STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILTIES COMMISSION

EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England	))))	DG 07-__

DIRECT TESTIMONY OF

John S. Stavrakas, P.E.

ON BEHALF OF

ENERGY NORTH NATURAL GAS, INC. d/b/a
KEYSPAN ENERGY DELIVERY NEW ENGLAND

September 14, 2007

I. INTRODUCTION

Q. Please state your name, address and position with KeySpan Energy Delivery New England.

A. My name is John S. Stavrakas. My business address is 52 Second Avenue, Waltham, Massachusetts 02451. My title is Director of Engineering.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of EnergyNorthNatural Gas, Inc. d/b/a KeySpan Energy Delivery New England ("KeySpan"). References in my testimony to "KeySpan" or the "Company" will refer to EnergyNorth, unless otherwise denoted.

Q. Would you please summarize your educational background and professional experience?

A. I graduated from The State University of New York at Stony Brook in 1983 with a Bachelors Degree in Mechanical Engineering. I also completed graduate work in mechanical engineering at the University of Pittsburgh in 1984 and 1985 (non-matriculated). I currently hold professional engineering licenses in the states of New Hampshire, Massachusetts and New York. From 1984 to 1985, I worked in the operating plants division at the Bettis Atomic Power Laboratory for Westinghouse Corporation. In 1986, I joined the Long Island Lighting Company (LILCO) and worked in various engineering and distribution capacities within the Gas Operations Division. In 1998, LILCO merged with KeySpan, which then acquired EnergyNorth in 2000. During this period, my responsibilities included planning engineering, project engineering, production engineering, and system operations. Currently, I am responsible for all engineering functions with KeySpan's New England service territories, including EnergyNorth.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the American Society of Mechanical Engineers and the National Society of Professional Engineers.

Q. Have you previously testified in regulatory proceedings?

A. Yes, I testified before the New York State Public Service Commission in the late 1990s regarding the proposed siting of electric generation facilities in Long Island, New York.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the alternatives that exist for meeting the identified need for incremental capacity using on-system facilities rather than contracting for incremental pipeline capacity. In addition, my testimony discusses the derivation of the cost projections for the on-system alternatives. The testimony of Mr. Paul DeRosa explains how those total costs were annualized so that the relative cost-effectiveness of the Concord Lateral Upgrade and on-system alternatives could be analyzed.

To that end, my testimony is organized as follows: Section II reviews the identification of alternatives to address the incremental capacity need that arises beginning in the 2009/10 winter heating season. Section III discusses the derivation of the cost estimates for these project alternatives. Based on this analysis, it is my professional opinion that on-system project alternatives are not feasible or cost-effective substitutes for the procurement of incremental pipeline capacity. Therefore, the Company's proposal to move ahead with the Proposed Agreement and the Concord Lateral Upgrade is the best option for delivering gas supplies to customers on a safe, reliable and least-cost basis, consistent with the Company's service obligation.

II. IDENTIFICATION OF PROJECT ALTERNATIVES

Q. How did the Company approach the analysis of alternatives to the procurement of interstate pipeline capacity from Tennessee?

A. As noted in the testimony of Ms. Arangio, there are just two options available to provide the level of incremental capacity (and associated gas supply) to the Company's New Hampshire service territory, which is needed to meet peak day and peak-season load requirements beginning in 2009/10. These options are (1) the expansion of existing interstate pipeline facilities, or (2) the addition or expansion of on-system supplemental storage and vaporization facilities. No other options exist that could provide the level of resources required to meet customer demand over the next 10 years, nor that would interconnect directly with the Company's New Hampshire distribution system on a safe and reliable basis.

Thus, the Company approached the analysis of alternatives by assessing the current capabilities of on-system resources in New Hampshire and evaluating the potential for expanding those facilities to address the incremental capacity need.

Q. What are the current capabilities of the Company's on-system supplemental facilities?

A. In the EnergyNorth service territory, the Company owns and operates three LNG storage and vaporization facilities and four propane storage and vaporization facilities. These facilities are specified in Table 1, below:

Table 1
On-System Supplemental Facilities

Location	LNG or Propane	Vaporization Capability (in MMBtus/day)	Storage Capability (in MMBtus)
Concord	LNG	4,800	4,200
Tilton	LNG	9,600	4,200
Manchester	LNG	8,400	4,200
Nashua	Propane	11,000	23,672
Amherst	Propane	0	28,450
Manchester	Propane	21,600	47,317
Tilton	Propane	2,000	4,730

Q. What are the considerations involved in assessing the potential opportunities for expanding the capabilities of one or more of these facilities to meet the incremental need?

A. There are five major considerations involved in assessing potential opportunities for installing incremental on-system capacity.

The first consideration in assessing on-system alternatives is that the amount of incremental capacity needed (i.e., 25,000 MMBtus/day) is relatively substantial in light of the capabilities of the existing on-system facilities. Because increased vaporization capability provides incremental capacity to the system only if there are adequate LNG or propane supplies available for vaporization, any on-system project alternative undertaken by the Company in lieu of the Proposed Agreement would require the construction of additional storage capacity in order to provide the system with the incremental capability of 25,000 MMBtus/day. Consequently, the potential alternatives for upgrade of these facilities are limited to those facilities at which storage capability could be added.

Second, on-system project alternatives are limited to those locations from which the Company's distribution system has sufficient "take away" capability to make use of the incremental supplies. Again, the relatively substantial amount of incremental need requires significant take-away capability on the distribution system. To address this consideration, the Company used the load requirements forecasted in the IRP pending before the Commission as inputs to the distribution system planning model (the "Stoner Model") in order to determine the points where the distribution system had the necessary "take-away" capability to reliably deliver additional LNG or propane supplies injected into the system. Through this analysis, the Company determined that on-system project alternatives greater than 25,000 MMBtus/day would be more expensive due to the need to increase vaporization and storage capacity as well as increasing the footprint of the plant which could impact real estate costs. Furthermore upgrades to the distribution system would be required in order to achieve the necessary take-away capability. Because the anticipated cost of increasing the capacity of the facilities along with distribution system upgrades would be substantial, the Company evaluated all project alternatives (including the Proposed Agreement/Concord Lateral Upgrade) based on the threshold of 25,000 MMBtus/day of incremental output. As discussed in the testimony of Ms. Arangio, there is no differential in total contract cost between 25,000 and 30,000 MMBtus/day under the Proposed Agreement. Therefore, inclusion of the costly upgrades that would be needed to achieve the 30,000 MMBtus/day of incremental capacity offered by the Proposed Agreement would only had the effect of substantially widening the gap in the relative cost-effectiveness of the Proposed Agreement versus the on-system project alternatives. Accordingly, the Company's project-alternative cost analysis is based on 25,000 MMBtus/day of incremental output. Based on this project size, the Company identified the optimal locations on the system that would offer sufficient take-away capability and were feasible to site a new facility of the size required to provide the requested output.

The third consideration is the need to interconnect new or expanded on-system supplemental facilities with the distribution system. This consideration is important because existing facility sites are located in close proximity to the distribution system and would allow for interconnection of new or expanded facilities (so long as land is available) without the incremental cost associated with the construction of a high-pressure distribution pipeline, which would be needed to tie a facility into the distribution system from a different location. Where land is not available at a current site, it becomes necessary to (1) acquire property, and (2) incorporate the cost of construction of a new high-pressure distribution pipeline to interconnect the new facility with the distribution system.

The fourth consideration is the relative feasibility of increasing shipments of LNG or propane to fill the expanded storage at specific locations. This is a significant consideration involved in the on-system project alternatives because of the need to ensure a high level of safety and reliability in meeting customer needs. In that regard, the Company recognized that adding liquefaction capability would provide the flexibility and opportunity to reduce the amount of trucking necessary to fill the storage tanks because pipeline supplies can be utilized during off-peak periods to refill storage rather than relying on truck shipments. Without liquefaction, approximately 300 additional truck deliveries would be required to fill the facility so that adequate gas supply that would be available over the peak season. However, the addition of liquefaction requires additional site space and consideration of environmental conditions. Adding liquefaction capability also increases project cost by approximately 1/3, as demonstrated by the difference in estimated capital costs for the LNG Project Alternatives (with and without liquefaction). These cost estimates are presented below.

Q. What is the fifth consideration that you referenced above?

A. The fifth consideration is specific to the Propane Project Alternative. Specifically, an important consideration with the use of propane/air storage and vaporization units is that propane has a higher specific gravity and Btu content than pipeline gas, which can have adverse consequences on the operation on customer appliances unless an optimal mixture of pipeline gas and propane gas is maintained in the distribution system. Therefore, to ensure the proper operation of customer appliances it is necessary to: (1) inject the propane gas with air through a compression process before the propane is released into the system; and (2) have sufficient pipeline gas available to achieve the optimal proportion of propane and pipeline gas in the system.

Thus, a ramification of the need to maintain an optimal mixture of propane and natural gas is that the propane facility must have a natural gas pipeline both at its inlet and its outlet. As mentioned above, if the propane facilities are located at some distance from the distribution system, additional pipeline facilities would have to be constructed to and from the propane unit to allow for interconnection. In addition, the propane and pipeline gas will stratify in the pipe when migrating over distances to customers. If this occurs, the operation of customer appliances would be compromised. Given these considerations, and the need to secure minimum of 16 acres of cleared land to accommodate the propane operations, identifying workable locations on which to site the units is a significant challenge.

Q. Are there any other considerations to take into account in evaluating potential on-system alternatives?

A. Yes. One final note is that the addition of compression was not an option for resolving the identified need. This is because the Company's need is for peak day and peak season capacity and related gas supply. Adding compression is a viable project alternative only when the issue to be resolved is inadequate pressure. Because the Company's need in this case is for incremental gas supply, any project undertaken by the Company would need to provide the capacity necessary to ensure deliverability of the incremental supply to meet customer load requirements. Compression does not achieve this objective.

Q. In the end result, what were the on-system projects that the Company identified as potential alternatives to the Proposed Agreement?

A. Based on its assessment of the considerations outlined above, the Company identified only two, feasible on-system projects that could be undertaken to provide an incremental 25,000 MMBtus/day of deliverability for the distribution system. These alternatives are: (1) constructing a new LNG facility at the Company's existing LNG facility in Concord, NH to add 0.3 Bcf (300,000 MMBtus) of storage capability (the "LNG Project Alternative"); and (2) constructing new and/or expanded propane facilities in both the Company's existing LNG site in Concord and a new site in Nashua, NH in order to add 0.15

Bcf of storage capability at each of those facilities (the "Propane Project Alternative"). Both the LNG and Propane Project Alternatives would be designed to ensure 25,200 MMBTus/day of incremental vaporization output capability. Other feasible and comparably priced on-site alternatives do not exist given the considerations outlined above, which argue for the use of existing sites to the maximum extent possible. Therefore, these two project alternatives represent the universe of potential options for meeting the identified need without incremental pipeline capacity.

III. COST ESTIMATES FOR ON-SYSTEM ALTERNATIVES

Q. How did the Company derive the cost estimates for the on-system project alternatives?

A. To derive a high-level, preliminary cost estimate for the LNG Project Alternative, the Company first reviewed publicly available information for existing and planned LNG facilities and scaled the cost of those projects to the potential KeySpan project based on the relative size of the facilities. The Company then presented these preliminary, "scoping" cost estimates to CHI Engineering Services, Inc. ("CHI"). CHI is an independent engineering company based in Portsmouth, New Hampshire, that the Company retained to develop cost estimates based on project design and engineering considerations specific to the Company's identified on-system project alternatives. CHI has worked on several projects for the Company and has extensive expertise with facilities design, permitting and build activities. CHI analyzed the Company's preliminary cost estimates and provided revised cost estimates based on a more thorough analysis of project requirements and current cost data.

For the Propane Project Alternative, the Company used a cost estimate developed by CHI for a project-alternatives analysis supporting a distribution pipeline-expansion project on Cape Cod, Massachusetts. This project (and the related cost estimates) was reviewed and approved by the Massachusetts Energy Facility Siting Board in 2006.

The summary results of CHI's analysis for the LNG and Propane Alternatives are reflected in Exhibit JSS-1, and are set forth more specifically in Exhibit JSS-2.

Q. What are the cost estimates that were developed by CHI?

A. In summary, CHI estimated the following project costs for the LNG and Propane Project Alternatives: (1) a total of $64.04 million for an additional LNG facility with 0.3 Bcf of storage capacity, 25,200 MMBtu/day of vaporization capacity and 3 MMSCFD of liquefaction capability; (2) a total of $46.68 million for an LNG facility with the same storage and vaporization capability but without liquefaction capability, and (3) a total of $37.87 million for the addition of propane facilities with 0.3 Bcf of storage capacity and 25,200 MMBtu of vaporization capacity. These estimates represent a concept-level, consolidated design/build/permit cost estimate.

Q. Are there special considerations involved in the cost estimate?

A. Yes. Because the property on which the Company's existing Concord facility is located encompasses sufficient land on which to construct the new facilities (10-12 acres for LNG and 16 acres for propane facilities), the Company based its cost estimate on the assumption that no additional land would be necessary at the Concord site. Also, unlike the LNG facility, the Company does not currently own sufficient land in Nashua, NH to construct the needed propane facilities and therefore, land acquisition costs based on available market data for comparable New Hampshire locations were included in the analysis.

In addition, construction of the Propane Project Alternative would require the construction of a new high-pressure pipeline from the hypothetical Nashua propane plant to the existing Bridge Street, Nashua propane plant (which is a total distance of approximately two miles, including a river crossing). This new pipeline would be needed to deliver gas with a proper mixture of propane air and natural gas from the new Nashua plant to the 130 psig (soon to be uprated to 185 psig) and 60 psig distribution systems. The existing pipeline from the take station in Hudson N.H. would continue to feed the Bridge Street, Nashua propane plant. This configuration would allow both propane plants to operate as needed.

Q. Are there any other considerations to take into account in assessing these cost estimates?

A. Yes. There is a high probability that the cost estimates prepared by the Company with the assistance of CHI <u>understate</u> the actual cost that the Company would incur if it were to construct either the LNG or Propane Project Alternative to meet the identified need. If the facilities were actually to be constructed, further studies would be needed, including a detailed permitting analysis (which is one of the areas that would be likely to increase the cost estimate). The Company estimates that this type of analysis would cost at least $75,000 and would take approximately two months to complete. The Company has not commenced this type of detailed study because the conceptual-level estimates developed by the Company and CHI clearly demonstrate that the Proposed Agreement is the best alternative for meeting the Company's identified need. Therefore, the cost of this additional expense was not reasonable or needed to assess the project alternatives.

Q. How were the total costs of the on-system alternatives analyzed for purposes of comparison to the Concord Lateral Upgrade costs?

A Once the Company estimated the total capital costs of the project alternatives, it performed pro forma calculations to estimate the annual revenue requirement associated with the project alternatives, including estimated O&M costs, which would be recovered from customers through rates. These annualized revenue requirements were then compared to the rate proposed by Tennessee for the Proposed Agreement, which would be recovered annually from customers through the cost of gas rates. This calculation is reviewed in the testimony of Mr. Paul DeRosa and analyzed in the testimony of Mr. Poe. As demonstrated therein, the Proposed Agreement is the least-cost alternative, exclusive of gas-supply costs.

Q. Aside from costs, are there other advantages of proceeding with the pipeline project rather than a distribution project?

A. Yes. There a number of significant non-cost factors aside from the considerations I discussed above, which favor a pipeline solution over a distribution solution to meet incremental send-out requirements.

For example, the type of on-system facilities identified as potential alternatives to the Proposed Agreement are generally relied on as "needle peaking" supplies to meet peak-day demand and/or hourly distribution system pressure requirements. These facilities are constructed to offset the high cost of subscribing for seasonal or annual pipeline transportation capacity and supplies for system, where that need occurs in periods of extremely short durations during the heating season. However, as system demand increases, it becomes necessary to procure incremental supplies to meet seasonal needs, which means that the need exists over a longer time period than would generally be served using a "needle peaking" facility during the heating season. Peaking facilities such as the propane or LNG facilities discussed above are not viewed to be as reliable as pipeline supply alternatives in meeting a seasonal supply need for two reasons: First, there is a greater potential for operational failure when a peaking facility is called upon in a continuous manner over the 151-day heating season. Although on-system facilities play a vital role within the context of the overall portfolio when used for (limited) peaking purposes, on-system facilities are much more susceptible to failure because of the need to transfer LNG and/or propane from a truck to storage during the winter period and because the process involves many more "moving parts," which require continuous maintenance and care and have the potential for failure. Underground pipeline facilities do not have this same susceptibility.

Second, these facilities operate only if the Company is able to truck sufficient supplies of LNG and propane facilities during the winter period to meet supply requirements. Without new liquefaction facilities, the Company would have to increase the number of truck deliveries by more than 300 trucks on an annual basis to ensure deliverability of the incremental 30,000 MMBtus/day that the Proposed Agreement would provide. However, the cost of adding this liquefaction is considerable and, in the final analysis, virtually triples the cost for customers on an annual fixed cost basis.

Other disadvantages of the LNG and propane options are that those facilities would be considerably more time consuming and difficult to permit and construct, which makes their ultimate cost harder to predict and control. Lastly, security has become an increasing concern for on-system storage facilities in recent years because of their visibility and presence. The case is not the same for underground pipeline facilities.

Q. Does this complete your testimony?

A. Yes, it does.

CONCORD LATERAL / ON SYSTEM ALTERNATIVES

ITEM	PROPANE ($ in M)	LNG ($ in M)	LNG w/ Liquefaction ($ in M)	Comments / Assumptions
Capital Costs (Permitting, Engineering, Materials & Construction)				
LNG Storage Tank	$0.00	$23.80	$23.80	One LNG tank in Concord; storage capacity of 300,000 MMBtu.
Send Out LNG Pump Systems	$0.00	$1.24	$1.24	
LNG Vaporization Systems	$0.00	$0.90	$0.90	Total Vaporization Output Capacity of 25,200 MMBtu/day for LNG and Propane alternatives.
LNG Boiloff Systems	$0.00	$0.81	$0.81	
LNG Trucking Stations	$0.00	$1.56	$1.56	With Pump and Scale
Liquefaction at Concord LNG Facility	$0.00	$0.00	$14.00	3.0 MMSCFD liquefaction capacity.
Propane Storage Tanks	$8.34	$0.00	$0.00	One Propane tank in Concord (550 MMBtu/hr) and one in Nashua (500 MMBtu/hr). 300,000 MMBtu combined storage capacity.
Propane Refrigeration Systems	$1.97	$0.00	$0.00	
Propane Delivery Systems	$4.01	$0.00	$0.00	Total Vaporization Output Capacity of 25,200 MMBtu/day for LNG and Propane alternatives.
Air Delivery Systems	$2.56	$0.00	$0.00	
Propane Air Metering & Regulating (M&R) Station	$1.37	$0.00	$0.00	
Pipeline Connection to New Nashua Propane	$1.00	$0.00	$0.00	Parcel near Hudson Take Station. Install high pressure (planned uprated 185#) inlet and outlet steel piping within a 2,500' common trench.
Pipeline from new Nashua Propane to existing Bridge St., Nashua Plant	$2.50	$0.00	$0.00	Install high pressure steel main from new Nashua Propane Plant, approximately 1.8 miles, including a river crossing, to existing Bridge St., Nashua plant. This pipeline will allow mixed (LP/Air & Natural) gas from the new plant to be discharged into the 130 psig (soon to be 185 psig) and 60 psig distribution systems. In addition, the existing Bridge St., Nashua
Land Cost	$3.52	$0.00	$0.00	16 acres of land needed for the new propane facility in Nashua. Land Cost based on $5.05/s.f. as provided by market comparisons of local land parcels. Assume KeySpan's Concord site has enough land for either the new LNG (10 - 12 acres needed) or Propane (16 acres needed) facility.
Indirect Costs	$5.95	$9.34	$9.34	Permitting, Engineering, Design and Construction Management
Total Direct Cost	$31.22	$37.65	$51.65	

CONCORD LATERAL / ON SYSTEM ALTERNATIVES

ITEM	PROPANE ($ in M)	LNG ($ in M)	LNG w/ Liquefaction ($ in M)	Comments / Assumptions
KeySpan Overhead	$6.65	$9.03	$12.39	Contractor Labor Overhead for Energy North is 48% (as of Jan. '07). This O/H was applied to 50% of project costs, excluding land.
GRAND TOTAL (Capital)	***$37.87***	***$46.68***	***$64.04***	
O&M Costs				
O&M Costs	$0.80	$1.00	$1.33	Administrative, Labor, Expenses, Utilities, etc.
Annual Insurance Costs	$0.20	$0.20	$0.20	Property & Liability Ins. Prepared by Tim Kiernan
Annual Taxes	$0.54	$0.84	$1.15	Prepared by Tom Laird
GRAND TOTAL (O&M)	***$1.54***	***$2.04***	***$2.68***	

NOTES:

Capital cost estimates shown above were provided by CHI Engineering, except for costs associated with: Land; Pipeline Connection to New Nashua Propane; Liquefaction; and Pipeline from new Nashua Propane to existing Bridge St., Nashua Plant.

March 12, 2007
KEDX07066.00

Ed Wencis
Project Engineer
Keyspan Energy Delivery
52 Second Ave
Waltham, MA 02451

RE: LNG Storage & Vaporization Facility Cost

Dear Ed,

In response to your request, we have prepared the following cost estimate for an LNG Storage & Vaporization Facility.

Design Basis:

The design basis for the facility is as follows:

Tank Capacity	0.3 BCF (108,000 BBLS)
Tank Design	Concrete Outer / 9% Nickel Inner
Send out Capacity	24 MMSCFD
Send out Pressure	200 PSIG
LNG Send out Pumps	2 – 100% Capacity Pumps (in tank)
Vaporization	2- 100% Capacity Remote Shell and Tube
Boil-off Compression	2 – 100% Capacity Units
Truck unloading/loading facilities	Two Truck Stations
Controls	PLC Based Control System

Budgetary Cost:

The budgetary (+/- 25%) cost break down of the facility outlined above is as follows:

Storage Tank	$23,800,000
Send out LNG Pump Systems	$1,235,000
Vaporization Systems	$900,000
Boil-off Systems	$810,000
Trucking Stations (with pump and scale)	$1,560,000
Total Direct Costs	$28,305,000
Total Indirect Costs	$9,340,000
Estimated Total Cost	$37,645,000

Other Cost Considerations:

In addition to the capital cost of the LNG facility, KED should also consider the following associated costs:

- Land Cost
- Operating Labor & Expenses
- Utility Costs
- Spare Parts
- Maintenance Labor & Expenses
- Maintenance materials/consumables
- Insurance Costs
- Administrative Costs

We believe this is a complete response to your request. Please review the information and give me a call if you have any questions or require any additional information.

Sincerely,

Peter C. Dirksen

Peter Dirksen P.E
Principal Engineer

PROPANE AIR PLANTS FOR CAPE COD DIVISION

Plant Data	Plant Location	1 Yarmouth	2 Harwich	3 ?	4 ?
Sendout Capacity (Natural Gas Equivalent)	MSCFH	550	500	50	50
Sendout Pressure	PSIG	200	200	200	200
Propane Flow	Lbs/Hr	26,463	24,057	2,406	2,406
Dry Air Flow	SCFM	5,378	4,889	489	489
Heater Output	BTUH	5,954,165	5,412,878	541,288	541,288
Annual Propane Storage Required	BBLS	202,862	173,109	20,286	20,286
Assumed Storage % of Annual		50%	50%	50%	50%
Assumed Storage	BBLS	101,431	86,555	10,143	10,143
Storage Tank Inner Diameter	FEET	85	80	39	39
Storage Tank Inner Height	FEET	101	96	47	47
Roof Rise	FEET	11	11	5	5
Height of Foundation	FEET	5	5	5	5
Total Tank Height	FEET	118	112	57	57

Installed Cost Estimate					
Storage Tank - Double wall, full containment	M$	7,500	6,400	700	700
Refrigeration System	M$	1,065	909	107	107
Propane Delivery System	M$	2,099	1,908	191	191
Air Delivery System	M$	1,340	1,220	120	120
P/A M & R Station	M$	720	650	70	70
Balance of Plant - No Land	M$	3,180	2,770	300	300
Total Estimated Installed Cost (No Land)	**M$**	**15,904**	**13,857**	**1,488**	**1,488**

Operating Data					
Estimated Minimum Land (A square)	Acres	18.0	17.8	16.2	16.2
Refrigeration System Operating	BHP	639	545	64	64
Air compression System Operating	BHP	1,222	1,111	111	111
Heater Fuel - Operating	MMBTUH	7.4	6.8	0.7	0.7