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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Re: EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England

2006 Integrated Resource Plan

DG 06-105

PREFILED DIRECT TESTIMONY
OF
ELIZABETH D. ARANGIO, A. LEO SILVESTRINI AND THEODORE POE

September 5, 2007

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SCHEDULES

I. INTRODUCTION

Q. Would each of you please state your name, position with KeySpan and business address for the record?

A. [Ms. Arangio] My name is Elizabeth Arangio. I am the Director of Gas Supply Planning for KeySpan Energy Delivery New England. My address is 52 Second Avenue, 4th Floor, Waltham, MA 02451.

[Mr. Silvestrini] My name is Leo Silvestrini. I am the Director of Sales and Load Forecasting for KeySpan Energy Delivery New England. My address is 52 Second Avenue, 4th Floor, Waltham, MA 02451.

[Mr. Poe] My name is Theodore Poe. I am the Manager of Energy Delivery for KeySpan Energy Delivery New England. My address is 52 Second Avenue, 4th Floor, Waltham, MA 02451.

Q. Please explain your responsibilities in your present position with KeySpan and your role in preparing the Company's integrated resource plan ("IRP") and provide your professional education and background.

A. [Ms. Arangio] That information is set forth in Schedule KeySpan-1.

[Mr. Silvestrini] That information is set forth in Schedule KeySpan-2.

[Mr. Poe] That information is set forth in Schedule KeySpan-3.

Q. What is the purpose of your testimony?

A. [Mr. Silvestrini] In this docket, KeySpan filed its 2006 IRP, in compliance with the settlement reached in DG 04-133 regarding KeySpan's 2004 IRP (the "IRP Settlement") and the Commission's order approving that settlement. Our testimony will discuss why the Company believes that its IRP complies with that settlement and is adequate, appropriate and sufficient. We will respond to the more significant criticisms of the IRP set forth in the testimony of Utility Analyst George McCluskey, and we will explain why the Company believes those criticisms are incorrect, unfair and inconsistent with prior Commission orders.

II. COMPLIANCE WITH APPLICABLE IRP FILING REQUIREMENTS

Q. Mr. McCluskey stated in his testimony that the Company's IRP is inadequate because it failed to comply with requirements articulated by the Commission in proceedings involving electric utilities. What is your response?

A. [Mr. Silvestrini] Mr. McCluskey ignores the relevant history of the Company's 2006 IRP filing and the specific precedent applicable to it. While the Company strongly believes that Mr. McCluskey's effort to apply electric IRP standards to a gas utility are misplaced, of greater significance in this case is the fact that the 2006 IRP filing is the direct result of an approved settlement agreement in a prior docket, DG 04-133. The settlement in that docket (the "IRP Settlement") was approved by this Commission in its Order No. 24,531, on October 25, 2005. Even Mr. McCluskey concedes that "the IRP addresses the issues required in Order No. 24,531." *Direct Testimony of George R. McCluskey* at 2. That was precisely what the Company's obligation was in this case—compliance with the IRP Settlement—and therefore the Company's IRP should be approved, and this proceeding should be closed.

Q. Please explain the history behind the Company's IRP filing in this case and the filing requirements agreed to in the IRP Settlement and approved by the Commission in Docket DG 04-133.

A. [Mr. Silvestrini] On August 2, 2004, KeySpan filed a fully documented Integrated Resource Plan, in response to which the Commission opened Docket DG 04-133 (the "2004 IRP Docket"). The genesis for the Company's filing in that proceeding was a settlement agreement in an earlier docket, DG 03-160, which was approved by the Commission in Order No. 24,323 dated May 7, 2004. That earlier settlement resolved a number of issues that related to KeySpan's 2003-2004 Winter Period cost of gas proceeding. In the settlement agreement in DG 03-160, the Company, the Office of the Consumer Advocate ("OCA") and the Commission staff ("Staff") agreed, among other things, that an IRP process would be a valuable tool in ensuring that KeySpan and Staff understand one another's views regarding KeySpan's supply needs and gas resource decisions. See Settlement Agreement at 4 (DG 03-160). The settlement provided that, in addition to agreeing to submit its own IRP, the Company would provide Staff with a copy of the IRP approved by the Massachusetts Department of Telecommunications and Energy for KeySpan's Massachusetts affiliates. In approving the settlement in DG 03-160, the Commission stated: "The filing of an IRP, in combination with other provisions of the Settlement Agreement, should enable Staff and the Commission to better understand and evaluate the IRP process as practiced by KeySpan and allow for a more thorough, methodical exploration of the changes in KeySpan's supply and dispatch operations resulting from: (i) the acquisition of ENGI by KeySpan Corporation, (ii) increased demand during recent years, and (iii) … the use of asset management agreements, than can be made in the normal course of expedited COG dockets." Order 24,323 at 17.

In compliance with Order No. 24,323 and the settlement agreement in DG 03-160, the Company filed an IRP on August 2, 2004. The 2004 IRP Docket was consolidated by the Commission with Docket DG 04-175, a docket established to address open gas dispatch issues from Staff's investigation of KeySpan's 2003 summer period gas costs. To assist the Staff in its analysis of the 2004 IRP, the Commission engaged an outside consultant to conduct a thorough review of the Company's filing and make recommendations regarding how the IRP could be modified and improved. After conducting extensive discovery, holding multiple technical conferences with the Company and even conducting an on-site management audit of the Company's gas supply planning and operating procedures at its offices in Waltham, Massachusetts, the Staff's consultant submitted a draft report to the parties for their review. Ultimately an agreement was reached regarding how the Company's 2004 IRP should be modified when the Company made its next IRP filing. That agreement was filed with and approved by the Commission in its Order No. 24,531 (the "2004 IRP Order").

The 2004 IRP Settlement stated in relevant part as follows:

> The Company agrees to file its next IRP on or before August 1, 2006. The IRP will cover the period November 1, 2006 through October 31, 2011 *and will incorporate the following changes to the plan filed in this proceeding*. [Emphasis added.] Settlement Agreement at 2 (Docket No. DG 04-133/DG 04-175).

Immediately following that statement the settlement included a list of nine specific changes to the 2004 IRP that the Company agreed to make when it filed its 2006 IRP. The context of this provision and its express wording plainly evidence the parties' intention, understanding and agreement that an IRP filing that included the specified changes to the 2004 IRP would satisfy the requirements of the settlement and be sufficient.

Particularly noteworthy is the fact that, in presenting the 2006 IRP Settlement to the Commission for its consideration, the Company and Staff made clear the difficulty they had had in reaching agreement. As the Company's witness in that case, I described in detail why the Company had been reluctant to agree to the modifications specified in the settlement, and discussed the fact that the Company had done so in the interest of resolving a number of outstanding issues with Staff. Transcript ("Tr.") at 70-71 (Docket DG 04-133/DG 04-175). In fact, in my testimony I specifically noted that the Company *disagreed* with certain of the recommendations of the Staff's consultant that were included in the settlement, but that the Company was nevertheless willing to agree to modify its IRP process as requested by Staff because it would resolve the disputes that were then pending and would contribute to mending the Company's relationship with the Staff. Tr. at 55, 70-71(Docket DG 04-133/DG 04-175). In my experience, it is highly unusual, if not unprecedented, for a party to a settlement to testify that it essentially disagrees with significant portions of the agreement, but is nevertheless willing to support it as being in the public interest.

For its part, the Staff similarly supported the IRP Settlement on the basis that it was an appropriate format for moving forward, that they believed it would improve relations among the parties, that it would improve the IRP process, and that it provided the parties with a solid foundation to meet the challenges of the future. Order 24,531 at 12.

Simply put, the record in the 2004 IRP Docket fully reflects the fact that both the Staff and the Company carefully weighed whether to agree to the terms of the settlement, given the significant compromises they were making from their litigation positions. The Commission's order approving the IRP Settlement clearly reflects the difficult circumstances that gave rise to the settlement and the sufficiency of the IRP process contemplated thereby.

> Significantly, Staff and the parties found a way to resolve those differences through the Settlement Agreement, which all assert is in the public interest. We conclude that the Settlement Agreement, along with steps taken since this docket was first opened,...resolve a number of contentious issues and will enable the parties and Staff to better identify and address areas of concern going forward. The Settlement Agreement requires KeySpan to file detailed, specific planning information in certain areas with the Commission for its review, creating greater transparency as to how KeySpan is providing reliable service in a cost effective manner. Order 24,531 at 20.

Thus, the IRP Settlement was not a casual settlement, if such a thing exists. It was the culmination of a significant investigation by the Commission, was arrived at after careful consideration by the Staff and the Company of the consequences of their agreement, and represented a willingness to compromise to resolve a number of outstanding issues. For its part, the Staff had the specialized advice of an outside consultant, engaged specifically to advise the Staff on the Company's IRP filing and other issues in that docket. The record in that docket reflects that the Staff and its consultant subjected the Company to massive discovery and multiple technical sessions, including an on-site management audit, and the parties subsequently engaged in an extended settlement process involving significant compromise by both sides. Settlement Agreement at 1 (Docket DG 04-

133/DG 04-175). Perhaps notably, Mr. McCluskey was not part of that process, and therefore does not fully appreciate the difficulty with which the agreement was arrived at and the basis for the Company's reliance on the Commission's order approving that agreement.

Q. What are the potential consequences if the Commission were to accept Mr. McCluskey's position in this docket and impose new, expanded IRP requirements on the Company instead of implementing the IRP Settlement as previously approved?

A. [Mr. Silvestrini] If the Commission were to modify its prior approval of a settlement in a case such as this one, I believe the harm to the regulatory process would go well beyond this one matter. When it approved the IRP Settlement, the Commission determined that it was in the public interest for KeySpan to modify its IRP process in accordance with the specific changes set forth in that agreement. I recognize that one might have recommended other changes or no changes at all to KeySpan's IRP process, and as I said in my testimony in DG 04-133, there are pros and cons to the various approaches espoused by the parties. Tr. at 55 (Docket DG 04-133/DG 04-175). But the fact is that a settlement was reached by Staff and the Company, and that settlement was approved by this Commission. Even Mr. McCluskey agrees with that much. Having determined that the Company's IRP filing in this case is consistent with what is described in the 2004 IRP Settlement, there is no proper basis for the Staff to now assert that KeySpan's filing was inadequate or not in the public interest.

Instead of reviewing the Company's IRP against the standard established by the Commission in its Order No. 24,531, however, Mr. McCluskey argues in his testimony that the Commission should (1) apply requirements that are entirely different from what the Staff and KeySpan agreed to in the IRP Settlement and (2) revive portions of Staff's consultant report from the 2004 IRP Docket that the Staff and Company specifically chose not to include in that settlement. Mr. McCluskey's testimony fails to cite a single deficiency in the Company's filing as compared to the requirements agreed to and approved in the IRP Settlement. If his position were to prevail in this case, the Company and all New Hampshire utilities would justifiably question the value of entering into settlement agreements. That would certainly not be in the public interest.

III. IRP STANDARDS FOR GAS UTILITIES

Q. Mr. McCluskey's testimony seeks to apply an electric utility IRP model as the basis for the requirements he asks the Commission to impose on KeySpan. Please explain why the Company believes such an approach is inappropriate.

A. [Mr. Poe] Unlike electric utilities, for which I understand there is a specific statutory basis for imposing IRP filing requirements, there is no independent basis in New Hampshire for requiring gas utilities to file an IRP or for determining what information must be included in a gas utility's IRP. In fact, it seems particularly noteworthy that the New Hampshire Legislature, as part of its efforts to restructure the electric industry, specifically authorized the Commission to waive IRP filing requirements even for electric companies. While there may be many reasons that the Legislature chose to specifically address electric IRP requirements and did not do so for gas utilities, this legislative background would seem to provide some indication that the Legislature did not believe that similar requirements should be imposed on gas utilities.

In the present case, Mr. McCluskey makes no mention of this background. Instead, he argues that the IRP filing requirements for KeySpan should be largely the same as those that the Commission has applied to PSNH. But PSNH is essentially a vertically integrated electric utility, which I understand was a significant consideration for the Commission when it determined to impose those standards.

Unlike vertically integrated electric utilities, gas utilities generally do not develop their own supply resources, but rather contract with third parties to meet their capacity and supply requirements. As a result, most realistic supply options for gas utilities involve resources that are obtained from others at either market, tariffed or negotiated prices, rather than relying primarily on projects that are developed by the utility itself. For that reason, for most realistic resource options, determining the costs of available options involves a process that consists largely of documenting information provided by others. Yet third party suppliers of those resources will not and can not provide firm pricing or even meaningful estimates of future prices for resource requirements that the utility is as yet unprepared to commit to. There are simply too many variables to be able to obtain a firm quote, and unless a utility is prepared to enter into a present commitment, no supplier will compromise its future negotiating position or allow itself to become a stalking horse for its competitors. As a result, the resource selection process that

Mr. McCluskey seeks to impose in the IRP process (i.e., analyzing an array of options that are hypothetically available to the utility at a given point in time prior to when the actual choice must be made) would be an essentially academic and largely meaningless exercise because it would be based on hypothetical price quotes for potential projects that might be sufficient to meet projected future requirements.

Because of the extremely limited value that this hypothetical resource selection process has versus the substantial burden it imposes on the utility and the regulatory process, the gas IRP process that I am aware of in most states (that is, of those states that have a gas IRP process at all) is one that is more typically limited to forecasting customer requirements for a defined period of time, identifying the existing resources the utility has to meet those requirements, determining the difference between the forecasted requirements and available resources, and documenting the process by which the utility will select additional resources necessary to meet any forecasted need. KeySpan's IRP filing in this case does exactly that. It documents the Company's portfolio of resources, discusses the Company's existing supply resources, shows how those resources contribute to meeting the need for reliability, flexibility and diversity, and discusses the process by which KeySpan will select additional resources or determine to renew existing resources to meet projected customer demand.

Q. Please provide an example of the type of problem you are talking about and why it would be inappropriate to require the Company to set forth actual resource selection decisions in its IRP.

A. [Mr. Poe] As I noted above, it is both impractical and extremely burdensome to use the IRP process to perform a hypothetical evaluation of possible resource alternatives to meet projected customer needs. In addition, such an analysis would be subject to legitimate questions and have little value because of the multiple assumptions that it would have to rely on and because the resource options and associated costs involved would be largely speculative.

As an example, the forecast in the Company's IRP filing in this docket indicates that an incremental supply source will be required beginning in the split year 2009/10 under the Company's base case design year analysis. Throughout the discovery process, Staff has focused on the output of the Company's SENDOUT® model, which shows a small incremental need on a handful of days in that year for a supply described as "Other Purchased Resource". At the same time, the model shows the bulk of the Company's requirements being met by the Company's existing portfolio. But the small incremental need reflected in the model is simply a function of the definition of the "Other Purchased Resource" that the model applies. The SENDOUT® model is designed to model "Other Purchased Resource" as an extremely high-priced resource as a means of helping the Company determine the extent to which its existing portfolio is sufficient to meet projected demand and the extent to which a separate new resource of some kind is required. (In other words, by putting a high price on the resource entitled "Other Purchased Resource", the model will only select that resource when all of the other existing resources have been utilized. This enables the Company to identify the shortfall in the existing portfolio.) An example of such a resource in reality might be a supply-sharing agreement which would give the Company access to supply on the coldest of days. Such a supply could have a very high cost and, hence, would be projected to be used to a minimum extent. However, in making its actual resource selection when the time comes to do so, nothing precludes the Company from actually obtaining a more flexible or cost effective resource, and such a resource may end up displacing other existing supplies even though the model would not have led one to believe that such a resource was necessary in the first place. Thus, *the actual resource selection will be driven by the nature and cost of the resources that are actually available at the time the resource selection is made*, not the resource selection that one might make at the time of the IRP filing based on hypothetical prices, hypothetical resource options and other information that is likely to be unreliable and subject to significant change. The point is that the Company uses the forecasted "Other Purchased Resource" requirement only to identify *when* capacity will be needed, which in turn provides the indication that the Company needs to begin to seriously survey the market for additional capacity. At that point, the Company then undertakes a separate analysis, implementing the process described in the IRP to select the actual resource to commit to, not just to meet the specific need identified in the IRP, but also to deliver service to its customers in the most cost-effective, reliable manner possible.

Q. Have you looked at gas IRP requirements in other states to see how what Mr. McCluskey is proposing in this case compares?

A. [Mr. Poe] I did attempt to conduct such a review to get a better sense of whether what Mr. McCluskey was proposing was consistent with what is being required in other states. There appear to be very few states that require anything approaching what Mr. McCluskey is suggesting here for a gas utility. Massachusetts has a formal IRP process for gas utilities and KeySpan files its IRP with them on a frequency of roughly once every two years. The format and substance of that filing was the basis of the Company's 2004 IRP filing in New Hampshire. In New York, the Company's affiliate provides a less-formal presentation to the New York Commission's staff annually, presenting its five-year load forecast and supply requirements. Outside of New England, I understand that there are several states (e.g. Georgia and Washington) in which there are IRP filing requirements, but these appear to be required more of electric or combination (electric and gas) utilities, where self-build might be an option.

Q. Can you describe the IRP process that the Company is subject to in Massachusetts?

A. [Mr. Poe] As I stated above, KeySpan is required to file an IRP with the Massachusetts Department of Public Utilities on a frequency of roughly once every two years. While the Company performs a five-year load forecast and resource requirements analysis annually as part of its planning cycle, it will formally document this forecast and include a description of the process it intends to follow when the Company reaches the point of requiring incremental resources. This IRP process includes a discovery phase as well as live testimony by

Company witnesses, with the intention of demonstrating that the forecasting process is appropriate, reviewable, and reliable.

IV. RESPONSE TO SPECIFIC CRITICISMS OF THE 2006 IRP

A. Demand Side Resources

Q. Mr. McCluskey's testimony includes several specific criticisms of the Company's IRP. What are they?

A. [Mr. Silvestrini] Mr. McCluskey criticizes the Company for the manner in which it reflects demand side resources in the IRP, the method by which it selected the design planning standards and several less significant issues.

Q. What is the Company's response to Mr. McCluskey's criticism regarding the way in which demand side resources were reflected in the IRP?

A. [Mr. Silvestrini] On page 15 of his testimony, Mr. McCluskey states that the Company's IRP failed to include an assessment of demand-side resources. However, he fails to mention that the IRP Settlement did not require an assessment of demand-side resources of the type that he says is lacking. The Company's filing in this case treated demand-side resources exactly the same way it did in its 2004 IRP, i.e., as a reduction to demand. In the 2004 IRP Docket, the Staff's consultant raised no objections to this method of showing the impact of DSM programs, and the IRP Settlement required no changes to the Company's IRP in this regard. Mr. McCluskey's proposed requirements are entirely new and go well beyond the terms of the settlement.

In addition, the Company's method for reflecting demand-side resources in an IRP is entirely appropriate. There is no need for a separate assessment of demand-side resources in the IRP because a full assessment was previously made in the Company's gas energy efficiency proceeding, Docket DG 06-032, as part of the Commission's process for reviewing and approving Company-sponsored DSM and market transformation measures and programs, the cost-effectiveness of those programs and the appropriate level of program costs and savings. The program savings targets approved in the energy efficiency docket were used in developing the IRP submitted in this proceeding, and are reflected as a reduction in the load requirement that the resource portfolio is designed to meet. The reduction in load was done by exogenously reducing the demand from the Company's econometric demand models. By reducing demand in this way, portfolio savings through DSM are implicit—demand is reduced, therefore the resources needed to meet the demand are reduced or avoided, and the costs associated with those resources are reduced or avoided.

Q. Mr. McCluskey also stated on page 4 of his testimony that "...because the cost-effectiveness of these [DSM] programs was determined based on New England-wide avoided supply costs rather than ENGI-specific avoided costs it is unclear whether (i) the approved programs are cost-effective relative to ENGI supply-side alternatives; and (ii) the quantity of approved programs is optimal." Why do you disagree with him?

A. [Mr. Silvestrini] Again, the Commission has already reviewed and approved as cost effective the very programs that Mr. McCluskey refers to, relying on the same data that Mr. McCluskey now implies is inadequate. Order No. 24,636 in DG 06-032 specifically affirmed the cost-effectiveness of the programs presented, stating "Each of the programs passes the cost-effectiveness screening test such that the net present value of the total program benefits is greater than the total program costs." Order No. 24,636 at 7. The program benefits used in the cost effectiveness test were quantified as the avoided retail gas costs derived from the results of the 2005 Avoided Energy Supply Costs in New England ("AESC") Final Report conducted for the New England gas and electric utilities. When the Commission initially approved the Company's energy efficiency programs in Docket DR 96-150, it also approved the method for screening the measures for cost-effectiveness and approved the use of the AESC data to determine the avoided cost benefits. In fact, the Staff was represented in the study group that oversaw the conduct of the 2005 AESC study.

In Order No. 24,636, the Commission also affirmed the size of the Company's energy efficiency programs stating that "The proposed budgets are appropriate as they reflect gradually increasing measure costs and inflation in total program costs of 2.5 percent per year." By approving the budget, the Commission approved the proposed program targets and goals and the quantity of the approved programs.

Mr. McCluskey's criticism of the use of New England-wide avoided supply costs, rather than ENGI-specific avoided costs, also ignores the fact that the retail gas avoided costs used to evaluate the cost-effectiveness of the Company's energy efficiency programs were calculated separately for Northern and Central New England (Massachusetts, New Hampshire and Maine), Southern New England (Connecticut and Rhode Island) and Vermont. The study divided New England into these geographic sub-regions because they are served by separate pipeline systems and face different resource costs. ENGI was combined with similarly situated New England utilities facing the same resource options (i.e. Tennessee Gas Pipeline long-haul and short-haul pipeline capacity and storage services, Maritime and Northeast pipeline, Portland Natural Gas Transmission System pipeline and Distrigas LNG services), and therefore similar avoided cost structures. Although the study was not ENGI-specific, the avoided costs were clearly representative of the avoided costs faced by ENGI, and therefore, as reflected by the Commission's approval of the DSM programs proposed in DG 06-032, they were sufficient.

An avoided cost study performed specifically for ENGI would not yield different results regarding the cost effectiveness of the Company's energy efficiency programs, but rather would unnecessarily add to the complexity of the IRP filing process and the regulatory expense and burden imposed on the Company. In particular, it is noteworthy that in the energy efficiency docket it was shown that the results of the benefit/cost ratios from the cost-effectiveness test ranged from 2.15 to 9.22 (Exhibit 3 Benefit Cost Report, Table 1, p. 3), meaning that the benefits out-weigh the costs by at least 2 to 1. The difference is not one that is a matter of degree but an order of magnitude[1]. Even if an ENGI-specific avoided cost study were to be conducted and the results differed from the Northern New England avoided costs in the AESC study, it is extremely unlikely that the

[1] The benefit/cost test used in DG 06-032 is the same test recommended by the New Hampshire Energy Efficiency Working Group and approved by the Commission in Order No. 23,574 (DR 96-150)(December 1, 2006).

difference would be significant enough to alter the selection of the cost-effective programs.

Finally, Mr. McCluskey appears to believe that gas utilities' DSM resources should be evaluated in their IRPs in the same way they are analyzed by electric utilities (i.e., treating demand-side resources as equivalent to supply options). Not only is there no statute, regulation or order establishing such a requirement, but from a planning standpoint DSM programs differ from traditional supply resources in a number of ways, including (1) unlike supply resources, demand-side resources cannot be dispatched when the resources are needed to meet sendout requirements, (2) the availability of demand-side resources is dependent on the behavior of customers, who can override the savings effect of the measure, and therefore the reliability of the measures, and (3) DSM measures may not achieve their estimated saving potential. An electric utility can handle a shortage with rolling brown/black outs and can more easily restore service after an outage. A gas utility can not do rolling brown outs – rather it will lose service to entire parts of its system. Moreover, once service is lost, a gas utility must restore service one pilot light at a time.

While the savings associated with energy efficiency programs are real and can not be ignored, the differences justify a different modeling approach for gas utilities. Thus, the Company incorporates them in its planning process by reducing its projected demand consistent with the projections used in the energy efficiency docket as previously approved by the Commission. Because the cost-effectiveness of the energy efficiency programs are based on avoided costs that are representative of ENGI's cost, the result is that they are evaluated on an equal footing to the Company's supply-side resources.

For these reasons the Company's treatment of demand-side resources in its IRP is adequate, reasonable, and appropriate, and conforms with the Commission's prior ruling regarding the Company's IRP requirements. It is inappropriate to criticize the Company for using methods and procedures that were previously recommended by the Staff and approved by this Commission.

B. Selection of Design Planning Standards

Q. Mr. McCluskey also criticized the Company's process for selecting design planning standards. How do you respond to the concerns he raises?

A. [Mr. Poe] Mr. McCluskey's approach does not appear to have been based on a rigorous analytical process like the one used by the Company to select the design planning standards. Rather, it appears that he arbitrarily picked a design planning standard and then criticized elements of the Company's process even though that process was consistent with what was recommended by the Staff's consultant in the 2004 IRP Docket and was based on appropriate data sources.

Q. Can you summarize why the choice of a design planning standard is significant to the IRP process?

A. [Mr. Poe] The design day planning standard is significant because it is used to establish the amount of capacity that should be under contract or available on a supplemental basis to provide adequate one-day throughput for the Company's firm customers on a reasonably-defined 'cold' winter day. For any given number of customers, the higher the planning standard, the more pipeline transportation and supplemental supply vaporization capacity the Company is required to hold even though the entirety of the capacity will not be needed other than on the design day. Thus, for a fixed number of customers, the greater the capacity required for the design day, the higher the cost per customer. Because customers ultimately bear the cost of this higher level of capacity, the Company must balance the goal of service reliability (i.e., the ability to deliver gas on the coldest day) with the cost of that reliability. At some point, it is more cost-effective for the Company and its customers to curtail service, rather than committing to the availability of additional high cost resources to provide service for relatively low probability conditions. It is this balancing that is the basis for the design day planning analysis that the Company conducts.

Q. Please describe the process that the Company followed in its IRP to select a design planning standard.

A. [Mr. Poe] In its IRP, the Company's analysis supporting the selection of a design day standard of 80 effective degree days (EDD), a figure that coincidentally was actually observed on January 15, 2004. The process for selecting the design planning standard was set forth on page 8 of the Company's IRP as follows:

- A statistical analysis was performed of the coldest days from a Monte Carlo analysis of weather data;
- A cost/benefit analysis was performed comparing the cost of incremental resources versus the cost to customers of experiencing service curtailments; and
- The design planning standard was selected such that the incremental cost of resource additions was equal to the incremental benefit of not curtailing demand.

This design day planning process was consistent with the recommendations from the Staff's consultants in their report in the 2004 IRP Docket. In particular, the consultant recommended at pages 8-9 of its report that the Company:

- Employ Monte Carlo simulation to develop a probability distribution of ENGI weather; and
- Base its design day standard on a statistical analysis of that distribution

The statistical results of the Monte Carlo analysis conducted by the Company indicated an overall mean of 66.98 EDD with a standard deviation of 5.99 EDD for the coldest day calculated for each of the 3,000 synthetic winter periods. The Company then balanced the probability-weighted damage costs of freeze-ups and loss of service with the annual costs of maintaining adequate capacity and found the intersecting point of this cost/benefit analysis to be centered at 80 EDD.

Q. How did Mr. McCluskey arrive at the design planning standard of 79 EDD that he argues the Company should have used?

A. [Mr. Poe] First, Mr. McCluskey appears to have based his conclusion on the mean and standard deviation statistics I cited above, as opposed to using the distribution table I presented on page III-52 of the Company's IRP. Then, Mr. McCluskey simply posited that the design day should be two standard deviations from the mean. Nowhere does he explain the basis for his "method". He simply asserts, without any support or analysis, that the design day should be two standard deviations from the mean, which would be 66.98 + 2 x 5.99, or 79 EDD. He then asserts on page 10 of his testimony that the Company's choice of 80 EDD instead of 79 EDD requires more resources (and more cost to consumers) than "the standard resulting from statistical analysis," even though his design planning standard is not based on any meaningful analysis.

Aside from the fact that Mr. McCluskey's conclusion is arbitrary rather than being based on a real analysis of the data, and fails to implement the recommendations from the Staff's own consultants, his conclusion is flawed in two additional ways:

- First, he arbitrarily selected a standard of once in 43.9 years as the appropriate frequency of occurrence of the design day without any justification as to the appropriateness of such a standard; and,

- Second, he calculated the resulting design day EDD level assuming that historically-observed coldest days are normally-distributed, even though the consultant's report that he referred to on page 8 of his testimony itself cast doubt on whether or not the data is actually normally-distributed.

Mr. McCluskey provided no evidence as to why he claims that once in 43.9 years is the appropriate frequency of occurrence of the design day and should be used for planning purposes. The Company's cost/benefit analysis, on the other hand, based its selection of the design planning standard on actual data such as the costs of resources to meet its customers' requirements and the costs of potential damages should the Company fail to contract for insufficient pipeline and supplemental resource capacity to meet its customers' requirements.

Q. With that in mind, what is your concern with Mr. McCluskey's recommendation regarding the Company's approach to selecting a design planning standard?

A. [Mr. Poe] Rather than go into additional detail here regarding the failings of Mr. McCluskey's approach, I have prepared a short summary that is attached to this testimony as Schedule KeySpan-4, which explains my concerns.

C. Planning Horizon

Q. What is the appropriate planning horizon for the Company's IRP?

A. [Ms. Arangio] To ensure that the information in the IRP is meaningful, the planning horizon should be five years. Beyond that time period, the high level of uncertainty in any assumptions regarding load growth, economic factors and other inputs used in the various models, as well as uncertainty about the timing and availability of resource options, would undermine the value of the plan as compared to the significant effort involved in putting it together.

Q. How does the Company's planning horizon for the IRP coincide with the timing and availability of resource options?

A. [Ms. Arangio] Although the Company files a formal plan with the Commission approximately every two years, it follows essentially the same process internally on an annual basis prior to each heating season, updating its models with the most recent information from the prior winter. This same updated information is also utilized by the Company's system planning group to ensure adequate on-system planning for the expected load for the same period. It is imperative that the Company perform this more frequent analysis of the supply/demand balance because it enables the Company to employ the best strategy available to attain the optimum resource portfolio to serve customer requirements. With the ever-changing landscape as it relates to upstream options, it is important for the Company to have the most up-to-date information on available supply and capacity options since, as Mr. Poe indicated, the Company needs to make decisions based on the resources actually available to the Company at *the time the* *resource selection is made.* A practical example of this timing issue is the Anadarko Petroleum Bear Head proposed liquefied natural gas (LNG) receiving terminal on the coast of Nova Scotia. On August 12, 2004, Anadarko announced it had acquired Access Northeast Energy Inc. (ANEI), a private Canadian company whose sole project is a proposed LNG receiving terminal on the coast of Nova Scotia. On October 28, 2004, Anadarko announced that construction was underway on the terminal and was expected to be complete by late 2007. On June 30, 2005, Anadarko announced it had signed agreements for nominated capacity on a planned expansion of the Maritimes & Northeast Pipeline (M&NP) system to deliver 750,000 MMBtus/day into Canadian and U.S. markets from their Bear Head terminal. On March 14, 2006, Anadarko announced it was rescheduling the onsite construction work of its LNG terminal at Bear Head to match the timing of LNG supply, which they expected would be determined over the next few quarters of 2006. On July 10, 2006, Anadarko announced it had agreed to sell Bear Head LNG Corporation, a wholly owned subsidiary that developed the LNG receiving terminal. Under the agreement with U.S. Venture Energy, a private equity firm, Anadarko received an 18-month option to secure up to 350 MMBtus/day of throughput capacity at competitive rates. By early 2007, Anadarko had officially written off its investment in the Bear Head LNG terminal by taking a $111-million charge against its fourth quarter 2006 earnings. Based on this chronology and looking at the Company's last two IRP filing dates (August 2, 2004 and August 21, 2006), the Company would not have considered the project as an option in its 2004 filing since the project wasn't announced until ten days after the Company's filing. In its 2006 filing, the Company would have considered it as a potential new resource, but then a few months following the filing, it would have been notified that the project was not a viable option after all. In fact, the Company was in contact with Anadarko throughout the life-cycle of the LNG project and at one point in time did consider the project as a viable option. However, without the ability to analyze firm pricing and other relative commercial terms, the Company continued to monitor the project while also seeking other more realistic options to meet its needs. In summary, the upstream dynamics are ever-changing, and at decision-making time the Company can only consider viable options. It would not be cost-effective nor would it be practical to commit the personnel and other resources necessary to consider theoretical options. A planning horizon beyond five years would put the Company in the position of theoretical planning as opposed to realistic planning.

D. Filing of Next IRP

Q. In his testimony, Mr. McCluskey proposed that the Company should be required to file its next IRP in 2008. Does the Company agree with that recommendation?

A. [Ms. Arangio] No. Obviously this proceeding will not even be completed until sometime in 2008, and perhaps Mr. McCluskey made his recommendation in the belief that the docket would conclude sooner than that. Regardless, the preparation of an IRP is a significant undertaking. Once the Company knows what the scope of its next IRP should be, it will need to gather updated data to conduct its analyses and prepare the necessary plan. Typically, August is the best month in which to file an IRP because the data from the preceding winter is available and can be incorporated into the forecast. There is significant lead time required in order to prepare the analyses that go into an IRP and carefully review all of the data. Without knowing what additional requirements the Commission will place on the Company in its next IRP, and what impact those requirements might have on the planning process and the necessary documentation that a filing entails, the Company can not commit to a filing in 2008.

E. Capacity Reserve

Q. In his testimony, Mr. McCluskey criticizes the Company for its position regarding whether a capacity reserve should be established and how the costs of such a reserve should be allocated. What is your response to his criticism?

A. [Ms. Arangio] Frankly, the Company was surprised because Mr. McCluskey's recommendation is ultimately the same as the Company's, namely that there is no need for a capacity reserve. That has consistently been the Company's position, even during earlier times when other members of the Commission staff indicated initial support for the concept. In the IRP, the Company noted that there is no evidence to support the creation of a capacity reserve, and in his testimony Mr. McCluskey agrees with that statement. Where he takes issue with the Company appears to relate to the hypothetical circumstance of who should pay for the reserve that the Company and he agree is not needed in the first place. Suffice it to say that the Company continues to believe that a capacity reserve, if it were established, should be assessed to all customers. However, because the Staff agrees with the Company that there is no basis for establishing such a reserve, it doesn't seem worthwhile to engage in an ongoing debate with Mr. McCluskey about who should be required to pay for it. That is a subject that would be best addressed if the Commission considers establishment of a capacity reserve for KeySpan's customers in the future.

V. CONCLUSION

Q. What is the Company asking the Commission to do in this proceeding?

A. We believe the Commission should approve the Company's IRP filing as being adequate, appropriate and consistent with the public interest and require the Company to file a new IRP in August 2009 consistent with the standards set forth in the IRP Settlement.

Q. Does that conclude your testimony?

A. Yes.

SCHEDULE KEYSPAN-1

Elizabeth D. Arangio
Background and Qualifications

Q. Please state your name and business address.

A. My name is Elizabeth D. Arangio. My business address is 52 Second Avenue, Waltham, MA 02451.

Q. Please explain your responsibilities in your present position with KeySpan.

A. I am the Director of Gas Supply Planning with responsibility for the resource portfolio of the local gas distribution companies ("LDC's") that operate as KeySpan Energy Delivery New England, which are Boston Gas Company ("Boston Gas"), Colonial Gas Company ("Colonial"), Essex Gas Company ("Essex"), and EnergyNorth Natural Gas, Inc. ("EnergyNorth"). In addition to New England, I am responsible for gas supply planning for the resource portfolios of The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island. In addition to my planning responsibilities, I also oversee the Company's customer-choice programs in both New England and New York. For purposes of this testimony, references to "KeySpan" or the "Company" will relate solely to EnergyNorth.

Q. Please summarize your educational background and professional experience.

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Business Administration. In 1995, I graduated from Bentley College with a Master of Business Administration. From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas

Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services, with responsibility for managing all activities associated with the customer-choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services with responsibility for the administration of the Company's gas-resource portfolio and customer-choice program in Massachusetts and, as of 2000 the acquisition of EnergyNorth located in, New Hampshire. In February 2004, I assumed the additional responsibility of gas supply planning for the resource portfolios of The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island. In 2005, I assumed responsibility for the customer-choice programs in Massachusetts, New Hampshire, New York and Long Island.

Q. **Please explain your role in preparing the Company's integrated resource plan ("IRP")**

A. I was directly responsible for preparation of Section IV subsections C and F and Section V of the Company's IRP.

SCHEDULE KEYSPAN-2

Leo Silvestrini
Background and Qualifications

Q. Please state your name and business address.

A. My name is Leo Silvestrini. My business address is 52 Second Avenue, Waltham, Massachusetts.

Q. Please explain your responsibilities in your present position with KeySpan.

A. I am the Director of Load and Sales Forecasting.

Q. Please summarize your educational background and professional experience.

A. I received a Bachelor of Arts Degree in History in 1973 from the State University of New York at Albany and a Master of Arts Degree in Economics from Tufts University in 1976. I have also received a certificate from the Northeastern University School of Business Management for the completion of the Management Development Program in 1987. I am a member of the American Gas Association, the Northeast Gas Association and the New England Chapter of the International Association of Energy Economists. I was hired by Boston Gas Company in October 1978 as an economic analyst in the Rate Department. In October 1980 I was promoted to Manager of Rates and Revenue Analysis. I was further promoted in February 1985 to the position of Director of Rates and Economic Analysis. Over the next seven years, I held similar director positions in Market Planning and Development, Corporate Strategic Planning and Gas Resource Planning. In December of 2000 I was named Director of Rates and Regulatory Affairs. In May 2005 I was named to my current position.

Q. What is your position with KeySpan Energy Delivery New England?

A. I am the Director of Load and Sales Forecasting. I am primarily responsible for forecasting gas loads for the New England, New York and Long Island local gas distribution companies ("LDCs") of KeySpan Corporation for the purpose of supply planning, distribution planning and sales revenue forecasting.

Q. Please explain your role in preparing the Company's integrated resource plan ("IRP").

A. I'm generally responsible for preparing KeySpan's short and long term gas demand forecasts that feed the Company's supply planning operations, distribution system planning, and sales and budget forecasting. In this IRP I was responsible for the forecast methodology section of the filing. I directed and prepared the forecast of incremental demand, and oversaw the preparation of the balance of the section, the regression analysis of sendout, forecasts of normalized customer requirements by year, planning standards, and forecasts of design customer requirements.

SCHEDULE KEYSPAN-3

Theodore E. Poe, Jr.
Background and Qualifications

Q. Please state your name and business address.

A. My name is Theodore E. Poe, Jr. My business address is 52 Second Avenue, Waltham, Massachusetts 02451.

Q. Please explain your responsibilities in your present position with KeySpan.

A. My title is Manager, Energy Planning.

Q. Please summarize your educational background and professional experience.

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science Degree in Geology. From 1981 to 1989, I worked as a Research Associate with Jensen Associates, Inc. of Boston where I was responsible for the development of a variety of computer forecasting models of natural gas supply and demand for interstate pipeline and local distribution companies. In 1989, when I joined Boston Gas Company, I was responsible for modeling and forecasting the natural gas resource requirements of its customers. Since 1998, I have assumed the added responsibilities of forecasting the requirements of Essex Gas Company, Colonial Gas Company and EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England.

Q. Please explain your role in preparing the Company's integrated resource plan ("IRP")

A. I was responsible for the preparation of Section III.C ("Regression Analysis"), Section III.D ("Normalized Forecasts of Customer Requirements by Year"), Section III.E ("Planning Standards"), Section III.F ("Forecasts of Design Year

Customer Requirements by Year"), as well as Section IV.A ("Portfolio Design"), Section IV.B ("Analytical Process and Assumptions"), and Section IV.D ("Adequacy of the Resource Portfolio").

SCHEDULE KEYSPAN-4

Description of Additional Failings of Mr. McCluskey's
Selection of Design Planning Standard

The data series used by the Company to conduct its cost/benefit analysis is the coldest day observed in each year during the twenty-five year period from 1981 – 2005, which provided 25 data points for the statistical distribution used in selecting a design planning standard in KeySpan's 2006 IRP. In accordance with the IRP Settlement in Docket DG 04-133, the Company modeled this data using a Monte Carlo analysis.

Rather than making the simplifying assumption of using a mean and standard deviation in order to determine the statistical distribution, the Company used the actual distribution that was the output of the Monte Carlo routine. The probability of occurrence for each level of EDDs that was obtained from this analysis was then used as input to the Company's cost/benefit analysis to determine the appropriate design day planning level. Since weather variability, customer mix, and economic conditions are all input variables into the analysis, the Company's analysis and the resultant design day planning standard are unique to its service territory.

In contrast, Mr. McCluskey's approach is to simply determine what he believes to be the appropriate frequency of occurrence of the design day (which, according to him, is once in 43.9 years). Having selected what he believes is the appropriate frequency of occurrence of the design day, he appears to believe that there is no further need for analysis, and therefore he criticizes the cost/benefit analysis applied by the Company and argues that it is flawed because it relies on quantifying how many "average" customers would be affected by an interruption of service (page 11). Mr. McCluskey's criticism relies on his argument that the Company would interrupt specific, lower-priority customers preferentially, and therefore the Company's use of an "average" customer for cost/benefit purposes is inappropriate. What Mr. McCluskey fails to consider, however, is the fact that, while the Company's design year standard simulates the ability of the Company to react with sufficient warning to curtail its lower-priority customers preferentially as Mr. McCluskey proposes, its design day model assumes that the uncertainty of short-term weather forecasts would not allow the Company to effectively interrupt service on a priority basis. In light of the fact that the type of priority approach to shut offs implicit in Mr. McCluskey's approach is unlikely to be possible in reality, the use of an average customer standard in the cost/benefit analysis is appropriate.

Mr. McCluskey then identifies three additional problems he believes exist with the Company's cost/benefit analysis:

1. Loss in consumer surplus,
2. Cost of re-lights; and
3. Lost revenue

With regard to loss in consumer surplus, as Mr. McCluskey calls it, the Company quantified the loss in consumer surplus as the freeze-up damages to residential establishments (supported by insurance industry data) and the loss of economic output to commercial/industrial establishments (supported by state economic data). Yet, Mr. McCluskey criticizes the Company for not including what he believes is meaningful market research into the values these customers would place on firm service

With regard to the cost of re-lights and potential lost revenue to the Company, the Company included the cost of relighting gas-fired equipment that would have been interrupted, but did not explicitly include the revenue it would lose directly due to the interruption, nor any lost future revenues due to the psychological effects to consumers caused by the need to interrupt firm service. The Company excluded this, not as Mr. McCluskey speculated 'because the Company apparently does not seek to recoup such losses' (page 12, footnote 7), but because the Company has not made a judgment at this point as to whether recovery of lost revenue (indirect costs) would be required. As a result, it included only the lost consumer surplus and relight expenses (direct costs).

In concluding his criticism of the Company's design day planning standard, Mr. McCluskey asserted that in its next IRP the Company should use it SENDOUT® model to test his arbitrary selection of 79 EDD as the design day standard (page 13)

Finally, Mr. McCluskey arbitrarily selects a design year standard for planning purposes at a level of 7,660 EDD, claiming, but without providing any supporting analysis, that this is a once-in-33 year occurrence, even though interpolating between the 7,600 and 7,700 EDD levels in Chart III-E-10 of the Company's filing would show that such a level would have a probability of occurrence of once-in-39.6 years. He then proposes that the Company use that design year standard to establish the amount of supply that should be under contract and stored (either underground or as supplementals) to have adequate supply for its firm customers to endure a reasonably-defined "cold" winter season. The Company's analysis, on the other hand, which is fully documented and set forth in the IRP demonstrates that its design year should be set at 7,680 effective degree days (EDD), and in fact 7,602 EDD was actually observed during the July 2002 – June 2003 period.