126 FERC ¶ 61,180
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Acting Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

ISO New England Inc. and New England Power Pool	Docket Nos. ER08-41-003 and ER08-41-004

ORDER DENYING REHEARING AND ACCEPTING COMPLIANCE FILING

(Issued February 26, 2009)

1. On October 29, 2008, NSTAR Electric Company (NSTAR) and the Massachusetts Attorney General (Massachusetts AG) requested rehearing of the Commission's September 29, 2008 order in this proceeding.[1] In that order, the Commission accepted a compliance filing of the ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) (together, the Filing Parties), which revisited the methodologies for calculating tie benefits and allocating Hydro Québec (HQ) Interconnection Capability Credits.[2] Moreover, in that order the Commission directed a report on the timetable for a stakeholder process to consider modeling of internal transmission constraints and tie benefits associated with individual tie lines. We deny the request for rehearing and accept the compliance filing, as discussed below.

I. Background

2. As part of ISO-NE's Forward Capacity Market, in February 2008, ISO-NE conducted the first Forward Capacity Auction for the 2010-2011 Capability Year.[3] In support of this first auction, the Filing Parties submitted the proposed 2010-2011 Capability Year values for the Installed Capacity Requirement, Local Sourcing Requirement, and Maximum Capacity Limit, all of which are key inputs in the Forward

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[1] *ISO New England Inc.*, 124 FERC ¶ 61,298 (2008) (September 2008 Order).

[2] These credits are also referred to as HQICCs.

[3] The 2010/2011 Capability Year extends from June 1, 2010, to May 31, 2011.

Capacity Auction.[4] The Filing Parties also submitted the proposed value for the HQ Interconnection Capability Credits, which is a key input in the calculation of the Installed Capacity Requirement.[5]

3. In an order issued in December 2007, the Commission accepted the proposed values for the Installed Capacity Requirement, HQ Interconnection Capability Credits and related parameters for the 2010/2011 Capability year.[6] The December 2007 Order also advocated a stakeholder process to address the tie benefit methodology. Specifically, numerous parties had raised concerns over the inconsistencies in the tie benefit methodology. While the total New England tie benefit value, composed of New England's three directly interconnected neighboring Control Areas (i.e., Québec, New Brunswick, and New York), was calculated probabilistically, those tie benefits were allocated under a different methodology. HQ Interconnection Capability Credits were explicitly calculated using a "deterministic" methodology that employed forecasted load and capacity for the Québec control area and the HQ Interconnection transfer limit.[7] Importantly, the tie benefits for New Brunswick and New York were reduced to reflect the HQ Interconnection Capability Credits: after subtracting the HQ Interconnection Capability Credit value from the total tie benefits value, the remainder was reallocated proportionally in the same ratio as the tie benefits from the original probabilistic analysis

[4] The Installed Capacity Requirement is the amount of resources needed to meet the New England Control Area reliability requirements of disconnecting non-interruptible customers (i.e., the Loss of Load Expectation) no more than once every ten years. The Local Sourcing Requirement represents the minimum amount of capacity that must be electrically located within an import-constrained Load Zone. The Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone to meet the Installed Capacity Requirement.

[5] The use of the HQ Interconnection is governed, in part, by support agreements between the four entities that own it and various public utilities and non-jurisdictional utilities known as Interconnection Rights Holders. Under the support agreements, the Interconnection Rights Holders received capacity rights over the HQ Interconnection and agreed to pay, in return, their allocable share of the amortized costs of the HQ Interconnection. Each Interconnection Rights Holder has an entitlement percentage of the HQ Interconnection's nominal 2000 MW that corresponds to its financial support obligations.

[6] *ISO New England Inc.*, 121 FERC ¶ 61,250 (2007) (December 2007 Order).

[7] Market Rule 1 § III.12.9.2.

for New York and New Brunswick, resulting in reduced tie benefits from New York and New Brunswick. The December 2007 Order supported a stakeholder process and directed a July 2008 compliance filing to summarize the results of the stakeholder discussions and to outline any proposed changes to the current tie benefit methodology.

4. Various parties sought rehearing of the December 2007 Order, arguing *inter alia* that the Commission-requested stakeholder process should not mandate a change in the tie benefits methodology, that the Commission failed to address specific arguments, and that the tie benefits methodology was illegitimate. In May 2008, the Commission issued an order denying rehearing.[8]

5. On compliance, the Filing Parties provided the Commission with information relating to four proposals that arose from the stakeholder process. The September 2008 Order accepted the proposal advocated by the Filing Parties, namely, to revise the methodologies for allocation as follows. First, the tie benefit value for Québec would be established using the results of the probabilistic calculation of tie benefits with Québec rather than using a deterministic calculation methodology. Second, ISO-NE would continue using the existing probabilistic methodology and a multi-area reliability model for calculating total tie benefits from the Québec, New Brunswick, and New York control areas. Finally, New England's directly interconnected neighboring control areas would continue to be modeled using "at criteria" modeling assumptions.[9] The filing was accepted. Addressing issues raised during the stakeholder process, the Commission directed ISO-NE and NEPOOL to develop a timetable for a subsequent stakeholder process to study modeling of internal transmission constraints and tie benefits associated with individual lines and to develop proposals to resolve these issues.

6. ISO-NE and NEPOOL submitted this report on November 26, 2008, providing that they have agreed to a timetable for starting the stakeholder process early in the second quarter of 2009.[10] The Filing Parties state that they have agreed that "the

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[8] *ISO New England Inc.*, 123 FERC ¶ 61,129 (2008) (May 2008 Rehearing Order).

[9] September 2008 Order, 124 FERC ¶ 61,298 at P 7.

[10] *ISO New England Inc.*, Compliance Report, Docket No. ER08-41-004, at 4 (filed Nov. 26. 2008) (Compliance Report).

stakeholder process, including any required NEPOOL Committee vote, will be completed in time for any proposed Market Rule 1 or other ISO Tariff changes to be filed with the Commission on or before February 1, 2010."[11]

7. On October 29, 2008, NSTAR and the Massachusetts AG requested rehearing of the September 2008 Order.

II. Request for Rehearing

8. NSTAR and the Massachusetts AG contend that the Commission acted arbitrarily and capriciously by approving the Filing Parties' proposed new tie benefits methodology. They first contend that the Commission abandoned its obligation under section 205 of the Federal Power Act (FPA)[12] by deferring its decision-making authority to the Filing Parties through a stakeholder process. Moreover, with respect to the Filing Parties' proposal to revise the tie benefits methodology, NSTAR and the Massachusetts AG maintain that the Commission merely agreed with the Filing Parties, rather than offering its own independent determination. They contend that the Commission's decision also represents a sharp departure from precedent; only the deterministic methodology calculates tie benefit values based on the actual availability of the generation resources, i.e., under the "as is" modeling assumption.[13] NSTAR and the Massachusetts AG acknowledge that the Commission is free to change its policies, but contend that it must identify the change and demonstrate, based upon reasoned analysis of a comprehensive record, that the new policy produces just and reasonable rates.[14] NSTAR and the Massachusetts AG contend that, without an acknowledged factual record of the impact, the Commission cannot possibly conclude that the cost increases are just and reasonable in light of the anticipated benefits, which are also unidentified in terms of nature or

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[11] Compliance Report at 4.

[12] 16 U.S.C. § 824d (2006).

[13] Request for Rehearing at 4-5 (citing *PG&E Nat'l Energy Group v. ISO New England Inc.*, 100 FERC ¶ 61,227, at P 24 (2002); *New England Power Pool*, 104 FERC ¶ 61,204, at P 2, 29 (2003); *ISO New England Inc.*, 114 FERC ¶ 61,055, at P 14 (2006)).

[14] *Id.* at 5 (citing *Mich. Pub. Power Agency v. FERC*, 405 F.3d 8 (D.C. Cir. 2005); *B&J Oil & Gas v. FERC*, 353 F.3d 71 (D.C. Cir. 2003); *Consol. Gas Supply Corp. v. Fed. Power Comm'n*, 520 F.2d 1176 (D.C. Cir. 1975) (change in policies must be explained by reasoned analysis)).

economic gain. According to NSTAR and the Massachusetts AG, the contested order merely represents approval by adoption, i.e., it simply adopts the stakeholder process as its own.[15]

9. NSTAR and the Massachusetts AG further contend that the Commission ignored manifest indications that the stakeholder process in this instance was inherently flawed. They state that "NSTAR's requests to have its alternative methodology modeled, as well as others, were simply rejected out of hand."[16] They aver that ultimately ISO-NE's proposal was the only one fully modeled and no alternatives were examined. They state that, subsequently, with respect to the tie benefit values proposed in the 2011/2012 Installed Capacity Requirement filing, NSTAR and the Massachusetts AG were denied a meaningful opportunity to challenge the values and make the conservative showing directed by the Commission because, during the stakeholder process, ISO-NE had rejected their requests to have NSTAR's alternative methodology modeled.[17] NSTAR and the Massachusetts AG maintain that their inability to exercise their opportunity to protest the tie benefits values proposed in the 2011/2012 Installed Capacity Requirement filing (given the lack of information provided to them during the stakeholder process) clearly supports and proves their claim of a deficient stakeholder process.[18]

10. NSTAR and the Massachusetts AG also contend that the Commission erred by finding that the "at criteria" assumption is not an issue in this proceeding. NSTAR and the Massachusetts AG explain that, by adopting the "at criteria" assumption for use under the proposed probabilistic methodology for calculating tie benefits over all three of the ties, the historical use of the "as is" assumption under the deterministic methodology for calculating HQ Interconnection Capability Credits has been eliminated. NSTAR and the Massachusetts AG acknowledge that the Commission found the "at criteria" assumption to be just and reasonable under the proposed new tie benefits methodology.[19] They also acknowledge that the "at criteria" *per se* is not being modified, but contend that it is an issue in this proceeding because the use of the "at criteria" assumption within the overall new tie benefits methodology results in overly conservative tie benefit values and

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[15] *Id.* at 7.

[16] *Id.* at 8.

[17] *Id.* at 9-10.

[18] *Id.* at 10.

[19] *Id.* at 10-11.

therefore is not just and reasonable. According to NSTAR and the Massachusetts AG, a thorough assessment as to the justness and reasonableness of the tie benefits proposal can only be made upon a comprehensive consideration of the methodology's mechanics and the assumptions driving the results, irrespective of whether the mechanics and assumptions were previously approved by the Commission under the old methodology.

III. **Compliance Filing**

11. On November 26, 2008, the Filing Parties submitted a report on the timetable for an additional stakeholder process regarding the methodology for calculating tie benefits. The Filing Parties note that they have agreed to a timetable for a stakeholder process to study and develop proposals regarding the impact of internal transmission constraints on the ability to receive emergency assistance from an external Control Area and to provide for an allocation of tie benefits to individual interconnections, rather than by control area. These issues arose from the prior stakeholder process to consider revisions to the tie benefits methodology that were approved in the September 2008 Order. The Filing Parties state that the process is planned to commence early during the second quarter of 2009. According to the Filing Parties, this process, including any required NEPOOL Committee vote, will be completed in time for any proposed Market Rule 1 or other ISO-NE tariff changes to be filed with the Commission before February 1, 2010. The Filing Parties explain that this timetable is intended to permit implementation of any such changes prior to the fourth Forward Capacity Auction, which is to be held in August 2010, and will allow any new rules to be in place before the Installed Capacity Requirements and informational filings must be made for that auction. In addition, the Filing Parties state that this timetable reflects other regional priorities involving the relevant stakeholders and ISO-NE personnel, including *inter alia* resource qualification for the third Forward Capacity Auction (to be completed during the first quarter of 2009), a stakeholder process to address Market Rule 1 changes to comply with Order No. 719 (to be filed by April 28, 2009),[20] and preparation for the first annual reconfiguration auction to be held in April 2009.

IV. **Notice and Responsive Pleadings**

12. Notice of ISO-NE's filing was published in the *Federal Register*, 73 Fed. Reg. 78,772 (2008), with interventions and protests due on or before December 17, 2008. The

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[20] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 61,400 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008).

Long Island Power Authority (LIPA) filed a timely protest. NEPOOL and ISO-NE submitted answers to LIPA's protest. LIPA filed a response to the answers of NEPOOL and ISO-NE.

13. LIPA complains that (due to the forward nature of the capacity market) the "practical effect of the proposed timetable is that any improvements would not be realized, at the earliest, until the 2013/2014 Forward Capacity Market."[21] LIPA contends that the Commission did not give ISO-NE a *carte blanche* by its recognition that the requested December 31, 2008 deadline was not enough time to resolve the reserved issues associated with the methodology for calculating tie benefits.[22] In LIPA's estimation, continuing to delay the correct calculation and attribution of these tie benefits perpetuates financial harm to New England customers. Specifically, LIPA explains that allocating the appropriate tie benefits related to the Cross Sound Cable and the 1385/Northport-Norwalk Cable (NNC) transmission ties (between Connecticut and New York) over time will reduce the capacity costs of customers in that region.[23] As such, LIPA requests that the Commission reject ISO-NE's Compliance Report and direct ISO-NE to make a compliance filing for "timely" resolution of how to both model local transmission constraints in developing tie benefits and allocate those benefits to individual ties.[24] Additionally, LIPA requests that the Commission direct ISO-NE to adopt an interim methodology to allocate tie benefits under its current methodology for external ties including the Cross Sound Cable and the 1385/NNC transmission ties that will be in effect for future FCM auctions pending a Commission approved resolution of this issue.

V. <u>Discussion</u>

A. <u>Request for Rehearing</u>

14. We deny the request for rehearing as discussed below.

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[21] LIPA Protest at 5-6.

[22] *Id.* at 6. LIPA lists the reserved issues as the modeling of internal transmission limits, calculation of tie benefits associated with individual ties, and modeling of additional neighboring control areas. *Id.* at 2 (citing September 2008 Order, 124 FERC ¶ 61,298 at P 20).

[23] *Id.* at 4-5.

[24] *Id.* at 7-8.

15. NSTAR and the Massachusetts AG have failed to provide new or newly persuasive evidence that the stakeholder process, which generated four different proposals for the calculation and allocation of tie benefits,[25] was deficient, flawed, or unfair.[26] NSTAR and the Massachusetts AG contend that ISO-NE's proposal was the only one fully modeled and no alternatives were examined. However, the Filing Parties discussed three alternative proposals in their July 31, 2008 filing in addition to ISO-NE's proposal. The Filing Parties stated that one of these three alternative proposals was presented to the Reliability Committee for its consideration, but a motion that the Reliability Committee recommend that the Participants Committee support this alternative proposal "failed with a vote of 38.59% in favor."[27] According to the Filing Parties, the stakeholder process commenced with a series of ten meetings of the Power Supply Planning Committee, a sub-committee of the Reliability Committee.[28] They explained that during this initial process ISO-NE, the NEPOOL Participants, and representatives of various New England utility regulatory authorities explored potential modifications to the current tie benefits calculation and allocation methodologies. They further explained that the Power Supply Planning Committee considered four proposals, one from ISO-NE, three from market participants. The Filing Parties stated that the process of considering these proposals included a survey to gauge the level of consensus.[29]

16. Moreover, the Filing Parties stated that the proponents of the three alternative proposals did not ask the Participants Committee to consider their proposals when this matter was presented to the Participants Committee.[30] NSTAR and the Massachusetts AG do not address our finding from the September 2008 Order that NSTAR chose not to present its proposal to the Reliability Committee or Participants Committee.[31] The Reliability Committee recommended ISO-NE's proposal, however, with a 73.95 percent

[25] September 2008 Order, 124 FERC ¶ 61,298 at P 10.

[26] *See id.* P 47, 53.

[27] Filing Parties, Transmittal Letter, Docket No. ER08-41-002, at 21 & n.67 (filed July 31, 2008).

[28] *Id.* at 19.

[29] *Id*.

[30] *Id.* at 21.

[31] September 2008 Order, 124 FERC ¶ 61,298 at P 53.

vote in favor, and the proposal was "overwhelmingly supported by the NEPOOL Participants."[32] While NSTAR's proposal was not widely supported in the tie benefits stakeholder process, that does not mean the stakeholder process was flawed.

17. NSTAR and the Massachusetts AG allege that the Commission accepted the proposed new tie benefits methodology in the September 2008 Order without sufficient analysis or a substantial record. They contend that the Commission abandoned its FPA section 205 obligation by merely adopting the Filing Parties' stakeholder process rather than offering its own independent determination. NSTAR and the Massachusetts AG maintain that, without an acknowledged factual record of the impact, the Commission cannot conclude that the cost increases are just and reasonable. However, the September 2008 Order discloses analysis of the proposed tie benefits calculation and allocation methodology that includes a reasoned reliance on the stakeholder process. In that order, the Commission agreed with the Filing Parties that the proposed tie benefits revisions are just and reasonable and are in compliance with the directives of the December 2007 Order, because "[t]he revised methodology calculates tie benefits consistently across the control areas and thus results in [Maximum Capacity Limit and Local Sourcing Requirement] values that more accurately reflect the actual tie benefits that are assumed to be available under the probabilistic analysis."[33] Further, in response to NSTAR and the Massachusetts AG, the Commission noted that it previously had established a stakeholder process in the December 2007 Order to consider whether the use of the deterministic methodology for calculating HQ Interconnection Capability Credits was still appropriate under the Forward Capacity Market.[34] Specifically, we reiterated our concern from the December 2007 Order that, in light of the Forward Capacity Market, it was "not clear that the current deterministic tie benefit allocation for Hydro Québec takes into account uncertainties with future load and capacity or the sharing of the Québec resources with other control areas, especially in support of an auction that takes place three years in advance of the Control Year."[35]

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[32] Filing Parties, Transmittal Letter, Docket No. ER08-41-002, at 3, 20-21 (filed July 31, 2008).

[33] September 2008 Order, 124 FERC ¶ 61,298 at P 50.

[34] *Id.* P 52.

[35] December 2007 Order, 121 FERC ¶ 61,250 at P 89.

18. NSTAR and the Massachusetts AG again challenge the use of the "at criteria" assumption, as they have throughout this proceeding.[36] They maintain that the use of the "at criteria" assumption represents a departure from the historical use of the "as is" assumption. They contend that the "at criteria" assumption is an issue in this proceeding, because a thorough assessment as to the justness and reasonableness of the tie benefits proposal can only be made upon a comprehensive consideration of the methodology's mechanics and the assumptions driving the results.

19. In the December 2007 Order, the Commission acknowledged that "the Filing Parties have not always calculated tie benefits under the 'at criteria' assumption reflecting a Loss of Load Expectation in neighboring control areas," but clarified that this was a reasonable approach since under the Forward Capacity market construct, the exact system conditions of neighboring control areas are not known three years in advance.[37] Subsequently, in the September 2008 Order, the Commission concluded that the "at criteria" assumption is not at issue in this proceeding, because the proposed revisions to the tie benefits methodology from the stakeholder process do not include modifications to the "at criteria" assumption.[38] The Commission explained that the issue being addressed in the compliance filing is whether the proposed revisions and corresponding tariff changes are just and reasonable, and not whether the proposal is more or less reasonable than other alternatives.[39]

20. In any event, the Commission responded again to NSTAR and the Massachusetts AG in the September 2008 Order with respect to the use of the "at criteria" assumption in the proposed tie benefits methodology. The Commission noted that section 12.9 of Market Rule 1 specifically states that "the ISO shall calculate tie benefits using 'at-criteria' assumptions for purposes of modeling the adjacent Control Areas."[40] Thus, the

[36] *See id.* P 73-74; May 2008 Rehearing Order, 123 FERC ¶ 61,129 at P 31; September 2008 Order, 124 FERC ¶ 61,298 at P 48.

[37] December 2007 Order, 121 FERC ¶ 61,250 at P 73; *see also id.* P 74 (finding methodology to be just and reasonable and consistent with the ISO-NE Tariff).

[38] September 2008 Order, 124 FERC ¶ 61,298 at P 49.

[39] *Id.* (proffering *ISO New England Inc.*, 114 FERC ¶ 61,315, at P 33 & n.35 (2006) (citing *Pub. Serv. Co. of New Mexico v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987), and *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984)).

[40] *Id.* P 48 (quoting ISO-NE, FERC Electric Tariff, Vol. No. 3, § III.12.9 (Market Rule 1: Tie Benefits), 1st Rev. Sheet No. 7307T).

Commission reasoned that under the current tie benefits methodology ISO-NE properly models the interconnected neighboring control areas using the "at criteria" assumption in the tie benefits determination.[41] We reiterate that use of the "at criteria" assumption, endorsed by significant stakeholder support,[42] is reasonable because it recognizes that the exact system conditions of neighboring control areas are unknown three years in advance and therefore builds a conservative margin of safety into its calculation of available tie benefits.[43]

21. We also noted in the September 2008 Order that the "at criteria" assumption was not modified in the compliance filing.[44] NSTAR and the Massachusetts AG concede here that the "at criteria" assumption was not modified in the instant proposal and thus does not require a just and reasonable determination on its merits.[45] However, they again contend—despite several Commission orders addressing this precise point—that the use of the "at criteria" assumption should be reviewed as part of the overall revised tie benefits methodology. We find that NSTAR and the Massachusetts AG have provided insufficient evidence that use of the "at criteria" assumption within the current tie benefits methodology produces an unjust or unreasonable result.

B. <u>Compliance Filing</u>

22. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2008), prohibits an answer to a protest and an answer to an answer unless otherwise ordered by the decisional authority. We are not persuaded to accept the answers and will, therefore, reject them.

23. We accept the Filing Parties' compliance filing. As detailed in the September 2008 Order, the objective of the directed compliance filing was for the stakeholders to "develop a timetable for a stakeholder process to study modeling of internal transmission constraints and tie benefits associated with individual lines and develop proposals to

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[41] *Id*.

[42] *See* Filing Parties, Transmittal Letter, Docket No. ER08-41-002, at 3, 20-21 (filed July 31, 2008).

[43] December 2007 Order, 121 FERC ¶ 61,250 at P 73.

[44] September 2008 Order, 124 FERC ¶ 61,298 at P 50.

[45] Request for Rehearing at 11.

resolve these issues."[46] The Filing Parties have fully complied with this request. While LIPA would like the Commission to direct a timely resolution for this modeling (notwithstanding LIPA's failure to define "timely"), we note that the "five-year delay" that LIPA contests is largely driven by the three-year forward nature of the Forward Capacity Market. As for the prioritization of issues in the NEPOOL stakeholder process, we typically allow the stakeholder process to establish those priorities, especially when there are other significant issues for the stakeholders to address.[47] Lastly, in a recent order approving the Installed Capacity Requirement values for the 2011/2012 deliverability year, we rejected an interim proposal by LIPA to allocate tie benefits to individual ties.[48] We note that such a proposal is outside the scope of the present compliance filing. In any event, LIPA has presented no new or newly persuasive information here that persuades us to revisit that decision.

The Commission orders:

The request for rehearing is hereby denied, and the compliance filing is hereby accepted, as discussed in the body of this order.

By the Commission. Commissioner Kelliher is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

[46] September 2008 Order, 124 FERC ¶ 61,298 at P 58.

[47] *See ISO New England Inc.*, 119 FERC ¶ 61,045, at P 69 (2007).

[48] *ISO New England Inc.*, 125 FERC ¶ 61,154, at P 57 (2008).