a competitive market. Id. at 28.

2. Developments at FERC

The lifting of the FERC-imposed price controls on interstate pipeline capacity is one of the conditions that must be fulfilled for the Department to regard the upstream capacity market as being fully competitive. D.T.E. 98-32-B at 27. FERC, however, continues to impose price controls on the release of pipeline capacity in the upstream capacity market (NSTAR Comments at 6; KeySpan Comments at 5, citing Regulation of Short-Term Natural Gas Transportation Service, Docket No. RM98-10-100 and Regulation of Interstate Natural Gas Transportation Services, Docket No. RM98-12-000 (February 9, 2000) and respective orders on rehearing, Order 637-A (May 19, 2000) and Order 637-B (July 26, 2000)). In Order No. 637, FERC temporarily removed price caps on short-term capacity release of less than one year beginning March 27, 2000, but reimposed them at the end of the experimental period on September 30, 2002 (KeySpan Comments at 5).[12] Further, FERC requires shippers to release or assign capacity in accordance with its capacity release program, which grants a priority to primary point shippers (id., citing Atlanta Gas Light Co., 100 FERC ¶ 61,071 at 61,278 (2002); FERC Order No. 637, at 31, 304-305). As a result, there is no assurance that capacity held by marketers under the current FERC capacity release program will remain

12 The price caps on long-term capacity release (one year or more) were not removed (KeySpan Comments at 5, n.3).

available to serve Massachusetts customers if the Department adopted a voluntary capacity assignment system.[13] Therefore, we conclude that the precondition that FERC-imposed pricing be lifted has not been met.

KeySpan, New England, and NSTAR indicate that many pipelines, in the wake of the Enron bankruptcy, have tightened their creditworthiness standards,[14] making it more onerous for replacement shippers (i.e., marketers) to obtain capacity in the secondary market. We note that FERC is currently investigating creditworthiness standards in a rulemaking proceeding, Creditworthiness Standards for Interstate Natural Gas Pipelines, 106 FERC ¶ 61,123 (2004). We expect that these changes and the continued uncertainty on the final standards will have an impact on the retail market by contributing to a reduction in counter-parties and difficulties by some marketers in qualifying to do business. Thus, we would expect that the competitiveness of the upstream market will not improve substantially until this and other issues are resolved.

3. Upstream Capacity Resources

In D.T.E. 98-32-B at 27, the Department stated that one of the conditions for us to regard the upstream capacity market as workably competitive is that there must be an increase in the number of alternative contract holders with firm rights to the interstate pipeline capacity serving Massachusetts. The evidence indicates that only three percent of the Tennessee and one percent of the Algonquin pipeline capacity (with New England citygates), was purchased

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13 The interstate pipelines are required to follow the provisions of their respective FERC Gas Tariffs in awarding capacity and delivering gas in accordance with the shipper's instructions (Algonquin Reply Comments at 2).

14 See, e.g., Tennessee Gas Pipeline Co., 100 FERC ¶ 61208 (2002).

by marketers licensed in Massachusetts as of January 2004 (KeySpan Reply Comments at 4). In addition, only four percent of the Hubline capacity is held by marketers serving Massachusetts (id. at 6). No marketer serving Massachusetts holds capacity on the M&NE system (id. at 6-7).[15]

Direct Energy and Hess have suggested that the Department should adopt a phased-in voluntary capacity assignment, arguing that the conditions required by the Department for a fully competitive wholesale market have improved as a result of the additional capacity and other resources that have come into New England since 1999 (Direct Energy Reply at 2; Hess Comments at 9-11). According to Hess, the additional resources include the M&NE capacity, which brings 530,000 MMBtu per day of increased capacity into the region, and the Distrigas expansion, which increased Distrigas' LNG imports from Trinidad and Algeria from 98.8 Bcf in 2000 to over 150 Bcf in 2003 (Hess Comments at 9-11). Hess further claims that the number of market participants other than LDCs that have purchased firm capacity into the region increased since February 1999. Hess states that, in January 2004, the total capacity held by entities other than LDCs and electric generating companies on the Tennessee and Algonquin pipelines with New England citygates in January 2004 was 24 percent and ten percent, respectively (id. at 12-14).

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15 According to Hess, marketers cannot hold capacity to Massachusetts citygates and, thus, have no incentive to purchase primary point capacity into Massachusetts because they are assigned capacity by the LDCs under the current mandatory capacity assignment system (Hess-1-5).

Information provided by and Algonquin, KeySpan, and NSTAR, however, indicates that Hess overstates the amount of new capacity and other resources that have come into Massachusetts since 1999. The information provided by Algonquin indicates that the total peak day mainline capacity on the Algonquin system with New England citygates is approximately 1,674,000 dekatherms, far less than the 2,333,374 dekatherms Hess claims is available to serve New England customers (Algonquin Reply at 2).[16] According to KeySpan, only twelve percent of the 51,000 MMBtu per day that Hess holds on Tennessee, and claims as serving New England, actually has a primary delivery point to New England (KeySpan Reply at 4, citing Tennessee Gas Pipeline Index of Customers: January 2004; Algonquin Gas Transmission Index of Customers: January 2004). Keyspan states that the remainder of the capacity has a primary delivery point to White Plains, New York (id. at 4). Additionally, increased LNG imports by Distrigas and the M&NE interconnect do not serve Massachusetts customers only, but also customers in the other New England states and in states outside New England (id.).

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[16] According to Algonquin, the figures provided by Hess may have included lateral capacity that is not part of the mainline system available to serve retail customers in Massachusetts (Algonquin Reply at 2). Also, contrary to Hess' assertion, the Hubline project does not interconnect with the Tennessee Gas Pipeline system anywhere in Massachusetts (id. at 1). The Hubline project, which is wholly owned by Algonquin, is an extension of the Algonquin Pipeline system from Weymouth, Massachusetts to a point of interconnection with the M&NE system in Beverly, Massachusetts (id.).

Based on information compiled in this proceeding, the Department concludes that new pipeline and other capacity resources have come into Massachusetts since 1999,[17] including the Portland Natural Gas Transmission System, M&NE, the Hubline Project and increased LNG imports and vaporization capability by Distrigas.[18] However, the incremental supplies are not sufficient to meet the increased demand from new and existing customers, and new demand from gas-fired electric generation in Massachusetts and the other New England States (New England Natural Gas Infrastructure Docket No. PL04-01-000, Staff Report of FERC, December 2003; see also Bay State Comments at 12; KeySpan Reply Comments at 4; NSTAR Comments, Appendix A).[19] As a result of the tight capacity situation in New England, the basis differential[20] between the NYMEX and New England markets, and between the New

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[17] Since 2001, FERC has certified pipeline projects totaling 1,595,500 Mcf per day affecting New England (New England Natural Gas Infrastructure Docket No. PL04-01-000, Staff Report of FERC, December 2003 at 6, table 1). Of this amount, 570,000 Mcf per day of capacity was awaiting permits from the Army Corp of Engineers (id.).

[18] Distrigas has recently increased the vaporization capability at its terminal from 435 MMcf per day to a maximum of 1 Bcf per day (http://www.northeast.org/publications/mkt_update1004.pdf).

[19] According to Bay State, close to 10,000 MW of new gas-fired electric generation has been added to the New England electric grid in the last five years alone, and that the quantity of gas used to generate electricity in the region increased from 180 Bcf in 1999 to 340 Bcf in 2002 (Bay State Comments at 12-13). This represents an 88 percent increase in gas used electric generators between 1999 and 2002 (id.).

[20] Basis differentials are the difference between a NYMEX price and a market area price for deliveries occurring over the same period (Bay State Comments at 13, n.5). Basis differentials provide an indication of the difference between supply availability in the production area and in the market area, and are primarily affected by the availability of pipeline and other upstream resources needed to deliver supplies from the production

(continued…)

England market and the Chicago market area has remained high (Bay State Comments at 13; Figure 3).

The information provided in this proceeding indicates that there has not been an adequate increase in the number of alternative contract holders with firm rights to the interstate pipeline capacity serving Massachusetts. We encourage more marketers to become contract holders with firm rights. Until that time, we conclude that this precondition to a finding of a workably competitive upstream market has not been met. Having reached this conclusion, we will review other factors that may influence the existence of a competitive market, including the number of marketers.

3. Number of Marketers

Another condition for us to regard the upstream capacity market as workably competitive is that there be a number of marketers serving Massachusetts customers. D.T.E. 98-32-B at 27, 38. The average number of marketers serving Massachusetts customers decreased by about 13.6 percent between the winter of 2000-2001 and the summer of 2003 (LDCs 1-7).[21] Data on the number of years of operation for marketers in the Colonial, Essex, and Unitil service territories indicate that, over the past 4.5 years (i.e., October 1999 to April 2004), the median number of years of operation for spent by marketers in these service territories ranged from approximately 1.7 years in the Colonial service territory to

[20](...continued)
areas to market areas (id. at 13).

[21] The Department excluded from the calculation the information provided by New England on the number of marketers because of incomplete data (New England 1-7).

approximately 3.3 years in the Unitil service territory (LDCs 1-8).[22] The median number of years of operations for marketers in the other service territories ranged from approximately 2.3 years over a six-year period in the Boston Gas service territory to approximately 3.7 years over 11.5 years period in the NSTAR service territory (id.).[23] Generally, the marketers have not established a long-term presence in Massachusetts.

Based on the information provided by the LDCs on market-share, the Department observes that market concentration, as measured by the sales concentration ratio,[24] was high at the beginning of the 2000-2001 winter season in all service territories (LDCs 1-7).[25] Since then, the sales concentration ratio has decreased significantly in the service territories of four of the LDCs (id.). In the other LDCs' service territories, the sales concentration ratio

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22 The figures for Colonial and Essex covered the period May 2000 and April 2004 (LDCs 1-8).

23 The periods covered by the data were as follows: January 1996 to May 2004 for Bay State; November 1993 to May 2004 for Berkshire; January 1997 to April 2004 for Boston Gas; April 1996 to April 2004 for New England; January 1992 to November 2003 for NSTAR; and August 1999 to April 2004 for Unitil (LDCs 1-8).

24 The sales concentration ratio (denoted as "CR4") is defined as the sum of the four largest market shares in the market. It measures the total market share (in terms of sales volume) of the four largest marketers in each service territory. The CR4 varies between zero and 100 percent. A CR4 of zero means there is no sales concentration in the market. A CR4 of 100 percent means maximum sales concentration in the market. In general, a market with a CR4 of 70 percent is considered highly concentrated. The CR4 is one of several standard measures of the degree of sales concentration in a market. Modern Industrial Organization, Carlton, Dennis W. and Perloff, Jeffrey M., Second Edition, 1994.

25 The Department excluded from the calculation the information provided by New England because of incomplete data (Exhs. New England 1-5; New England IR-1-7).

increased (id.). Overall, there is a slight decrease in the level of market concentration in Massachusetts as a whole.

The above information indicates that the retail gas market in Massachusetts over the past four years has not experienced significant growth in terms of marketer participation. There is not significant decrease in sales concentration. In addition, the number of years that marketers remained in the market has declined. Therefore, the precondition of an increase in the number of marketers has not yet been met.

4. Number of Transportation Customers

Information provided by the commentators on the number of transportation customers and the percentage of the market that converted to transportation service indicates that, between the start of the 2000-2001 winter season and the summer of 2003, the number of transportation customers increased by approximately 1.9 percent[26] (or 63.9 percent excluding Bay State's transportation customers)[27] (Exh. LDCs 1-5). This increase in transportation customers represents less than two percent of all customers in Massachusetts (id.).[28] The data further indicate that the number of transportation customers who returned to sales service

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26 The Department excluded from the calculation the information provided by New England because of incomplete data (New England 1-5).

27 Bay State's Pioneer Valley Customer Choice Program started on November 1, 1996 and ended on November 1, 2002, when full customer choice was implemented. A large number of the residential transportation customers enrolled in the pilot program but returned to sales service when marketers exited the Massachusetts market. Bay State Gas Company, D.T.E. 02-75, at 11, n.10 (2004).

28 The percentages are higher in some service territories than others.

increased from 16,351 customers (or 229 excluding Bay State) in the winter of 2000-2001 to 33,535 (or 1,584 excluding Bay State) in the summer of 2003 (Exh. LDCs IR-1-6).[29] During this period, the rate of reverse migration[30] increased nearly seven-fold, from approximately three percent of all transportation customers in the winter of 2000-2001 to approximately 21 percent by the end of the summer of 2003 (id.).[31]

As of the summer of 2003, C&I customers represented over 99.5 percent of the total number of transportation customers in Massachusetts (Exh. LDCs 1-5). While the participation of residential customers in transportation service is negligible, the participation of small C&I customers has increased from approximately 30 percent of all transportation customers in the winter of 2000-2001 to 40 percent in the summer of 2003 (id.). Further, during the same period, the average consumption by transportation customers in Massachusetts has not changed dramatically, when adjusting for seasonality (id.).[32] The average transportation volume as a percentage of the LDCs' aggregate sendout increased by 3.8 percent between the winter of 2000-2001 and the summer of 2003.

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[29] Data were not available to determine how long a customer remained in transportation service before returning to the LDC.

[30] The reverse migration rate is calculated as the number of transportation customers who return to sales service as a percentage of the total number of transportation customers during any given period.

[31] The Department excluded from the calculation the information provided by NSTAR and New England on reverse migration because of incomplete data (Exh. NSTAR 1-6).

[32] Based on the information provided by LDCs, the Department computed the difference between the average usage of transportation customers for the period winter 2000-2001 and summer 2001 and the average usage transportation customers for the period winter 2002-2003 and summer 2003.

In conclusion, the Department finds that customer participation in retail choice in Massachusetts is stagnant, and likely declining. Although the C&I market has experienced a slight increase in the number of customers moving to transportation service since 1999, transportation customers represent less than two percent of all customers in Massachusetts. In addition, a significant percentage of transportation customers have returned to the LDCs. Retail competition in the residential market is virtually nonexistent.

5. Conclusion

Based on our review of the information before us, the Department concludes that the upstream capacity market for Massachusetts is not yet workably competitive as envisioned by D.T.E. 98-32-B: FERC continues imposition of price controls in the upstream capacity market; the number of active marketers has not increased significantly and there has been a fair amount of turnover among marketers that did enter the market; and, there has been no significant increase in transportation volumes since 1999. Further, unlike New York, Massachusetts is capacity-constrained. Therefore, we will not modify the Department's mandatory capacity assignment policy. For the same reasons as enunciated in D.T.E. 98-32-B, the Department directs the LDCs to continue to plan for and procure upstream pipeline capacity to serve firm customers.

Therefore, the Department will not convert to voluntary capacity assignment or gradually introduce voluntary capacity at this time. We will continue to monitor the market as well as developments at FERC and initiate a proceeding into capacity assignment as conditions warrant.

Having concluded that the mandatory assignment method for assigning capacity should not change, we will now turn to whether competition may be enhanced by streamlining the capacity assignment process. We first examine the marketers' request that we convert from a slice-of-system approach to a path approach for assigning capacity.

IV. METHOD OF CAPACITY ASSIGNMENT: SLICE VERSUS PATH

A. Position of the Commenters

The marketers request that the Department reconsider its decision in D.T.E. 98-32-B to adopt a slice-of-system method of capacity assignment rather than a path approach (Direct Energy Reply at 2, 7; Energy East Comments at 1; Energy East Reply at 6-9; Hess Comments at 6-7; Hess Reply at 2; Select Comments at 3). Several marketers assert that the slice-of-system approach is a substantial barrier to competition in Massachusetts (Direct Energy Reply at 5-7; Energy East Comments at 3-6; Hess Reply at 2). The marketers state that the assignment of capacity on a pro rata basis leaves them with a portfolio of fragmented capacity contracts that increases (1) administrative burdens; (2) the risk of error in nominating; and (3) the average capacity costs for marketers (Direct Energy Reply at 8; Energy East Comments at 3-7; Hess Comments at 3-7; Select Energy Comments at 2-3). The marketers contend that under certain contracts, capacity volumes assigned to them are smaller than the minimum gas nomination levels, and since the marketers must pay for such effectively inaccessible capacity, they face higher average capacity costs than the LDCs (id.).

Recognizing the Department's long-standing concern about cost inequities, Energy East and Hess recommend that, in adopting a path-based capacity-assignment approach, the

Department should order that marketers be charged or credited for the difference between the cost of capacity along the capacity path assigned to them and the average cost of an LDC's upstream capacity, as they state is done in Rhode Island (Energy East Comments at 6-8; Hess Comments at 6-7). In addition, Hess suggests that paths should be determined and released annually so as to prevent early market entrants from receiving the most advantageous capacity paths (Hess Comments at 6-7). In its Reply Comments, Direct Energy expresses full support for the proposals made by Energy East and Hess, stating that a path approach with a credit/surcharge mechanism can be implemented in such a way as to meet the Department's goal of a capacity-allocation system that eliminates cost inequities and cost shifting (Direct Energy Reply at 7, 10-11). Direct Energy also expresses its support for Hess's proposal for annual release of capacity paths so that marketers are given an equal opportunity to claim the paths they desire (id. at 11).

Hess urges the Department to hold technical sessions similar to those held for the electric industry to discuss proposals to improve the existing programs and to enhance the competitive natural gas market in Massachusetts (Hess Comments at 23-24). Energy East echoes Hess's call for a technical session, asserting that (1) the Department was mistaken in its belief that a slice-of-system method to capacity assignment would necessarily result in shifting of costs among suppliers and consumers they serve; and (2) the capacity fragmentation problem can be remedied easily and quickly by developing a credit/surcharge method to be implemented in concert with a path-based capacity assignment policy (Energy East Reply at 8-10).

Unitil acknowledges that capacity fragmentation under the slice-of-system method can render some capacity effectively valueless when the capacity block assigned is too small for nomination (Unitil Comments at 4). Unitil proposes that the Department modify the slice-of-system method so that capacity can be assigned to marketers in larger, more useful block sizes, which Unitil asserts can be done in such a way that the cost of assigned capacity will "equal or nearly equal" the capacity cost under a literal slice-of-system method (id.). Unitil also raises concern that a path-based system could hamper an LDC's access to storage if a marketer takes pipeline capacity along a particular path without taking a pro rata share of storage capacity along the same path (Exh. Unitil 2-2). Unitil requests that, should the Department proceed with a path approach, LDCs be permitted to refuse a marketer's long-haul capacity path choice unless the marketer agrees to take and fill a pro rata share of storage capacity (id.)

Bay State does not oppose a path approach similar to that proposed by Energy East and Hess (Bay State Reply at 6). Bay State notes, however, that there are commodity cost differentials as well as fixed (capacity) cost differentials among paths, and these commodity costs would have to be mitigated similarly to the fixed cost differentials to prevent subsidies (id.). According to Bay State, if the commodity price differentials associated with various paths are not included in the capacity assigned under a path assignment approach, firm customers would end up subsidizing competitive services, and transportation customers would not see the true cost or value of their service (id.). Bay State also argues that the credit/surcharge mechanism that must be developed in order to switch to a path-based capacity assignment approach would need to be fair to remaining sales customers and must comply with FERC capacity release rules (Exh. Bay State 2-2). Bay State indicates that various provisions of the LDCs' terms and conditions would need to be developed before a path-based system could be implemented and suggests that the Department allow at least six to eight months following a decision to move to a path-based standard before the new standard would take effect (id.). Finally, Bay State suggests that any path system that might be developed would have to include a process for resolving disputes over the economic value of paths (Bay State Reply at 7).

In response to Bay State's concern about path-related commodity cost differentials, Direct Energy argues that the current system is already complex, and complexity should not be a reason to reject the path approach (Exh. Direct Energy 2-1). Moreover, Direct Energy states that a credit and surcharge mechanism could involve establishing an initial price estimate associated with any particular path, and a true-up mechanism to adjust the cost of each available path so that the net cost of any particular path is equal to the utility's weighted average system cost (id.). Direct Energy contends that the industry is capable of developing an equitable path system that is superior to the current slice-of-system method (id.). Hess and Select agree that a path system can be developed so that cost differentials are negligible and adds that the mechanics of such a system can be developed in a technical sessional (Exh. Hess/Select 2-1). Energy East asserts that if the paths and the credit/surcharge mechanism are properly developed, shifting to a path-based capacity-assignment standard will simplify gas-supply operations, which can reduce scheduling errors and gas-supply costs, thereby encouraging expansion of customer choice in Massachusetts (Exh. Energy East IR-2-2).

The remaining LDCs reject the marketers' path proposal. KeySpan argues that the current slice-of-system method represents a fair allocation scheme among marketers and, despite the marketers' concerns about the administrative burdens of managing the portfolios assigned to them, the diversity of the portfolios protects their customers' reliability of service (KeySpan Reply at 10). KeySpan asserts that path assignment can impair system reliability because if gas transmission service along a marketer's path is curtailed for any reason, the marketer would not be able to meet its delivery obligations (Exh. KeySpan 2-2). KeySpan also states that the marketers have provided insufficient reasons to reconsider the slice-of-system method, adding that KeySpan already has gone to great lengths and investment to address the administrative concerns marketers have raised regarding the management of upstream capacity contracts and that these efforts are examples of ways in which LDCs have sought to refine the existing policy, which provides the most protections to customers (KeySpan Reply at 13-15). Furthermore, KeySpan echoes Bay State's claim that commodity prices can vary significantly among paths and that these differentials would have to be addressed in a switch to a path-based capacity assignment system to eliminate cost shifting between customers (Exh. KeySpan 2-1).

New England states that it is willing to work with marketers to streamline the capacity assignment process but that the path approach suggested by the marketers was designed to work within the regulatory framework of other states and may not be appropriate for Massachusetts (New England Reply at 2). New England cautions the Department that if capacity were assigned along paths without regard for commodity costs, then cost shifting to firm customers could be substantial. Cost differences along paths can be modest, however, if commodity costs are included in the path assignment analysis (Exh. New England 2-1).

Berkshire contends that conditions in the marketplace have not changed sufficiently to warrant a change in the Department's capacity-assignment policy (Berkshire Reply at 1). Further, Berkshire asserts that while a path-based capacity assignment approach might "artificially" enhance prospects for marketers, it would also enable marketers to avoid assuming their share of existing capacity commitment (id. at 4, citing D.T.E. 98-32-B at 34). According to Berkshire, the Department should maintain its current capacity-assignment policy and reassess the market in three to five years, as any change in policy now would expose customers to substantial risk in terms of service reliability and cost subsidization (id. at 2, 5). On the other hand, Berkshire argues that if the Department moves to a path-based capacity standard, commodity cost differentials must be factored in with fixed cost differences in order to prevent cost inequities (Exh. Berkshire 2-1).

NSTAR indicates that it is willing to work with the Department and commenters in this proceeding to examine ways to reduce administrative burdens on the marketers, however, NSTAR argues that many of these burdens can be mitigated without the need to implement changes to the Terms and Conditions, as would be required in order to adopt a path approach (NSTAR Reply at 13). Specifically, NSTAR claims that it has made progress towards reducing the number of small contracts in its portfolio that could result in the sort of fragmented capacity that the marketers seek to prevent, and NSTAR suggests, on the basis of recent data, that Energy East and Hess have both unrealistically overstated the extent to which small blocks of fragmented capacity are assigned (id. at 13-14).

Both KeySpan and NSTAR caution the Department against adopting the path approach as used in Rhode Island, arguing that in Rhode Island, only large and mid-sized C&I customers are permitted to take transportation service, whereas in Massachusetts, transportation service is available to all ratepayers (KeySpan Reply at 14-15; NSTAR Reply at 14). Both KeySpan and NSTAR agree that implementing path-based capacity assignment in Massachusetts would be more complex than in Rhode Island (id.).

NSTAR also contends that the path approach is risky because it reduces the diversity of supply for marketers and LDCs alike (Exh. NSTAR 2-2). NSTAR adds that because of the price differentials along discrete paths, a shift to the path approach must include a calculated true-up of commodity costs in addition to the true-up of fixed gas costs to prevent unfair cost shifting (Exh. NSTAR 2-1). NSTAR, like Unitil, also argues that any decision to address capacity assignment must also address the allocation of storage capacity, as well as peaking and company-managed supplies, all of which have both fixed and variable cost components that must be considered to avoid cost inequities (Exh. NSTAR 2-2). Like Bay State, NSTAR requests that if the Department decides to switch to the path approach, sufficient time be permitted for NSTAR to develop a comprehensive proposal that addresses the application of the path standard to its supply portfolio (id.)

Blackstone indicates that it would bear no impact from a change from slice-of-system to path-assignment of capacity because the company has only one transportation contract and under the terms of Tennessee's tariff, Blackstone cannot assign or release any portion of its Tennessee Pipeline capacity (Exh. Blackstone 2-1).

B. Analysis and Findings

In D.T.E. 98-32-B at 34, the Department stated that the mandatory slice-of-system method allocates capacity costs to all customers on an equitable basis.[33] The Department concluded that mandatory slice-of-system method to capacity assignment was the appropriate regulatory framework to a transitional market because it enabled converting customers to gain access to capacity, while maintaining reliability and avoiding improper transfer of cost responsibility. Id. at 35. Finally, the Department also expressed its expectation that LDCs and marketers will work cooperatively concerning the status of existing and future capacity contracts and their renewal and termination. Id. at 34.

In this proceeding, marketers argue that the slice-of-system method forces them to receive certain capacity contracts that, due to the small size of the assignment, increase administrative burdens, the risk of error in nominating, and the average capacity costs for marketers. Therefore, marketers argue, a path approach to capacity assignment is a more efficient allocation method.

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33 Specifically, the Department stated that, "under the 'slice-of-system' method customers receive their pro rata share of each capacity contract. As a result, migrating and remaining customers assume identical capacity costs. Under the 'path' approach, customers migrating to transportation early will have the opportunity to select the least expensive capacity, while customers who select to remain with the LDC's bundled service will be burdened with the less desirable and more expensive capacity." D.T.E. 98-32-B at 34, n.19.

To determine whether a path approach to capacity assignment is a feasible option, we will examine several factors. First, we will review the upstream pipeline capacity flowing into Massachusetts. Second, we will review the regulatory environment in which the LDCs operate in Massachusetts. Third, we will review the development and administration required in adopting a path approach.

With respect to upstream capacity, Massachusetts is at the end of several pipelines. In most instances, one pipeline does not have adequate capacity to satisfy the needs of every LDC. Massachusetts LDCs have, as a result of FERC Order 636, been assigned capacity contracts of varying volumes on the pipelines that are used to serve them. Marketers contend that managing fractions of these smaller capacity contracts is inefficient and cumbersome. The Department notes that, since the issuance of D.T.E. 98-32-B, Massachusetts LDCs have submitted and have received approval for proposals to streamline their portfolios.[34] We expect that the concern regarding fractions of small contracts will be eventually obviated. That is, as LDCs streamline their portfolios, we anticipate that they will shed the smaller, less-efficient

[34] Since the issuance of our unbundling decision, Massachusetts LDCs have submitted to the Department and have received approval of plans to restructure their upstream capacity portfolios. See, e.g., Bay State Gas Company., D.T.E. 04-64 (2004); Bay State Gas Company, D.T.E. 03-37 (2003); NSTAR Co., D.T.E. 02-59 (2003); Fitchburg Gas & Electric, D.T.E. 02-55 (2003); KeySpan Energy Delivery New England, D.T.E. 02-54 (2002). Pursuant to Department directives, LDCs are required to notify all active marketers of these portfolio changes prior to making a decision to renew an expiring capacity contract. D.T.E. 98-32-B at 41. However, marketers generally do not participate in these proceedings. We encourage marketers to consider participating in future such proceedings.

capacity contracts, thereby eliminating the marketers' concern regarding slices of small capacity paths.

With respect to the regulatory environment under which LDCs operate, we note that the LDCs are required to have a diversified resource portfolio. Commonwealth Gas Company, D.P.U. 94-174-A at 28-29 (1996). As a result, and to the extent possible, Massachusetts LDCs must acquire commodity and interstate capacity from varying sources. Assigning capacity using a path approach has the potential to leave LDCs with capacity that limits their supply options in violation of regulatory requirements.[35] A marketer's selection of a specific capacity path would not only limit an LDC's access to certain resources, as discussed by Unitil, but could potentially impair system reliability.

With respect to the development and adoption of a path approach, marketers argue that a cost allocation formula can be developed to prevent cross-subsidization. We have reviewed the marketers' proposal, including the annual "re-assignment" of capacity, as well as the proposal for marketers to pay the average cost of capacity. Although the marketers' proposal addresses the cost effect with regard to the allocation of capacity costs to all customers, it does not properly address the "commodity cost differentials" issue raised by Bay State, nor the increase in LDC administrative costs to monitor such a program. We agree with Bay State that at certain delivery points, commodity is priced higher than at others. If marketers are allowed to select the paths where commodity is traded at a lower level, LDCs and newer entrants may

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[35] Diversity of supplies is one of the criteria used to evaluate LDC acquisition of both commodity and capacity resources. D.P.U. 94-174-A at 29 (1996).

be left to assume the higher commodity cost paths. Marketers have offered a vague proposal to address the commodity cost differential issue. However, any proposal to resolve the commodity cost differential, even if it properly addresses the issue, raises yet another issue - that of additional administrative burdens on LDCs. We note that marketers have been silent on the matter of administrative costs. However, we expect that any proposals that require “reconciliation” of costs will increase administrative and processing costs. We conclude that these costs will eventually be borne by the ratepayers. The path approach to capacity assignment will increase administrative costs and raise cross-subsidization concerns, as suggested by the majority of the LDCs. In D.T.E. 98-32-B at 34, the Department stated that competition using a slice-of-system method constitutes a fair market regime for all, and will allocate capacity costs to all customers on an equitable basis. Such competition should be based on the underlying capabilities of the marketers, not on perhaps short-lived circumstances. The Department continues to believe that the slice-of-system method constitutes a fair market regime which allocates all costs on an equitable basis.

Finally, commenters have argued that Massachusetts should follow or emulate other jurisdictions where the path approach is being applied. Although we believe that such suggestions are well intended, there is nothing on the record to indicate that because an approach has been successful in a certain jurisdiction it will be successful in Massachusetts as well. Differences in geography[36] and geology[37] render comparisons between jurisdictions unreliable. In response to the recommendation that Massachusetts emulate Rhode Island's approach, we agree with NSTAR and KeySpan that, since the natural gas unbundling in the neighboring state does not encompass all customer classes, such recommendation would not necessarily be applicable to Massachusetts.

In closing, we note that most of the LDCs have suggested that they are either already working with marketers or are willing to work with marketers in an effort to reduce the administrative burdens associated with managing small, segmented capacity portfolios under the slice-of-system method. We encourage the LDCs to continue to work towards this goal. Similarly, we recognize the continuing efforts of the LDCs to streamline their upstream pipeline and storage portfolios. We encourage the marketers to participate in this process, which we believe will eventually eliminate the small contracts. We are concerned that the path approach as proposed by the marketers may lead to reliability issues. In particular, the path approach would limit the LDCs' access to diverse resources when marketers choose capacity. Finally, the path approach would disadvantage late comers because all the desirable paths would be taken. For this reason and all reasons stated above, we find that the slice-of-system

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36 Massachusetts is at the end of the pipeline. Therefore, as a natural gas market, it is more susceptible to pipeline problems upstream of the Massachusetts delivery points.

37 Similarly, Massachusetts' lack of underground storage facilities minimizes any flexibility for nominations during the peak months.

method continues to be the most appropriate method for assigning capacity in Massachusetts.[38] We will now examine issues other than mandatory, slice-of-system capacity assignment raised during this proceeding.

V. OTHER ISSUES

A. Monthly Recall and Release Process

1. Position of the Commenters

Hess recommends that the Department eliminate the practice of some LDCs of recalling and re-releasing all assigned capacity every month (Hess Comments at 7-8). Hess contends that with monthly release, marketers are unable to maximize the value of capacity and that the capacity assigned to marketers is worth less than capacity held by LDCs (id. at 7). Hess suggests that the Department adopt the New York method for releases, whereby LDCs calculate and release baseload levels of capacity associated with the marketers' annual load requirements and only execute monthly recalls and re-releases of incremental levels of capacity (id. at 8). The LDC and marketer would only have to agree on the baseload level (id. at 7- 8). Hess argues that this method would improve efficiencies for LDCs and marketers and would give marketers a closer approximation of the value of the capacity held by LDCs, and customers would benefit because prices would reflect this value (id. at 8).

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38 The Department also concurs with Bay State that any credit/surcharge mechanism to address the capacity cost differential should be in compliance with FERC rules regarding capacity release. However, since the Department will not adopt a path method, we will not elaborate further on this point.

Direct Energy agrees with Hess on the problems created by the current monthly release process (Direct Energy Reply at 13). Direct Energy suggests eliminating the LDCs' practice of recalling and re-releasing all assigned capacity every month and adopting a modified version of the New York method (id. at 14). Direct Energy proposes using annual baseload releases, but LDCs would release between 70-80 percent of the marketer's capacity based on the marketer's current customer base (id.). Direct Energy states that a 70-80 percent annual release, rather than 100 percent, would provide additional flexibility to both the marketers and the LDCs to address normal monthly fluctuations in the number of customers served (id.). According to Direct Energy, LDCs would maintain their right to recall any or all of a marketer's assigned capacity in the event a marketer is declared ineligible to nominate gas for thirty days or is disqualified from service for a year (id.). Also, LDCs would maintain their right to recall permanently any or all of the marketers' capacity if the marketer fails to meet its responsibilities (id., citing D.T.E. 98-32-D (2000), Model Terms and Conditions, § 13.7.7).

Three LDCs addressed this issue. KeySpan indicates that it does not release and recall capacity on a monthly basis (KeySpan Reply at 16). Rather, it releases capacity to marketers through the termination date of each contract as required by § 13.5.2 of its terms and conditions (id.).

As one of the two LDCs that releases capacity on a monthly basis, Bay State is not opposed to Hess' proposal and is willing to study the New York method of releases (Bay State Reply at 8). Bay State suggests that the New York method would increase the number of contracts assigned to marketers (id.). Bay State further indicates that Hess previously opposed increasing the number of contracts when Hess advocated for a change to capacity assigned by path (id.).

NSTAR acknowledges that § 13.5 of the Model Terms and Conditions indicates that releases may be for longer than a one-month period (Exh. NSTAR 2-6; NSTAR Reply at 15). NSTAR states that it releases capacity on a monthly basis in order to minimize the financial risk for customers due to marketer credit implications (NSTAR Reply at 15). NSTAR asserts that a policy of longer-term capacity release increases the risk for customers in the event of marketer non-payment, insolvency, or bankruptcy (id.).

2. Analysis and Findings

The LDCs' terms and conditions with respect to this issue are clear and unambiguous. Section 13.5.2 states that capacity will be released "for a term . . . through the expiration date of the respective capacity contract being assigned." Currently, not all of the LDCs are releasing capacity in the manner directed by their terms and conditions (Bay State Reply at 8; NSTAR Reply at 15). We expect each and every LDC to comply with the Department-approved Terms and Conditions.

The Department is very concerned that some LDCs are varying the operating practice spelled out by their terms and conditions. We encourage interested entities to bring LDC practices that vary from the approved terms and conditions to our attention. The Department directs LDCs to follow the terms and conditions unless they seek and obtain Department approval to do otherwise.

B. Non-Daily Metered Algorithms

1. Position of the Commenters

The marketers request changes to § 12.3 of the LDCs' terms and conditions regarding non-daily metered customers. The first requested change to § 12.3 would require the LDCs to provide algorithms to marketers to replicate the process and results that the LDCs use to develop daily delivery requirements for non-daily metered customers (Direct Energy Reply at 15; Energy East Comments at 12). The marketers state that the terms and conditions, as presently written, do not require LDCs to provide actual consumption algorithms used to determine the Adjusted Target Volume ("ATV") (Exhs. Direct Energy 3-1; Energy East 3-1). The marketers contend that LDCs only provide the forecasted ATV generated by algorithms, but do not provide the baseload and temperature-sensitive components of the algorithms, creating difficulties for marketers to tailor supply to the customer's load requirements (Energy East Comments at 12; Direct Energy Reply at 15-16). The marketers argue that they need accurate, adequate, and timely information to stay within the tolerances and avoid the penalties (Exh. Energy East 3-1).

The requested change to § 12.3 requires the LDCs to modify the temperature-sensitive algorithms whenever the temperature-sensitive usage does not occur. The marketers contend that this modification will eliminate a source of unnecessary discrepancy between nominated and actual volumes (Direct Energy Reply at 15; Energy East Comments at 12).

With respect to access to the consumption algorithms, most LDCs assert that the Model Terms and Conditions do not explicitly require LDCs to provide algorithms to marketers, but only require the LDCs to provide forecasted ATVs[39] (Exhs. Berkshire IR-3-1; KeySpan IR-3-1; NSTAR 3-1;). However, most LDCs are willing to provide consumption algorithms upon request (Exhs. Berkshire 3-1; New England 3-1; NSTAR 3-1; Unitil 3-1).[40] Furthermore, several LDCs state that they provide electronic data[41] to marketers upon request (Exh. Bay State 3-1; KeySpan Reply at 17).

NSTAR asserts that it would not be opposed to amending its terms and conditions requiring it to provide algorithms, but it would prefer that any such amendment only require that algorithms be provided upon request (Exh. NSTAR 3-1). In addition, some LDCs contend that it is not necessary to amend the terms and conditions to provide that information (Exhs. Berkshire 3-1; New England 3-1).

With respect to the revision of the consumption algorithms, LDCs provided the percentage difference between forecasted and actual peak and off-peak usage for the period 2001 through 2004. The difference varies between 6.7 percent and 19 percent for Bay State,

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39 Section 12.3.2 of the terms and conditions mandates the LDCs to provide the ATV for each marketer's Aggregation Pool of customers taking non-daily metered service (Exh. Berkshire 3-1).

40 Because the use of these algorithms is specific to a particular customer's usage, the Company only provides it upon a specific request from a marketer provided that the request is for the marketer's customer (Exh. New England 3-1).

41 Data includes the customer's name, account number, rate classification, baseload volume, heating factor, capacity assignment volume, receipt point, billing cycle, original transportation data and start date with current marketers, and whether the customer is daily or non-daily metered (KeySpan Reply at 17). Bay State indicates that it posts data on customer-level baseload and heating increments on a daily basis on its website (Exh. Bay State 3-1).

-.33 percent and 7.73 percent for Berkshire, -1.69 percent and 7.04 percent for KeySpan, 2 percent and 24 percent for New England Gas, -3.44 percent and .86 percent for NSTAR, and -24 percent and 26 percent for Unitil (Exhs. Bay State 4-1; Berkshire 4-1; KeySpan IR-4-1; New England 4-1; NSTAR 4-1; Unitil 4-1).

Some LDCs suggest various approaches to improve the algorithms' accuracy, including: (1) assessing the supplier's Aggregation Pool load profile for functionality (Exh. Berkshire 3-2); (2) communicating with account representatives to report any substantial increase or departure from historical usage from which the ATVs are derived (id.); and (3) introducing an adjustment factor in the daily ATV calculation for any marketer's pool where the true-up was outside a specified percentage bandwidth (Exh. New England 3-2).

On the other hand, NSTAR claims that its consumption algorithms are already very accurate and therefore, NSTAR disagrees with the marketers' premise (Exh. NSTAR 3-2). Further, Unitil states that the Company has not received any complaint from marketers suggesting that the algorithms have been inaccurate (Exh. Unitil 3-2). KeySpan is willing to undertake a review of its algorithms to determine if changes are necessary (KeySpan Reply at 18).

2. Analysis and Findings

The Department finds that access to the LDCs' algorithms will enable the marketers to gain a better understanding of how the ATVs are determined, which, in turn, will allow marketers to better manage their supply portfolios. Therefore, we direct the LDCs to amend their terms and conditions so that the algorithms are made available to marketers upon request and to submit such amended terms and conditions to the Department for approval.

With respect to the revision of the current algorithms for non-daily metered customers, the record indicates that presently, the current algorithms do not accurately portray actual consumption (Exhs. Bay State 4-1; Berkshire 4-1; KeySpan 4-1; New England IR-4-1; NSTAR 4-1; Unitil 4-1). The differences vary between 6.7 percent and 19 percent for Bay State, -3.33 percent and 7.73 percent for Berkshire, -1.69 percent and 7.04 percent for KeySpan, 2 percent and 24 percent for New England, -3.44 percent and .86 percent for NSTAR, and -24 percent and 26 percent for Unitil. Such variances are so great as to cause over- and under-deliveries of gas and should be corrected to the extent possible. Therefore, the Department directs the LDCs and marketers to work together to design an approach to adjust the weather-sensitive consumption algorithms to minimize imbalances and make the algorithms more accurate. The LDCs and marketers must report back to the Department on their effort, jointly, within six months of the issuance of this Order.

C. Monthly True-ups for Non-Daily Metered Customers

1. Position of the Commenters

Currently, true-ups to account for differences in forecast versus billed usage for non-daily metered customers are performed, pursuant to § 12.6 of the terms and conditions, only once or twice per year. Direct Energy suggests that the terms and conditions be modified to require that true-ups be undertaken monthly (Direct Energy Reply at 16). Direct Energy argues that requiring monthly true-ups will encourage more accurate forecasting by the LDCs and, in turn will result in lower costs for all participants (id.). Direct Energy, Energy East, Hess, and Select also favor monthly true-ups (Exhs. Direct Energy IR-3-2; Energy East IR-3-2; and Hess/Select 3-2;).

NSTAR responds to Direct Energy's argument for monthly true-ups by stating that since 2001, it has had no variance greater than one percent (NSTAR Reply at 17). NSTAR indicates that its most recent cash-out was within 0.4 percent (id.). Thus, it argues that it has no need to perform monthly true-ups (id.).

Berkshire, KeySpan, and New England oppose monthly adjustments and say monthly adjustments are not necessarily more accurate than annual true-ups (Exhs. Berkshire 3-2; KeySpan 3-2; New England 3-2). Berkshire and Keyspan contend that monthly adjustments would be administratively difficult because of the mismatch between calendar months and billing periods (Exhs. Berkshire 3-2; KeySpan 3-2). Bay State indicates it will be using data on a calendar-month basis by mid-2005 (Exh. Bay State 3-2). KeySpan suggests that customers should choose daily-metered service if they want monthly adjustments (Exh. KeySpan IR-3-2).

2. Analysis and Findings

While NSTAR's cash-out variances are small and do not cause concern, some of the other LDCs have larger variances for the period from May 2001 through April 2004. For example, the variances for Bay State range from 1.9 percent to 23.4 percent, for Fall River from two to 24 percent, and for Unitil range from -19 percent to 35 percent (Exhs. Bay State 4-1; Fall River 4-1; Unitil 4-1). The magnitude of these numbers indicates that there may be a problem with the algorithms or how the LDCs formulate their forecasts. While the LDCs express their theoretical support for accurate estimates, the variances for cash-outs indicate that the algorithms are not always providing accurate forecasts for non-daily metered customers. The Department is concerned about larger variances and instructs the LDCs to work with the marketers toward a goal of keeping the variances within five percent. The Department directs the LDCs to submit the data on variances to the Department as part of each Cost of Gas Adjustment Clause filing. We expect that access to the algorithms by the marketers as discussed in § V.B.1 will improve the variances. If we find that the variances are not within five percent, we will consider directing the LDCs to implement monthly true-ups.

D. Operational Flow Order Imbalance Penalties[42]

1. Position of Commenters

Hess argues that the operational flow order ("OFO") imbalance penalties, which are currently set at five times the Gas Daily index price for imbalances exceeding a two percent tolerance, are excessive and should be revised (Hess Comments at 8-9). Hess claims that the current penalty level was established at a time when commodity prices were fairly stable on a day-to-day basis and did not deviate significantly from prices that prevailed during non-OFO periods (id.). In addition, the penalty level, at the time it was established, approximated the

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[42] An OFO is issued by an LDC pursuant to § 19.2 of its Terms & Conditions because circumstances exist that constitute a threat to the operational integrity of the LDC's system. Such circumstances include, but are not limited to: (1) a failure of an LDC's distribution, storage, or production facilities; (2) the near-maximum utilization of an LDC's distribution, storage, production, and supply resources; (3) an inability to fulfill firm service obligations; and (4) the issuance of an OFO or similar notice by upstream transporters (KeySpan Reply Comments at 16, n.8).

level of penalty of $15 per dekatherm stipulated in the pipeline tariffs (id.). According to Hess, with recent gas prices routinely reaching the $15 to $25 per dekatherm level during OFO periods, and sometimes reaching as high as $75 per dekatherm, the current penalties are excessive and overly punitive (id. at 9). Hess suggests reducing the penalties to two times the Gas Daily index price (id.). Hess and Select claim that a lower penalty will decrease the price that customers pay for gas (Exh. Select IR-2-8).

Unitil agrees with Hess and Select that reducing the OFO imbalance penalty level to two times the cost of gas is an adequate economic incentive for marketers to remain in balance during times of OFO, as proposed by Hess and Select (Exh. Unitil 2-8). Unitil has proposed that the Department add a provision to the LDCs' Terms and Conditions to make the OFO imbalance penalty level the higher of either two times the cost of gas or the OFO imbalance penalty assessed by the interstate pipeline (Exh. Unitil IR-2-8).

Bay State, KeySpan, New England, and NSTAR disagree with Hess' proposal to reduce the OFO imbalance penalty level to two times the Gas Daily index (Exhs. KeySpan IR-2-8; New England 2-8; Bay State Reply at 8-9; KeySpan Reply at 16-17). KeySpan claims that the penalties were established purposely to ensure that marketers do not under-deliver gas during OFO periods (Exh. KeySpan 2-8; KeySpan Reply at 16-17). According to KeySpan, the fact that marketers under-delivered gas during the January 2004 cold snap underscores the need for the penalties to be increased, not decreased, to serve as a deterrent to marketers (Keyspan Reply at 16-17.). KeySpan argues that in the interest of effective economic disincentive, the penalties must move in parallel with market prices (id.).

Bay State, New England, and NSTAR similarly argue that the penalty structure is an important component of ensuring system reliability during OFO periods, when reliability is most critical (Exhs. Bay State Reply at 8-9; New England 2-8; NSTAR 2-8). According to New England, the OFO imbalance penalty level must exceed the daily and intra-day gas prices if it is to deter marketers from selling gas elsewhere during OFO periods when prices are high (Exh. NSTAR 2-8). In addition, the penalties should be sufficiently high as to cover the OFO imbalance penalties that pipelines charge the LDCs, but not so high as to affect retail competition in Massachusetts (Exh. NSTAR 2-8). New England has suggested that the OFO imbalance penalty could be set at twice the greater of (1) the gas daily price and (2) the highest price paid for gas by the LDC for the day, including any pipeline penalty paid by the LDC, plus the highest pipeline penalty the LDC could have been charged for the day (Exh. New England 2-8). Finally, Bay State contends that because such operational issues are beyond the scope of this proceeding, they should be addressed by the Commenters informally, rather than in the instant proceeding (id.).

2. Analysis and Findings

Maintaining system integrity and reliability is a primary concern of the Department, and is especially critical during the heating season. The Department notes that in a situation where multiple parties are responsible for delivering supplies to LDC citygates on behalf of customers, system integrity and safety could be compromised if a marketer fails to deliver gas to meet its daily requirements. The responsibility to deliver enough gas to maintain system reliability in such a case falls on the LDC. During OFO periods, LDCs rely on all resources available to them, including both upstream as well as local production and storage. These resources, and especially the local facilities, typically operate at maximum capacity during such periods. Under-deliveries by marketers during OFO periods clearly put local distribution systems at peril, because, as suppliers of last resort, the LDCs must acquire sufficient gas commodity supplies to meet firm sendout requirements. System integrity is put at particular risk during OFO periods, when reliability is critical and greater potential exists for market indices to fluctuate significantly (Exh. Bay State 2-8). The Department agrees with the LDCs that the OFO imbalance penalty level is an important component in ensuring system integrity and reliability. The penalty level must be sufficient, without being overly punitive, to serve as an effective incentive for marketers to meet transportation load during OFO periods.

According to Hess, the imbalance penalty provisions were set at a time when gas prices were fairly stable, and approximated the level of penalties in the pipeline tariffs. In approving the LDCs' Terms and Conditions, the Department defined the current OFO imbalance penalty level as a multiple of the market price of gas. By doing so, the Department created an economic incentive for marketers to meet load requirements during OFO periods, that changes as gas prices vary. It was not the Department's intent to establish a penalty ceiling. Therefore, the Department will retain the present level of the OFO imbalance penalty. Marketers can avoid the penalties by delivering gas to meet their daily requirements during OFO periods.

E. Synchronization of Nomination Deadlines and Procedures

1. Positions of the Commenters

Energy East requests that the Department correct the operational mismatch between industry standard practices for gas trades around holiday periods and the "patchwork" of holiday nomination schedules among the Massachusetts LDCs (Energy East Comments at 11). Energy East claims that the standard schedule reflected in the dates used by the Intercontinental Exchange[43] (http://www.theice.com) addresses both US and Canadian holidays and sets the dates for various products traded (e.g., US Next Day, Canadian Next Day, etc.) (id.). According to Energy East, the International Exchange's schedule drives the procurement activities of marketers around holiday periods but is not aligned with the holiday nomination schedules of the Massachusetts LDCs (id.). Energy East states that this mismatch exposes marketers and consumers to increased risk of imbalances and cash-outs around each affected holiday, and should be corrected (id.). Energy East recommends that the Department modify the Terms and Conditions to synchronize the holiday nomination schedules of marketers and LDCs using current industry standards (id.).

KeySpan states that it recognizes the concerns raised by Energy East and that it currently follows the industry standard of requiring that nominations be made on the business day prior to the gas industry holiday (Exh. KeySpan 3-3; KeySpan Reply at 17). Accordingly, KeySpan does not think that the Terms and Conditions should be modified (Exh. KeySpan 3-3). Berkshire, on the other hand, states that it is not opposed to modifying

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43 The Interchange is a global electronic marketplace in energy, metals and emissions.

§ 11.3.3 and § 12.3.4 of the Terms and Conditions to improve the nomination practices (Exh. Berkshire 3-3). Bay State and Unitil also do not object to a synchronization of the nomination schedule over holiday periods consistent with current industry trading and scheduling practices (Exhs. Bay State 3-3; Unitil 3-3). Bay State, however, contends that because such operational issues are beyond the scope of this proceeding, they should be addressed by the Commenters informally, rather than in the instant proceeding (Bay State Reply at 8-9).

2. Analysis and Findings

The LDCs and marketers alike express a willingness to cooperatively pursue resolution of nomination scheduling conflicts (Exhs. Berkshire 3-3; KeySpan 3-3; Unitil 3-3; Hess Reply at 5; KeySpan Reply at 17; see also Bay State Reply at 8-9). Therefore, the Department encourages the LDCs and the marketers to initiate such a process and report on their progress to the Department within six months of the date of this Order. Consequently, the Department finds that a modification of the Terms and Conditions at this time is not necessary.

VI. CONCLUSION

Based on our review of the information before us, the Department concludes that the upstream capacity market for Massachusetts is not yet workably competitive enough as envisioned by D.T.E. 98-32-B: FERC continues imposition of price controls in the upstream capacity market; the number of active marketers has not increased significantly and there has been a fair amount of turnover among marketers that did enter the market; and, there has been no significant increase in transportation volumes since 1999.[44] Further, Massachusetts remains capacity-constrained. Therefore, we will not modify the Department's mandatory, slice-of-system, capacity assignment policy. For the same reasons as enunciated in D.T.E. 98-32-B, the Department directs the LDCs to continue to plan for and procure upstream pipeline capacity to serve firm customers.

The Department remains committed to its longstanding goal to facilitate the transition of the natural gas market in Massachusetts from a regulated monopoly to competition wherever the market is capable of delivering enhanced benefits to the consumers in the form of broader choice, increased efficiency and lower cost. Our role is to put in place the structural conditions necessary for an efficient competitive process and remove, to the extent possible, all the barriers to such a process. The Department encourages all market participants to bring to our attention any impediments that may hamper the transition to a fully competitive gas market in Massachusetts. Our commitment is to give all proposals appropriate consideration.

Consistent with this commitment, we have reviewed the five impediments to the marketplace raised during this proceeding and we hereby direct the LDCs to improve performance or implement procedures, in accordance with our findings stated above, on the following matters: (1) the monthly recall and release of assigned capacity; (2) access to and

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44 The Department will continue to monitor the conditions in the natural gas market in Massachusetts. Consequently, the Department directs the Massachusetts LDCs to provide the information requested in the tables attached in Appendix A. This information should be delivered to the Director of the Department's Gas Division on May 31st, and November 30th of each year. The information should be provided in hard-copy and electronic format (Excel Spreadsheets).

modification of consumption algorithms; and (3) monthly true-ups of differences between forecast usage and billed usage. With respect to the operational concerns regarding the synchronization of nomination schedules and procedures, we direct the LDCs and marketers to resolve differences amongst themselves and report back to the Department within six months. With respect to the OFO penalty level, we reject the proposal of the marketers to reduce the imbalance penalty level. Further, we reject the Attorney General's proposal to expand the scope of this proceeding. Finally, all LDCs and marketers must comply with all other mandates of the Order.

By Order of the Department,

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Paul G. Afonso, Chairman

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James Connelly, Commissioner

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W. Robert Keating, Commissioner

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Judith F. Judson, Commissioner