Robert J. Humm
Senior Counsel

September 19, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4846 - 2018 Distribution Adjustment Charge
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] responses to the First Set of Data Requests issued by the Division of Public Utilities and Carriers (Division) in the above-referenced docket.

This filing contains a Motion for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain customer-related information, which is provided in response to Division 1-2 and Attachments DIV 1-2-1 and DIV 1-2-2. Accordingly, National Grid has provided the PUC with one complete unredacted copy of the confidential materials in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release,"** and has included redacted copies of the materials for the public filing.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosures
cc: Docket 4846 Service List
Leo Wold, Esq.
Al Mancini, Division
John Bell, Division
Bruce Oliver, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7415 ■ Robert.humm@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

September 19, 2018
Date

Docket No. 4846 – National Grid –2018 Annual Distribution Adjustment Charge Filing (DAC) - Service List as of 9/11/18

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Distribution Adjustment Charge 2018	)	Docket No. 4846

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On September 18, 2018, National Grid filed responses to the First Set of Data Requests from the Division of Public Utilities and Carriers in this docket (Division Set 1). Division Set 1 includes Data Request Division 1-2, seeking information regarding projects presently being considered by the Company for inclusion in the Advanced Gas Technology (AGT) program. The Company's response to Division 1-2 includes the identity and usage-related information of a customer considering participation in the AGT program. The Company's response to

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Division 1-2 also includes Attachment DIV 1-2-1, which similarly contains the customer's identity and usage-related information, and Attachment DIV 1-2-2, which is a technical assistance study analyzing the customer's potential involvement in the AGT program. As the customer has not yet committed to the AGT program, the customer-related information in the Company's response to Division 1-2 and the attachments thereto is information the Company ordinarily would not share with the public. Additionally, the customer has requested that the Company keep its identity confidential until it has committed to the project. In accordance with Rule 1.2(g)(3), National Grid has provided a redacted public version of the responses and attachments to Division 1-2, as well as an unredacted, confidential version.

Therefore, the Company requests that, pursuant to Rule 1.2(g), the PUC afford confidential treatment to the customer-related information contained in: (1) the Company's response to Division 1-2; (2) Attachment DIV 1-2-1; and (3) Attachment DIV 1-2-2.

II. LEGAL STANDARD

Rule 1.2(g) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40, 47 (R.I. 2001).

The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The customer-related information contained in the Company's response to Division 1-2 and Attachments DIV 1-2-1 and DIV 1-2-2 should be protected from public disclosure. As discussed herein, the response and attachments contain confidential customer-related information, including the identity and usage information of a customer considering whether to participate in the AGT program. The information is of the type that the Company ordinarily would not disclose to the public. In addition, the customer has requested that the Company keep its identity confidential until it has committed to the project. Accordingly, the Company is providing its response to Division 1-2 and Attachments DIV 1-2-1 and 1-2-2 to the PUC on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

_____
Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7415
Dated: September 19, 2018

Division 1-1

Request:

Re: The Direct Testimony of Witness Ann E. Leary at page 7, line 12, though page 8, line 10, for existing AGT project, please identify each potential project considered by the Company for inclusion in the AGT program over the last year and provide:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes by year for the proposed facility;

c. Description of the advanced technology to be utilized;

d. Any workpapers, studies and analyses relied upon to support the Company's assessment of the proposed project;

e. The estimated amount of rebate the Company would offer for each project and the calculations and assumptions used to compute the estimated rebate;

f. The estimated in-service date for the proposed facility;

g. The anticipated schedule for payment of rebates.

Response:

a. The following customers had projects included in the Advanced Gas Technology (AGT) program over the last year: Toray Plastics Inc. (Toray), Aspen Aerogels (Aspen), and Crowne Plaza.

b. Toray's projected annual gas increase volume is 6,349,418 therms. Aspen's projected annual gas increase volume is 471,407 therms. Crowne Plaza's projected annual gas increase volume is 30,311 therms.

c. The advanced technology being used is combined heat and power (CHP) for all three customers.

Division 1-1, page 2

d. The Company used Technical Assistance (TA) studies to determine eligibility for the AGT rebate. Please refer to Attachments DIV 1-1-1, 1-1-2, and 1-1-3 for copies of the TA study for each customer. In addition, the Company performed AGT program financial analyses to determine eligibility. Please refer to Attachments DIV 1-1-4, 1-1-5, and 1-1-6 for copies of the financial analysis for each customer. For additional materials regarding the Company's assessment of the Toray project, please refer to Docket No. 4397.

e. Toray received a $1,800,000 rebate (see Attachment DIV 1-1-4). Aspen received a $300,000 rebate (see Attachment DIV 1-1-5). Crowne Plaza received a $50,000 rebate (see Attachment DIV 1-1-6). The Company determined the rebate amounts based on the available AGT budget under the Distribution Adjustment Charge, the customer's need for the project, and the financial analyses set forth in Attachments DIV 1-1-4 through 1-1-6.

f. Toray's AGT project went in service in December 2015. Aspen's AGT project went in service in June 2017. Crowne Plaza's AGT project went in service in June 2018

g. The schedule for payment of rebates for each project is as follows:

The Company paid Toray four annual rebates – in August 2015 ($500,000), August 2016 ($500,000), August 2017 ($500,000), and September 2018 ($300,000) – for a total of $1,800,000 in rebates. The Company paid Aspen its rebate of $300,000 in September 2017. The Company paid Crowne Plaza its rebate of $50,000 in September 2018.

Combined Heat & Power

Technical Assistance Study

prepared for

Toray Plastics (America), Inc.
North Kingstown, Rhode Island

&

National Grid
Providence, Rhode Island

(Primarily based on Waldron's Combined Heat & Power Feasibility Study dated July 25, 2012.)

Executive Summary

Toray Plastics (America), Waldron Engineering and National Grid jointly participated in a Technical Assistance Study to investigate and conclude the optimal Combined Heat & Power System (CHP) based on Toray's 2011 energy usages and anticipated energy and preventive maintenance costs.

The optimal CHP concluded is a pair of Kawasaki reciprocating engines totaling 12 MWe (Net), while also generating a total of 11,500 Pounds per Hour (pph) of 135 psig steam and 1,000 Tons of chilled water. Medium pressure steam is generated from the engines' exhaust gases heat and the chilled water is generated by a steam turbine-driven, centrifugal chiller. All of the generated electricity will be directed toward the FAN building's loads and all of the chilled water will be directed to the Lumirror building's loads. The generated steam will be used by both the Lumirror and FAN buildings.

Boiler No.3 will continue to remain in Hot Standby (5,000 pph, 650 psig steam) and Lumirror's existing Combustion Gas Turbine (CGT) will continue to serve Lumirror's electric loads. Although the CGT's Duct-Burner will continue to operate, it will be at a much reduced load due to the engines' steam production. Lumirror's chilled water plant will continue utilizing Free-Cooling as the first choice and be followed by the steam turbine-driven chiller when excess steam is available, then the existing electric chillers.

Toray has requested and received contractor costs for the major components of the project (i.e., building, piping, electrical, controls, electric and NG utility interconnections, etc.) in addition to vendor prices on the major equipment (i.e., engine-generator sets, radiators, heat recovery boilers, emission control systems, etc.); including a special offer from Kawasaki for the engines-generators sets.

The following two (2) tables summarize the anticipated financial and energy performance of the proposed CHP, respectively.

Financial Summary

Case Description	Capital Cost ($)	Electricity & Natural Gas Incentives[1] ($)	Net Capital Cost ($)	Electric Costs[2] ($)	Natural Gas Costs[3] ($)	Preventive Maintenance Costs ($)	Total Costs ($)	Net Simple Payback (Years)
Existing	N/A	N/A	N/A	$7,987,360	$4,704,237	$776,309	$13,467,906	N/A
Proposed	$22,700,000	$13,150,000	$9,550,000	$1,382,711	$8,451,663	$2,021,480	$11,855,854	N/A
Savings/(Costs)	($22,700,000)	$13,150,000	($9,550,000)	$6,604,649	($3,747,326)	($1,245,171)	$1,612,052	5.9

Notes:

1. *Electric Energy Efficiency Program Incentive of $11,350,000 and Natural Gas Advanced Gas Technologies Program Incentive of $1,800,000.*
2. *Based on NGrid's projected electric B-62 Distribution Tariff and Toray's projected electric commodity price.*
3. *Based on Toray's projected Natural Gas commodity price.*

Energy Summary

Case Description	Electric Energy (kWh/Y)	Electric Demand (kW)	Natural Gas (Therms/Y)	Steam 650 psig (Lbs./Y)	Steam (135 psig) (Lbs./Y)	Electric Chilled Water[1] (Ton-H)	Steam Chilled Water (Ton-H)
Existing	101,657,000[1]	21,000[1]	7,970,581[2]	339,753,934[3]	0	6,670,597[3]	0
Proposed	14,184,000	14,000	14,319,999	321,191,954	88,805,215	2,167,292	4,503,305
Decreases/(Increases)	87,473,000	7,000	(6,349,418)	18,561,980	(88,805,215)	4,503,305	(4,503,305)

Notes:

1. *Based on NGrid's total, metered data for both Lumirror and FAN in 2011.*
2. *Based on NGrid's total, metered data for the CTG CHP and Boiler No.3 in 2011; all other NG usages excluded.*
3. *Based on metered data provided by Toray.*

2 Facility Description

Toray Plastics (America) has a 70 acre campus located in North Kingston, RI that houses the TorayFan and Lumirror factories along with the corporate headquarters. The TorayFan factory was built in 1987 and is approximately 400,000 square feet. The Lumirror factory, which was built in 1989, is approximately 300,000 square feet. Toray Plastics (America) employs about 680 people and operates twenty-four hours per day, seven days per week, 365 days per year.

The following table summarizes the existing utility infrastructure for both Lumirror and TorayFan.

Existing Lumirror CHP Facility Equipment	
(1) Combustion Turbine Generator, Taurus 70	7.5 MWe, nominal output
(1) Heat Recovery Steam Generator with Natural Gas Duct Burner	600 psig, saturated steam 28,000 lbs/hr Unfired 65,000 lbs/hr with Duct Firing
(5) Electric Centrifugal Chillers	(4) at 450 tons each, 0.567 kW/ton (1) at 700 tons, 0.67 kW/ton
Existing TorayFan Chiller Plant Equipment	
Area A3 Chiller Plant	(2) at 450 ton Electric Centrifugal Chillers
Area A4 Chiller Plant	(2) at 450 ton Electric Centrifugal Chillers
Area A5 Chiller Plant	(2) at 400 ton Electric Centrifugal Chillers
Area J Chiller Plant	(1) at 400 ton Electric Centrifugal Chiller (1) at 500 ton Electric Centrifugal Chiller
Existing Central Boiler Plant Equipment (serves both Lumirror and TorayFan)	
Boiler 1 (being decommissioned)	650 psig, saturated steam 33,000 lbs/hr
Boiler 2 (being refurbished)	650 psig, saturated steam 33,000 lbs/hr
Boiler 3 (normal hot stand-by boiler)	650 psig, saturated steam, 80,000 lbs/hr each

Figure 5 - Existing Facility Equipment Summary

Figure 6 is a schematic representation of the utility infrastructure at Toray Plastics. For additional site information, see the site plan in Appendix A.

Facility Description

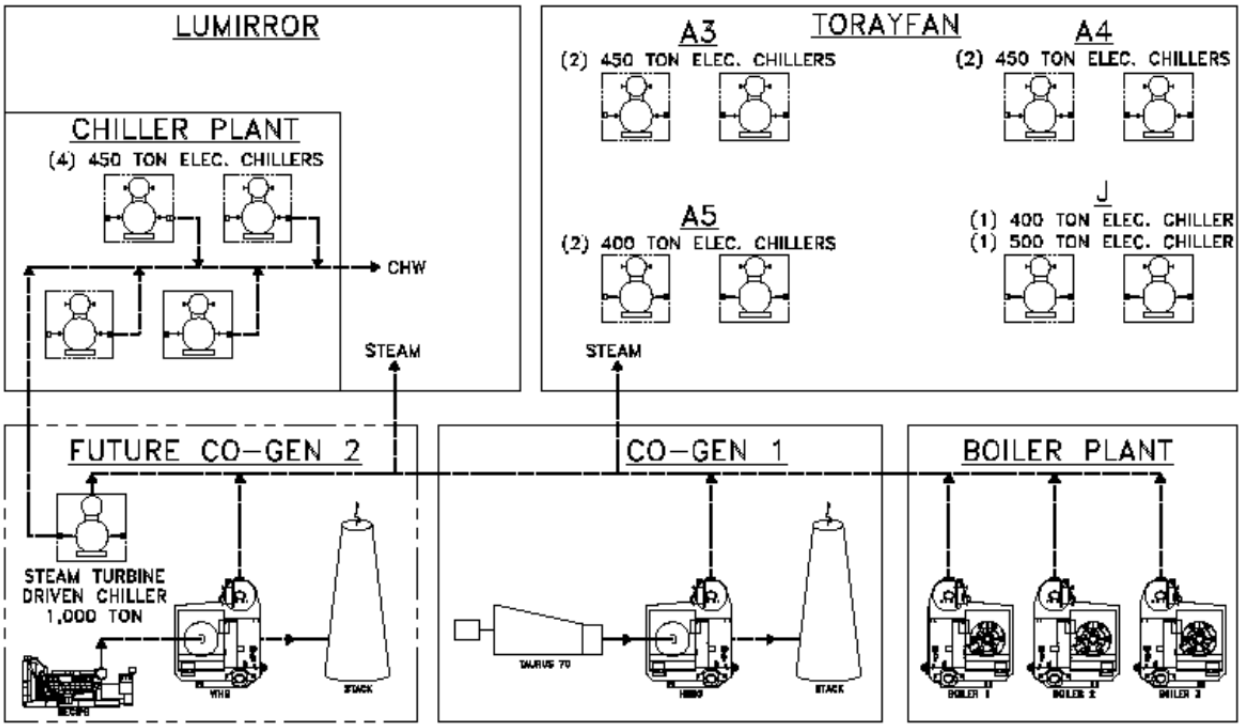


Figure 6 - Utility Infrastructure Schematic

Historic Energy Usages & Costs							
Month	Year	Natural Gas			Electricity		
		(Therms)	($/Therm)	($)	(kWh)	($/kWh)	($)
Jan	2011	814,239	$0.841	$684,775	7,648,363	$0.07857	$600,943
Feb	2011	713,326	$0.841	$599,907	6,916,410	$0.07857	$543,433
Mar	2011	771,750	$0.841	$649,042	7,876,312	$0.07857	$618,854
Apr	2011	635,224	$0.841	$534,224	8,915,153	$0.07857	$700,477
May	2011	631,286	$0.841	$530,912	8,441,409	$0.07857	$663,254
Jun	2011	637,478	$0.841	$536,119	8,589,428	$0.07857	$674,884
Jul	2011	625,631	$0.841	$526,155	9,695,895	$0.07857	$761,821
Aug	2011	625,898	$0.841	$526,380	9,154,925	$0.07857	$719,316
Sep	2011	594,280	$0.841	$499,789	8,757,692	$0.07857	$688,105
Oct	2011	596,348	$0.841	$501,529	9,428,865	$0.07857	$740,840
Nov	2011	620,901	$0.841	$522,177	8,059,351	$0.07857	$633,235
Dec	2011	704,221	$0.841	$592,250	8,173,406	$0.07857	$642,197
Totals		**7,970,581**	**$0.841**	**$6,703,259**	**101,657,209**	**$0.07857**	**$7,987,360**

4 Load Profiles

The first phase of the study was to develop hourly utility load profiles for steam, chilled water, and electricity. These hourly load profiles are loaded into Waldron's 8,760 model to calculate prime mover performance, auxiliary electric loads, waste heat recovery, utility costs, and operating and maintenance costs.

4.1 Steam Load Profile

There are four (4) steam pressure systems used at Lumirror and TorayFan. Currently, all the campus steam is generated at 45 bar. A portion of the steam is reduced to 16 bar for steam loads in Lumirror, another portion is reduced to 7 bar for steam loads in TorayFan, and a third portion is reduced to 5 bar for building heating loads.

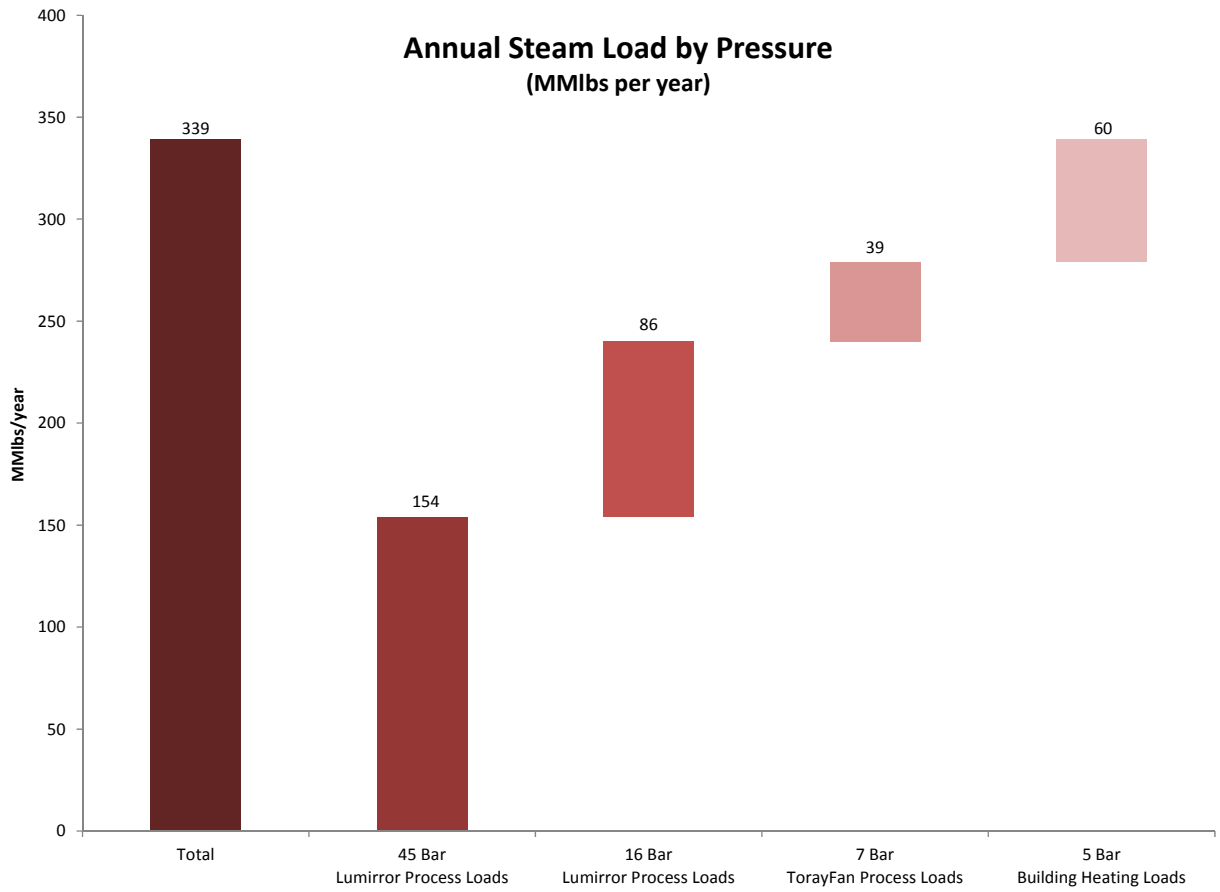


Figure 9 - Annual Steam Load by Pressure

During peak heating season, the unfired capacity of the HRSG is not sufficient to cover the entire steam load, so the duct burners are fired to increase steam production. In the event that the duct fired capacity of the HRSG is insufficient to cover the loads, Boiler #3 is dispatched to cover the remainder.

Toray provided Waldron with historical steam load data for each of the pressure headers on a daily basis.

Hourly steam load data was also provided for a one month period of time. This hourly load data was used to develop the shape of a normalized curve that correlates to the steam load in excess of the process steam load. The process steam load is taken to be constant throughout the year and equates to 30,500 lbs/hr. The 8,760 steam profile was developed by taking the total steam production for the day, netting out the process load, and applying the normalized curve to the residual steam. As a result of this, the general shape of the steam profile for each day is similar, but the magnitude of the curve varies based on the daily total steam load. Figure 10 below shows three examples of the daily steam profile; one curve is for a winter daily steam load of 1.415 MMlbs/day, one curve is for a shoulder season daily steam load of 1.115 MMlbs/day, and one curve is for a summer daily steam load of 0.775 MMlbs/day. In all cases, there is a constant steam process load of 0.732 MMlbs/day.

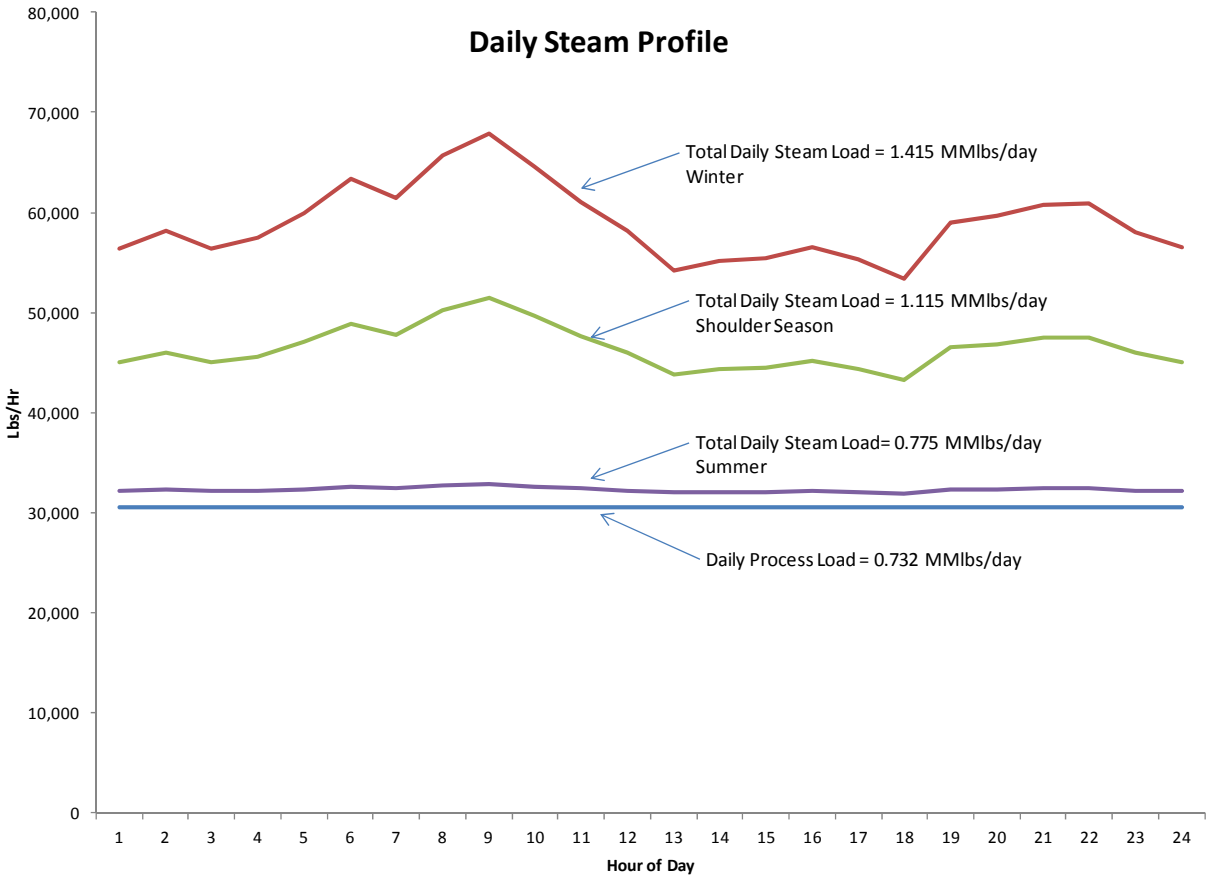


Figure 10 – Shape Examples of Daily Steam Profile

Figure 11 below shows the 8,760 hour total steam load profile for 2011. The annual total of this 8,760 steam profile is within 0.23% of the annual total of the daily load data provided by Toray.

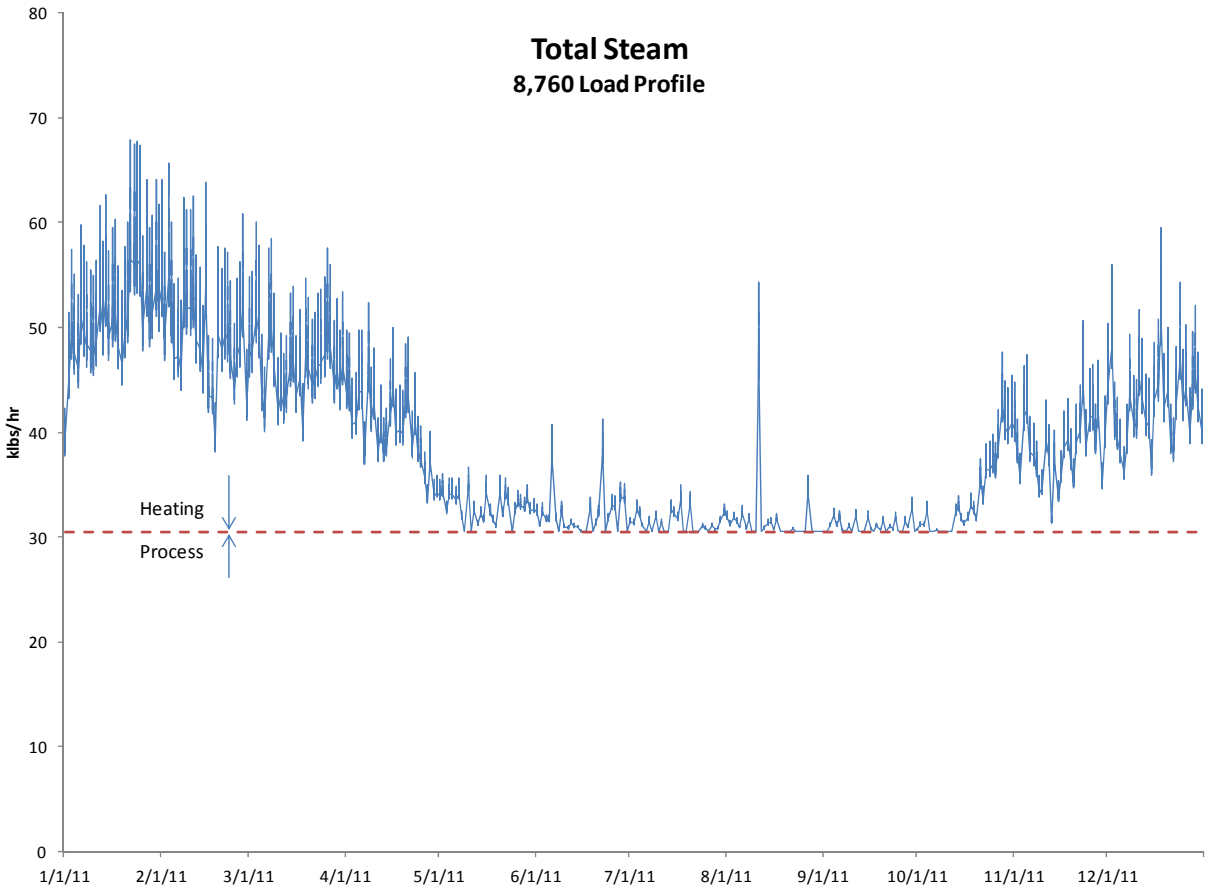


Figure 11 - 8,760 Steam Load Profile

Figure 11 shows the manufacturing process steam load of just over 30 kpph is maintained throughout the year. During the heating season, the steam load increases to a peak of about 68 kpph. The general shape and magnitude of the steam profile was the same for 2010 and 2011.

To maximize the steam production from the recip engines, they were configured to produce steam at 9.5 bar. This provides for better heat recovery compared to generating at 45 bar, and provides sufficient pressure to the steam turbine driven chiller. In order to verify that the steam could be fully utilized, a second steam profile was generated using the same methodology. This steam profile, shown in Figure 12 on the following page, corresponds to the 7 and 5 bar loads and was the profile against which the recip waste heat boilers operate.

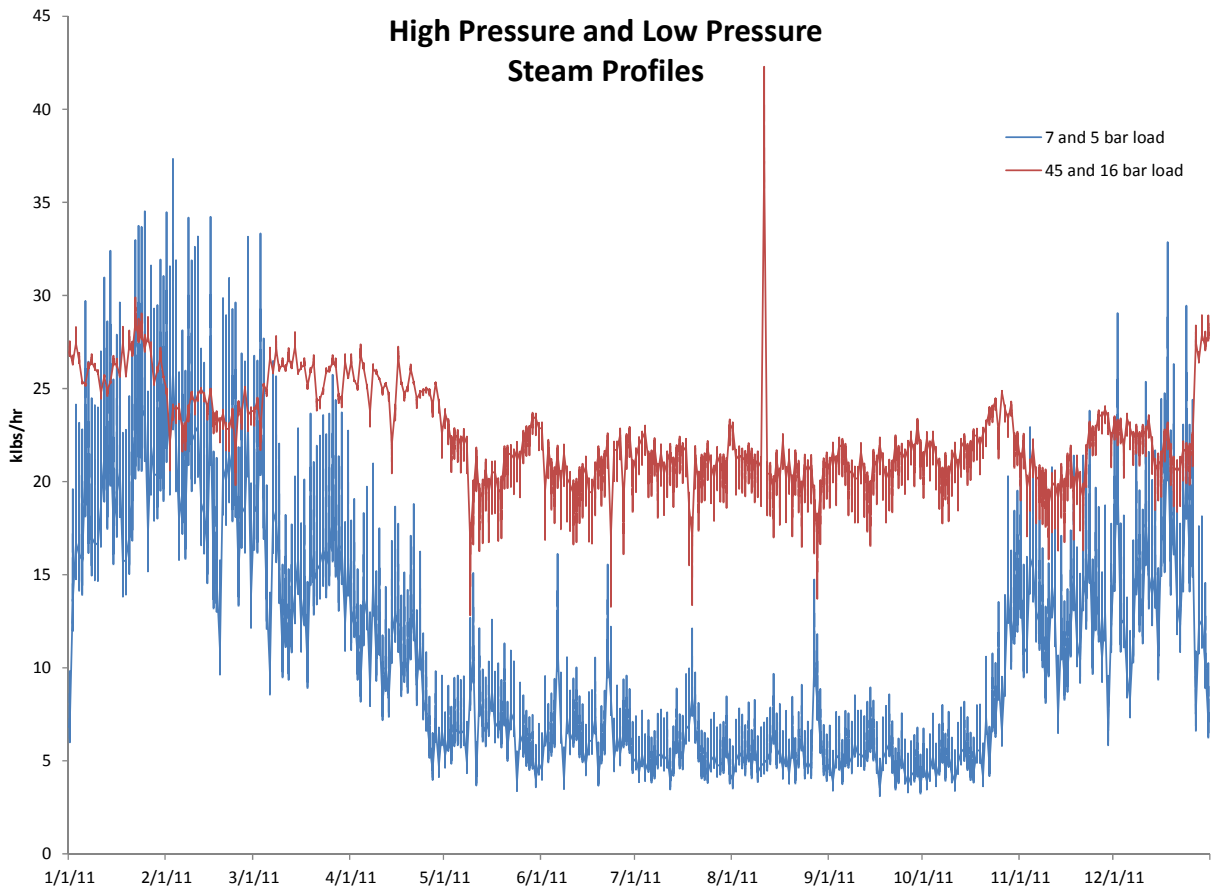


Figure 12 - High Pressure and Low Pressure Steam Profiles

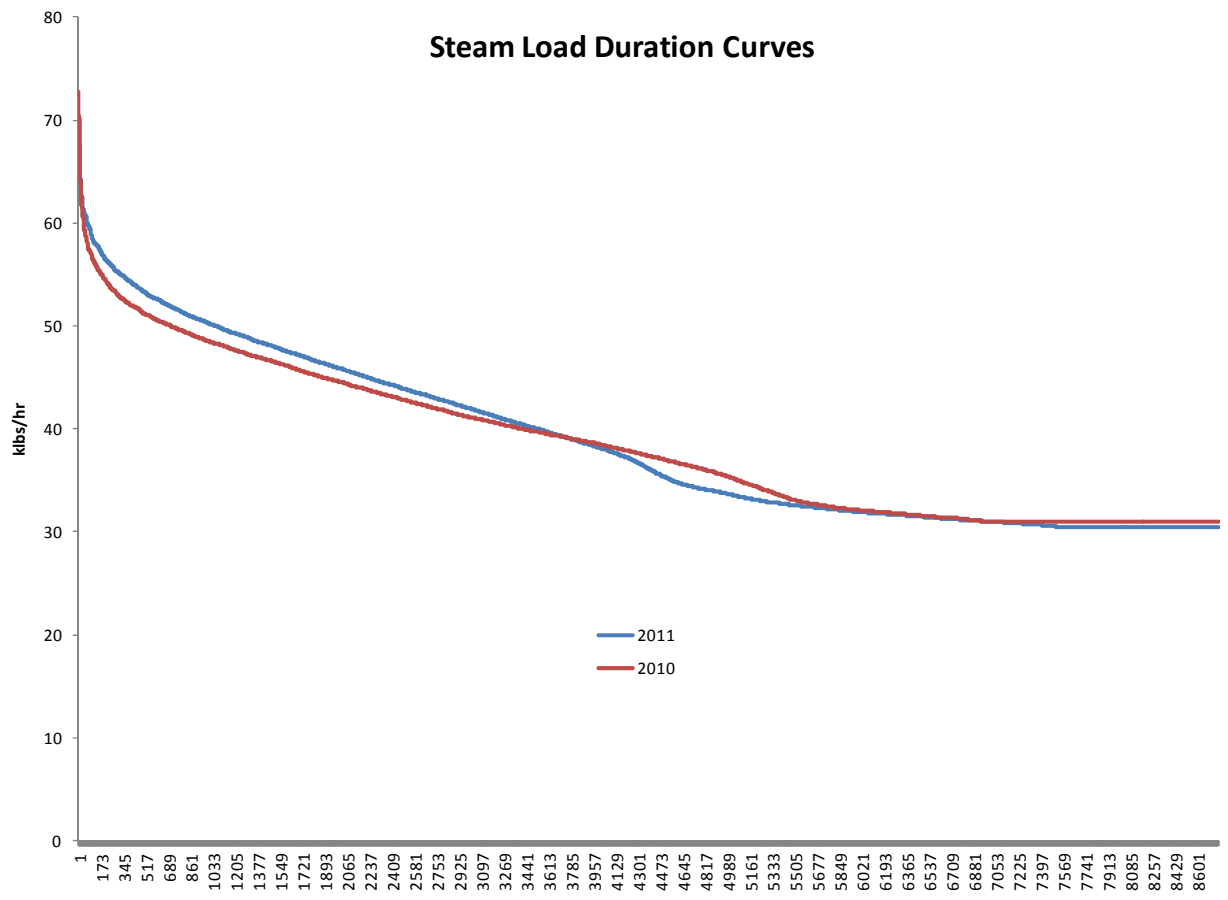


Figure 13 - Steam Duration Curves

Figure 13 shows the load duration curve for 2010 and 2011, which confirms that the year to year steam loads do not differ significantly.

4.2 Electrical Load Profile

Currently the Lumirror factory and the TorayFan factory are metered separately. The Lumirror factory uses the electricity generated by the Solar Taurus 70 CTG in Cogen 1 to offset purchased electricity. Any required electricity that is not provided by the CTG is purchased.

The TorayFan factory has no on-site electrical generation and therefore purchases all needed electricity.

8,760 electric load profiles were generated for both factories based on historical 15 minute interval data provided by Toray.

Although Lumirror and TorayFan are independent load centers, Toray Plastics is a single customer to the utilities (e.g. Toray Plastics receives a single bill for both factories).

The Lumirror electric load profile was used to model the hourly performance of the Taurus 70 CTG, which in turn affects the steam production of the HRSG and Duct Burner. The TorayFan electric profile

was used to model the performance of the proposed CHP. Details of the modeling calculations are provided in Section 6 Modeling Methodology.

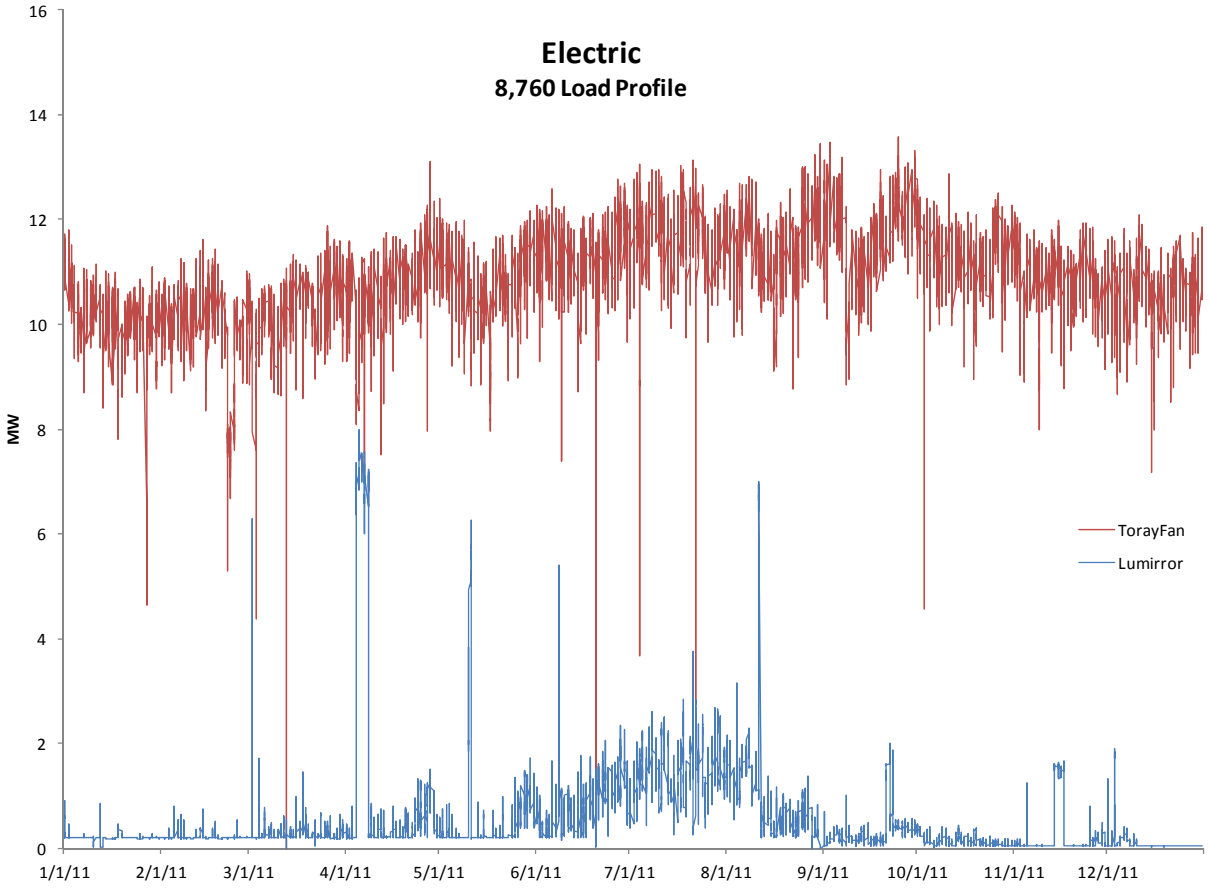


Figure 14 - 8,760 Electric Load Profiles

Figure 14 shows the 8,760 electric load profiles for both TorayFan and Lumirror. Figure 15 shows the load duration curves for both Lumirror and TorayFan for the years 2010 and 2011.

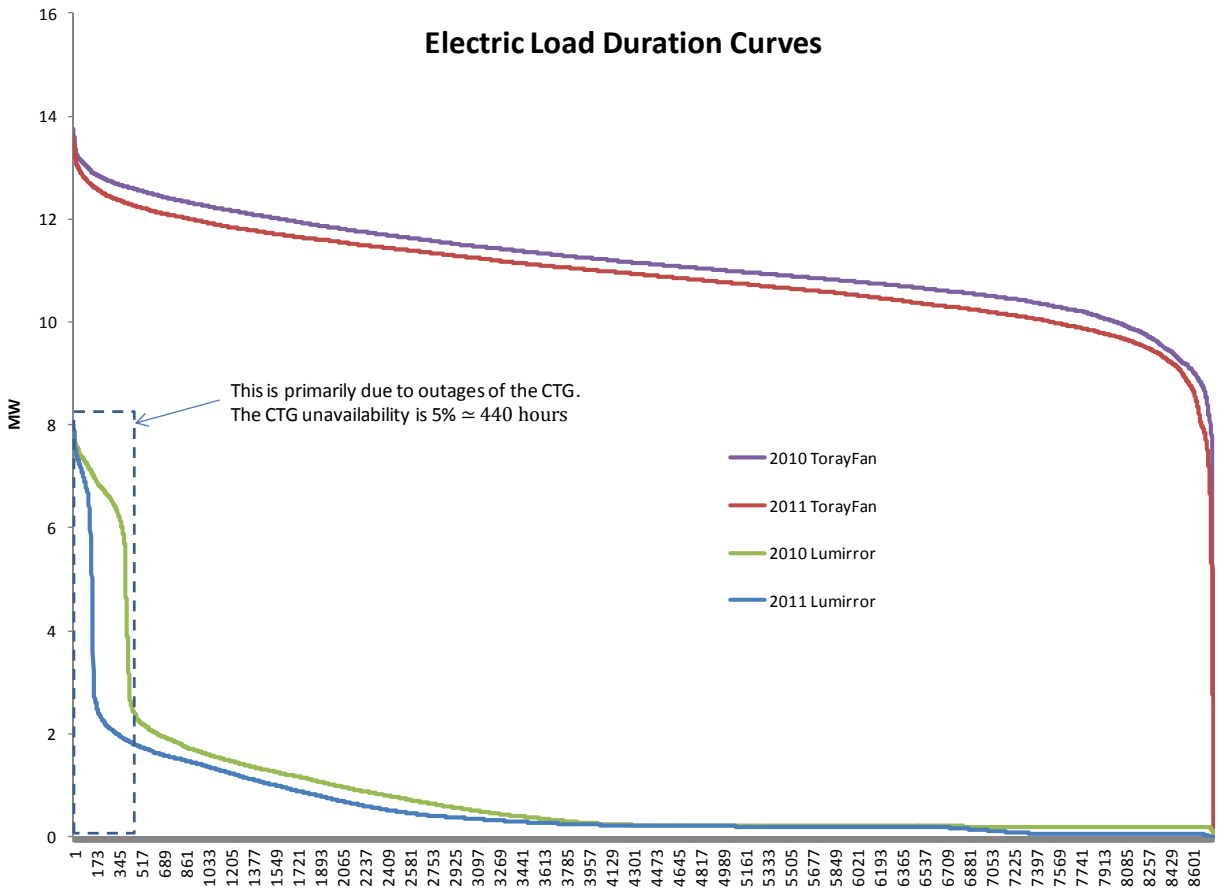


Figure 15 - Electric Load Duration Curves

4.3 Chilled Water Load Profiles

Chilled water for the TorayFan plant is supplied from four different chiller plants within the factory. Historical load data was not available for these chillers. Furthermore, it would be expensive to distribute chilled water from the proposed CHP site to the distributed chiller plants in the TorayFan facility because of their locations relative to the site of the proposed CHP. The Lumirror chiller plant, on the other hand, is located adjacent to the proposed CHP site and it houses all of Lumirror's chillers and chilled water pumps. It would be more cost effective to connect to this system and historical load data existed for this plant, therefore, it was decided to use the proposed steam turbine driven chiller in the CHP to offset the electric motor driven chillers in Lumirror.

Section 6 Modeling Methodology details the electric and thermal interactions between TorayFan and Lumirror and the effects that connecting to Lumirror's chiller plant has on the existing Cogen 1 performance.

Figure 16 shows the 8,760 chilled water profile for Lumirror for 2011. The graphic also illustrates the times during the year when a "free cooling" heat exchanger was used to cover the chilled water load. When the free cooling heat exchanger is used, it is able to cover the entire chilled water load.

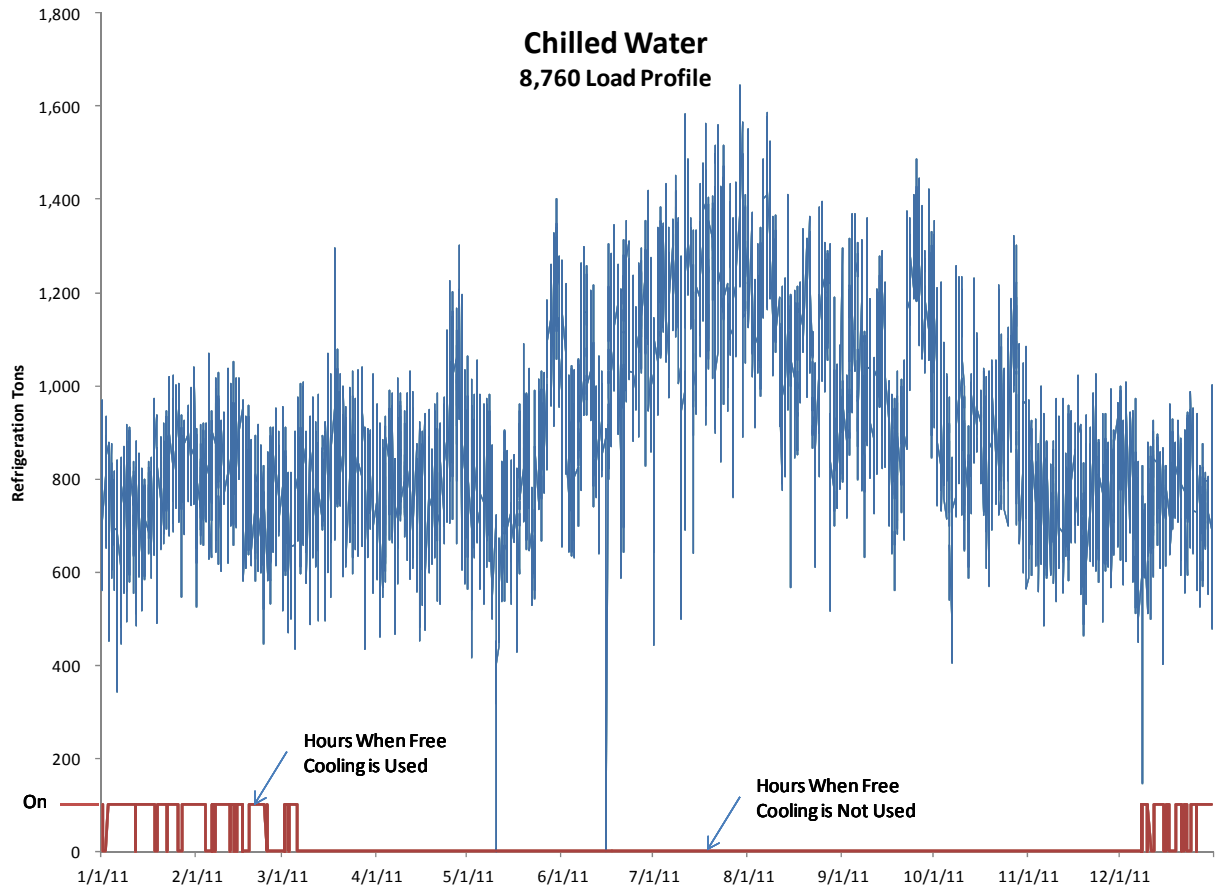


Figure 16 - Chilled Water Load Profile

CHP System Description

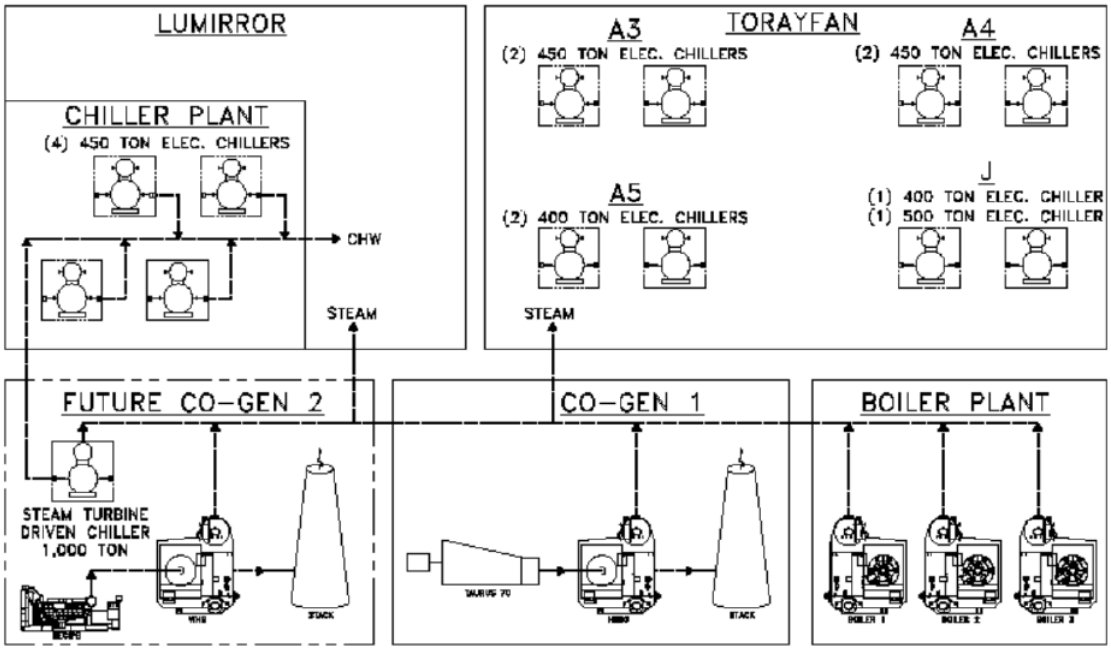
The proposed CHP consists of the following major equipment and is graphically represented by the below diagram.

1. 1 x Reciprocating engine rated at 7.5 MWe and manufactured by Kawasaki Heavy Industries; M/N: KG-18-V.
    a. 1 x Heat Recovery Steam Generator (HRSG) rated at 7,000 pph of 135 psig saturated steam and manufactured by Cleaver-Brooks; M/N: S-2.5-1414.
    b. 1 x Air-Cooled Hot Water Waste Heat Radiator.
    c. 1 x NO_x and CO emissions control system.
    d. 0 x Natural Gas (NG) compressor (i.e., 38 psig supply pressure is acceptable).
2. 1 x Reciprocating engine rated at 5.0 MWe and manufactured by Kawasaki Heavy Industries; M/N: KG-12-V.
    a. 1 x HRSG rated at 4,500 pph of 135 psig saturated steam and manufactured by Cleaver-Brooks; M/N: S-2.5-1414.
    b. 1 x Air-Cooled Hot Water Waste Heat Radiator.
    c. 1 x NO_x and CO emissions control system.
    d. 0 x Natural Gas (NG) compressor (i.e., 38 psig supply pressure is acceptable).
3. 1 x Steam Turbine-Driven Chiller rated at 1,000 Tons and manufactured by York International; M/N: YSTLKLJH9-KGF.
4. 1 x Lot of Electric Parasitic Loads equal to 443 kWe (i.e., 3.54% of each engine's electrical rating).
    a. Various fans and pumps for radiator fans, building exhaust fans, emission control solution pumps, boiler feed-water pumps, etc.
5. 1 x Lot of controls for the proposed CHP and also to integrate the existing CHP's control.
6. 1 x Lot of a new building to house all of the abovementioned equipment as well as the new electric switchgear, piping, plumbing, etc.

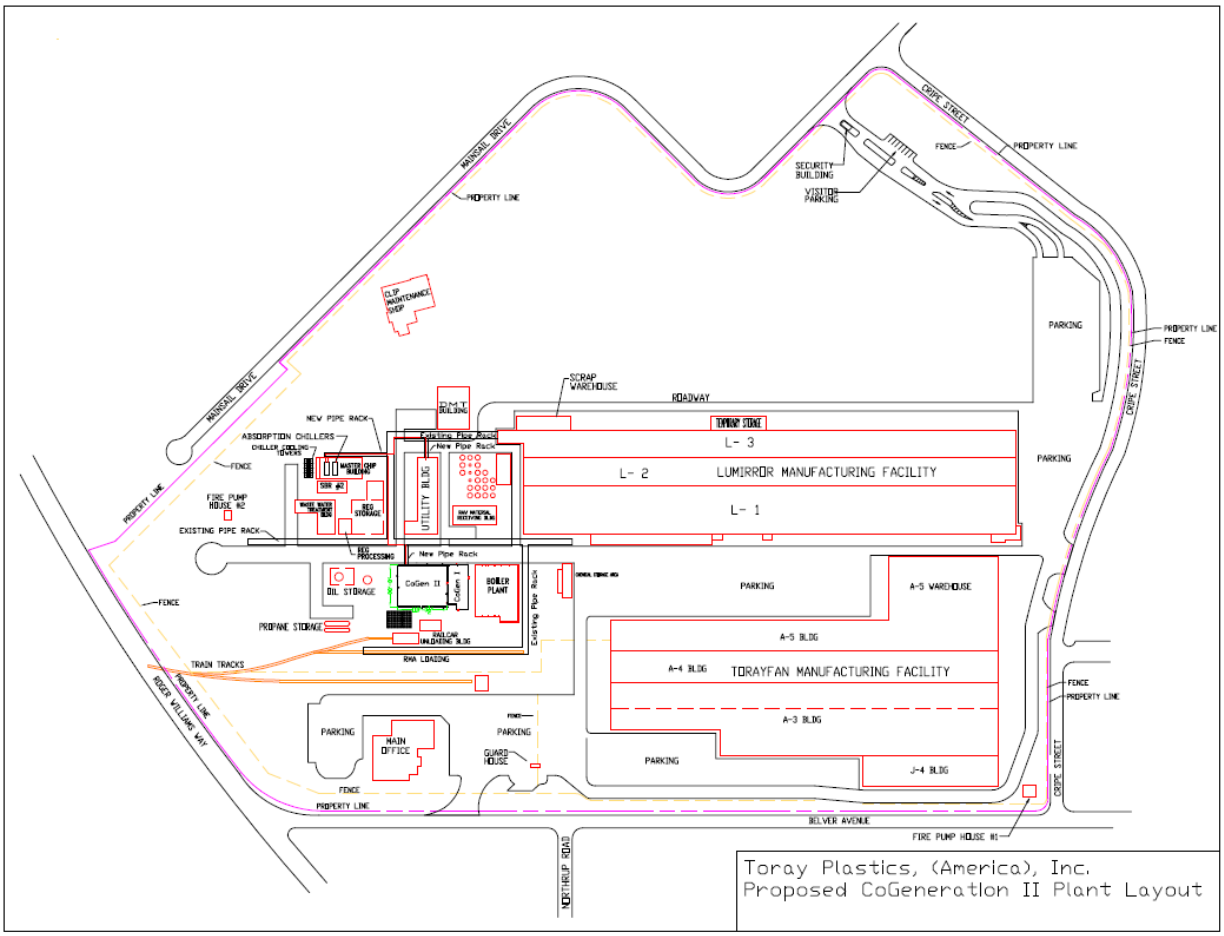
All of the generated electricity will be directed toward the FAN building's process and general loads and all of the chilled water will be directed to the Lumirror building's process and general loads. The 135 psig generated steam generated by the reciprocating engines will be used by both the Lumirror and FAN buildings for both process and space heating and to generate chilled water via the proposed steam turbine-driven chiller.

With regard to the existing major equipment and systems, Boiler Nos. 1 & 2 will remain inoperative, while Boiler No.3 will continue to remain in Hot Standby (i.e., always generating ~5,000 pph, 650 psig steam). Lumirror's existing CGT will continue to serve Lumirror's process and general electric loads. Although the CGT's Duct-Burner will continue to operate, it will be at a significantly reduced 650 psig steam load due to the engines' generating virtually all of the 135 psig steam for Lumirror and FAN. Lumirror's chilled water plant will continue utilizing Free-Cooling as the first choice and be followed by the steam turbine-driven chiller when sufficient steam is available from the reciprocating engines. The existing electric chillers will be the last choice for generating chilled water for Lumirror's process and general chilled water loads. FAN's decentralized chiller plants will not be affected by the proposed CHP.

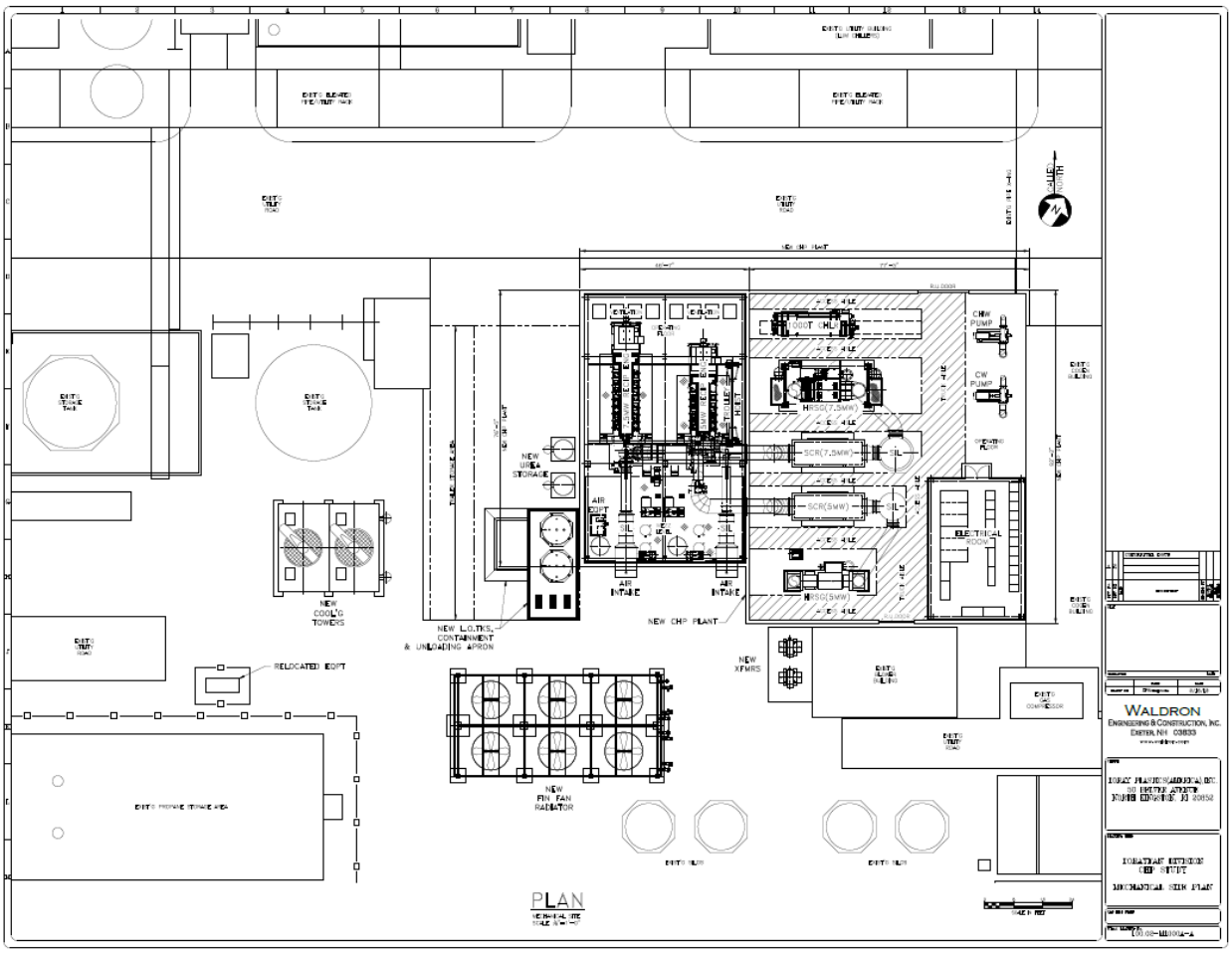
Existing & Proposed Major Equipment & Systems Schematic Diagram



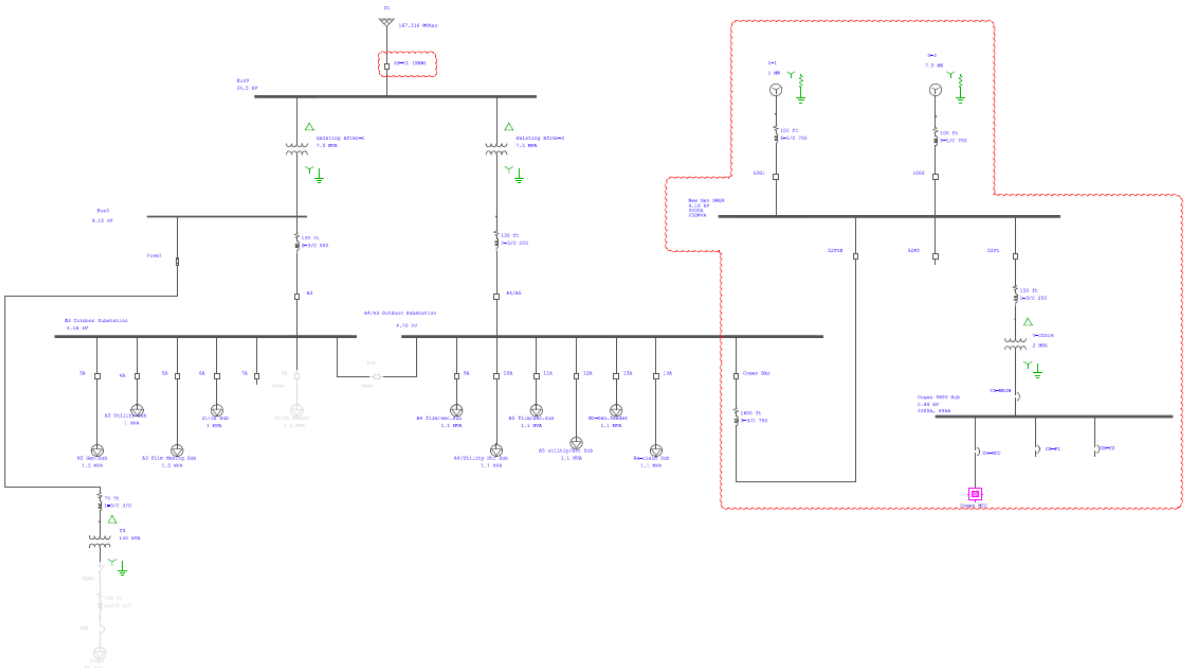
Proposed CHP System Site Plan Building Location



Proposed CHP System
General Arrangement



Proposed CHP System
Electric One-Line Diagram



6 Modeling Methodology

The model developed for this study dispatches the available plant equipment associated with each case in each hour of the year in a sequence intended to meet the facility's utility loads in the lowest overall cost of operation possible. The model contains equipment dispatch sequences for electricity production, steam production and chilled water production, as well as a methodology for utilizing steam and/or electricity to produce chilled water which is dependent upon the available on-site electrical and steam generation resources.

The purchased fuel and electricity associated with the results of each hourly dispatch calculation are fed into rate structure models which apply each line item of the applicable tariffs in order to calculate utility expenses. In addition to the costs associated with purchased fuel and purchased electricity, operation and maintenance costs are accrued in the model based upon equipment operating hours and maintenance cost factors for prime movers, boilers and chillers. Refer to Section 5.1Utility Cost Basis for a summary of the actual prices applied to each of these line item components of overall operating costs.

The model was run for one representative year for each case, and then a life cycle model was created by applying the capital cost and annual savings for each case into a 15-yr pro forma model. The life cycle model treats the capital cost of each case as an "overnight cost", and escalates the annual savings in each future year by 2.2%/yr to create the cash flows over the life of the project.

6.1 Dispatch Sequences and Constraints

Electrical Generation Dispatch Sequence

Electrically, although Toray Plastics is billed by its local utility (NGrid) and its electricity supplier (Freedom?) as a single entity, physical constraints within the facility necessitated the creation of two independent electric nodes within the model: one for Lumirror and one for TorayFan. At each node, the prime movers contained in each case were dispatched in an effort to meet, but never exceed, the electric load of the respective node. Put simply, the existing Taurus 70 combustion turbine at Lumirror can only serve Lumirror electric loads, and likewise new electrical generators proposed for the TorayFan node can only supply power to meet the TorayFan profile. As a result of this configuration, the model independently dispatches the electric generators at each node in each hour of the year, and then calculates the various cost components under the electrical tariff by assessing the coincident outcomes at each node. It is important to note that a minimum electric import is employed in the model at each node to provide a buffer against exporting electricity to the grid. For the CTG the minimum import is 200 kW and for the proposed plant, the minimum import is 350 kW.

The sequencing at each node is straightforward because the electric loads at each node far exceed the minimum operating load of the equipment considered in each case. Thus, the equipment always runs- subject to an availability profile which shuts the equipment down in various hours to simulate scheduled and forced outages- in a load-following mode at each node.

The electrical load at each node is the sum of multiple components: the base electrical profile of the node, the calculated auxiliary loads required to run the utility plant, and the calculated auxiliary loads required

to produce chilled water.

Steam Generation Dispatch Sequence

With respect to steam, the model contains a "high pressure" (45 bar) and "low pressure" (9.5 bar) profile. The high pressure profile corresponds to the combination of the 45 and 16 bar loads; the low pressure profile corresponds to the 7 and 5 bar loads. The low pressure header is intended to be maintained at 9.5 bar to provide adequate steam pressure to the steam turbine driven chiller.

The steam load is the sum of multiple components: the base steam profile of the facility and the calculated steam consumption of steam chillers as applicable in each case. (Note: pegging steam to the deaerator is implicitly contained within the base steam profiles.) Steam is dispatched to produce chilled water in accordance with the Chilled Water Dispatch Sequence described in the following section.

Once the steam load is established, the steam dispatch sequence is as follows:

1. Maximize use of steam produced using waste heat from the electric generators at each node, without duct-firing. Excess unfired steam production from waste heat is simply vented to atmosphere in the model.

2. If additional steam is needed to satisfy the steam loads, dispatch duct-firing in the existing HRSG at Lumirror.

3. If the Taurus 70 is down for maintenance and duct-firing is not available, dispatch one of the existing package boilers at the facility.

Chilled Water Generation Dispatch Sequence

The model explicitly deals with a single chilled water node, which is at Lumirror. The existing chilled water load(s) at TorayFan are implicitly contained within the historical TorayFan electrical load profile, and are addressed simply by supplying the required electricity. The electricity required historically to meet the Lumirror chilled water demand, however, was calculated in an hourly model (which also took into account historical free cooling at Lumirror) and then subtracted from the historical electric profile at Lumirror. The corresponding chilled water load profile for Lumirror was included in the model, and chillers are dispatched in the hourly dispatch calculations as required to meet this profile.

Because the summer steam load of the entire facility is already satisfied using steam produced by the existing HRSG at Lumirror, any steam produced in the summer from waste heat at the new TorayFan electrical node would be under-utilized. A steam-turbine driven chiller was thus included at Lumirror in each case in an effort to better utilize the available steam and improve the overall efficiency and economics of the proposed cases.

The introduction of a steam-driven chiller introduces new interactions to the model, however, since chilled water could be produced from six different resources (not listed in order of priority):

- Electricity self-generated at Lumirror with the Taurus 70;

- Steam self-generated at Lumirror from waste heat;
- Steam self-generated at Lumirror from duct-firing;
- Steam self-generated at Lumirror from package boiler operation;
- Steam self-generated at TorayFan from waste heat; and
- Grid-purchased electricity.

The actual dispatch sequence for chilled water production follows the following dispatch sequence in order to produce the lowest possible production cost for each case:

1. Utilize steam produced from waste heat first; however, only use unfired steam for chilled water production if the process steam load has been satisfied. This means that much of the year unfired steam is unavailable for chilled water production.
2. If the Taurus 70 at Lumirror is less than fully loaded, increase electrical output of the combustion turbine and use the incremental electricity to produce chilled water and/or power chiller plant auxiliary loads, while using the incremental unfired steam production to produce chilled water in the steam-driven chiller.
3. These two modes cover the bulk of the annual chilled water production at Lumirror; however, if the combustion turbine is down for maintenance or additional chilled water is still required, then grid-purchased electricity is utilized to produce chilled water. This was selected as the next resource dispatched because of the low cost of power: in the base case model chilled water may be produced for approximately 1¢ per ton cheaper using power purchased from the grid.
4. Finally, steam from package boilers is utilized to produce chilled water.

6.2 Equipment Performance Calculations

Combustion Turbine Performance

Four basic parameters of combustion turbine performance are calculated in each hour for the existing Taurus 70 at Lumirror: output, heat rate, exhaust mass flow and exhaust temperature. Each of these values is calculated as a function of turbine load (% of full load output at the ambient temperature that hour) and ambient temperature (using typical meteorological year data for Providence, RI, per NGrid's requirements). The model contains a curve for turbine performance for each parameter at 100%, 75% and 50% load, covering a range of ambient temperatures from 0-100 deg F. The values used in the model for each hour are based upon interpolation between these curves.

These curves were calibrated to historical performance of the Lumirror Taurus 70 utilizing data supplied by Toray and corresponding historical weather data. Comparisons between vendor performance maps and actual measured performance at several operating points were made, and the performance curves were scaled accordingly. The "calibrated" performance map of the turbine was validated by calculating annual fuel consumption of this turbine as it ran against an historical generator output profile, in an 8,760-

hr model, and comparing the calculated fuel consumption to historical fuel records provided by Toray. A similar approach was taken to calibrate steam production in the existing waste heat boiler to historical values.

The performance maps of the existing Taurus 70 are shown below for output and heat rate.

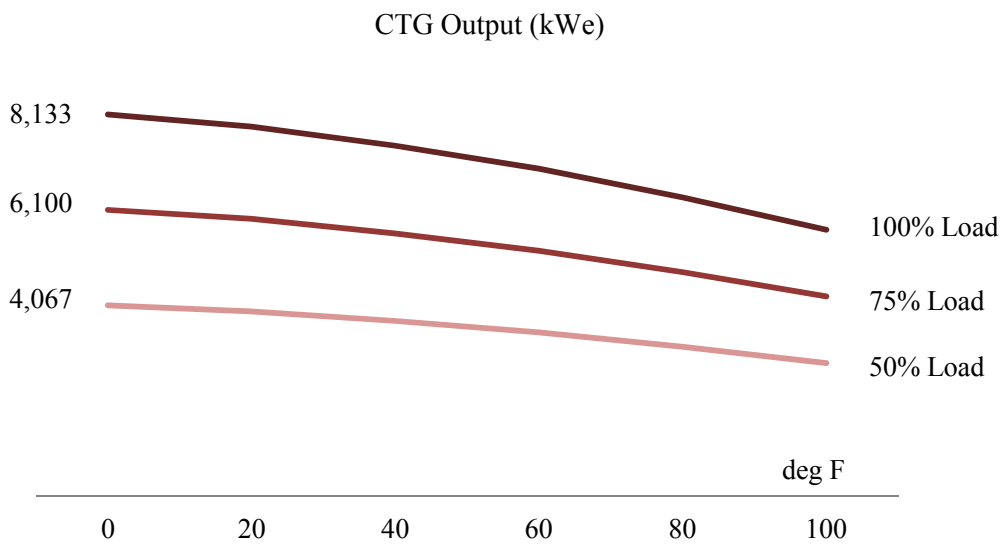


Figure 22 - Existing Taurus 70 Output Curves

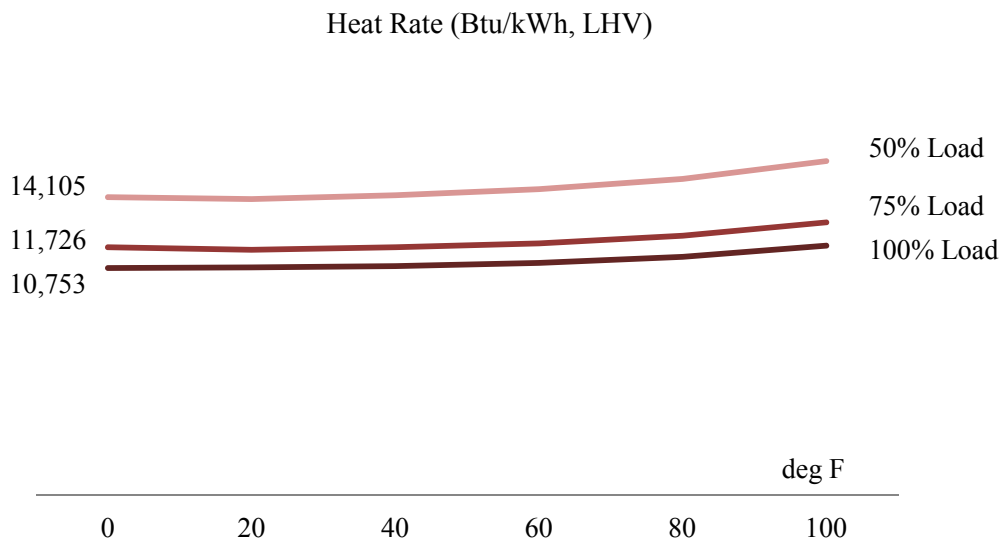


Figure 23 - Existing Taurus 70 Heat Rate Curves

Ambient Temperature (deg F)	100% Output (kW)	75% Output (kW)	50% Output (kW)	100% Heatrate (Btu/kWh, LHV)	75% Heatrate (Btu/kWh, LHV)	50% Heatrate (Btu/kWh, LHV)
0	8,133	6,100	4,067	10,792	11,769	14,157
20	7,875	5,907	3,938	10,811	11,654	14,061
40	7,465	5,599	3,733	10,880	11,765	14,236
60	6,977	5,232	3,488	11,026	11,960	14,523
80	6,367	4,775	3,184	11,317	12,317	15,019
100	5,677	4,258	2,839	11,845	12,946	15,866

Ambient Temperature (deg F)	100% Exhaust Flow (lb/hr)	75% Exhaust Flow (lb/hr)	50% Exhaust Flow (lb/hr)	100% Exhaust Temp (deg F)	75% Exhaust Temp (deg F)	50% Exhaust Temp (deg F)
0	244,703	204,267	160,686	887	905	978
20	237,585	195,449	152,549	904	921	1,006
40	230,335	189,706	148,442	910	928	1,013
60	221,387	182,483	143,216	919	940	1,024
80	209,188	172,760	136,116	935	957	1,040
100	195,745	162,121	128,366	961	983	1,063

Figure 24 - Existing Taurus 70 Performance Data Table

Reciprocating Engine Performance

An identical methodology is utilized for calculating the performance of the reciprocating engines proposed for the various cases. The data tables for the reciprocating engines reviewed in this study are contained below, and are based upon data supplied by Kawasaki (refer to Appendix F):

Ambient Temperature (deg F)	100% Output (kW)	75% Output (kW)	50% Output (kW)	100% Heatrate (Btu/kWh, LHV)	75% Heatrate (Btu/kWh, LHV)	50% Heatrate (Btu/kWh, LHV)
10	5,000	3,750	2,500	6,784	6,964	7,418
30	5,000	3,750	2,500	6,840	7,023	7,485
50	5,000	3,750	2,500	6,895	7,081	7,551
60	5,000	3,750	2,500	6,918	7,106	7,579
80	5,000	3,750	2,500	6,965	7,155	7,635
100	5,000	3,750	2,500	7,037	7,231	7,722

Ambient Temperature (deg F)	100% Exhaust Flow (lb/hr)	75% Exhaust Flow (lb/hr)	50% Exhaust Flow (lb/hr)	100% Exhaust Temp (deg F)	75% Exhaust Temp (deg F)	50% Exhaust Temp (deg F)
0	66,960	50,760	35,280	583	655	691
20	66,960	50,760	35,280	590	662	698
40	66,960	50,760	35,280	597	669	705
60	66,960	50,760	35,280	601	673	709
80	66,960	50,760	35,280	608	680	716
100	66,960	50,760	35,280	622	695	730

Figure 25 - Kawasaki KG-12 Engine Performance Data Table

Ambient Temperature (deg F)	100% Output (kW)	75% Output (kW)	50% Output (kW)	100% Heatrate (Btu/kWh, LHV)	75% Heatrate (Btu/kWh, LHV)	50% Heatrate (Btu/kWh, LHV)
10	7,500	5,625	3,750	6,784	6,964	7,418
30	7,500	5,625	3,750	6,840	7,023	7,485
50	7,500	5,625	3,750	6,895	7,081	7,551
60	7,500	5,625	3,750	6,918	7,106	7,579
80	7,500	5,625	3,750	6,965	7,155	7,635
100	7,500	5,625	3,750	7,037	7,231	7,722

Ambient Temperature (deg F)	100% Exhaust Flow (lb/hr)	75% Exhaust Flow (lb/hr)	50% Exhaust Flow (lb/hr)	100% Exhaust Temp (deg F)	75% Exhaust Temp (deg F)	50% Exhaust Temp (deg F)
0	100,440	76,140	52,920	583	655	691
20	100,440	76,140	52,920	590	662	698
40	100,440	76,140	52,920	597	669	705
60	100,440	76,140	52,920	601	673	709
80	100,440	76,140	52,920	608	680	716
100	100,440	76,140	52,920	622	695	730

Figure 26 - Kawasaki KG-18 Engine Performance Data Table

Chiller Performance

The energy consumption per ton (e.g. lbs/hr of steam or kW of electricity) is calculated for each chiller dispatched. This parameter is calculated as a function of condenser water temperature and chiller load factor. The condenser water temperature is set based upon the ambient wet bulb temperature. The model contains performance data tables for each chiller which contain data from a chiller manufacturer for the energy consumption per ton at three condenser water temperatures- 65°F, 75°F and 85°F- at load factors from 10% - 100%.

Chiller Load	65F ECWT	75F ECWT	85F ECWT
10%	0.545	0.635	0.738
20%	0.454	0.536	0.618
30%	0.423	0.498	0.585
40%	0.414	0.485	0.568
50%	0.414	0.484	0.567
60%	0.446	0.524	0.616
70%	0.441	0.518	0.609
80%	0.441	0.516	0.608
90%	0.444	0.519	0.612
100%	0.451	0.527	0.62

Figure 27 - Chiller Performance Data, Existing Electric Chillers (kW/ton)

Chiller Load	65F ECWT	75F ECWT	85F ECWT
15%	7.62	9.98	13.82
20%	7.01	9.17	12.36
30%	6.42	8.55	11.39
40%	5.97	8.27	10.75
50%	5.87	7.99	10.13
60%	5.96	7.73	9.73
70%	6.09	7.64	9.56
80%	6.26	7.69	9.70
90%	6.42	7.84	9.76
100%	9.94	8.31	9.93

Figure 28 - Chiller Performance Data, Steam Turbine Driven Chiller (lbs/ton-hr)

The steam turbine driven chiller performance is based on a York YSTLKLJH9-KGF.

Auxiliary Steam and Electric Loads

The model calculates auxiliary loads by multiplying an auxiliary load factor by a corresponding quantity of generation. For instance, in order to calculate the electrical power to operate the pumps and fans associated with operation of the reciprocating engines, the electrical output of the engines is multiplied by 4% to estimate these auxiliary loads.

The following auxiliary load factors were applied:

Reciprocating Engine, Balance of Plant Electric Auxiliaries:	4% of Output
Combustion Turbine, Balance of Plant Electric Auxiliaries:	3.54% of Output*
Electric Chiller Operation, Chilled/Condenser Water Auxiliaries:	0.2 kW per ton
Steam Chiller Operation, Chilled/Condenser Water Auxiliaries:	0.25 kW per ton

* The CTG auxiliaries are based on 75% of the Cogen-1 connected auxiliary equipment motor load list, including: oil cooler(s), gas compressor, air compressor(s), etc.

Unfired Steam Production

Steam production from waste heat is calculated in accordance with the following basic equation:

$$Steam_{Unfired} = \frac{Mass_{exhaust} * C_{p,exh} * (T_{exh} - T_{stack})}{(h_{steam} - h_{feedwater})}$$

$Mass_{exhaust}$ = Prime Mover Exhaust Flow, lbs/hr, from Performance Curves
$C_{p,\ exh}$ = Specific Heat of Exhaust Gas, 0.265 Btu/lb-deg F
T_{exh} = Primer Mover Exhaust Temperature, deg F, from Performance Curves
T_{stack} = Exhaust Temperature After Heat Recovery, 354 deg F for Cogen-1 and 402 deg F for the new CHP.
h_{steam} = Enthalpy of Steam, 1,202 Btu/lbm (650 psig, saturated)
$h_{feedwater}$ = Enthalpy of Deaerated Feedwater, 208 Btu/lbm

Duct Fired Steam Production

Steam production from duct-firing is calculated in the same basic manner; however, the exhaust temperature in the numerator of the equation above is replaced with the duct burner outlet temperature, and the stack temperature is reduced to reflect increased efficiency of heat transfer with duct-firing. The stack temperature when duct firing is interpolated between the un-fired and fired temperatures shown in Figure 28. The interpolation is based on the ratio of duct burner fuel input for that hour to the maximum duct burner fuel input.

	Exhaust Stack Temperature (°F)	
	Unfired	Fired
Gas Turbine	354	289
Recip Engine	402	n/a

Figure 29 - Stack Temperatures

The heat input to the duct burner is calculated assuming a 90% efficiency on an HHV basis, meaning that 90% of the HHV energy content of the fuel is available for steam production.

Modeling Interactions

The above sections describe the basic methodology of the model; however, they do not in and of themselves provide insight into some of the types of interactions that emerged as a result of its application. The trends described below are described in relation to the 12.5 MW Kawasaki Case, which is the case that produced the best overall economic result.

Reduced CTG Output at Lumirror

The use of unfired steam from the new reciprocating engine plant at TorayFan to produce chilled water at Lumirror resulted in a slight reduction in the annual electrical output of the existing Taurus 70. The magnitude of the reduction was approximately 3.6% of the Base Case value.

Reduced Duct-Firing at Lumirror

Duct-firing at Lumirror was reduced due to the steam production from the new reciprocating engine plant at TorayFan. The magnitude of the reduction was 83% of the Base Case value.

Increased Unit Price of Electricity

Although the total annual cost of purchased electricity dropped considerably as a result of the electrical production from the new reciprocating engine plant at TorayFan, the residual quantity of purchased electricity cost nearly twice as much as the Base Case value on a unit basis.

In the Base Case, the all-in cost of purchased electricity was $0.079/kWh, and in the 12.5 MW Kawasaki Case the value increased to $0.098/kWh. The former value is for a purchased electricity profile with a very high and consistent load factor, and the latter reflects a plant with a fairly low load factor. This is primarily due to the fact that demand charges simply do not fall in proportion to the reduction of total purchased electricity.

Availability Assumptions

In all the models that Waldron generated, the Taurus 70 CTG availability was based on the historical availability of the plant, which was derived from the electric metered data for the CHP.

In models that included a Recip engine, an availability of 93% was used to randomly generate periods of time for scheduled and unscheduled maintenance.

	Screening Model	Refined Model
Combustion Turbine with Medium Pressure HRSG's ($/kWh)	0.014	0.014
Reciprocating Engine ($/kWh)	0.012	0.014
MP Boiler Plant ($/klb)	0.15	0.15
Chiller Plant O&M ($/ton-hr)	0.004	0.004 (electric) 0.0052 (steam)

Capital Cost Methodology & Estimate

The proposed CHP's Capital Cost estimate was initially estimated by Waldron Engineering and later-on refined by Toray's Engineering Department. Waldron's original estimate is shown in the below table, but is not used in this TA Study, since Toray has chosen an in-house approach on constructing their CHP project, rather than Waldron's initially proposed turn-key approach.

Toray's Capital Cost estimate refinement eliminated services and the commensurate costs typically provided by third-parties proposing turn-key services, while simultaneously adding other necessary line items such as, electric utility interconnection costs. Since Toray has previously installed a 7.5 MWe CHP onsite, it plans on providing these services with their in-house staff. To that end, the below table represents Toray's refined pricing, which is partly based on Waldron's line item estimates and more detailed pricing for the major equipment and installation services from major equipment vendors (i.e., reciprocating engines, switchgear, controls, etc.) and local construction (i.e., site work, building, piping, plumbing, electrical, controls, etc.) companies. Where local construction costs were used, the average of two (2) or more proposals was used.

It's important to note the most significant component of *Line Item No.2 - Procurement (Equipment)* is the Kawasaki engine-generator sets and their shipping charge. In short, Toray solicited and used local pricing to support ~90% of the total, Capital Cost of $22,700,000 (i.e., 92% = $21,000,000 ÷ $22,700,000).

Capital Cost Estimate

		WALDRON	TORAY	
ITEM NO.	DESCRIPTION	$	$	
1	Engineering	$1,299,196	Included	
2	Procurement (Equipment)	$13,992,237	$12,022,168	
3	Construction Directs			
	Building	$2,061,059	$1,600,000	
	Piping/Insulation	$773,575	$2,445,898	
	Elect/Controls	$702,535	$3,584,513	Includes Elect. Equip.
	Rigging	$275,840	$275,840	
	Duct	$143,293	$143,293	
	Construction Support	$1,515,868	Included	
	Ngrid Interconnection	$0	$1,200,000	
	Subtotal # 1	$5,472,170	$9,249,544	
4	Construction Indirects	$0		
5	Commissioning & Start-up	$319,327	$319,327	
6	Construction Management	$1,167,864	$0	
	Subtotal # 2	$22,250,795	$21,591,039	
7	7% Sales Tax	$1,170,983	$0	
8	3% Estimating Contingency	$667,524	$0	
	Subtotal # 3	$24,089,301	$21,591,039	
9	7.5% Construction Contingency	$410,413	$0	
10	5.0% Project Contingency	$0	$1,079,552	
	Subtotal # 4	$24,499,714	$22,670,591	
11	5% Overhead	$1,224,986	$0	
12	5% Profit	$1,224,986	$0	
	Subtotal # 5	$26,949,685	$22,670,591	
13	FINAL TOTAL	$26,949,685	$22,670,591	
14	FINAL TOTAL	$26,950,000	$22,700,000	

Financial Analysis

The financial analysis focuses on quantifying the Operating Costs associated with purchasing NG, displacing electricity and NG and performing Preventive Maintenance on the existing and proposed equipment. In short, future energy costs were applied to the Base Case (2011 energy usages) and Proposed Case (modeled energy usages). Both Cases' energy usages were modeled for 8,760 Hours/Year, therefore, the correct energy and demand values could be easily identified and used to correctly calculate the "all-in" electricity and NG costs (i.e., Commodity and regulated Distribution services). Preventive Maintenance costs were performed in similar level of detail and precision. Once these costs were correctly assigned, the Proposed Case's total, Operating Cost was subtracted from the Base Case's total, operating Cost to arrive at the net, annual Operating Cost savings.

Since Toray has its own in-house, Internal Rate-of-Return Financial Analysis, this TA Study focused on providing the data essential to Toray running its analysis. Thus, only Simple Payback (i.e., Capital Cost ÷ Annual Operating Savings) is addressed in this TA Study.

Natural Gas

The NG costs are comprised of three (3) major components…

1. Commodity;
2. Basis points; and
3. National Grid's current Distribution Service Rate.

The Commodity unit cost is derived from the NYMEX (Henry Hub delivery point) Wholesale Charge for Futures Contracts. At the time of this TA Study (i.e., Trade date of 02/08/2012.), the traded, unit price for Commodity was $4.092/MMBtu for a 01/01/2014 Delivery date (i.e., initially estimated CHP availability).

The Basis Points is the charge a third-party marketer will charge Toray to move the NG from Henry Hub to National Grid's "RI City Gate". Toray has supplied documentation illustrating its purchasing power to acquire this service at $0.86/MMBtu (i.e., "TPA Utility Cost Analysis 2-20-12.xls" and an invoice).

The Distribution Service Rate used in this TA Study is National Grid's Extra-Large, High Load Factor, Rate 24. After running the Base Case and Proposed Case through the Service Rate, it results in $0.95/MMBtu.

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Trade Date: 2/8/2012

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Month	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Lo Limit	Updated
Mar 2012		2.482	+0.010	2.472	2.492	2.508	2.390	98,720	5.472 No Limit	11:37:47 AM CT 2/8/2012
Apr 2012		2.621 b	-0.007	2.628	2.638	2.649	2.547	42,653	5.628 No Limit	11:37:42 AM CT 2/8/2012
May 2012		2.725	-0.019	2.744	2.757	2.761	2.660	33,670	5.744 No Limit	11:37:35 AM CT 2/8/2012
Jun 2012		2.810	-0.022	2.832	2.828	2.840 b	2.750	19,224	5.832 No Limit	11:35:40 AM CT 2/8/2012
Jul 2012		2.886 b	-0.024	2.910	2.915	2.920 b	2.830 a	16,649	5.910 No Limit	11:37:42 AM CT 2/8/2012
Aug 2012		2.923	-0.022	2.945	2.950	2.957	2.864 a	11,391	5.945 No Limit	11:35:41 AM CT 2/8/2012
Sep 2012		2.931	-0.025	2.956	2.921	2.948	2.875	4,080	5.956 No Limit	11:38:12 AM CT 2/8/2012
Oct 2012		2.975	-0.026	3.001	3.009	3.014	2.921 a	10,170	6.001 0.001	11:38:38 AM CT 2/8/2012
Nov 2012		3.135	-0.027	3.162	3.161	3.171 b	3.095	1,517	6.162 0.162	11:35:34 AM CT 2/8/2012
Dec 2012		3.431 b	-0.030	3.461	3.461	3.472 b	3.387 a	1,802	6.461 0.461	11:35:41 AM CT 2/8/2012
Jan 2013		3.562	-0.029	3.591	3.589	3.602 b	3.522	3,151	6.591 0.591	11:37:35 AM CT 2/8/2012
Feb 2013		3.571 b	-0.028	3.599	3.581	3.582	3.541	478	6.599 0.599	11:38:39 AM CT 2/8/2012
Mar 2013		3.553	-0.027	3.580	3.560	3.568	3.512 a	802	6.580 0.580	11:23:06 AM CT 2/8/2012
Apr 2013		3.517 b	-0.024	3.541	3.541	3.556 b	3.465	1,013	6.541 0.541	11:35:41 AM CT 2/8/2012
May 2013		3.545 b	-0.025	3.570	3.512	3.554	3.509	101	6.570 0.570	11:38:27 AM CT 2/8/2012
Jun 2013		3.584 a	-0.020	3.604	3.575	3.591	3.561	79	6.604 0.604	11:38:15 AM CT 2/8/2012
Jul 2013		3.625 a	-0.022	3.647	3.587	3.637	3.587	154	6.647 0.647	11:34:12 AM CT 2/8/2012
Aug 2013		3.639	-0.025	3.664	3.612	3.653	3.599	119	6.664 0.664	11:13:48 AM CT 2/8/2012
Sep 2013		3.645 b	-0.020	3.665	3.605	3.650	3.602	50	6.665 0.665	11:35:41 AM CT 2/8/2012
Oct 2013		3.685 b	-0.019	3.704	3.710	3.713 b	3.622	388	6.704 0.704	11:35:41 AM CT 2/8/2012
Nov 2013		3.785 a	-0.017	3.802	3.780	3.795	3.776 a	28	6.802 0.802	11:34:06 AM CT 2/8/2012
Dec 2013		3.986 a	-0.013	3.999	3.973	3.990	3.973	12	6.999 0.999	11:34:06 AM CT 2/8/2012
Jan 2014		4.092 a	-0.014	4.106	4.042	4.098	4.042	35	7.106 1.106	11:34:12 AM CT 2/8/2012
Feb 2014		4.080 a	-0.014	4.094	-	4.084 b	4.077 a	0	7.094 1.094	11:34:06 AM CT 2/8/2012
Mar 2014		4.040 a	-0.016	4.056	4.038	4.046 b	4.038	0	7.056 1.056	11:20:16 AM CT 2/8/2012
Apr 2014		-	-	3.941	-	-	-	0	6.941 0.941	8:44:58 AM CT 2/8/2012
May 2014		3.940	-0.016	3.956	3.940	3.940	3.940	0	6.956 0.956	8:44:58 AM CT 2/8/2012
Jun 2014		-	-	3.981	-	-	-	0	6.981 0.981	8:44:58 AM CT 2/8/2012
Jul 2014		4.010	-0.007	4.017	4.010	4.010	4.010	0	7.017 1.017	8:44:58 AM CT 2/8/2012
Aug 2014		-	-	4.034	-	-	-	0	7.034 1.034	8:44:58 AM CT 2/8/2012
Sep 2014		-	-	4.036	-	-	-	0	7.036 1.036	8:44:58 AM CT 2/8/2012

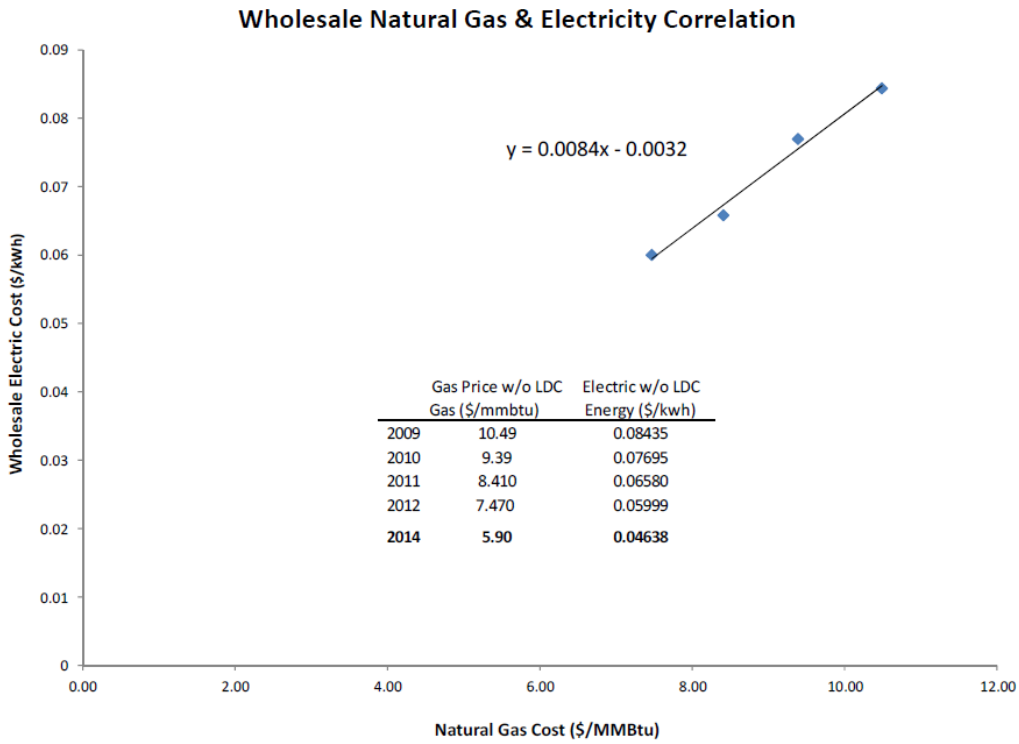
When project comes on-line

Electricity

The electricity costs are comprised of four (4) major components…

1. Commodity/Wholesale;
2. Forward Capacity Market;
3. Broker Fee; and
4. National Grid's anticipated, future Distribution Service Rate.

The Commodity cost is the future unit cost of just the energy portion (kWh) of purchasing electricity. In New England, due to the large number of power plants using NG as their primary fuel, the cost of electric energy directly correlates to the Commodity cost of NG. To estimate the future electric energy Commodity cost, Toray correlated their historic, annual average Commodity NG costs to their historic, annual average electric energy Commodity costs. Using this correlation and the NYMEX Futures Contract NG cost for January 2014 ($4.092/MMBtu) an electric Commodity cost of $0.0464/kWh results. This unit cost was credited to all kWhs displaced by the proposed CHP. See the below graphic illustration of this site specific correlation.



	Gas Price w/o LDC Gas ($/mmbtu)	Electric w/o LDC Energy ($/kwh)
2009	10.49	0.08435
2010	9.39	0.07695
2011	8.410	0.06580
2012	7.470	0.05999
2014	**5.90**	**0.04638**

The second major component of the electric costs is the Forward Capacity Market charge (FCM), which represents the cost to purchase and reserve "space"/capacity on the electric transmission system to move the electric energy cited in the first major electricity cost component to National Grid's distribution system. At the time of this TA Study, ISO-NE's posted price for 2014 was $3.209/kW. This charge was calculated monthly by taking the peak demand needed for the month and multiplying it by the FCM unit cost of $3.209/kW to match Toray's current billing. Toray provided this unit cost via its document titled "TPA Utility Cost Analysis 2-20-12.xls".

The third major component of the electric costs is the Broker Fee, which is a charge Toray pays a third-party to solicit the best price for electric energy based on Toray's needs. It's important to note Toray's historic, annual costs used to develop the aforementioned correlation includes a Broker Fee of $0.0004/kWh. This unit cost was credited to all kWhs displaced by the proposed CHP.

The forth – and last - major component of the electric costs is the appropriate National Grid Service Rate. Since Toray already has a large CHP and its multiple meters are merged and billed as a single Service Rate, the appropriate Service Rate for both the Base Case and Proposed Case is the *3,000 kW Back-Up Service Rate (B-62), Retail Delivery Service*. Starting on January 1, 2012, National Grid instituted a slightly redesigned Distribution Service Rate that applies to the proposed CHP. This Service Rate defines the cost to distribute the electric energy from National Grid's point of differentiation between Transmission and Distribution to National Grid's electric meters serving Toray's facilities. Although most of the $/kWh and $/kW charges are straightforward, in order to properly estimate Toray's future costs, the currently anticipated future costs associated with the Deepwater Project have been added to this Financial Analysis. The value used is based on a currently anticipated $500,000,000 profit margin for the Deepwater project. The Deepwater Component used is $0.0036/kWh.

Preventive Maintenance

The following unit costs were applied to the appropriate equipment (i.e., existing and proposed major equipment) as part of calculating the total, Operating Cost for both the Base Case and Proposed Case.

1. Base Case Major Equipment
    a. Combustion Gas Turbine with Medium Pressure HRSG: $0.014/kWh.
    b. Medium Pressure Boiler Plant: $0.15/kLbs.
    c. Electric Chillers: $0.004/Ton-H.
2. Proposed Case Major Equipment
    a. Reciprocating Engines: $0.014/kWh.
    b. Medium Pressure Boiler Plant: $0.15/kLbs.
    c. Electric Chillers: $0.004/Ton-H.
    d. Steam Turbine-Driven Chiller: $0.0052/Ton-H.

The most important part of the Preventive Maintenance costs relates to the CGT and reciprocating engines' costs. The CGT costs are based on historic costs Toray incurred, while the 2 x reciprocating engines' costs are based on following Kawasaki's Preventive Maintenance Schedule averaged over a 12 year period. This is common-place to format the Preventive Maintenance costs (i.e., materials, labor hours and labor rates) as an "annuity" for the life of the CHP in CHP analyses.

The following table summarizes the anticipated financial performance of the proposed CHP.

Financial Summary

Case Description	Capital Cost ($)	Electricity & Natural Gas Incentives[1] ($)	Net Capital Cost ($)	Electric Costs[2] ($)	Natural Gas Costs[3] ($)	Preventive Maintenance Costs ($)	Total Costs ($)	Net Simple Payback (Years)
Existing	N/A	N/A	N/A	$7,987,360	$4,704,237	$776,309	$13,467,906	N/A
Proposed	$22,700,000	$13,150,000	$9,550,000	$1,382,711	$8,451,663	$2,021,480	$11,855,854	N/A
Savings/(Costs)	($22,700,000)	$13,150,000	($9,550,000)	$6,604,649	($3,747,326)	($1,245,171)	$1,612,052	5.9

Notes:

1. *Electric Energy Efficiency Program Incentive of $11,350,000 and Natural Gas Advanced Gas Technologies Program Incentive of $1,800,000.*
2. *Based on NGrid's projected electric B-62 Distribution Tariff and Toray's projected electric commodity price.*
3. *Based on Toray's projected Natural Gas commodity price.*

Building Energy Efficiency Measures

National Grid's Energy Efficiency Program's CHP Initiative is focused on and designed to support projects that first address reducing the total quantity of energy used to conduct a given company's business, then provide incentives to use the remaining, minimal amount energy efficiently. To that end, over the past several years Toray has aggressively pursued the identification and implementation of energy projects that both reduce usage through conservation and further increase the efficient use of the remaining energy to lower costs to not only itself, but also all customers participating in the System Benefits Charge (SBC).

As part of the CHP Initiative, it's important to ensure Toray has conserved a significant amount of energy, so the CHP is sized and applied to electric, steam and chilled water load profiles with little chance of significantly changing due to future energy efficiency projects. This provides the CHP with the best opportunity to be economically successful for the foreseeable future. The following lists the potential Energy Efficiency Measures (EEM) identified with Toray's Utility Engineering Department in late 2011. Although the list is comprehensive, not any individual or the sum of them will have a significant impact on the load profiles used in this TA Study to model the energy and financial performance of the proposed CHP.

Torayfan and Lumirror

- Plant wide pump and fan optimization – The two facilities have hundreds of fans and pumps, most of which are not controlled by VFDs. The future survey efforts will focus on identifying the fans and pumps for VFD application and other system changes for improvements.
- Steam trap assessment – A steam trap survey to identify the largest traps was discussed so that as soon as the big traps fail they can be identified for replacement.
- Insulation - According to the facility staff, majority of the steam, condensate and chilled water pipes are well insulated. However, there may be small pockets of no insulation, worn insulation, uninsulated valves and heat exchangers that will be reviewed in the future.
- Compressed air optimization - The Lumirror and Torayfan operations have independent compressor plants, each with over 4 to 5 compressors each in excess of 150-hp. All compressors are water-cooled, rotary screw, load-unload, oil-free type. Most of them were two-stage compressors, which is good. A compressed air study was done a couple years ago. The study largely focused on identifying air leaks and found that retrofitting the compressors with VFDs was not economical. Opportunity exists to review the entire compressed air system starting with a review of the end uses (review inappropriate end

uses such as vacuum, cooling etc), survey of leaks (as an annual survey is highly recommended), survey of uncontrolled end uses and then a review of the compressor plant for optimization. The facility also has a mix of blower driven desiccant dryers which could be reviewed for efficient alternatives.

- Chilled water system optimization - The chiller plant in both buildings are fairly new (less than 5 years). The chiller plant in Lumirror is setup for free cooling while the one in Toray fan is not. The chillers are all VFD driven centrifugal type. The chilled water plant is setup with variable primary flow. The chilled water is supplied constantly at 45 F throughout the year. The cooling tower water is set at 72 F. The chilled water pumps and the tower fans feature VFDs. Several opportunities exist associated with optimizing the chilled water plant operations –
  - VFDs on condenser water pumps
  - Free cooling in Toray fan. A4/A5 lines do not have free cooling.
  - Optimizing the chilled water, condenser water temperatures with outdoor conditions
- HVAC controls optimization - The Lumirror process areas are conditioned by nine large AHUs that maintain tight temperature and humidity conditions at all times. Humidification is achieved by injecting steam in the ducts. Cooling is supported by the chillers and heating is supported by steam provided by the central plant. All fans in these units feature VFDs that are manually controlled by the operators in the process areas. These units are not connected to any energy management system (EMS). We suggested testing the large AHUs for cooling, heating, humidification optimization. It is not uncommon to find simultaneous heating and cooling in these types of units that can be avoided by simple programming changes or by replacement of sensors. The Torayfan process areas are conditioned using six DX type AHUs. The control network in this facility was upgraded two years ago. Therefore, savings potential is projected to be limited. Potential for installing low pressure drop filters in the AHUs is also on the list of future measures.
- Cogged belts and sheaves – According to the facility staff a review of the v-belts and sheaves could result in savings.

Lumirror Only

- Pit exhaust blower control - This is a project identified by the in house energy team. The intent here is to install dampers on these blowers to reduce the heat loss during the winter months. The current practice is to operate the blowers at full speed all the time.

- Metalizer cooling optimization - The Metalizer requires cooling and when it goes down for maintenance, the cooling pumps continue to run at constant speed in dead head condition. The proposed action is to install VFDs on these cooling pumps. Preliminary analysis of one system indicated savings of $3,000 per year. Additionally, there are three 20-hp and one 15-hp pumps that could also benefit from this retrofit.

- Warehouse heating optimization – Replace steam based forced air units with gas fired infrared heaters. The facility management is currently reviewing its options connected with heating its warehouses.

- Replace steam orifice plates in the process with control valves - According to the facility staff, the process areas have over 60 orifice plates that are used to achieve design steam flow to the drums. Due to the simple design of the orifice plate, it cannot adjust to fluctuating production conditions. The energy team is interested in reviewing other steam flow control alternatives to the orifice plates. One potential alternative is to install ball valve type control valves with feedback controls. The energy savings would result from avoiding steam being dumped into the condensate return during non design operating conditions.

- Replace steam hot water heater with condensing gas fired unit - The Lumirror building has a steam fired tankless heater that supplies domestic hot water to majority of the building. The energy team is interested in reviewing replacement options for this heater. One replacement idea is to replace the steam heater with a new gas-fired tankless condensing hot water heater.

- REG tower steam vent - According to site staff, the REG tower has a steam vent coming off of the condensate return tank. We will review opportunities to recover the heat from this flash steam.

- Replace DC motors with AC alternatives - The facility has numerous DC motors totaling over 1,000 hp that operate the process equipment. We will review DC motors that can be replaced with new VFD driven AC motors.

- Polyarea lighting - The Lumirror building has over 500 explosion-proof, 2-lamp T12 fixtures in the Poly area. These lights stay on 24x7. As a part of this measure we will review a couple fixture replacement alternatives – such as LED and induction lighting as the labor costs associated with replacing the lamps in these fixtures is very high

Cogen/Boiler Room

- Boiler optimization - Boiler #3 runs at low fire year round. It has older fuel and air controllers. There is a small potential to save by installing new controllers and fuel metering. The boiler was observed to run at 3% oxygen during the site visit. It was also noted that the FGR on the boiler requires operating the boiler a slightly higher oxygen

  levels in the exhaust. In non FGR setup, the oxygen in exhaust could be brought down to 2% or lower.

Based on our understanding of the operations in the facility, the listed measures will not significantly affect the steam consumption in the Lumirror building. The few steam based measures identified for the Lumirror building have small potential that will not significantly alter the steam demand in the facility. Majority of the steam use in the Lumirror building is used in process heating and those operations are not going to change in the near future.

Appendix A: Capital Cost

Sequential Order:
Toray eMail.
Grand-Total Estimate.
Major Equipment Sub-Estimate.
Kawasaki Engine-Generator Sets Proposal (Partial).
Kawasaki Engine-Generator Sets Shipping Estimate.
HRSGs & Emissions Controls Systems Proposal (Partial - RENTECH).
Building Design/Build Construction (Sample – NAPPA Construction).
Piping/Insulation/Rigging Design/Build Construction (Sample – SPEC).
Electrical/Controls Major Equipment & Design/Build Construction (Sample – ABB).
National Grid Interconnection Costs (Narrative).

From: Eric Carlson/NKCorp/TPA
To: "McKiernan, Frederick" <Frederick.McKiernan@nationalgrid.com>
Cc: "'Jeffrey.L'Heureux@TorayTPA.com'" <Jeffrey.L'Heureux@TorayTPA.com>, "'Shigeru.Osada@Toraytpa.com'" <Shigeru.Osada@Toraytpa.com>
Date: 07/18/2012 12:19 PM
Subject: RE: CoGen 2 budget

Hello Fred,

Here is the requested information.
First, a few points of clarification.

Item No. 1 - The engineering costs were removed in TPA's estimate. This is because we quoted the building, piping and electrical work, design build.

Item No. 2 - I have attached the detail sheet which shows how we arrived at the total.
For items we received competitive quotes on I have attached those.
Unless indicated otherwise, we used Waldron's estimates.
Please note the electrical items have been removed and are include in the Electrical/Controls quote.

Item No. 3 -
For the building, we received 4 quotes. We used the average.
For the piping, we received 3 quotes. We used the average.
Elect/Controls we received one quote to date, ABB it is for turnkey supply and install.
For Rigging and Duct, we used Waldron's numbers.

CG-2 BUDGET SUMMARY

		WALDRON	TORAY	
ITEM NO.	DESCRIPTION	$	$	
1	**Engineering**	$1,299,196	Included	
2	**Procurement (Equipment)**	$13,992,237	$12,022,168	
3	**Construction Directs**			
	Building	$2,061,059	$1,600,000	
	Piping/Insulation	$773,575	$2,445,898	
	Elect/Controls	$702,535	$3,584,513	Includes Elect. Equip.
	Rigging	$275,840	$275,840	
	Duct	$143,293	$143,293	
	Construction Support	$1,515,868	Included	
	Ngrid Interconnection	$0	$1,200,000	
	Subtotal # 1	$5,472,170	$9,249,544	
4	**Construction Indirects**	$0		
5	**Commissioning & Start-up**	$319,327	$319,327	
6	**Construction Management**	$1,167,864	$0	
	Subtotal # 2	$22,250,795	$21,591,039	
7	**7% Sales Tax**	$1,170,983	$0	
8	**3% Estimating Contingency**	$667,524	$0	
	Subtotal # 3	$24,089,301	$21,591,039	
9	**7.5% Construction Contingency**	$410,413	$0	
10	**5.0% Project Contingency**	$0	$1,079,552	
	Subtotal # 4	$24,499,714	$22,670,591	
11	**5% Overhead**	$1,224,986	$0	
12	**5% Profit**	$1,224,986	$0	
	Subtotal # 5	$26,949,685	$22,670,591	
13	**FINAL TOTAL**	$26,949,685	$22,670,591	
14	**FINAL TOTAL**	$26,950,000	$22,700,000	

Waldron Engineering & Construction

Date:

CLIENT: TORAY Plastics 24-Feb-12
Project: CHP Study
Location: North Kingston, RI

Estimate Sheet: Procurement

CODE	DESCRIPTION	Type/Size	QTY	UOM	LABOR						PLANT EQUIPMENT		MATERIAL		SUBCONTRACTOR		OTHER			Notes
					CREW SIZE	HRS PER DAY	DAYS	MAN HOURS	LABOR RATE	LABOR $	UNIT EQ $	EQ $	UNIT MAT $	MAT $	UNIT SUB $	SUB $	UNIT OTH $	OTHER $	TOTAL $	
	Kawasaki 5MW Recip Genset		1.0	Ea							3,125,000	3,125,000						435,300	3,560,300	shipping included
	Kawasaki 7.5MW Recip Genset		1.0	Ea							3,575,000	3,575,000						435,300	4,010,300	shipping included
	Fin Fan Radiator for Engines		2.0	Ea							185,000	370,000							370,000	
	Fresh and Waste Lube Oil Storage Tanks		1.0	Lot							30,000	30,000							30,000	
	Exhaust Expansion Joints		1.0	Lot							55,000	55,000							55,000	
	Engine Exhaust Expansion Joints		1.0	Lot							40,000	40,000							40,000	
	Engine cooling circuit Exp Tanks		1.0	Lot							25,000	25,000							25,000	
	Heat Recovery Steam generators (7.5 MW machine)		1.0	Ea							738,000	738,000							738,000	Rentech Boilers
	Exhaust Stack																			
	SCR/CO Catalyst																			
	UREA Dosing Pump																			
	Economizer																			
	Duct																			
	Heat Recovery Steam generators (5 MW machine)		1.0	Ea							685,000	685,000							685,000	Rentech Boilers
	Exhaust Stack																			
	SCR/CO Catalyst																			
	UREA Dosing Pump																			
	Economizer																			
	Duct																			
	Steam Absorption/Turbine Driven Chiller (1000 tons)		1.0	Ea							1,100,000	1,100,000							1,100,000	York Chiller
	Pressure Regulators		1.0	Lot							35,000	35,000							35,000	
	Control Valves		1.0	Lot							35,000	35,000							35,000	
	Purge Air Fan Filters		2.0	Ea							1,500	3,000							3,000	
	Purge Air Fans		2.0	Ea							5,000	10,000							10,000	
	Purge Air Dampers		2.0	Ea							7,500	15,000							15,000	
	Recip Engine Comb Air Filters		4.0	Ea							20,000	80,000							80,000	
	Oil Mist Eliminators		4.0	Ea							15,000	60,000							60,000	
	Relief Valves		1.0	Lot							15,000	15,000							15,000	
	Gas Detection (panel and monitoring)		1.0	Lot							35,000	35,000							35,000	
	Fresh Lube Oil Pumps		2.0	Ea							5,300	10,600							10,600	
	Waste Lube Oil Pumps		1.0	EA							5,300	5,300							5,300	
	Waste Water/Sump Pump		1.0	EA							7,000	7,000							7,000	
	Boiler Feedpumps		3.0	Ea							25,000	75,000							75,000	

Waldron Engineering & Construction

Date:

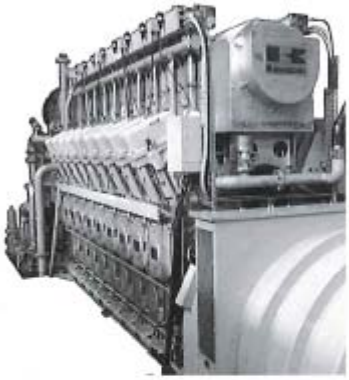
CLIENT: TORAY Plastics 24-Feb-12
Project: CHP Study
Location: North Kingston, RI

Estimate Sheet: Procurement

CODE	DESCRIPTION	Type/Size	QTY	UOM	LABOR						PLANT EQUIPMENT		MATERIAL		SUBCONTRACTOR		OTHER			Notes
					CREW SIZE	HRS PER DAY	DAYS	MAN HOURS	LABOR RATE	LABOR $	UNIT EQ $	EQ $	UNIT MAT $	MAT $	UNIT SUB $	SUB $	UNIT OTH $	OTHER $	TOTAL $	
	Cooling Water Pumps (fin-fan radiators)		2.0	EA							7,500	15,000							15,000	
	Overhead Bridge Crane		1.0	Ea							75,000	75,000							75,000	
	Monorail Cranes		6.0	Ea							5,000	30,000							30,000	
	Air Compressors		2.0	EA							50,000	100,000							100,000	
	Chilled Water Pumps		2.0	EA							15,000	30,000							30,000	
	Chiller Cooling Water Pumps		2.0	EA							15,000	30,000							30,000	
	Chiller Radiator		1.0	EA							100,000	100,000							100,000	
	HVAC Units		1.0	Ea							25,000	25,000							25,000	
	Explosion Relief Valves/Rupture discs		4.0	Ea							16,000	64,000							64,000	
	Starting Air Receiver		2.0	Ea							20,000	40,000							40,000	
	National Grid Rapid Instrumentation for Grant																			
	Engine Exhaust Silencer		2.0	Ea							50,000	100,000							100,000	
	Engine Intake Silencer		2.0	Ea							25,000	50,000							50,000	
	Urea Tanks		2.0	Ea							18,000	36,000							36,000	
	CEMS/PEMS		1.0	Ea							150,000	150,000							150,000	
	Freight & Insurance		1.5%														11,844,500	177,668	177,668	11,844,500
	PROCUREMENT TOTAL											**10,973,900**						**1,048,268**	**12,022,168**	
																		TOTAL	**$ 12,022,168**	

Messrs. Toray Plastics (America), Inc.

COMMERCIAL PROPOSAL



FOR

7.5MWe x 1 Set + 5MWe x 1 Set Total 12.5MWe

KHI REF. NO. KG-PP-GA-167.00 REV 1

April 2012

H. Kugimiya,
Manager
Power Generation Sales Dept.
Machinery Division
Gas Turbine & Machinery Company
KAWASAKI HEAVY INDUSTRIES, LTD.

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KAWASAKI HEAVY INDUSTRIES, LTD.

COMMERCIAL PROPOSAL

KHI PROPOSAL NO.: KG-PP-GA-167.00 REV1 2012/April/26

A. PRICE

(A-a) BASE SCOPE OF SUPPLY (FOB JAPANESE and European SEAPORT BASIS):

0.	KG-12-V Gas Engine Generator Package *1	1 set	JPY: 290,000,000 – (Say Two hundred and Ninety million Japanese Yen only)
0-1	Very Special Discount of KG-12-V for Toray		JPY:-40,000,000- (Deduct Forty million Japanese Yen)
1	KG-12-V Gas Engine Generator Package *1 after very special discount.	1 set	JPY: 250,000,000 – (Say Two hundred and Fifty million Japanese Yen only)
2	KG-18-V Gas Engine Generator Package *2	1 set	JPY: 320,000,000 – (Say Three hundred and twenty million Japanese Yen only)
3.	Special Discount for above item No1 and 2.	-	JPY: -34,000,000- (Deduct Thirty four million Japanese Yen)
4	Gland Total	-	JPY 536,000,000- (Say Five hundred and Seventy four million Japanese Yen only)

(A-b)OPTIONAL ITEMS FOR GAS ENGINE GENERATOR PACKAGE

1.	TECHNICAL ADVISORY SERVICE	-	REFER TO ANNEX-2 "FIELD SERVICE RATES"

NOTE:

*1

ABOVE PRICE IS SUBJECT TO OUR TECHNICAL PROPOSAL No. KG-T-GA-167.01 REV1 dated 26th April 2012.

*2

ABOVE PRICE IS SUBJECT TO OUR TECHNICAL PROPOSAL No. KG-T-GA-167.02 REV dated 15th May 2012.

B. DELIVERY TERMS and TIME

Total Two (2) sets of Gas Engine Generator Packages will be ready for shipment on a basis of FOB Kobe and European Sea Port by following schedule, subject to contract effective date.

Eight (8) Months from contract effective date.

The delivery period proposed above shall be general information, and shall be confirmed before receipt of purchase order.

All proposed goods shall be delivered within the delivery period mentioned as above after our receiving your first milestone payment as provided in the PAYMENT TERMS of this COMMERCIAL PROPOSAL.
Delivery condition shall be in accordance with INCOTERMS 2010.

KAWASAKI HEAVY INDUSTRIES, LTD.
COMMERCIAL PROPOSAL

KHI PROPOSAL NO.: KG-PP-GA-167.00 REV1 2012/April/26

C. VALIDITY

This PROPOSAL shall remain valid and effective until 26th May, 2012. Further Validity extension of the PROPOSAL shall be subject to confirmation.

D. PAYMENT TERMS

Payments shall be made by T.T within 30 days and an Irrevocable Letter of Credit as per progress payment based on the Milestone as follows;

No	(%)	MILESTONE SCHEDULE	MEANS
1.	20%of Total Contract Price	Due upon placement of order or Letter of Intent by Buyer to us for this Project whichever comes earlier.	By Telegraphic Transfer within 30 days after the date of Invoice.
2.	75% of Total Contract Price	Due upon shipment of each Gas Engine Generator Package.	By an irrevocable Letter of Credit at sight.
3	5% of Each Lot	Due upon issue of Acceptant Certification for each Gas Engine Generator Package by Buyer.	By Telegraphic Transfer within 30 days after the date of Invoice.

A) Payment shall be made on each Package basis.

B) If any amount payable to us under the Contract is overdue, KHI may charge the Buyer simple interest on overdue amount at one (1) percent per months calculated on a day to day basis from the date payment is due until the date when such payment is received by KHI.

C) Amendment to Order Price effected after acceptance of the original Order shall be subject to the same milestones and shall be invoiceable on a cumulative basis for milestone previously achieved.

D) Above L/C for No.2 and 3 payments shall be irrevocable, and the same shall be issued within two (2) months after Contract effective date by a first class international bank acceptable to KHI.

BY Toray International

Total Shipping Cost for KHI Engine CIF NY Port 5/4/2012

EX-GO value	本体価格	¥ 536,000,000	80	$ 6,700,000.00	

		JPY	currency ($1= JPY)	USD	
Shipping fee	物流費用	¥38,000,000	80	$ 475,000.00	
Insurance fee	保険	¥1,300,000	80	$ 16,250.00	
Customes procedure fee	輸入通関料	¥23,000	80	$ 287.50	
Customes duty	関税	¥13,555,000	80	$ 169,437.50	FOB Value(=6,200,000JPY) 536,000,000JPY(Ex-Go value)+6,200,000JPY=542,200,000JPY 542,200,000JPY*2.5%=13,555,000 JPY
VAT(Value added TAX)	付加価値税	¥720,000	80	$ 9,000.00	
TI fee	TI手数料	¥13,400,000	80	$ 167,500.00	EX-go value(=536,000,000 JPY)*2.5%
Toray Purchasing Dept.fee	資材部手数料	¥5,360,000	80	$ 67,000.00	EX-go value(=536,000,000 JPY)*1.0%
	Shipping Cost	**¥72,358,000**		**$ 904,475.00**	

Total Price	**¥ 608,358,000**		**$ 7,604,475.00**

Shipping Fee=海上運賃 +FOB費用(31.8百万+6.2百万=38百万)
Ex-Go value=税抜き本体価格
FOB Value=船積料金、クレーン費用

HSコードについて、物流部経由で再度現地へ確認させたところ、税率の変更がありました。
申し訳ありませんが、訂正させてください。当初は２．０％でのご案内をさせて頂きましたが、
税番が8502.39となりますので２．５％となります。
（理由）
★ 天然ガスを燃料として、エンジンを動かして発電するため
★ 原動機とセットにした発電機のうち、ディーゼルエンジン、ピストンエンジン以外のエンジンと
セットにした発電機のため

HRSG

CROSS FLOW

RENTECH

Budget Proposal:

For

Toray Plastics
HRSG/SCR

RENTECH Boiler Systems Quotation: GTB-3621-KS

Boilers for people who know and care

"RENTECH *Boilers for people who know and care.*"®

May 2, 2012

Toray Plastics

Attn: Jeffrey L'Heureux

Subject: HRSG & SCR for Kawasaki Engine
RENTECH Proposal No. GTB-3621-KS

Within the pages of this proposal you will find our unique offering which is tailor made to meet the specific requirements of your application.

Please to not hesitate to contact us if you want to discuss this HRSG offering in more detail.

Very truly yours,
RENTECH Boiler Systems, Inc.

Kevin Slepicka
Sr. Sales Engineer
Email: kslepicka@rentechboilers.com

Cc: Joe Richter

RENTECH Boiler Systems, Inc. • 5025 E. Business 20 • Abilene, TX 79601 • Phone: 325-672-3400 • Fax: 325-672-9996

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I. Summary Information

A. General Design Conditions

The HRSG system described in this proposal has been designed for the following main parameter:

Engine	
Size:	7.5 MW & 5 MW
Fuels:	Natural Gas
Steam Conditions:	
Steam Pressure:	100 psig
Steam Temperature:	Saturated
Steam Flow (7.5 MW/ 5 MW):	7,100 / 4,700
F.W. Temperature	228 °F (Deaerated)
HRSG Design Pressures	
Evaporator:	200 psig
Economizer:	250 psig
HRSG Design Codes	
Evaporator:	ASME Section I
Economizer:	ASME Section I

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V. HRSG Pricing Summary

A. Budget Price – 7.5 MW Engine

The budget price for the supply of one (1) HRSG/SCR system as described within this proposal for the 7.5 MW engine, Ex-Works Abilene, TX is: ***$738,000 USD.***

B. Budget Price – 5 MW Engine

The budget price for the supply of one (1) HRSG/SCR system as described within this proposal for the 7.5 MW engine, Ex-Works Abilene, TX is: ***$685,000 USD.***

C. Terms of Payment

For this order, progress payments in accordance with the following schedule will be required.

10% Upon receipt of purchase order
10% Upon submittal of approval drawings
15% Upon receipt of tubes
15% Upon receipt of drum cylinders
20% Upon stabbing first tube
25% Upon shipment
5% Upon documentation

Payment Terms: Net 30 days

Warranty – 12 months from acceptance, not to exceed 18 months from shipment.

D. Drawing Schedule

The following preliminary schedule is provided for your consideration.

Schedule for Drawing Submittals will be as follows:
Overall General Arrangement – 8 Weeks ARO
Trim and Piping Drawing – 8 Weeks ARO
Foundation Plan with Loads – 8 Weeks ARO
Process and Instrument Drawings – 8 Weeks ARO
Return of approved drawings: 2 weeks ARO.

E. Shipment

The following preliminary schedule is provided for your consideration.

The HRSG equipment will be ready for shipment 36 weeks after order with release to purchase long lead materials at the time of the purchase order.

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NAPPA CONSTRUCTION MANAGEMENT, LLC

473 Washington Street
Providence, Rhode Island 02903

p 401.274.3917
fx 401.521.5030

June 28, 2012

Jeffrey L'Heureux
Mechanical Engineer
Toray Plastics (America), Inc.

Dear Mr. L'Heureux,

Nappa Construction Management proposes to furnish all materials, labor and equipment necessary to complete the CG II Project Lumirror Division new building to be located at 50 Belver Avenue, No. Kingstown, Rhode Island 02852.

Our Pricing and scope are based on a design build scenario. It is with our experience and understanding of the building code requirements that we feel this project can be completed for the budget.

The cost to complete the scope is One Million Four Hundred Two Thousand One Hundred Forty Three Dollars ($1,402,143.00)

The Scope of work is based on the plans provided by Toray as well as the detailed scope letter provided. In addition, the Architectural Services Proposal from RGB and the Engineering Services Proposal from BER is included with this document and is included in our design build costs..

The following qualifications were considered as part of this proposal:

- At this time, all Gen-set equipment and connections are by others
- The pre-engineered building and components are by Star Buildings.
- Architectural and Engineering services will be provided by RGB
- Onsite staging area and unfettered access to the area to be provided to GC.
- Cooling will be provided for the electrical room only.
- Underground utilities are assumed to be within 10' of building perimeter.
- Lighting is considered as high bay lighting in open areas and industrial lighting under mezzanine.

The completion of this scope will take approximately twenty (28) weeks from issuance of the building permit with the following milestone dates for key items:

- Design phase Six (6) weeks from acceptance- approximately August 7, 2012
- Groundbreaking Eight (8) weeks from acceptance – approximately August 21, 2012
- Foundation complete on or about October 16, 2012
- Building erected by November 15, 2012.

Nappa Construction Management carries general liability insurance as well as full worker's compensation insurance. Certificates of insurance are available upon request. We also offer a one (1) year warranty on all work completed within our scope. Please don't hesitate to contact us with any question or concerns.

Thank you for the opportunity to work with you on this project.

Sincerely,

Accepted

Bill Brzoza

Project Manager

_____

RGB architecture engineering interior design

June 25, 2012

Bill Brzoza
Nappa Construction Management
473 Washington Street
Providence, RI 02903

Re: Professional Service Proposal
Cogeneration 2 Project
RGB #305-072-2

Dear Mr. Brzoza,

The Robinson Green Beretta Corporation (RGB) is pleased to submit this proposal for professional design services for the proposed new Cogeneration 2 project located at Toray Plastics in North Kingstown, Rhode Island.

Scope of Work:
The scope of work is to design an approximate 8,350 square foot insulated metal building addition to house the cogeneration 2 plant and provide construction administration services.

Scope of Services:
RGB will provide professional design services, drawings and specifications for obtaining a building permit and for construction. Design services include civil, architectural, structural, mechanical, electrical, plumbing and fire protection and acoustical engineering.

- Civil engineering includes site grading and resurfacing at the perimeter of the addition; fire service to the building and tank truck unloading pad.
- Architectural services includes meetings, coordination of the team of engineers, construction drawings and specifications and construction administration.
- Structural engineering includes structural design of the foundations and equipment and tank pads, mezzanines, stairs and miscellaneous steel items.
- Mechanical engineering includes HVAC design for the split system cooling for the high voltage electric room, supply and exhaust fans, and intake louvers.
- Electrical engineering includes designing all panels, transformers and feeders to support house loads in the addition, lighting fixtures, exit signs, emergency lighting and controls for the addition, and general purpose receptacles for the addition. Design for fire alarm devices, tied to an existing fire alarm control panel, power provisions for the split system cooling, and building mounted security lighting.
- Plumbing engineering includes designing floor drains tied to a sump pump.
- Fire protection engineering to design new incoming sprinkler service and new pre-action system with branch sprinkler piping and head layouts for the addition.
- Acoustical engineering design to reduce the interior-to-exterior sound level from 110 to 85 db; at the exterior walls and roof.

Both the roof construction and sprinkler design will conform to Factory Mutual Insurance requirements. RGB will attend bi-weekly construction meetings and site visits, assuming construction duration of four months.

50 Holden Street · Providence, Rhode Island 02908 · Tel: (401) 272-1730 · Fax: (401) 273-7156
www.rgb.net

Schedule
The proposed schedule is as follows:

July 6, 2012	Notice to proceed
August 3, 2012	Complete construction documents; project goes out to bid, Drawings submitted for review for permitting
August 24, 2012	Bids due
September 7, 2012	Construction begins

Exclusions
Furnishing and installation of cogeneration equipment as defined in the documentation provided by Toray Plastics, Inc. Soil investigations and testing; testing and/ or upsizing utilities to supply the facility, Zoning research or hearings, RIDEM approvals, Town approvals, fire flow testing. Assumes the prefabricated metal building engineer designs the building structure; RGB provides the drawing documents and specifications for the building structure. Tel/data provisions are provided by Toray. Evaluation of site noise levels and evaluation of noise to receptors would be considered and additional service.

Fees:
Compensation for the scope of services indicated above shall be broken down as follows:

Civil	$8,500.00	
Allowance for Survey (within 50' of building perimeter)	$1,800.00	
Subtotal		**$ 10,300.00**
Architectural	$59,800.00	**$ 54,200.00**
Structural	$20,900.00	**$ 20,900.00**
Mechanical	$ 6,900.00	**$ 6,900.00**
Electrical	$ 7,900.00	**$ 7,900.00**
Plumbing	$ 3,200.00	**$ 3,200.00**
Fire Protection	$ 5,200.00	**$ 5,200.00**
Acoustical Engineer	$ 3,850.00	**$ 3,800.00**
Subtotal		**$112,400.00**

Please note that if the acoustical engineer is required to design for interior noise reductions the fee will increase by $1,650.00.

All requests for payment will be billed on a monthly basis. Payments are due within 30 days of invoice date. Payments that are due to RGB and unpaid under the Agreement after 31 days from invoice date shall bear interest at the rate of 1.5% per month.

RGB

Mr. Jeffrey L'Heureuz
Toray Plastics
Re: Professional Service Proposal
Cogeneration 2 Project
RGB #305-072-2
June 15 2012

Expenses:
Reimbursable Expenses are in addition to the Basic Compensation and include actual expenditures made by the Architect and the Architect's employees and/or consultants in the interest of the project. Additional reimbursable expenses will include all printing, photocopying, mailing, shipping, etc.

All reimbursable expenses will be invoiced at cost with the markup of 10% for handling and administrative costs.

Additional Services:
If additional services beyond the scope those outlined are required, the fee for these services will be in addition to the basic fee and provided only upon the authorization of Toray Plastics, Inc.

If the schedule, scope of work or value of construction for this project is adjusted, RGB reserves the right to renegotiate this Agreement.

Expiration:
The fee for the Scope of Services as set forth in the Agreement is valid for 60 days from the date of the Agreement.

Thank you again for the opportunity to submit this Agreement/Proposal. If the terms of this Agreement are acceptable to you, please sign both copies and return one copy to us.

This letter shall serve as a letter of intent to begin work. RGB will then prepare and execute an AIA Document A107, which will serve as our Agreement for this project. Please call me if you have any questions or require additional information.

Respectfully submitted,

Cyndi Gerlach, AIA, NCARB, LEED AP
Associate
The Robinson Green Beretta Corporation

DLD:cae

cc: DLD, JRB/ANR, RGB

Accepted by: _____

Name: _____

Title: _____

Date: _____

BER

BUILDING ENGINEERING RESOURCES, INC.

(Revised June 25, 2012)
June 15, 2012

Ms. Cyndi Gerlach
Robinson Green Beretta Corp.
50 Holden Street
Providence, Rhode Island 02908

RE: Toray Plastics – North Kingstown, RI
Engineering Services Proposal

Dear Cyndi:

We are pleased to provide this Proposal for Mechanical, Electrical, Plumbing and Fire Protection engineering services for the proposed renovation addition to the Toray Plastics Facility located on Belver Ave in North Kingstown, Rhode Island. Our Proposal is as follows:

DESCRIPTION OF WORK:

A. We understand this project is a 14,000sf multi-level addition. The addition will house new Co-Gen equipment to be furnished and installed by Client. All process related systems are not included. This Proposal is for Base Building shell provisions only. Engineers shall field verify all "MEP/FP" existing conditions.

B. This Proposal includes all Affidavits and Code required Calculations and Narratives.

C. This Proposal is for "Design-Build" level services. We anticipate the General Contractor will have preferred Sub-Contractors. Sub-Contractors will assist Team with pricing and preferred Equipment Vendors.

SCOPE OF WORK:

A. Design:

1. Provide HVAC engineering and design services, drawings and specifications for the following:

   a. Split system cooling for high voltage Electric Room.
   b. Supply and exhaust fans.
   c. Intake louvers.
   d. Unit heaters and controls for all areas.

2. Provide Electrical engineering and design services, drawings and specifications for the following:

    a. Provide all panels, transformers and feeders to support house loads in addition.
    b. Lighting fixtures, Exit signs, emergency lighting and controls for addition. All emergency lighting via battery units.
    c. General purpose receptacles for addition.
    d. Fire Alarm devices tied to the existing Fire Alarm Control Panel (FACP) and coordination with local Fire Department.
    e. Power provisions for HVAC equipment.
    f. Tel/Data outlet backboxes and backboards only.
    g. Building mounted security lighting.

3. Provide Plumbing engineering and design services, drawings and specifications for the following:

    a. Utilize existing domestic water, sanitary and gas services.
    b. Coordinate new gas loads with Utility Company.
    c. Gas piping and connections for new rooftop units and stubs for Co-Gen units.
    d. Floor drains tied to existing sump pump.

4. Provide Fire Protection engineering and design services, drawings and specifications for the following:

    a. New incoming sprinkler service. Interface with existing service.
    b. New Pre-action System with branch sprinkler piping and head layouts for addition.

5. Scope of Work shall include Spec Notes on Plans.

6. Field Verification and Meetings:

    a. Engineers shall perform one (1) initial site visit to verify "MEP/FP" existing conditions.
    b. Engineers shall attend one (1) "Team" Design Coordination meeting.

7. Deliverables:

    a. Progress Plot Sets will be available at each milestone. We anticipate two (2) Progress Sets for Coordination.
    b. One (1) set of Final Plots and Specifications to be delivered at 100% completion.
    c. Emails of "electronic" files are available upon request at no charge.

B. Excluded from Scope of Work:

1. Security System wiring and equipment.
2. Sound/PA System wiring and equipment.
3. Tel/Data wiring and equipment.
4. Upgrades of Base Building "MEP/FP" Systems.
5. Flow Test for Fire Protection System.
6. Cost Estimating and Life Cycle Cost Analysis.
7. UPS System.
8. Emergency Generator.
9. Value Engineering: Including Recommendations, Meetings, and Plan Revisions.
10. FM 200 Fire Suppression System.
11. Site lighting.
12. Acoustic Consulting.
13. Demolition Drawings.
14. As-Built Record Drawings.
15. Commissioning of HVAC, Plumbing and Electrical Systems
16. LEED Design Services.
17. Design utilizing "3D" modeling, Revit, etc.
18. Design of structural supports, site utility support, concrete pads, trenching and backfill of utilities.
19. High Voltage Distribution Equipment Co-Gen Units.

C. Assumptions:

1. Tel/Data wire management shall include conduit, pullstrings, backboxes and plywood backboards only.
2. All Base Building "MEP/FP" systems are adequate to support the proposed build-out.
3. Fire Alarm System is ADA Compliant.
4. Sprinkler service has a backflow preventor.
5. No internal roof drains required. Gutters and downspouts by Others.
6. New Restrooms.
7. No changes required to existing Pre-Action System.
8. Architect is to provide Base Plans in AutoCAD Format.
9. Field verification is based on receipt of Existing Condition Documents. If documentation is not available Existing Conditions take-off will be billed on a *"Time and Materials Basis"*.

D. General Conditions of this Proposal:

1. Substantial Revisions or Scope changes after start of Design will be considered "Additional Services".

E. Construction Administration to include shop drawing reviews, responses to Contractor field questions, three (3) Progress Site Visits, Final Punch List and Final Affidavits. Additional site visits will be performed only as requested by the Owner and will be billed on a *"Time and Materials Basis"*. Please allow $600.00 average per visit.

FEE:

A. Our Fee for the above outlined Scope of Work will be invoiced monthly as follows:

1. Design Development:		$ 20,000
2. Construction Administration:		$ 3,200
	Total	$ 23,200

B. See Attached "Terms and Conditions" sheet.

C. Reimbursable Expenses Includes:

1. Please budget $1,000 for Reimbursable Expenses.

   a. Basic in-house printing, plotting and copying are included in our Base Fee. Printing of multiple "Review" Sets, "Permit" Sets and "Bid" Sets will be billed at Cost.
   b. Express/Overnight mail and Courier delivery services will be billed at Cost.
   c. Mileage for travel to site and meetings will be invoiced at $0.46 per mile.

UNDERSTOOD AND ACCEPTED BY:

A. If you are in agreement with the above Scope of Work and Fees, please sign and return a copy of this Proposal to our office so we may begin the work.

Name/Title: _____ **Date:** _____

If you should have any questions with the above, please do not hesitate to contact this office.

Very truly yours,

Marc R. Plante, PE
Principal

Attachment

TERMS AND CONDITIONS (*)

Reimbursable Expenses:

Reimbursable expenses will include the following:

- Out of town travel and travel related expenses (hotels, meals, car rental, taxis, etc.).
- Messenger service and Overnight mail.
- Document printing, reproduction and plotting costs (Permit Sets).
- Specialty Consultants (if required and approved by the Client).
- Services of Systems Testing Agencies (if required and approved by the Client).
- Automobile expenses at $0.46 per mile.

Reimbursable expenses will be billed with a 10% mark-up.

Hourly Rates:

The following hourly rates are used for "Additional Services" and for Contracts that Building Engineering Resources, Inc. (BER) is performing basic services on a time and material basis. These rates are valid through December 31, 2012.

• Principal-in-Charge:	$175
• Senior Engineer:	$135
• Engineer:	$110
• Designer:	$ 90
• Draftsperson/CADD Operator	$ 75

Payment Schedule:

Once our work has commenced, invoices for Basic Services, Additional Services and Reimbursable Expenses will be submitted on a monthly basis. Invoices will be considered correct as rendered if not questioned in writing by your office within five (5) days of the invoice date. Payment is due within 30 days of the invoice date. Payment of the Fee shall not be dependent upon project financing.

BER reserves the right to suspend all work on the project if payment is not received when due. In the event of such suspension, the Client will waive all rights, claims, etc. which it might otherwise have against BER as a direct or indirect result of such suspension.

If the Client defaults and fails to pay according to the terms of this contract, then BER shall have the right to terminate this contract immediately and to seek to collect any fees, costs or reimbursable expenses due by the Court. The Client agrees that in addition to the amount invoiced, the Client shall be responsible for any and all attorney fees or costs incurred by BER in any efforts to collect this balance due.

Terms and Conditions:

In the event that BER is bound by the terms of a Prime Agreement with the Client/Owner, the Architect shall provide BER with a complete copy of this agreement for our review and comment, prior to the execution of the agreement.

The Architect shall disclose to BER, in writing and prior to the execution of this agreement, any contingent or other special provisions relative to Compensation, that is included in the Architect's understanding with the Client/Owner or in the Prime Agreement. In the absence of such disclosure, such contingencies or special provisions will not bind BER.

Any items that are not specifically stated in the above proposed services are to be considered excluded from this Agreement, and if requested, will constitute an Additional Service Fee.

No deductions will be made from the compensation on account of any penalty, liquidated damages or other sums withheld from payments to Contractors, or on account of the cost of changes in the Project.

In the event of any dispute, claim, question or controversy arising out of this Agreement, its performance, breach and/or interpretation, the same will be determined by arbitration pursuant to the Construction Industry Arbitration Rules of the American Arbitration Association.

If the project is suspended in whole or in part for a period of more than ninety (90) days, the balance of the Fee shall be entitled to an equity adjustment.

BER will not be responsible for or be liable in any way with the discovery, presence, handling, removal, disposal of or exposure of persons to hazardous materials in any form at the Project.

BER will not be responsible for the acts or omissions of the Contractor, Subcontractors or any other persons performing any of the work or for the failure of any of these parties to carry out the work in accordance with the Construction Documents.

This Agreement may be terminated by either party upon fourteen (14) days written notice in the event that the other party fails substantially to perform its obligations under this Agreement through no fault of the party initiating the termination. BER will be paid for all services rendered up to and including the date of termination.

BER will not be liable to redesign to meet the Project Budget Costs unless this is a pre-condition of the Contract and BER has agreed to the Project Budget Costs.

Location	Phase Code	Description	Takeoff Quantity	Unit	Material Amount	Labor Cost	Unit Cost	Total Amount	Location Total	SF COST
		Torray Plastics								2,200
DIVISION 1 - GENERAL REQUIREMENTS				LS				$ 230,625.00	$ 230,625.00	$ 104.83
DIVISION 2 - EXISTING CONDITIONS										
	02 41 19	Selective Demolition	1	LS			$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 2.27
DIVISION 3 - CONCRETE										
	03 00 00	Footings, Foundations, and pads Labor	1	LS			$ 61,500.00	$ 61,500.00	$ 186,250.00	$ 84.66
	03 00 00	Footings, Foundations, and pads concrete material	800	CYD			$ 100.00	$ 80,000.00		
	03 00 00	Slab on grade place and finish	1	LS			$ 14,500.00	$ 14,500.00		
	03 00 00	Concrete slabs on grade					$ -	$ -		
	03 00 00	Re-inforcing steel and mesh allowance (10 tons)	1	Allowance			$ 25,250.00	$ 25,250.00		
	03 00 00	Misc. Concrete material	1	LS			$ 5,000.00	$ 5,000.00		
DIVISION 4 - MASONRY										
	04 00 00								$ -	$ -
	04 00 00						$ -	$ -		
							$ -	$ -		
DIVISION 5 - METALS										
	05 00 00	Metal building component with Siding w/ steel supports for ope	1	LS			$ 225,000.00	$ 225,000.00	$ 380,000.00	$ 172.73
	05 00 00	Metal building erection	1	LS			$ 54,000.00	$ 54,000.00		
	05 00 00	Galvanized exterior stair case	1	LS			$ 30,000.00	$ 30,000.00		
	05 00 00	Interior galvanized platforms and stairs	1	LS			$ 56,000.00	$ 56,000.00		
	05 00 00	Galvanized cooling tower frames	1	LS			$ 15,000.00	$ 15,000.00		
DIVISION 6 - WOOD, PLASTIC, AND COMPOSITES										
	06 10 00	Misc. Rough Carpentry	1	LS			$ 25,000.00	$ 25,000.00	$ 25,000.00	$ 11.36
DIVISION 7 - THERMAL AND MOISTURE PROTECTION										
	07 10 00	Foundation sealer and Insulation	1	LS			$ 3,800.00	$ 3,800.00	$ 81,000.00	$ 36.82
	07 21 00	Insulation - included in building compnents		LS			$ -	$ -		
	07 31 13	EDPM Roofing	1	LS			$ 75,000.00	$ 75,000.00		
	07 71 19	Gutters and downspouts	1	LS			$ 2,200.00	$ 2,200.00		
DIVISION 8 - OPENINGS										
	08 10 00	Doors frames and hardware	1	LS			$ 1,800.00	$ 1,800.00	$ 19,800.00	$ 9.00
	08 71 00	Coiling overhead doors	4	EA			$ 4,500.00	$ 18,000.00		
DIVISION 9 - FINISHES										
	09 29 00	Gypsum Board partitions at electrical room	1	LS			$ 20,000.00	$ 20,000.00	$ 36,000.00	$ 16.36
	09 90 00	Painting - Interior	1	LS			$ 16,000.00	$ 16,000.00		
DIVISION 10 - SPECIALTIES										
							$ -	$ -	$ -	$ -
DIVISION 11 - EQUIPMENT										
		All Equipment, associated power and connections are by others		LS			$ -	$ -	$ -	$ -
DIVISION 12 - FURNISHING									$ -	$ -
DIVISION 13 SPECIAL CONSTRUCTION									$ -	$ -
DIVISION 14 CONVEYING SYSTEMS									$ -	$ -
DIVISION 15									$ -	$ -

Location	Phase Code	Description	Takeoff Quantity	Unit	Material Amount	Labor Cost	Unit Cost	Total Amount	Location Total	SF COST
		Torray Plastics								2,200
DIVISION 16 ELECTRICAL									$ 100,000.00	$ 45.45
16100		General Lighting, outlet, and fire alarm w/ associated panels	1	LS			$ 100,000.00	$ 100,000.00		
							$ -	$ -		
DIVISION 17 through 20									$ -	$ -
		NOT USED					$ -	$ -		
DIVISION 21									$ 53,000.00	$ 24.09
		Fire Suppression	1	LS			$ 53,000.00	$ 53,000.00		
DIVISION 22 - PLUMBING									$ 25,000.00	$ 11.36
		Plumbing	1	LS			$ 25,000.00	$ 25,000.00		
		Trench Drain - Sump pump	1	LS						
DIVISION 23 - HVAC									$ 20,000.00	$ 9.09
		Cooling at electrical room	1	LS			$ 20,000.00	$ 20,000.00		
DIVISION 31 - EARTHWORK									$ 43,000.00	$ 19.55
		Excavation / Backfill	1	LS			$ 20,000.00	$ 20,000.00		
		Slab prep	1	LS			$ 8,000.00	$ 8,000.00		
		Misc. Clean fill	1	Allowance			$ 15,000.00	$ 15,000.00		
DIVISION 32 - EXTERIOR IMPROVEMENTS									$ 45,000.00	$ 20.45
		Asphalt paving allowance	1000	SYD			$ 30.00	$ 30,000.00		
		Site drainage allowance	1	Allowance			$ 15,000.00	$ 15,000.00		
DIVISION 33 - UTILITIES									$ 25,000.00	$ 11.36
		Utility allowance	1	LS			$ 25,000.00	$ 25,000.00		
							$ -	$ -		
									$ 1,274,675.00	$ 579.40
								Fee	$ 127,467.50	$ 57.94
								Total	$ 1,402,142.50	$ 637.34
									$ -	
									$ 1,402,142.50	

SPEC
PROCESS ENGINEERS WHO BUILD
www.spec-eng.com

June 19, 2012

Eric Carlson
Director of Engineering
Toray
50 Belver Ave.
North Kingstown, RI 02852

Dear Eric:

SPEC is pleased to provide this proposal in response to your CGII Piping Bid Package for the installation of the two KGG modules and two KGA modules at Toray's North Kingstown, RI facility.

Scope of work
SPEC will design the associated piping and install the two KGG and two KGA modules according to the equipment installation documentation provided by Toray. This work will include the design of piping systems to connect the modules based on the P&IDs provided, and the design and installation of pipe supports to meet Toray's pipe support specification. As part of the installation scope, SPEC will pull a mechanical building permit with P.E. stamped drawings.

Schedule and Pricing
SPEC is proposing to complete the above scope of work in a duration of approximately 7 to 8 months and assumes that Toray's equipment procurement, overall permit, and related subcontractor efforts would support a duration no longer than 8 months for our portion of the work.

SPEC's Budget Estimate for the Mechanical piping design and installation is **$3,294,000.** The budget is based upon the scope documents received and the following key provisions:

1. All equipment procured and delivered to the site by Toray
2. All instrumentation provided by Toray, installed by SPEC
3. All concrete work, steel work, electrical work, exhaust duct, & roofing work by Toray(except as noted)
4. Steam blow temporary piping and gas line high velocity air blow excluded(start up)
5. RI Sales Taxes(assumed Toray will provide tax exempt certificate)

The scope we have provided and estimated at this time includes:

1. Piping design, stamped drawings, mechanical permit
2. Construction coordination, field supervision, project management
3. Rigging of listed equipment per the Toray's list with additions as discussed
4. Piping installation with supports, expansion loops, tie ins and testing
5. Structural steel for rack to Utility Building as discussed(including excavation, concrete, and backfill for three pipe bridge foundations)
6. Demo of the Utility Building Wall to remove Chiller Number 5 and replace of same once installation of the new turbine driven chiller has been completed.

17 A Street Burlington, Massachusetts 01803
Phone { 781 } 743-0123 Facsimile { 781 } 221-7212

SPEC
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www.spec-eng.com

7. Piping Insulation is excluded at this time as the subcontractor bid was not received In time for this response.

The rigging involved with the proposed project is extensive and involves a significant portion of the quoted budget estimate. The interfacing of the equipment suppliers with a riggers yard or directly to the site will be a key project issue. Site preparation for the rigging equipment will also be extensive due to the weights involved(90 and 120 tons for the engines involved). A detailed rigging package with all equipment cuts, weights, dimensions, building drawings and a site plan is needed in order to confirm this major scope item and provide better pricing than that which we have obtained in the short time available. Industrial Transfer and Storage would be our preferred rigger and they have both the equipment and recent Cogen experience. On the piping side we have teamed with Notch Mechanical who has worked with SPEC for over 8 years. Both these subcontractors have worked with SPEC in Rhode Island and have excellent work practices and safety records.

Thank you for your interest in working with SPEC, I will follow up with you to make sure this proposal meets with your approval.

Sincerely,

Steve Murray
Vice President of Design

17 A Street Burlington, Massachusetts 01803
Phone { 781 } 743-0123 Facsimile { 781 } 221-7212

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

Toray Plastics Co-Generation Plant, at Rhode Island, USA

Proposal For
ELECTRICAL, AND CONTROL SYSTEM

JUNE 2012

ABB INC.

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

Toray Plastics (America), Inc.
ABB Toray Plastics Co-Generation Palnt
PROPOSAL No. 12720 4044_0

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3.2 Out of Scope of Supply and Services
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3.5 System Design Description

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BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

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5 Product Literature.....TAB5

TAB 1

June 20, 2012

Toray Plastics America
North Kingstown, RI

Attention: Geoffrey D. Saucier

Reference: Toray Plastics Gas Engine Co-generation System
ABB Integrated electrical and control system
ABB Proposal No. 12720 4044_0

Attached is our proposal for the electrical and control balance of plant scope for the Toray Plastics (America) Co-generation project being consider at the Torayfan Division in New Kingstown, RI.

The ABB electrical and control solution provides a single source of supply for the equipment, engineering, installation and project management of the critical electrical core and automation infrastructure.

The scope of our solution is detailed in the commercial and technical offer along with the attached appendices.

We hope that you will find our submission valuable and informative. We guarantee the highest possible level of quality in all of our products and services and look forward to an opportunity to discuss this tender in detail. All enquires of technical or commercial nature should be directed to Rick Ulam at 330 423 8667 (cell).

Thank you very much for your interest in our solution.

Yours truly,

Rick Ulam
Executive Account Manager
Power Generation System
ABB
Wickliffe, Ohio
O: 234 759 3160
M: 330 423 8667
E: rick.l.ulam@us.abb.com

ABB

Per: Indra K Kusuma
Power Systems Power Generation
Bids and Proposal Manager
ABB Inc.

Per: John A Ieraci
Power Systems Power Generation
NAM Sales Manager
ABB Inc.

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 2

2. COMMERCIAL SUMMARY

IMPORTANT NOTE: This ABB budgetary estimate is preliminary and not final and as such is non-binding. It is tendered for discussion only, does not constitute a term to contract and ABB can, without notice, make any changes in ABB own discretion.

2.1 Confidentiality

This proposal contains information that is proprietary to ABB Inc.

2.2 Abbreviation Key

The following abbreviations apply throughout this proposal:

ABB / ABB Inc. = ABB Inc.

Client / Customer / Owner / Others = Toray Plastics (America), Inc.

2.3 Bid Pricing

The prices below include the scope of supply for Toray Plastics Co-Generation Plant as described in the Technical Proposal is as follows:

TORAY PLASTICS CO-GENERATION ELECTRICAL AND CONTROL EQUIPMENT	PRICE (USD)
B.1 Price for procurement package with scope as described in the Technical Proposal under TAB 3.	USD$2,410,799.00

2.4 Optional Pricing

Optional Pricing is offered as follows:

TORAY PLASTICS CO-GENERATION INSTALLATION OF ELECTRICAL AND CONTROL EQUIPMENT	PRICE (USD)
O.01 Price for installation of equipment quoted under 2.3 above only (Union Labour), including Site Manager services and excluding Site Supervision Services described under 2.6 below.	USD$1,173,714.00

2.5 Project Execution

Anticipated Notice to Proceed : July 20, 2012

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 2

Anticipated Commercial Operation Date (COD) : July 20, 2013

2.6 Site Services

Site supervision services for installation and commissioning are not included in our price. but can we quoted if requested.

2.7 Currency

All pricing shown is in USD.

2.8 Bonds

Our proposal does not include for any bonds or Letters of Credit.

2.9 Terms of Payment

We have prepared our proposal based on payment milestones which would allow for a neutral cash flow, with the consequent savings of financial expenses.

The terms of payment suggested in this offer are:

15% Advance Payment

20% of offer price upon submission of Design Engineering;

10% of offer price upon approval of Design Engineering;

30% of offer price upon Advice of Ready to Ship;

20% of offer price upon Arrival at Site;

5% of offer price upon Commissioning;

The payment will be effected through an irrevocable, standby Letter of Credit from an investment-grade bank, in terms acceptable to ABB. This LoC will be required at the time of the Contract signature and it will be for a value representing the difference between the Contract Value and the Advance Payment. Bank fees for LoCs will be paid by the applicant.

2.10 Freight

Freight is DAP to site, per INCOTERMS 2010.
The equipment will be shipped using ABB standard packaging procedures.
Equipment is shipped via ABB selected carrier.

2.11 Delivery

The schedule is to be decided by mutual agreement between Toray Plastics and ABB. We have prepared our proposal based on the following key dates:

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 2

Our latest estimated delivery time is 34 Weeks until Advice of Ready to Ship.

Please note that our estimated delivery time is based on contract effectiveness and timely receipt of necessary design data and approval.

2.12 Taxes and Duties

Taxes are excluded from our proposal. Duties are not applicable.

2.13 Warranty

Proposed warranty is 18 months from shipment or 12 months after acceptance, whichever occurs first.

Please note that above warranty will cover the costs of replacement of the warranted item EXW the respective supplier's factories. All other costs associated with the item's replacement (including diagnosis, removal, shipment to supplier's factory, and re-installation in the system) are not covered under the warranty.

2.14 Publication

Purchaser approves the use of its name in ABB newsletters, press releases, proposals, experience lists, and resumes (for proposal purposes) of our employees.

2.15 Training

Training is not included in this offer, but can be quoted if requested.

2.16 Spare Parts

Spares are not included in this offer, but prices can be quoted if requested.

2.17 Tests and Inspections

All equipment is subject to standard manufacturing tests. Should acceptance tests be required, then these will be charged extra.

2.18 Meeting

The following meetings are considered in our proposal.

- One (01) one-day Kick of Meeting with Toray Plastics in Rhode Island, USA
- One (01) two-day design review meeting with Toray Plastics at ABB, Burlington, Ontario, Canada (See Note* below)

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 2

- One (01) one-day design review meeting with Toray Plastics in Rhode Island, USA
- One (01) one-day pre construction meeting with Toray Plastics in Rhode Island, USA (If Installation Option O.01 under 2.4 above is purchased)
- One (01) one-day construction follow-up meeting with Toray Plastics in Rhode Island, USA (If Installation Option O.01 under 2.4 above is purchased)

Note*: Expenses for Toray Plastics personnel are not included.

If required, ABB is ready to actively participate in any necessary meetings. In such case the offer price will be adjusted by mutual agreement between Toray Plastics and ABB.

2.19 Documentation

This Price includes one (1) electronic set of standard ABB manuals in the English language.

Please note that due to copyright considerations, third party documentation for hardware and software not produced by ABB is limited to the form and number of software licenses or equipment purchased from the third party.

2.20 Quote Validity

The proposal is valid until July 20, 2012.

2.21 Order Acceptance

Order acceptance is subject to credit approval by ABB.

2.22 Named Suppliers

ABB Inc. reserves the right to replace named suppliers for others of equal performance and quality.

2.23 Standard Equipment

All ABB standard specifications (e.g.: cabinet size, paint, colors, etc.) apply unless otherwise noted in our proposal. ABB reserves the right to provide the revisions of software and hardware that are in current use at the time of project execution. Also, ABB is not responsible for any design provided by the client or client's consultant.

2.24 Site Requirements for Site Services

Following are the Site Requirements for our personnel during the site activities:

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 2

- Health and Safety program for the overall site works
- Safe temporary power, water and lighting.
- Site medical services facilitated by the owner
- Access roads to the site and to go through the site
- Secure warehousing for equipment storage
- Site office equipped with photocopier, internet access, etc.

This proposal considers that the above requirements will be provided to ABB free of charge.

2.25 Soil, Access Roads and Civil Works Conditions

ABB is not responsible for the conditions of the soil, access roads or civil works and, should ABB incur in a delay due to soil, access roads or civil works conditions, it shall not be penalized for any delay; and should any additional costs be incurred by ABB due to soil, access roads or civil works conditions, such costs shall be passed to the Client. ABB assumes that any required work to correct soil, access roads or civil works conditions in order to install the equipment at site will be done by others

2.26 Destination Control

End Use
This offer is based on the condition that a statement of end use regarding the offered products, technical data and/or services will be supplied to ABB by the end user, prior to ABB's acceptance of any order for such products/technical data or services.

Nuclear Restrictions
The products delivered by ABB under this order must not under any circumstances be used in connection with a nuclear reactor or other nuclear facility. Any such nuclear use requires full protection against nuclear liability for the benefit of ABB and its sub-suppliers in accordance with conditions to be determined by ABB.

ABC-Weapons Restrictions

(a) The items described herein are not for use, directly or indirectly, in any activities related to the design, use or stockpiling of chemical, biological or nuclear weapons or missiles.

(b) The sale, re-export, delivery, or retransfer, directly or indirectly, to any activities related to the design, production, use, or stockpiling of chemical, biological or nuclear weapons or missiles is strictly prohibited.

Export/Re-Export Authorization
This offer is based on the condition that required export/re-export authorizations will be granted by the competent authorities in the countries of origin of the offered product and its parts and components. Refusal or withdrawal of said

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

3.1 Scope of Supply and Services

ABB is pleased to provide this Electrical, and Control engineered solution for the Toray Plastics Co-Generation Plant at the Torayfan Division, New Kingston Rhode Island, USA facility. In addition to the security of knowing that you are working with a world-class organization in ABB, the proposal affords the following benefits.

- Lower overall cost
- Reduced procurement effort
- Reduced sub-supplier coordination effort
- Reduced risk in electrical/automation/mechanical system changes that impact cost and schedule
- More efficient electrical, mechanical and automation engineering
- Long term life cycle service

ABB's scope of supply and services for the Toray Plastics Co-Generation Plant is based on the following integrated solution (please refer to the single line diagram in Appendix A-1, and Appendix A-4, TAB 4 of this proposal):

Electrical, and Control Package:

Electrical

One (1) Set	:	4.16kV Medium Voltage Switchgear System (Two Breakers + Transition cell to be added to the existing outdoor 4.16 kV line-up. Another lineup of four breakers to be installed at the Cogen plant location to take care of the two Generator, Auxiliary Transformer and Outgoing feeder to the existing outdoor 4.16 Switchgear.)
Two (2) Sets	:	Neutral Grounding Cubicle
Two (2) Sets	:	460V Low Voltage Motor Control Center
Two (2) Set	:	230V AC Distribution Panels
One (1) Set	:	3500kVA Auxiliary Transformer
Two (2) Sets	;	50kVA Auxiliary Transformers
Two (2) Set	:	DC Distribution Panels
One (1) Set	:	Battery Bank of 125V
One (1) Set	:	Charger / Rectifier
One (1) Set	:	Uninterrupted Power Supply System (UPS)
One (1) Set	:	4.16kV Medium Voltage Cable, 600V Low Voltage, Control Cable, Optical Fiber Cable (to connect to computers), and Cable Terminals
One (1) Set	:	Grounding Cable (for equipment under ABB's Scope of Supply and Services, from Equipment to Grounding Grid) and Grounding Rod (4 Nos.)

Control

One (1) Set	:	Control Cabinet
One (1) Set	:	Desk and Computer (One Control Desk and Four Personal Computers)

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

Services:

- Engineering – for ABB scope of supply and services stated in the ABB's proposal
- Procurement (Negotiation, order placement and delivery) - for ABB scope of supply and services stated in the ABB's proposal
- Project Management - for ABB scope of supply and services stated in the ABB's proposa
- Drawings and documents - for ABB scope of supply and services stated in the ABB's proposal
- O&M Manuals - - for ABB scope of supply and services stated in the ABB's proposal
- Painting and exposed surfaces of equipment - for ABB scope of supply and services stated in the ABB's proposal

Services (Option):

- Installation - for ABB scope of supply and services stated in the ABB's proposal
- Commissioning - for ABB scope of supply and services stated in the ABB's proposal
- Site Management, Site Health and Safety - for ABB scope of supply and services stated in the ABB's proposal
- Site supervision services during project execution (i.e. installation, commissioning etc.)
- Permit - for ABB scope of supply and services stated in the ABB's proposal

3.2 Out of Scope of Supply and Services

All equipment and services other than those stipulated in Section 3.1 above are not included in our proposal.
For example:

- Gas Engine
- Generator and Accessories
- Generator Control Panel
- Engine Control Panel (generator control, supervising and protection)
- Generator Protection
- Generator CTs [ex. (3) pcs at Generator neutral side, (3) pcs for loose supply, (3) pcs at Generator neutral side etc.]
- Remote Monitoring System
- Instrumentation
- Mechanical Auxiliary Equipment
- Any Kind of Civil Work
- Site preparation civil works
- Performance testing

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

3.3 Proposal Base

The technical proposal is prepared as a result of the optimum system design based on the Customer's specification as listed below, including several comments from the requirements as stated in the Customer's specification. (Current version as of June 08, 2012).

- TFN-TIE-IN.DWG
- TA5-P50013-E1001-OUTDOOR TA5-P50013-E1001 (1).pdf
- Air View TPA 2.pdf
- Equipment Layout.pdf
- SITEPLAN,COGEN2 Layout A size (1).pdf
- GA-167-02 Toray Plastics(USA)_KG18V_Tech proposal_R2 120531.pdf
- GA-167-02 Toray Plastics_USA__KG18V_appendix_120531.pdf
- GA-167-01 Toray Plastics(USA)_KG12V_Tech proposal_R2 120531.pdf
- GA-167-01 Toray Plastics_USA__KG12V_appendix_120314.pdf
- Cogen1 Building_1.jpg
- Cogen1 Building_2.jpg
- Cogen2 Building Location_1.jpg
- Cogen2 Building Location_2.jpg
- Electric Utility Manhole Cover Behind Switchgear.jpg
- Outdoor Switchgear_1.jpg
- Outdoor Switchgear_2.jpg
- T1 & T2 Utility Transformers.jpg
- ABB Assumptions

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

3.4 Document Priority

In the event of any inconsistencies between descriptions in the documents constituting the technical proposal, the order of precedence of the documents shall be in accordance with the following

1. Technical Comments, Section 3.6, TAB 3 of this proposal
2. Scope of Supply and Services, Section 3.1, Out of Scope of Supply and Services , Section 3.2, System Design Description, Section 3.5, TAB 3 of this proposal
3. Other documents of this proposal
4. Customer's specification as stated in Section 3.3, TAB 3 of this proposal

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

3.5.10 Control System

3.5.10.1 Introduction

3.5.10.1.1 Symphony PlusTM

Symphony PlusTM represents the new generation of ABB's widely acclaimed Symphony family of distributed control systems (DCS) – the most widely used DCS in the power generation and water industries. In all, there are more than 6,000 Symphony DCS installations in operation all over the world, with more than 4,000 in power and water applications.

For more than 30 years, ABB has evolved the Symphony family, ensuring that each new generation enhances its predecessors and is backwardly compatible with them – all in accordance with our long-held policy of 'Evolution without obsolescence.'

With Symphony Plus, ABB is taking the Symphony success story to the next level. Like its predecessors, Symphony Plus is designed to meet the requirements of plant owners in all geographic markets and in all types of power generation and water plants and meet the performance objectives of various users – in operations, maintenance, engineering, IT and management. And it targets the key focus areas of the power and water industries – plant productivity, energy efficiency, operation security, plant safety, and cost of ownership.

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

3.5.10.1.2 S+ Operations

Operator effectiveness is fundamental to plant performance. With fewer plant operators, a generational shift in the operator workforce, and increasing complexity of plant operations, this is becoming ever more challenging, but not insurmountable. Symphony Plus, with its intuitive, easy-to-use human machine interface (HMI), leads operators to greater awareness, faster response and better decisions.

S+ Operations is based on the proven technology of Power Generation Portal (PGP) that has more than 2,300 installed systems worldwide. S+ Operations also has an integrated Power Generation Information Manager (PGIM) that is another proven ABB technology.

Features	Benefits
Simple and flexible system architecture/structure	Low investment, low maintenance costs
Large-scale networks possible	Expandable when needs evolve
Flexible single and multi-system facility	Adapts to any requirement - even the most demanding
Server-less and server-based installations possible	Adapts to any requirement
Miscellaneous data from multiple servers seamlessly integrated in one display	Saves time, efforts and thus human resources
Any requested redundancy possible	Provides the maximum system stability and reliability
Easy modification and expansion of configurations	Protects existing assets as the business evolves
Active (real-time) data and history information fully integrated in the information management system	Provides quick, easy, and seamless access to all stored data within one single system
Short-time history data stored within every workstation	Enables a quick overview of the evolution of situations; gives the time and opportunity for correct decision-making
Dedicated history servers	Guarantees data consistency under all circumstances
Elaborate human machine interface	Delivers intuitive, clearly-arranged workplaces and direct access to all details
Utilizing web standards	Allows utilization of standard software and hardware
Perfect basis for ABB optimization tools	Facilitates proactive and predictive maintenance

3.5.10.1.3 S+ Engineering: Composer Harmony

Symphony Plus includes a comprehensive suite of engineering tools. S+ Engineering's Composer tools provide a visual environment for easy configuration of the control system strategies, global configuration databases, and manage system libraries of reusable software components.

The working environment provided by Composer simplifies the configuration and maintenance of Symphony™ and Symphony™ Plus systems. Composer is designed to operate on the Microsoft Windows 7 Professional or Server 2008. It is compatible with INFI 90 OPEN system configurations and is capable of importing existing WinTools configurations. Once imported, these configurations can be fully integrated into Composer and utilize all its features.

BUDGETARY ESTIMATE – FOR DISCUSSION ONLY

TAB 3

3.5.10.1.4 Control Processors

ABB's Symphony Plus Controller is the latest evolution of Harmony Controllers. The Symphony Plus Controller Package is made up of a DIN Rail mountable termination unit and the Harmony Control Processor (HC800) and Communications Processor (CP800) modules. The control network between the Symphony Plus Controllers and Symphony Plus Servers is based on 100MB Fast Ethernet TCP/IP.

The Harmony Control Processor executes INFI 90 fuction codes and includes the combined functionality of the Harmony Rack BRC and HPG modules. It can process up to 30,000 INFI 90 Function Blocks, Batch 90, UDF and 'C' programs and registers up to 1,000 Exception Reports per second.

The Communications Processor is the control network interface. This module has the combined functionality of the NIS and NPM Harmony Rack Modules.

The Symphony Plus Controller Package is mounted on the Communication Termination Board (CTB810/811) which follows the same form factor as the 800xA AC800M Controllers allowing it to easily integrate with ABB's S800 I/O. The Termination Board also accepts a typical S800 24 VDC power supply removing the necessity of the MPSIII Power System. The Termination Board features the following interfaces:

- HN800 H-Net Interface for communication with Rack I/O and S800 I/O
- CW800 provides peer-to-peer communications between controllers
- Ethernet Modbus TCP interface for control level interfaces
- Fast Ethernet TCP/IP for communication to the Symphony Plus Operations Console.

3.5.10.1.5 System Architecture

Please see the System Overview Drawing for a description of the proposed architecture in Clause Appendix A-3, TAB 4 of this proposal.

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3.6 Technical Comments

Technical Assumptions, Exceptions, Comments and Clarifications

This offer is based on the Specification Documents sent by Customer for Toray Co-Generation Plant. This solution's scope of supply is only related to the electrical, control equipment as stated of this proposal. We have not identified any important deviations which would, in our view, prevent our solution from providing you with a safe and easily operable and maintainable system.

ABB considers the management of the design, engineering and execution phases to be critical to the success of both the schedule and costs of this type of project. Therefore, the engineering hours included are based upon the assumption that a rigorous and mutually agreed design methodology and schedule is developed for execution of the works, prior to commencement of the contract. This is necessary in order to efficiently employ the resources of both the customer and ABB to maximize the effectiveness of the contract execution.

We are prepared to discuss these points further in more detail after your review of our budgetary proposal, in order to finalize and be clear on technical details.

General:

1. All equipment and services other than those stipulated in Clauses 3.1, and 3.5, TAB 3 of this proposal are not included in our proposal.
2. This proposal is based on ABB standard practices for power generation and other engineering projects. Unless otherwise explicitly stated, ABB's standard design, practices, equipment, documentation, etc, will be applied.
3. The installation services included in this proposal as an option and are in accordance with the project specifications. The general principles of the installation scope includes the placement of the equipment, fixations to the concrete floor or steel wall frame, bonding of the supplied equipment to the embedded grounding system, supply and installation of necessary cable tray network, and the supply, installation, and termination of power and control cables interconnecting the equipment supplied within the defined scope.
4. Permit fees are not included in our proposal.
5. The Customer shall provide ABB details of the existing bus such as horizontal and vertical elevation, quantity and size bus bar per phase etc.

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6. The Customer shall provide ABB complete list of auxiliary load.
7. Seismic information was not received from the Customer. This offer therefore does not considered special provisions for meeting seismic requirements.
8. Seismic studies and/or a system stability study are not included.
9. The execution of civil works is not included in the offer. Primary and secondary concrete work is not included in our proposal.
10. The pre-operation, operation and soil studies for the power plant are not included in this offer.
11. The Environmental and archeological Studies as well as preparation of report are not included.
12. MV metal-clad switchgear is non arc resistant design.
13. The T7 Main circuit breaker has been priced with (2) CT's and ABB standard Shark200 Digital Meter (for LV MCC).
14. Electrical equipment is suitable for is Toray Co-Generation site altitude.
15. The installation and commissioning supervisor services are not included in this proposal for ABB's scope of supply and services stated in Clause 3.1 and 3.5, TAB 3 of this proposal.
16. ABB cannot provide any design analysis or design calculations because it is considered intellectual property.
17. The proposed equipment will be manufactured in conjunction with quality standards and the best engineering practices. Blanket compliance to all codes and standards cannot be offered because many are inapplicable to all classes of equipment and some are mutually exclusive. In general, it is ABB's practice to comply with relevant sections of major standards.
18. All equipment will be tested in the factory prior to shipping to site. This estimate does not include manufacturer's standard Factory Acceptance Testing (FAT) customer-witnessed for the equipment supplied by the ABB.

    If witness test required by the Customer the following shall be applied.

    1) Where the production facility or test/inspection location for travels inside Bolivia;
    Fixed test/inspection date : Seven (7) calendar days in advance

    2) Where the production facility or test/inspection location for overseas travels from Bolivia;
    Fixed test/inspection date : Twenty-one (21) calendar days in advance

    The customer or its representative shall inform to the ABB whether the Customer or its representative will attend the test and inspection, no later than five (5) calendar days prior to the commencement of notified test and inspection.

    Should the customer fail to attend on the appointed date, the test shall proceed in his absence and shall be deemed to have been made in his presence and the customer shall be bound by the results thereof. Should ABB agree to delay a witnessed test specified above, all

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reasonable expenses which ABB may incur as a result of the delay will be charged extra and shall be payable by the Customer.

19. The Customer and ABB will mutually agree the submission dates and which documents have to be submitted for approval or for information.
20. This proposal is based on a once-through review of the engineering documents within two weeks. Additional reviews with extra comments not addressed on the first review or providing comments after two weeks from receipt of documents will result in a schedule delay and extra engineering/management costs which will apply accordingly as additional fees.

    Failure of Customer to respond within two weeks shall be interpreted as deemed approval of the drawings as submitted without comment.
21. The design, manufacture, and testing of equipment are based on the applicable editions/versions of the codes and standards as on the date of the proposal submission. If codes and standards are revised after the submission of proposal and it is felt necessary to follow the updated / revised versions during the execution phase of the project then, the ABB may use a later version after notifying the customer and applying the required procedure such as an amendment of contract. As a consequence, cost and project schedule implication if any for adopting the revised standards and codes shall be adjusted accordingly.
22. Local laws, standards and regulations other than clearly mentioned in the customer's specification are not considered in our proposal.
23. ABB and its suppliers have history to supply standard equipment in the power industry. ABB will provide standard information about our quality assurance to Customer. ABB's proposal does not considered to provide additional information and/or to our standard program.
24. Standard packing will be used for equipment under ABB's cope of supply and services. Special packing provision will not be applied.
25. Operation and maintenance manuals will be provided only for the ABB's equipment within the scope of supply.
26. On site assembly manual will not be provided as ABB is not responsible for installation.
27. The manufacturer standard painting specification will be used.
28. ABB reserves the right to change suppliers based on project and time requirements.
29. The Customer shall at his expense provide open space as the ABB reasonably requires for all activities connected with the execution of site works (If Installation Option O.01 under 2.4, TAB 2 is purchased).

    As soon as additional open space is necessary for the activities connected with the execution of site works, the ABB shall be able to obtain such open space on free of cost from the Owner.
30. The Customer shall at his expense provide utilities below as the ABB reasonably requires for erection use, commissioning use, temporary storage/workshop, and temporary ware/tool house and ensure that such facilities and assistance are safe and comply with legislation, by-laws, standards, codes of practice and other requirements from time to time applicable (If Installation Option O.01 under 2.4, TAB 2 is purchased).
    - Electricity

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- Water
- Telephone
- Fax
- Internet

The ABB shall not be held responsible to make his own back up arrangement for such utilities mentioned above. The ABB shall not be liable for any unavailability of or interruption to supply.

In case of non-availability of electricity and water from Customer at the desired quality and quantity, the ABB shall be entitled to claim for an extension of time for completion of the works as well as variation to contract price.

31. The Customer shall arrange for canteen facilities to cater to the requirements of the ABB's personnel (If Installation Option O.01 under 2.4, TAB 2 is purchased).
32. All costs for import and export, duties, legal fees, taxes or other costs incurred in connection with the presence of our tools in the country of installation shall be carried by the Customer. If the tools cannot be exported back to the country of origin immediately after the completion of the installation work, the Customer shall pay rent for the tools until shipment takes place
33. It is the customer's duty to ensure that the ABB shall have the right of reasonable access to any place or facility for carry out the activities connected with the execution of site works without the prior approval of customer and restriction of time (If Installation Option O.01 under 2.4, TAB 2 is purchased).
34. The customer shall provide adequate training his personnel in the application of the site-specific safety rules (If Installation Option O.01 under 2.4, TAB 2 is purchased).
35. The Customer shall at his expense provide waste disposal facilities in the power plant. The ABB will dispose disassembled and/or useless parts and/or waste removed by the ABB to the designated place by the Customer in the Power Plant (If Installation Option O.01 under 2.4, TAB 2 is purchased).
36. The Customer shall at his expense provide sewage system for the ABB at site. The ABB will connect the ABB's temporary sewage system for his temporary site office and accommodation to the Customer's sewage system near the ABB's temporary site office and accommodation (If Installation Option O.01 under 2.4, TAB 2 is purchased).
37. The HAZOP studies are by others.
38. The ABB will provide First-aid facilities for his employees, representatives and workmen at the site, Subject to the ABB may be permitted to use, free of charge the Customer's First-aid medical facility (If Installation Option O.01 under 2.4, TAB 2 is purchased).
39. ABB will not be responsible for building and maintaining at his own cost temporary installations which are not part of the project works such as roads and other temporary constructions.

National Grid – Electric Interconnection Costs (Fred McKiernan, 401-784-7413)

As of 07/31/12, National Grid has estimated the total cost of performing all engineering, coordination and field work to be approximately $1,200,000, which is shown in Toray's Grand-Total Capital Cost Estimate.

Appendix B: Energy Analysis

Sequential Order:
Base Case - Summary Output[1] (Waldron's Proprietary Software).
Proposed Case – Summary Output[1] (Waldron's Proprietary Software).

Notes:

1. *Due to the 8,760 H/Y type analysis performed for this project, there is too much raw, intermediate and final data and information to present in the limited space of 8.5" x 11.0". With Toray's written permission and acknowledgement, this information is available by contacting Fred McKiernan at National Grid (401-784-7413).*

Base Case -Take 4_OUTPUT

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
Demand, Campus (MW)	18	19	19	20	19	20	20	19	19	19	19	19	20
Demand, Auxiliaries (MW)	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Electricity Demand (MW)	19	19	19	21	20	21	21	21	20	20	19	19	21
Direct-Connected Bldg Loads (MWh)	12,438	11,054	12,380	12,393	12,447	12,685	13,375	12,870	12,327	12,800	11,546	12,279	148,594
Grid-Connected Bldg Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Chilling Auxiliary Loads (MWh)	177	156	177	141	162	168	160	159	150	140	141	157	1,888
Chilled Water Production (MWh)	42	116	331	370	399	493	678	605	526	442	345	173	4,519
Total Electricity Required (MWh)	12,657	11,326	12,889	12,904	13,007	13,347	14,212	13,634	13,003	13,381	12,031	12,609	155,001
CTG Electricity Production (MWh)	5,009	4,410	5,013	3,989	4,566	4,757	4,516	4,482	4,245	3,952	3,972	4,436	53,347
Recip Electricity Production (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Production (MWh)	5,009	4,410	5,013	3,989	4,566	4,757	4,516	4,482	4,245	3,952	3,972	4,436	53,347
Peak Purchased Demand (MW)	12	17	19	19	20	14	21	19	19	19	14	18	21
On-Peak Electricity Purchased (MWh)	3,217	2,883	3,123	3,276	3,060	3,698	3,690	3,978	3,566	3,297	2,907	3,625	40,319
Off-Peak Electricity Purchased (MWh)	4,432	4,034	4,753	5,639	5,382	4,891	6,006	5,177	5,192	6,131	5,152	4,548	61,338
Steam Balance													
Demand, Buildings & Process (klbs/hr)	63	61	55	47	32	36	30	49	29	43	46	55	63
Demand, Chilling & Auxiliaries (klbs/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Network Total Steam Demand (klbs/hr)	63	61	55	47	32	36	30	49	29	43	46	55	63
Non-Chilling Steam Load (klbs)	35,024	30,385	31,484	25,922	20,824	19,545	19,641	19,827	18,776	21,567	24,428	28,532	295,954
Steam to Chilled Water Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Plant Parasitic Steam Loads (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Steam Production Required (klbs)	35,024	30,385	31,484	25,922	20,824	19,545	19,641	19,827	18,776	21,567	24,428	28,532	295,954
HRSG Steam Production (klbs)	35,024	29,809	30,906	20,405	21,157	21,842	20,960	21,132	19,866	18,835	21,665	27,372	288,972
MP Boiler Steam Production (klbs)	0	576	578	5,574	694	0	1,267	1,220	980	3,631	2,773	1,159	18,453
Recip WHB Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Steam Production (klbs)	35,024	30,385	31,484	25,979	21,851	21,842	22,227	22,352	20,846	22,466	24,438	28,531	307,425
Chilled Water Balance													
Peak Chilled Water Demand (tons)	970	1,069	1,296	1,300	1,400	1,420	1,645	1,587	1,487	1,356	1,025	1,009	1,645
On-Peak Chilled Water Load (ton-hrs)	11,731	63,655	209,062	225,791	214,916	315,066	353,634	357,602	309,906	235,989	200,600	109,308	2,607,262
Off-Peak Chilled Water Load (ton-hrs)	53,961	121,003	316,445	358,820	386,204	402,962	565,733	468,566	444,393	444,331	348,263	164,714	4,075,394
Total Chilled Water Required (ton-hrs)	65,691	184,658	525,508	584,611	601,120	718,028	919,367	826,168	754,299	680,320	548,864	274,022	6,682,656
Electric Drive Chilled Water (ton-hrs)	65,811	183,504	522,400	584,117	601,852	718,033	919,360	826,008	754,621	678,722	543,316	272,852	6,670,597
Steam Drive Chilled Water (ton-hrs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Chilled Water Production (ton-hrs)	65,811	183,504	522,400	584,117	601,852	718,033	919,360	826,008	754,621	678,722	543,316	272,852	6,670,597
Fuel Balance													
Fuel to Combustion Turbines (MMBtu)	62,543	55,151	62,073	49,053	57,549	59,110	56,388	56,118	53,754	49,590	50,378	56,588	668,296
Fuel to Duct Burners (MMBtu)	14,259	11,301	9,772	3,164	107	164	0	354	0	973	3,840	7,791	51,725
Fuel to Medium Pressure Boilers (MMBtu)	0	706	708	6,832	850	0	1,553	1,495	1,201	4,450	3,399	1,421	22,616
Fuel to Recips (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Fuel Consumption (MMBtu)	76,802	67,158	72,553	59,049	58,507	59,275	57,941	57,968	54,955	55,013	57,617	65,800	742,637
Energy-Only Expenses													
On-Peak Electricity Charges	$201,646	$180,708	$195,773	$205,382	$191,811	$231,825	$231,302	$249,374	$223,539	$206,714	$182,236	$227,272	$2,527,582
Off-Peak Electricity Charges	$277,830	$252,882	$297,993	$353,509	$337,381	$306,646	$376,533	$324,549	$325,481	$384,381	$323,005	$285,119	$3,845,309
Backup Demand Charges	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$19,031	$228,371
Supplemental Dist Demand Charges	$33,764	$33,732	$34,252	$39,035	$35,949	$38,440	$40,344	$38,120	$36,772	$35,510	$34,207	$34,175	$434,300
Supplemental Transm Demand Charges	$33,633	$33,558	$34,012	$38,820	$38,292	$40,135	$43,620	$39,927	$39,661	$36,007	$34,170	$35,026	$446,862
Forward Capacity Market Charges	$38,004	$37,920	$38,432	$43,865	$43,268	$45,351	$49,289	$45,116	$44,816	$40,686	$38,611	$39,578	$504,936
Fuel Charges	$453,284	$396,365	$428,207	$348,510	$345,305	$349,840	$341,968	$342,125	$324,344	$324,685	$340,056	$388,352	$4,383,041
Total Energy Costs	$1,057,191	$954,196	$1,047,700	$1,048,153	$1,011,038	$1,031,269	$1,102,087	$1,058,242	$1,013,644	$1,047,014	$971,316	$1,028,552	$12,370,401
Operation & Maintenance Expenses													
Lumirror (CTG) O&M	$70,387	$62,560	$72,352	$59,016	$66,433	$69,472	$67,098	$66,235	$62,597	$58,593	$58,197	$63,370	$776,309
TorayFan (Recip) O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Site Electric Demand (Gen + Import)	19.06	19.05	19.23	20.90	19.82	20.69	21.36	20.58	20.11	19.67	19.21	19.20	
Billing Demand	19.06	19.05	19.23	20.90	19.82	20.69	21.36	20.58	20.11	19.67	19.21	19.20	
Back-Up Demand	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	
Supplemental Distribution Demand	11.81	11.79	11.98	13.65	12.57	13.44	14.11	13.33	12.86	12.42	11.96	11.95	
Supplemental Transmission Demand	11.84	11.82	11.98	13.67	13.48	14.13	15.36	14.06	13.97	12.68	12.03	12.33	
Total Costs	$1,127,578	$1,016,756	$1,120,052	$1,107,169	$1,077,471	$1,100,741	$1,169,185	$1,124,477	$1,076,241	$1,105,607	$1,029,513	$1,091,922	$13,146,711
Average $/MMBtu	$5.90												
Average $/kWh	$0.0786												
Average btu/kWh	12,527												

Kawasaki 12.5MW- Take 4_OUTPUT

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
Demand, Campus (MW)	18	19	19	20	19	20	20	19	19	19	19	19	20
Demand, Auxiliaries (MW)	1	1	1	1	2	1	1	2	1	1	1	1	2
Total Electricity Demand (MW)	19	19	20	21	20	21	21	20	20	20	20	20	21
Direct-Connected Bldg Loads (MWh)	12,438	11,054	12,380	12,393	12,447	12,685	13,375	12,870	12,327	12,800	11,546	12,279	148,594
Grid-Connected Bldg Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Chilling Auxiliary Loads (MWh)	428	385	440	382	429	439	457	446	422	389	388	422	5,026
Chilled Water Production (MWh)	35	111	306	251	165	197	335	277	232	248	239	145	2,541
Total Electricity Required (MWh)	12,902	11,550	13,126	13,025	13,041	13,321	14,166	13,594	12,981	13,436	12,173	12,846	156,161
CTG Electricity Production (MWh)	4,994	4,391	4,938	3,849	4,312	4,570	4,414	4,206	3,885	3,686	3,780	4,379	51,405
Recip Electricity Production (MWh)	7,100	6,498	7,492	6,931	7,809	7,820	8,486	8,386	8,043	7,300	7,183	7,533	90,580
Total Electricity Production (MWh)	12,094	10,889	12,430	10,780	12,122	12,390	12,900	12,592	11,928	10,986	10,963	11,912	141,985
Peak Purchased Demand (MW)	6	7	8	13	8	9	10	9	11	14	8	7	14
On-Peak Electricity Purchased (MWh)	356	218	232	752	257	445	462	472	372	844	468	438	5,316
Off-Peak Electricity Purchased (MWh)	451	443	465	1,493	662	486	807	533	681	1,607	742	495	8,868
Steam Balance													
Demand, Buildings & Process (klbs/hr)	63	61	55	47	32	36	30	49	29	43	46	55	63
Demand, Chilling & Auxiliaries (klbs/hr)	9	7	8	10	10	10	10	10	10	10	9	9	10
Network Total Steam Demand (klbs/hr)	72	68	63	57	42	46	40	59	39	53	54	64	72
Non-Chilling Steam Load (klbs)	35,024	30,385	31,484	25,922	20,824	19,545	19,641	19,827	18,776	21,567	24,428	28,532	295,954
Steam to Chilled Water Production (klbs)	212	250	1,104	3,041	4,936	5,555	6,313	5,787	5,591	4,478	3,191	958	41,415
Steam to Plant Parasitic Steam Loads (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Steam Production Required (klbs)	35,235	30,634	32,588	28,963	25,760	25,100	25,954	25,614	24,367	26,045	27,619	29,490	337,369
HRSG Steam Production (klbs)	27,982	23,746	24,528	18,754	22,071	22,932	22,352	21,724	20,459	18,681	19,151	22,490	264,870
MP Boiler Steam Production (klbs)	0	448	447	4,143	418	0	730	779	574	2,212	1,957	814	12,522
Recip WHB Steam Production (klbs)	7,328	6,722	7,771	6,772	7,801	7,514	8,014	7,970	7,530	6,917	6,987	7,480	88,805
Total Steam Production (klbs)	35,309	30,916	32,746	29,668	30,291	30,446	31,096	30,473	28,563	27,810	28,095	30,784	366,197
Chilled Water Balance													
Peak Chilled Water Demand (tons)	970	1,069	1,296	1,300	1,400	1,420	1,645	1,587	1,487	1,356	1,025	1,009	1,645
On-Peak Chilled Water Load (ton-hrs)	11,731	63,655	209,062	225,791	214,916	315,066	353,634	357,602	309,906	235,989	200,600	109,308	2,607,262
Off-Peak Chilled Water Load (ton-hrs)	53,961	121,003	316,445	358,820	386,204	402,962	565,733	468,566	444,393	444,331	348,263	164,714	4,075,394
Total Chilled Water Required (ton-hrs)	65,691	184,658	525,508	584,611	601,120	718,028	919,367	826,168	754,299	680,320	548,864	274,022	6,682,656
Electric Drive Chilled Water (ton-hrs)	49,352	168,448	457,130	277,431	30,997	45,663	222,932	157,251	101,136	188,848	268,068	200,037	2,167,292
Steam Drive Chilled Water (ton-hrs)	16,161	15,613	66,015	301,344	566,736	661,924	690,424	656,212	643,434	485,702	275,938	71,416	4,450,918
Total Chilled Water Production (ton-hrs)	65,513	184,062	523,145	578,775	597,733	707,586	913,356	813,462	744,569	674,550	544,006	271,452	6,618,210
Fuel Balance													
Fuel to Combustion Turbines (MMBtu)	62,463	55,020	61,463	47,885	55,337	57,545	55,564	53,755	50,551	47,220	48,661	56,127	651,591
Fuel to Duct Burners (MMBtu)	4,186	2,703	952	180	0	0	0	17	0	6	39	753	8,835
Fuel to Medium Pressure Boilers (MMBtu)	0	549	548	5,077	513	0	895	954	704	2,711	2,398	998	15,347
Fuel to Recips (MMBtu)	55,033	50,453	58,244	53,654	60,715	60,638	65,785	65,004	62,192	56,394	55,510	58,185	701,805
Total Fuel Consumption (MMBtu)	121,682	108,725	121,207	106,796	116,564	118,183	122,244	119,731	113,446	106,331	106,607	116,062	1,377,578
Energy-Only Expenses													
On-Peak Electricity Charges	$22,305	$13,680	$14,513	$47,140	$16,133	$27,923	$28,951	$29,580	$23,328	$52,917	$29,340	$27,477	$333,287
Off-Peak Electricity Charges	$28,298	$27,768	$29,173	$93,627	$41,483	$30,460	$50,621	$33,417	$42,718	$100,760	$46,543	$31,055	$555,922
Backup Demand Charges	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$22,434	$269,214
Supplemental Dist Demand Charges	$0	$147	$573	$4,292	$2,205	$3,301	$5,244	$2,906	$1,898	$479	$288	$426	$21,761
Supplemental Transm Demand Charges	$1,867	$1,627	$3,032	$4,262	$22,740	$4,264	$24,829	$3,978	$5,755	$20,140	$795	$1,792	$95,081
Forward Capacity Market Charges	$2,111	$1,839	$3,426	$4,816	$25,695	$4,819	$28,056	$4,496	$6,504	$22,758	$899	$2,026	$107,446
Fuel Charges	$718,169	$641,694	$715,365	$630,309	$687,961	$697,516	$721,486	$706,650	$669,560	$627,566	$629,196	$684,995	$8,130,468
Total Energy Costs	$795,184	$709,190	$788,517	$806,881	$818,651	$790,718	$881,622	$803,462	$772,197	$847,054	$729,496	$770,205	$9,513,178
Operation & Maintenance Expenses													
Lumirror (CTG) O&M	$70,117	$62,210	$71,023	$55,621	$60,560	$64,163	$62,800	$59,630	$54,881	$52,695	$54,282	$62,235	$730,216
TorayFan (Recip) O&M	$99,486	$91,059	$105,233	$98,597	$112,275	$112,919	$122,394	$120,810	$115,946	$104,719	$101,997	$105,830	$1,291,264
Total Site Electric Demand (Gen + Import)	19.34	19.46	19.61	20.91	20.18	20.56	21.24	20.43	20.07	19.58	19.51	19.56	
Billing Demand	19.34	19.46	19.61	20.91	20.18	20.56	21.24	20.43	20.07	19.58	19.51	19.56	
Back-Up Demand	19.41	19.41	19.41	19.41	19.41	19.41	19.41	19.41	19.41	19.41	19.41	19.41	
Supplemental Distribution Demand	0.00	0.05	0.20	1.50	0.77	1.15	1.83	1.02	0.66	0.17	0.10	0.15	
Supplemental Transmission Demand	0.66	0.57	1.07	1.50	8.01	1.50	8.74	1.40	2.03	7.09	0.28	0.63	
Total Costs	$964,788	$862,459	$964,773	$961,098	$991,486	$967,800	$1,066,816	$983,902	$943,024	$1,004,468	$885,775	$938,270	$11,534,658
Average $/MMBtu	**$5.90**												
Average $/kWh	**$0.0975**												
Average btu/kWh	9,532												

Appendix C: Technical Data

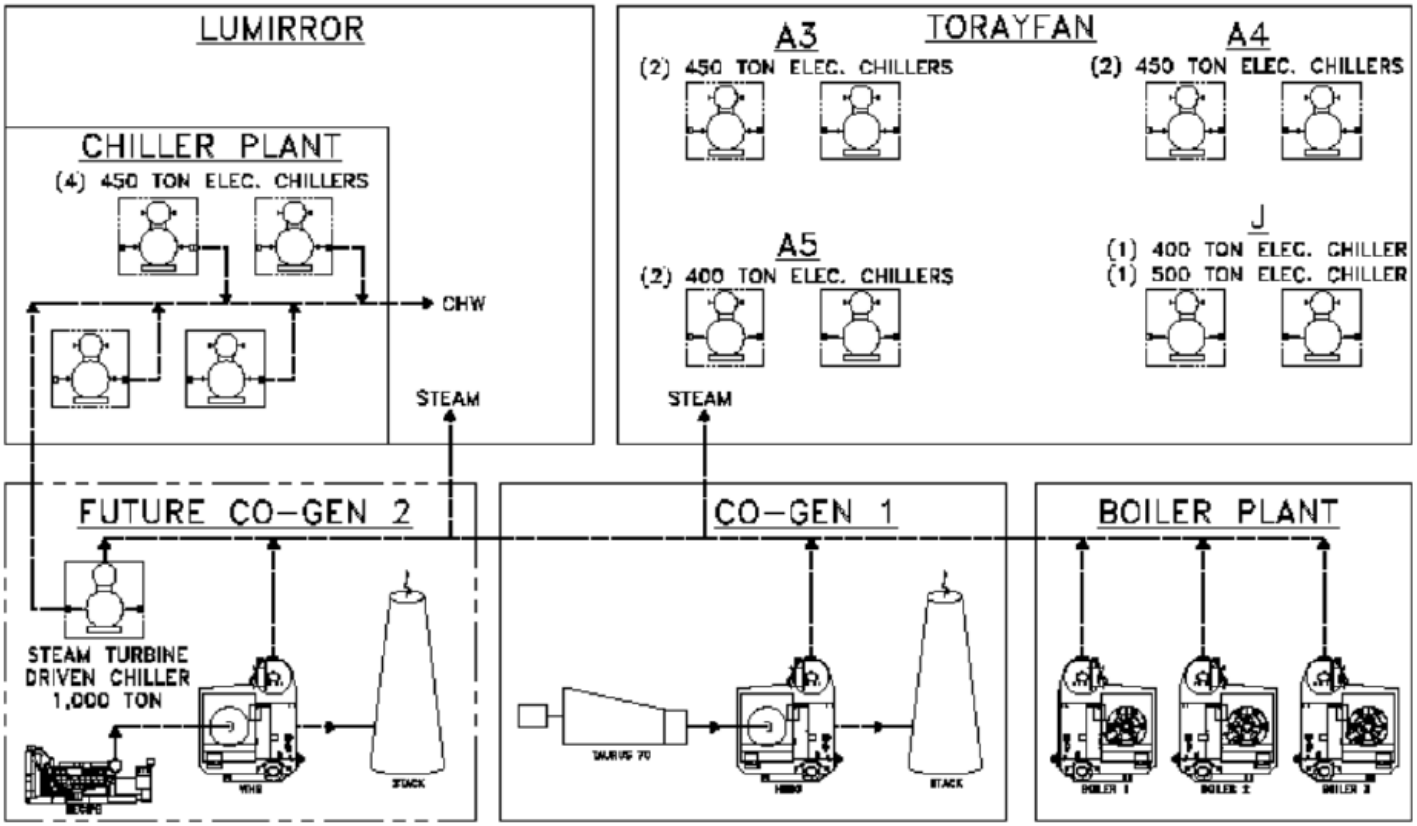
Sequential Order:

Existing & Proposed Major Equipment & Systems Schematic Diagram
Proposed CHP System Site Plan Building Location Drawing
Proposed CHP System General Arrangement Drawing
Proposed CHP System Electric One-Line Diagram
Reciprocating Engines' Electric & Steam Performances (100% Load; Part- Load in TA Study.)
HRSGs' & Emissions Controls Systems' Performances (Quoted HRSGs, not Modeled.)
Steam Turbine-Driven Chiller's Performance
Electric Parasitic Nameplate Loads – Existing Combustion Gas Turbine
Hourly Load Profiles Data[1] (Electric; Steam, 45 Bar; Steam, 7 Bar; Steam, 5 Bar; Chilled Water; Free-Cooling)
Free-Cooling Heat Exchanger Design Capacity
Reciprocating Engines' Recommended Preventive Maintenance Labor & Materials Costs
Waldron's Minimum Technical Requirements© (Preliminary) Rev. B, Dated 07/06/12[2]

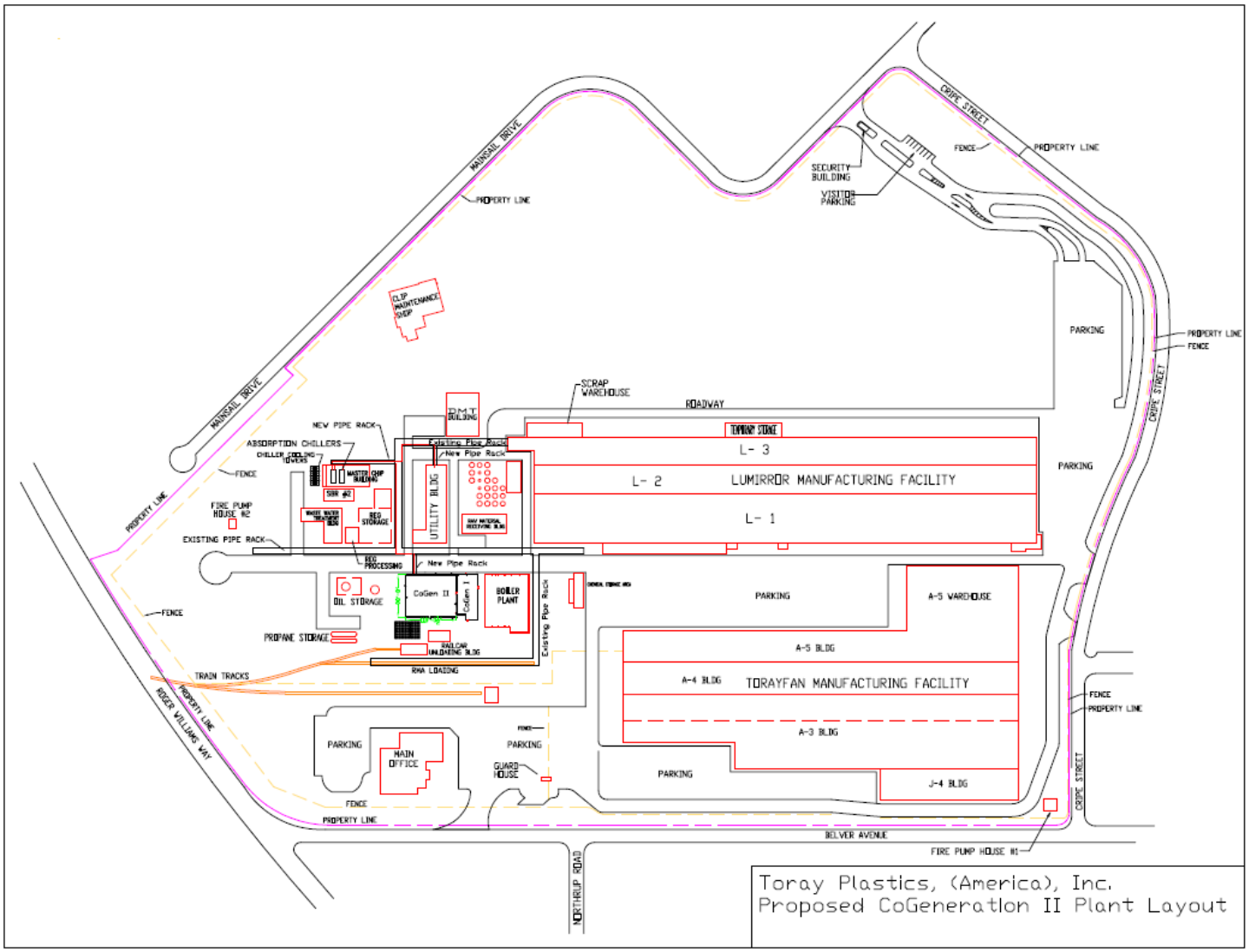
Notes:

1. *Due to the 8,760 H/Y type analysis performed for this project and the editing of the metered Electric, Steam, Chilled Water and Free-Cooling raw data, there is too much raw, intermediate and final data and information to present in the limited space of 8.5" x 11.0". With Toray's written permission and acknowledgement, this information is available by contacting Fred McKiernan at National Grid (401-784-7413).*
2. *This product is proprietary to Waldron Engineering & Construction, Inc. and all rights are reserved under copyright law, therefore, it is only available by contacting Waldron Engineering at (603) 772-7153.*

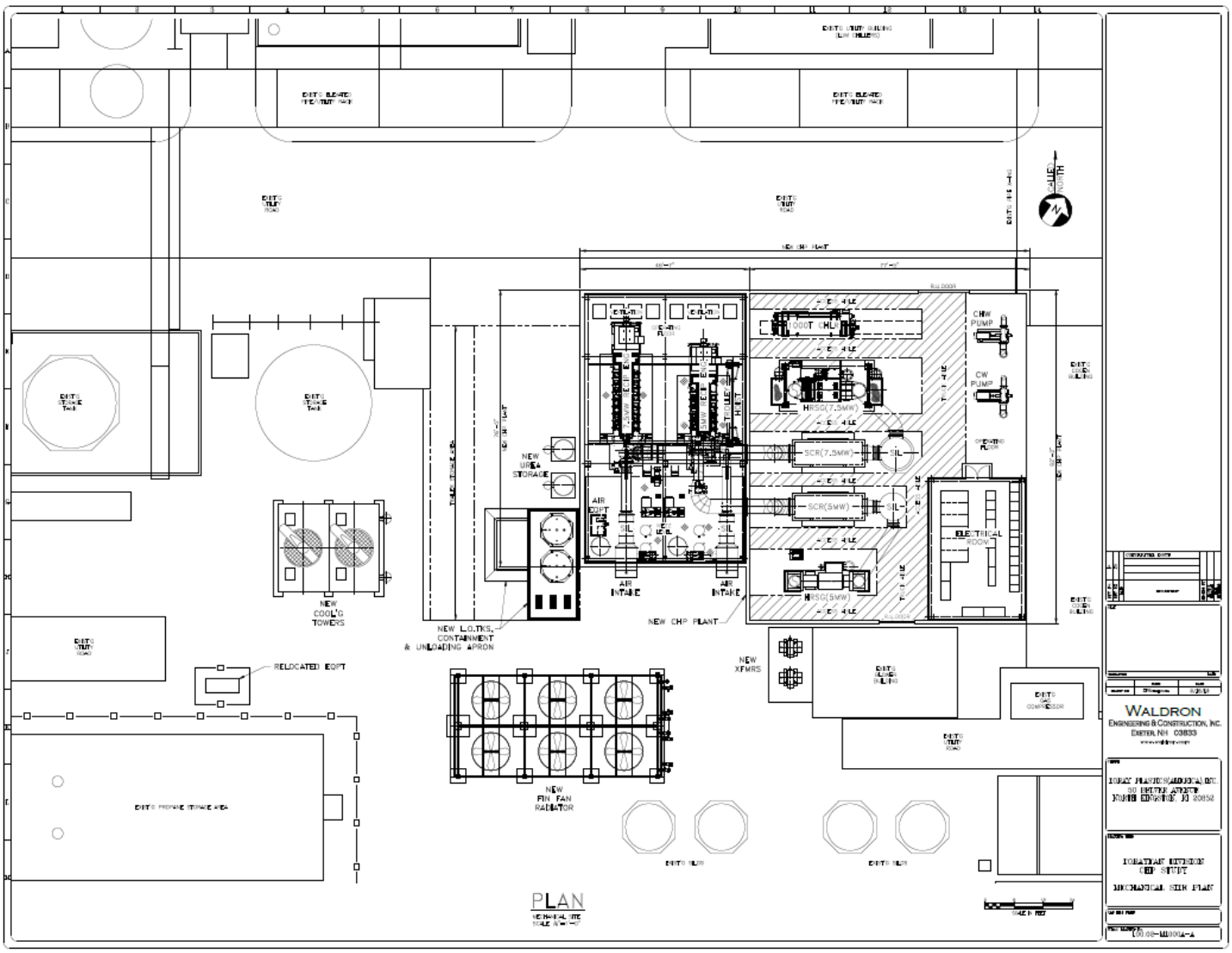
Existing & Proposed Major Equipment & Systems Schematic Diagram



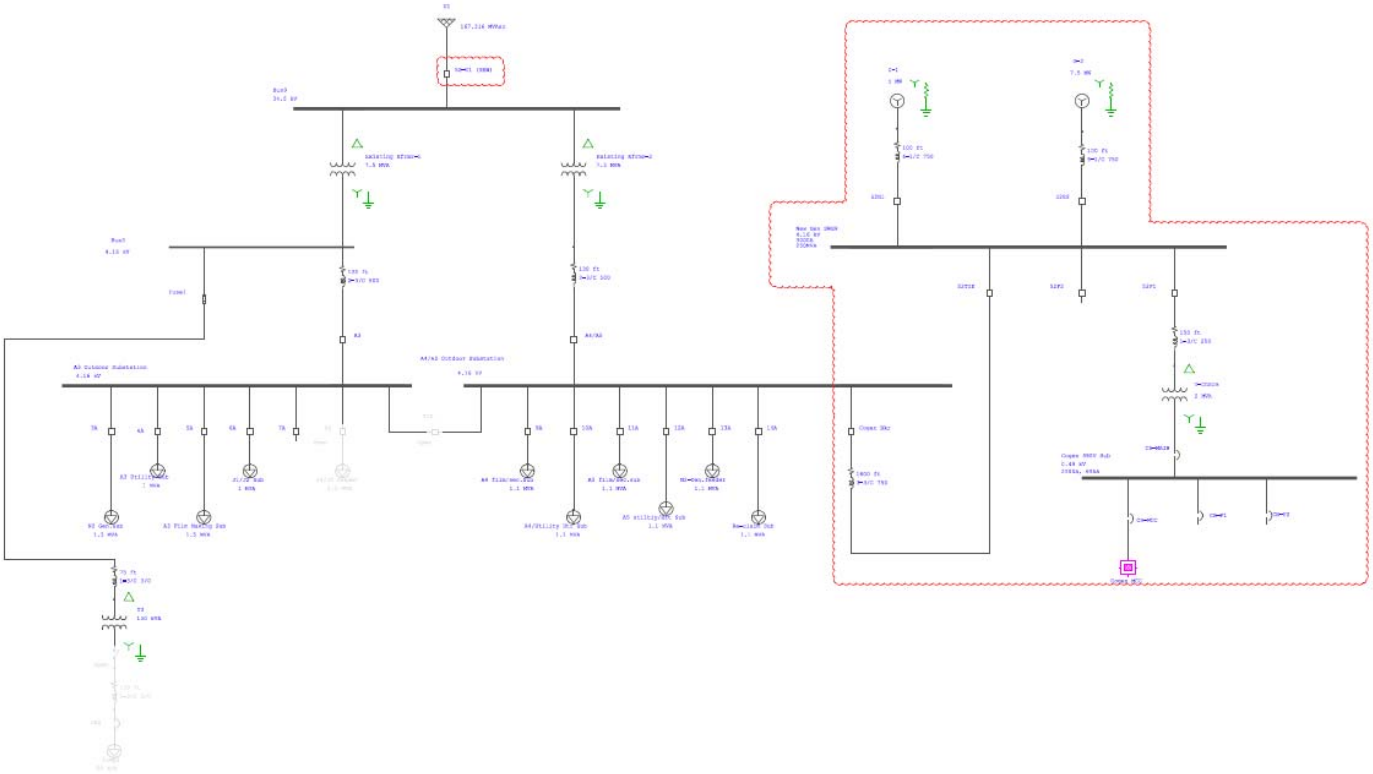
Proposed CHP System Site Plan Building Location Drawing



Proposed CHP System General Arrangement Drawing

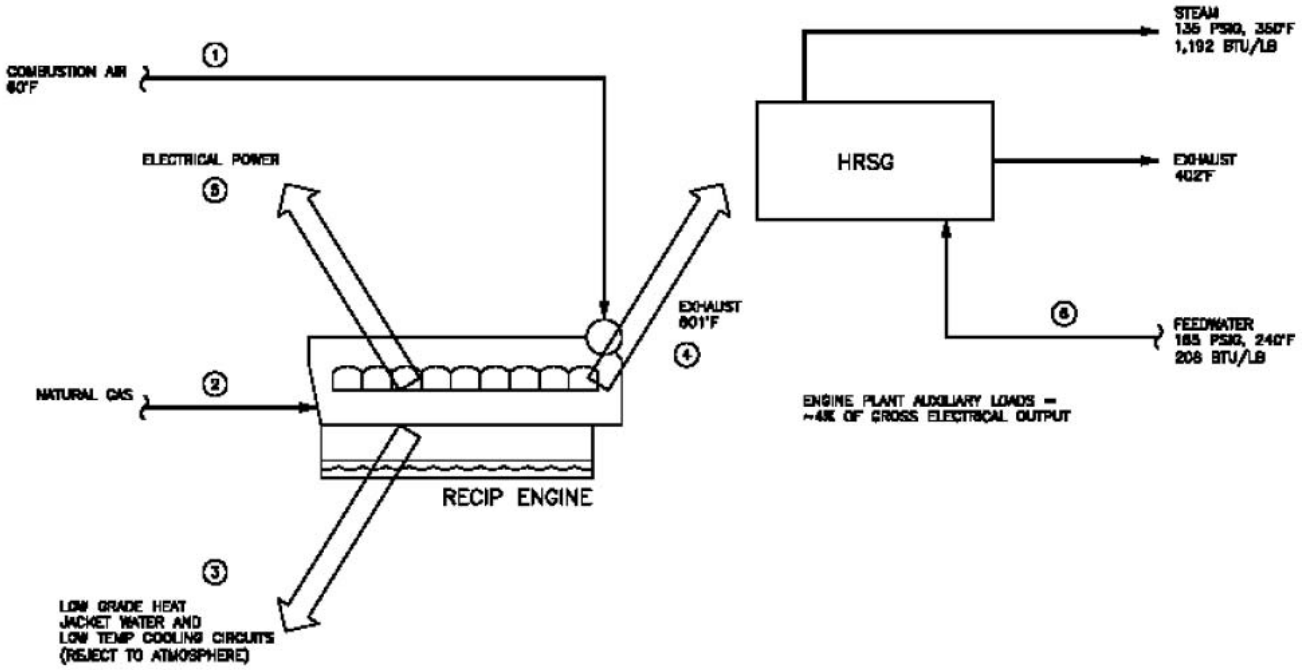


Proposed CHP System Electric One-Line Diagram



12.5 MW Option - Heat Balance

	Combustion Air (lbm/hr) 1	Natural Gas (MMBtu/hr, LHV) 2	Low Grade Heat (MMBtu/hr) 3	Engine Exhaust (lbm/hr) 4	Electricity (MW) 5	Steam Cycle Flow (lbm/hr) 7	Fuel Utilization Efficiency, LHV (%)
7.5 MW Engine	97,846	51.89	6.296	100,440	7.5	5,382	59.5%
5 MW Engine	65,230	34.59	4.198	66,960	5.0	3,588	59.5%



HRSG

CROSS FLOW

RENTECH

Budget Proposal:

For

Toray Plastics
HRSG/SCR

RENTECH Boiler Systems Quotation: GTB-3621-KS

Boilers for people who know and care

I. Summary Information

A. General Design Conditions

The HRSG system described in this proposal has been designed for the following main parameter:

Engine	
Size:	7.5 MW & 5 MW
Fuels:	Natural Gas
Steam Conditions:	
Steam Pressure:	100 psig
Steam Temperature:	Saturated
Steam Flow (7.5 MW/ 5 MW):	7,100 / 4,700
F.W. Temperature	228 °F (Deaerated)
HRSG Design Pressures	
Evaporator:	200 psig
Economizer:	250 psig
HRSG Design Codes	
Evaporator:	ASME Section I
Economizer:	ASME Section I

RENTECH Boiler Systems, Inc. • 5025 E. Business 20 • Abilene, TX 79601 • Phone: 325-672-3400 • Fax: 325-672-9996

"RENTECH *Boilers for people who know and care.*"®

C. Expected HRSG Performance

Gas Side	Units	7.5 MW Engine	5 MW Engine
Gas Flow	Lb/Hr	100,080	66,720
Gas Inlet Temperature	°F	608	608
Stack Temperature	°F	333	332
Gas Pressure Drop	In. WC	7.57	7.41
Flame Temperature	°F	608	608
Burner Duty	MMBTU/Hr	0	0
Fuel Flow	Lb/Hr	0	0
FLUE GAS ANALYSIS - Turbine Exhaust			
CO2	% vol	4.32%	4.32%
H2O	% vol	9.56%	9.56%
N2	% vol	73.93%	73.93%
O2	% vol	11.30%	11.30%
Ar	% vol	0.88%	0.88%
Group Data			
Final Steam Flow	Lb/Hr	7,169	4,798
Spray Flow	Lb/Hr	0	0
Process Flow	Lb/Hr	0	0
Steam Drum Exit Flow	Lb/Hr	7,169	4,798
Blowdown Flow	Lb/Hr	146	98
Feedwater Temperature		228	228
Feedwater Flow	Lb/Hr	7,316	4,896
Steam Pressure at exit	psia	114	114
Steam Saturation Temp	°F	341	341
Steam Final Exit Temp	°F	341	341
Pinch	°F	20	18
Approach	°F	17	19

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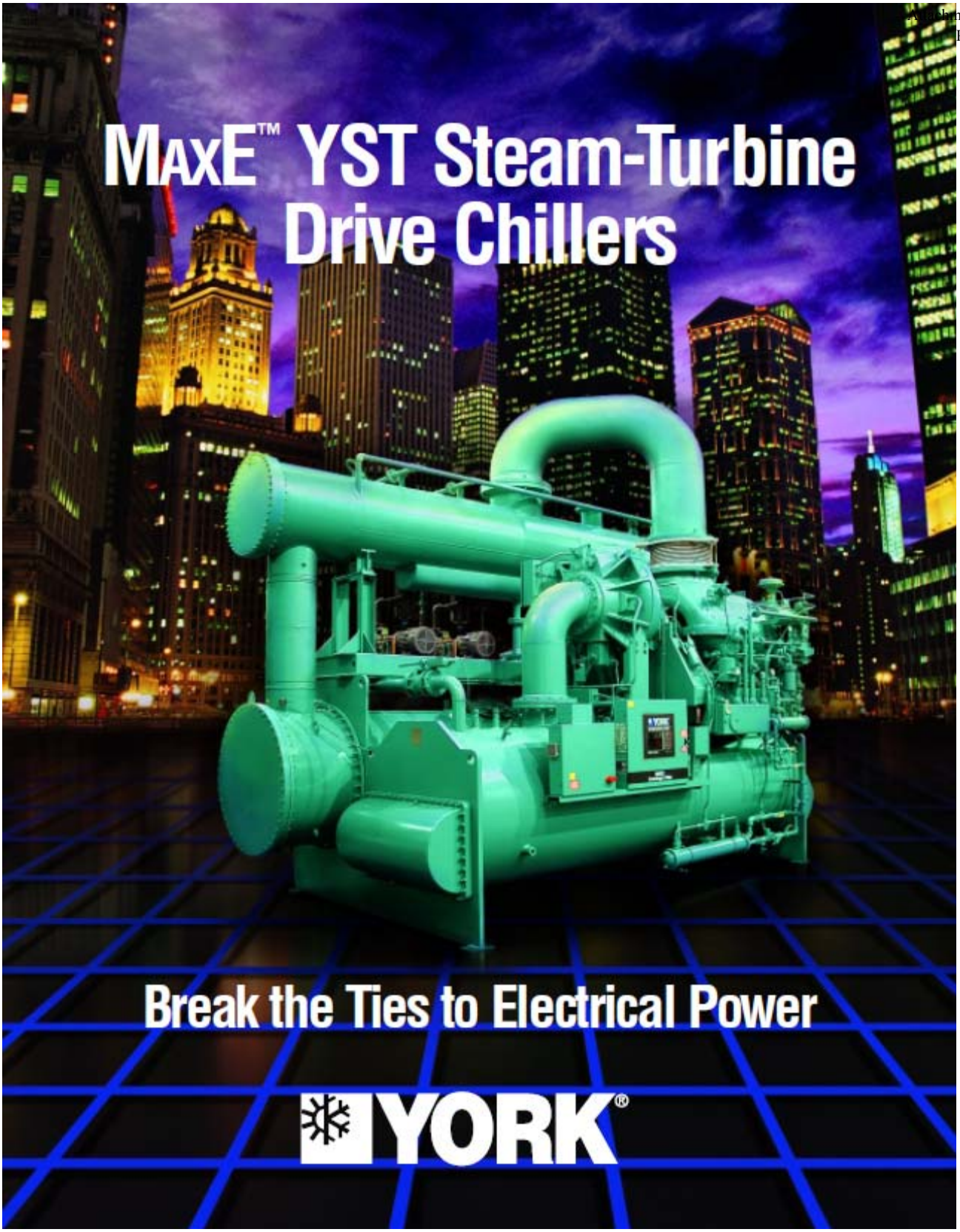

MAXE™ YST Steam-Turbine
Drive Chillers
Break the Ties to Electrical Power
YORK®

Issue Date: 5/12
Project: Project
Engineer: Sales Eng
Customer: customer

Program: LTC
Rev: v1_121.idd
Date: 05/21/12
Page: 2 of 2

PART LOAD PERFORMANCE:

Pct Load	Capacity (TR)	Pct Steam Flow	Shaft HP (HP)	RPM	COP	Steam Flow (lb/hr)	No. Nozzle	EEFT (°F)	ELFT (°F)	CEFT (°F)	CLFT (°F)	Steam CLFT (°F)
100.0	1000.0	100.0	737.0	4424.5	1.08	9934	8	54.00	42.00	85.00	94.30	100.50
90.0	900.0	58.2	414.0	3741.2	1.62	5778	6	52.80	42.00	65.00	72.90	76.60
80.0	800.0	50.4	345.2	3558.6	1.66	5010	6	51.60	42.00	65.00	72.00	75.20
70.0	700.0	42.9	280.6	3380.5	1.71	4261	6	50.40	42.00	65.00	71.10	73.90
60.0 *	600.0	36.0	227.7	3228.6	1.74	3573	6	49.20	42.00	65.00	70.20	72.60
50.0 *	500.0	29.6	187.4	3200.0	1.76	2936	6	48.00	42.00	65.00	69.30	71.30
40.0 *	400.0	24.0	153.2	3200.0	1.73	2388	6	46.80	42.00	65.00	68.50	70.00
30.0 *	300.0	19.4	123.9	3200.0	1.61	1927	6	45.60	42.00	65.00	67.60	68.90
20.0 *	200.0	14.1	90.1	3200.0	1.47	1401	6	44.40	42.00	65.00	66.80	67.70
15.0 *	150.0	11.5	73.5	3200.0	1.35	1143	6	43.80	42.00	65.00	66.30	67.10

(*) The performance is not guaranteed for any part load point. Points further identified with an * are outside the normal calculation range and are best estimates only.
Ratings outside the scope of AHRI STD 550/590.

YORK®
A JOHNSON CONTROLS COMPANY

Issue Date: 5/12
Project: Project
Engineer: Sales Eng
Customer: customer

Program: LTC
Rev: v1_121.idd
Date: 05/21/12
Page: 3 of 3

PART LOAD PERFORMANCE:

Pct Load	Capacity (TR)	Pct Steam Flow	Shaft HP (HP)	RPM	COP	Steam Flow (lb/hr)	No. Nozzle	EEFT (°F)	ELFT (°F)	CEFT (°F)	CLFT (°F)	Steam CLFT(°F)
100.0	1000.0	100.0	611.9	4164.1	1.27	8305	8	54.00	42.00	75.00	84.10	89.30
90.0	900.0	85.0	517.4	4001.4	1.34	7056	6	52.80	42.00	75.00	83.10	87.60
80.0	800.0	74.0	436.1	3835.0	1.37	6150	6	51.60	42.00	75.00	82.20	86.10
70.0	700.0	64.4	366.5	3692.6	1.37	5349	6	50.40	42.00	75.00	81.20	84.70
60.0	600.0	55.8	308.3	3567.5	1.36	4636	6	49.20	42.00	75.00	80.30	83.30
50.0	500.0	48.1	258.6	3516.7	1.31	3994	6	48.00	42.00	75.00	79.40	82.10
40.0 *	400.0	39.8	211.7	3461.5	1.26	3306	6	46.80	42.00	75.00	78.60	80.70
30.0 *	300.0	30.9	164.8	3421.9	1.22	2565	6	45.60	42.00	75.00	77.70	79.40
20.0 *	200.0	22.1	118.6	3411.1	1.13	1833	6	44.40	42.00	75.00	76.80	78.00
15.0 *	150.4	18.0	98.2	3491.9	1.04	1497	6	43.80	42.00	75.00	76.40	77.40

(*) The performance is not guaranteed for any part load point. Points further identified with an * are outside the normal calculation range and are best estimates only.
Ratings outside the scope of AHRI STD 550/590.

Issue Date: 5/12
Project: Project
Engineer: Sales Eng
Customer: customer

Program: LTC
Rev: v1_121.idd
Date: 05/21/12
Page: 3 of 3

PART LOAD PERFORMANCE:

Pct Load	Capacity (TR)	Pct Steam Flow	Shaft HP (HP)	RPM	COP	Steam Flow (lb/hr)	No. Nozzle	EEFT (°F)	ELFT (°F)	CEFT (°F)	CLFT (°F)	Steam CLFT (°F)
100.0	1000.0	100.0	737.0	4424.5	1.08	9934	8	54.00	42.00	85.00	94.30	100.50
90.0	900.0	88.4	634.5	4239.2	1.09	8784	8	52.80	42.00	85.00	93.30	98.80
80.0	800.0	78.2	547.4	4108.2	1.10	7762	8	51.60	42.00	85.00	92.40	97.30
70.0	700.0	67.4	469.9	3983.5	1.11	6692	6	50.40	42.00	85.00	91.40	95.70
60.0	600.0	58.8	402.4	3939.0	1.09	5840	6	49.20	42.00	85.00	90.50	94.20
50.0	500.0	51.0	340.7	3903.0	1.04	5063	6	48.00	42.00	85.00	89.60	92.80
40.0	400.0	43.3	280.6	3872.3	0.98	4298	6	46.80	42.00	85.00	88.70	91.50
30.0 *	300.0	34.4	218.2	3839.0	0.92	3418	6	45.60	42.00	85.00	87.80	90.00
20.0 *	200.0	24.9	160.8	3914.0	0.85	2472	6	44.40	42.00	85.00	86.90	88.50
15.0 *	150.4	20.9	137.4	4073.1	0.76	2073	6	43.80	42.00	85.00	86.40	87.80

(*) The performance is not guaranteed for any part load point. Points further identified with an * are outside the normal calculation range and are best estimates only.
Ratings outside the scope of AHRI STD 550/590.

COGEN 1							
EQUIPMENT							
	HP	Frame	RPM	Volts	Amps	Ser. Fact	Effic.
Turbine							
Oil Cooler Motor	7.5	213T	1760	480	10.2	1.15	89.5
Gas Compressor							
Main Motor	400	S449SS	3570	480	420	1.15	95.8
Cooler Motor	15	254T	1800	480	17	1.15	85.5
Oil Pump Motor	1	145TS	1745	480	1.5	1.15	82.5
Air Compressor							
Motor	15	215T	3450	480	17.5	1.15	89.5
Fuel Oil Forwarding Pump							
Motor	1.5	192T	1165	480	2.8	1.15	85.5
Scanner Air Blower							
Motor	1.5	143TCZ	3450	480	2.5	1.15	N/A

1. Actual load data was not provided by Toray.
2. Waldron assumed 75% of the attached HP would be a reasonable approximation of load during operation.

Total attached motor capacity of auxiliaries:	441.5	HP
75% of above:	331.125	HP
Equivalent kW:	247.1082	kW
Capacity of CTG:	6.977	MW
kW/kW:	**3.54%**	

This was used in the model to estimate CTG auxiliary loads

TPA Engineering

☐ Approved ☐ Rejected
☑ Approved with Comments
Name: [illegible]
Date: 3/11/99 3/16/99

graham
Vacuum and Heat Transfer
PLATE HEAT EXCHANGER SPECIFICATIONS

Max load covered by free cooling HX in model is 1040 tons.
1398 > 1040, so ok.

Toray Plastics (America), Inc.
Customer: Carrier
Customer Ref: Withem & Assoc.
Item: HX-3 (Alt.#3)

Graham Ref: 183 HVA 98
Date: 03/05/99
Engineer: RLO

3500gpm x 500 x (55.59-46) = 16.8MMbtu
16.8MMbtu/12,000 btu/ton = 1398 tons

	HOT SIDE	COLD SIDE
Fluids:	Water	Water
Flow (gpm)	3360.00	3500.00
Flow (pph)	1679931.38	1750498.13
T-in (deg. F)	58.00	46.00
T-out (deg. F)	48.00	55.59
Specific Gravity	1.00	1.00
Specific Heat (Btu/lb./F)	1.00	1.00
Thermal Conductivity	0.35	0.35
Viscosity (cp)	1.22	1.26
Operating Pressure (psig)		
Pressure Drops (psi)	10.00	10.00
Passes	1.	1.
Nozzle Diameter (inches)	12.0	12.0
Nozzle Material	316SS	316SS

Heat Exchanged (Btu/hr) ..... 16862422.

DON'T TO HAVE S.S. STAMPED TAG WITH TPA PART # & EQ. NAME.
IE CH2-16-1 FREE COOLING HEAT EXCHANGER.

Model	GPE-145
Plate Thickness (inches)	0.0197
Plate Material	304SS
Gasket Material	Nitrile
Frame Material	CARBON STEEL
Design/Test Pressure (psig)	125./188.
Design Temperature (deg. F)	220.
Est. Weight: empty/flooded (lbs.)	13640./17380.

Remarks:
Construction per ASME Section VIII Division I.
ASME inspection and stamp available for a premium.
Shipment stated reflects current inventory and manufacturing schedules. Improvement in shipment may be possible upon your request.
Customer to verify suitability of materials.
Performance is guaranteed in accordance with data and operating conditions stated herein.
Terms of payment net 30 days.
F.O.B. Batavia, New York.

Terms & Conditions of Sale per GMC-1002-E unless otherwise indicated.

Graham Corporation, P.O. Box 719, Batavia, NY 14021-0719
Corporate and Sales Headquarters: 20 Florence Avenue, Batavia, NY 14020
TEL:716-343-2216 FAX:716-343-1097 EMAIL:equipment@graham-mfg.com WEBSITE:http://www.graham-mfg.com

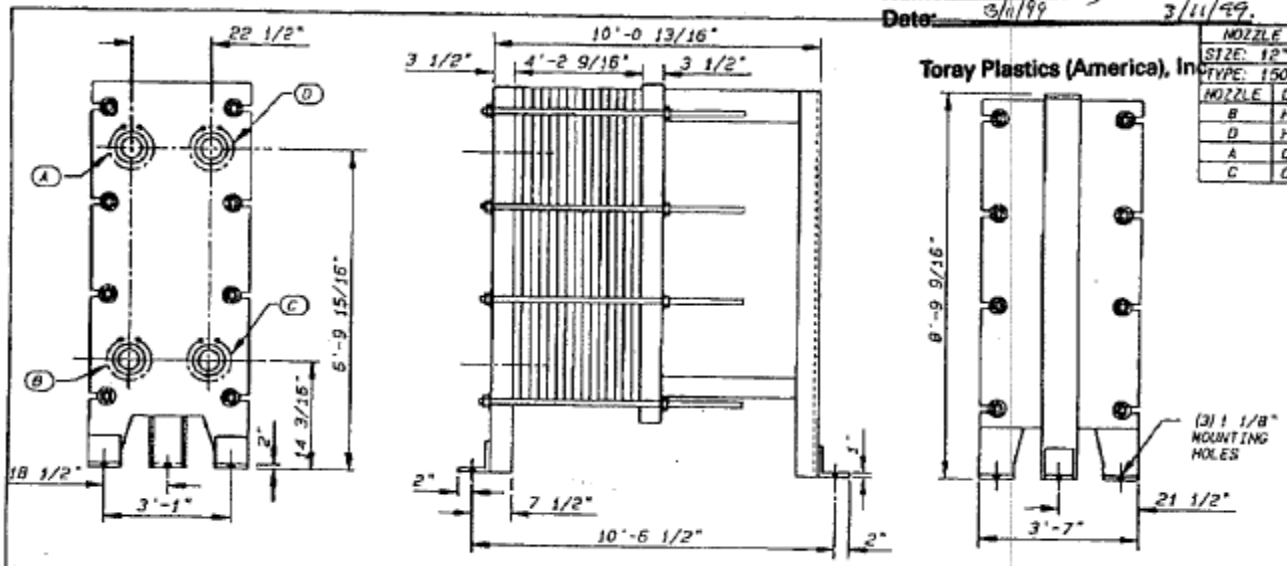
MAR 8 '99 14:52

4013330285 PAGE.003

TPA Engineering

☐ Approved ☐ Rejected
☑ Approved with Comments
Name: Kim Hully Vincent Lathe
Date: 3/11/99 3/11/99.

Toray Plastics (America), Inc.



NOZZLE SCHEDULE	
SIZE: 12"	
TYPE: 150# STUDDED	
NOZZLE	DESCRIPTION
B	HS INLET
D	HS OUTLET
A	CS INLET
C	CS OUTLET

CUSTOMER: Carrier
CUSTOMER REF. NO.--
GRAHAM REF. NO.--
DESIGN / CONSTRUCTION: 183 HVA 98
INSPECTION: ASME Section VIII Division I
STAMPING: none
SURFACE PREPARATION: GRITBLAST PER SSPC-SP6
PAINT (EXT CARBON STL): INDURACOTE IC-7837 ~~(GRAHAM BLUE)~~ FORM GREEN
TAG:

LIZ-16-1

FREE COOLING HEAT EXCHANGER

NOTES:
1. OVER-PRESSURE PROTECTION MUST BE PROVIDED BY OTHERS PRIOR TO PLACING THE VESSEL IN SERVICE.
2. PULSATING PUMPS MUST HAVE ADEQUATE PULSATION DAMPENERS PROVIDED.
3. UNIT SHOULD BE LIFTED BY HOLES/TABS PROVIDED ON FRONT FIXED COVER AND REAR SUPPORT LEG. LIFTING UNIT BY REAR MOVABLE COVER MAY CAUSE DAMAGE.
4. BOLT HOLES STRADDLE CENTERLINES.
5. MARK ALL CONNECTIONS WITH FLOW LABELS.
6. ALL CONN. ARE ANSI STD PIPE THREAD.

HX-3 (A)1.#3)

PRELIMINARY
GRAHAM MFG. CO. INC.

PLATE HEAT EXCHANGER MATERIAL LIST		
PART NAME	MATERIAL	SPEC. NO.
FIXED COVER	CARBON STEEL	SA-516-70
MOVABLE COVER	CARBON STEEL	SA-516-70
CARRYING BAR	CARBON STEEL	A-36
GUIDE BAR	304SS	SA-240
HS LINERS/NOZ	316SS	SA-240
CS LINERS/NOZ	316SS	SA-240
PLATES	304SS	SA-240
GASKETS	Nitrile	----
BOLTING	ALLOY STEEL	SA-193-B7, SA-194-2H

	M.A.W.P. (P.S.I.G.)	TEMPERATURE NORM/DESIGN (DEG F)	HYDRO TEST (P.S.I.G.)	NUMBER OF PASSES	EST'D WGTS. (LBS)	
HOT SIDE	125.0	0/ 220.0	187.5	1	EMPTY	13640
COLD SIDE	125.0	0/ 220.0	187.5	1	FLOODED	17380

RLO 03/05/99 > PE153804.BLK

GRAHAM MANUFACTURING CO., INC.
20 FLORENCE AVE. BATAVIA, NEW YORK

GPE-145 PLATE HEAT EXCHANGER

SCALE	MADE	CHKD	DATE	DWG. NO.	REV.
NONE	RLO	---	03/05/99	A-183 HVA 98-1	0

MAR-08-99 04:29P CARRIER DIVISION SYSTEMS 315 454 7000 P.03

Maintenance cost (Engine+Control) for KG-18

Year	Operating Hour	Maintenance Level	Expected Downtime (Days)	Main Works	PARTS ONLY CONVERSION TO $ @ 78 YEN/$	LABOR ESTIMATE @ $100/HOUR	TOTAL PARTS AND LABOR	ANNUAL COSTS BY YEAR				
1	2,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	4,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	6,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	8,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$112,465	$112,465	99.43%	$0.002	$/kWh
2	10,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	12,000	C	12	Replacement of piston rings	$511,323	$64,500	$575,823					
	14,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	16,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$622,854	$735,319	98.86%	$0.006	$/kWh
3	18,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	20,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	22,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	24,000	D	14	Replacement of Crankpin and main bearings and valves,battery	$750,371	$113,800	$864,171	$960,528	$1,695,846	98.55%	$0.009	$/kWh
4	26,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	28,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	30,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	32,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$112,465	$1,808,311	98.77%	$0.007	$/kWh
5	34,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	36,000	C	12	Replacement of piston rings	$511,323	$64,500	$575,823					
	38,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	40,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$622,854	$2,431,165	98.68%	$0.008	$/kWh
6	42,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	44,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	46,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	48,000	E	17	Replacement of piston crowns and thrust bearing ,battery	$1,232,739	$137,800	$1,370,539	$1,466,896	$3,898,060	98.50%	$0.010	$/kWh
7	50,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	52,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	54,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	56,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$112,465	$4,010,525	98.63%	$0.009	$/kWh
8	58,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	60,000	C	12	Replacement of piston rings ,Cylinder controller and ignition device	$1,053,958	$64,500	$1,118,458					
	62,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	64,000	A	1	Replacement of Spark Plug	$14,908	$1,200	$16,108	$1,165,489	$5,176,014	98.59%	$0.010	$/kWh
9	66,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	68,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	70,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	72,000	D	14	Replacement of Crankpin and main bearings and valves ,battery	$750,371	$113,800	$864,171	$960,528	$6,136,541	98.52%	$0.011	$/kWh
10	74,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	76,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	78,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	80,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$112,465	$6,249,006	98.61%	$0.010	$/kWh
11	82,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	84,000	C	12	Replacement of piston rings	$511,323	$64,500	$575,823					
	86,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	88,000	A	1	Replacement of Spark Plug ,battery	$14,908	$1,200	$16,108	$622,854	$6,871,860	98.58%	$0.010	$/kWh
12	90,000	B	2	Replacement of non-return valves	$57,434	$8,000	$65,434					
	92,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	94,000	A	1	Replacement of Spark Plug	$14,262	$1,200	$15,462					
	96,000	F	17	Replacement of cylinder liners ,battery	$1,502,730	$136,000	$1,638,730	$1,735,087	$8,606,947	98.50%	$0.011	$/kWh
Sub Total					$7,745,147	$861,800	$8,606,947	$8,606,947				
								$717,245.59				
				0.036073059								
			158				717,246					
				Years Average			$0.0120	$/kWh				

Appendix D: Minimum Requirements Document

Minimum Requirements Document

nationalgrid

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

This document specifies the agreed upon minimum equipment specifications and operational requirements of the proposed system. These requirements shall address the criteria necessary to be met to achieve the demand and energy savings estimated in the engineering analysis for this project. (Use additional sheets if necessary).

Circle yes or no Pre Construction	SEQUENCE OF OPERATION: Provide a description of equipment operating sequences, setpoints, operating schedules, balancing requirements (flow, velocity, head, etc) or any other required operating parameters Submittals: Provide major equipment data sheets
Yes No	**Milestone No.1. Equipment submittal and approval of Sequence of Operation (SOO).** Required Completion Date: Before the start of the CHP installation at the site and prior to releasing the production of the major equipment. 1. **2 x Reciprocating Engines (Normal Operation):** Both engines' electric output will be dedicated to FAN's total electric loads and always attempt to have Net Production equal Load, minus Import/Export Controller's set-point. Both engines will operate in parallel with each other and NGrid's distribution system. Both engines will operate under the electrically load following Mode of Operation (MOO) and at equal electric Load Factors. CHP system's Import/Export Controller set-point will allow a continuous electricity import from NGrid's distribution system less than or equal to 350 kWe, but not ever allow CHP generated electricity to export into NGrid's distribution system. Both engines' planned maintenance will not simultaneously occur and each engine will follow the respective, attached maintenance schedule and durations (Attachment No.1 for NG-Fired, Kawasaki, M/N: KG-18-V Reciprocating Engine. M/N: KG-12-V's planned maintenance will be equal to or less than KG-18-V engine.); inclusive of engines' cool-down and start-up durations. 2. **2 x Heat Recovery Steam Boilers (Normal Operation):** Each engine's Heat Recovery Steam Generator (HRSG) will be connected and operated so as to always receive each engine's full exhaust flow to maximize 135 psig steam production. Any decreased 652 psig steam load as a result of the engines' HRSGs production will first reduce the Combustion Gas Turbine's (CGT) HRSG's Duct-Burner (DB) firing-rate. If, after full DB reduction, more reduction is needed, then the CGT's HRSG will vent excess 652 psig steam. Each engine's HRSG will generate saturated, steam at 135 psig. Both HRSGs will be tied-into a common steam header and production will be connected down-stream of FAN's 652 psig-to-102 psig Pressure Reduction Valve (PRV), while a second connection will be down-stream of Lumirror's 652 psig-to-73 psig PRV. Both connections' pressure will be set high enough to allow all of the 2 x HRSGs' steam production to always take higher priority over all other 102 psig and 73 psig steam production sources. Both HRSGs' planned maintenance will only occur simultaneously with its respective engine's planned maintenance schedule and not exceed the respective engine's down-time duration. 3. **2 x Engine's Hot Water Rejection Systems (Normal Operation):** Both engines will direct all sources of engine generated hot water to individual Waste Heat Radiators (WHR) to control engine return water temperatures.

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

4. **2 x Engine NO_x & CO Emission Control Systems (Normal Operation):** Both Emission Control System's will operate on a continuous basis to meet applicable Local, State and Federal emission permit limits with it's respective engine and planned maintenance will only occur simultaneously with its respective engine's planned maintenance schedule and not exceed the respective engine's down-time duration.
5. **1 x ST CH & Lumirror CHW Plant (Normal Operation):** Free-Cooling will be higher priority than electric-driven and steam-driven chilling. The Steam Turbine Chiller (ST CH) will be higher priority than the electric CHs, whenever both proposed CHP HRSGs' combined production is greater than the total process steam load (i.e., 102 psig FAN process load and 73 psig Lumirror process load) by an amount equal to the ST CH's minimum steam flowrate when mechanical CHW production is required. Lumirror's CHW Plant's electric CHs will always operate at equal Load Factors regardless of the quantity needed to meet CHW load; unless a more energy efficient electric CH sequence is demonstrated. ST CH's planned maintenance will occur during Free-Cooling periods and/or periods when ST CH is not commanded On (i.e., see second sentence SOO). The ST CH's down-time will not exceed the duration of either of these periods.
6. **CGT's & Reciprocating Engines' Electric Parasitic Loads:** The respective electric parasitic loads will only operate when the individual, associated engine (i.e., CGT or Reciprocating) is running and will not exceed 3.54% of each engine's gross electrical production at the corresponding loads and weather conditions.
7. **Sequence of Operations (SOO):** Provide detailed written description of the above proposed SOO of the existing and proposed CHP systems and all connected systems. The SOO must include detailed descriptions of how the proposed CHP sub-systems will be "first in-line" to serve electric, steam and CHW loads as well as track the same loads.
8. **Equipment Submittals:** Prior to releasing the proposed CHP equipment for production, customer shall provide a copy of the major and parasitic load equipment submittals including performance ratings for review of general compliance with this Minimum Requirements Document (MRD) and the final assumptions, savings calculations and Technical Assistance Study approved by NGrid.
9. **Electric and P&IDs:** Electric and Process & Instrumentation Diagrams showing all proposed CHP system equipment, inclusive of electrical systems (i.e., engine-generators and parasitic loads) and meter(s), fuel and meter(s), lube oil, steam and meter(s), hot water, chilled water and meter(s), emissions' systems consumables and instruments.
10. **Performance Criteria:** The proposed CHP system is designed to meet the following minimum performance criteria. Average, annual production equal to or greater than a) 90,579,920 kWh (Net), b) 4,450,918 Ton-Hrs of (ST CH) chilled water, c) 88,805,215 Pounds of 135 psig saturate steam, d) Electrical Efficiency = 44.1% (HHV), E) Thermal Efficiency = 12.6% (HHV), and F) Total Efficiency = 56.6% (HHV). Average, annual NG usage by the two (2) engines will be less than or equal to 7,018,053 Therms (HHV). CHP system's minimum, average annual availability will be equal to or greater than 93.0% (each engine and related equipment).

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

Post Inspection	**Installation Completion:** Provide a list of equipment or materials installed as part of this project. Include mfr, model, HP, kW, efficiency ratings, etc .and confirm completion
Yes No	**Milestone No.2a. - Installation Completion**

1. **2 x Reciprocating Engines:** 1 x NG-Fired, Kawasaki, M/N: KG-18-V Reciprocating Engine running at 720 rpm and nominally rated at 7.5 MWe (Gross) continuous output. 1 x NG-Fired, Kawasaki, M/N: KG-12-V Reciprocating Engine running at 720 rpm and nominally rated at 5.0 MWe (Gross) continuous output. Different engines may be selected based on customer's competitive bid process, however, the proposed CHP system will have a minimum, power output equal to 12.0 MWe (Net) and an electrical efficiency of 49.0% (LHV) at 100% load with 38 psig NG delivered to the engines' skids. Moreover, part-load curves will be equal or greater energy efficiency than provided below. The proposed CHP system will meet applicable Local, State and Federal codes, including pollutant emissions, environmental and noise regulations and will comply with National Grid's interconnection requirements. See Attachment No.2 for details.

Ambient Temperature (deg F)	100% Output (kW)	75% Output (kW)	50% Output (kW)	100% Heatrate (Btu/kWh, LHV)	75% Heatrate (Btu/kWh, LHV)	50% Heatrate (Btu/kWh, LHV)
10	5,000	3,750	2,500	6,784	6,964	7,418
30	5,000	3,750	2,500	6,840	7,023	7,485
50	5,000	3,750	2,500	6,895	7,081	7,551
60	5,000	3,750	2,500	6,918	7,106	7,579
80	5,000	3,750	2,500	6,965	7,155	7,635
100	5,000	3,750	2,500	7,037	7,231	7,722

Ambient Temperature (deg F)	100% Exhaust Flow (lb/hr)	75% Exhaust Flow (lb/hr)	50% Exhaust Flow (lb/hr)	100% Exhaust Temp (deg F)	75% Exhaust Temp (deg F)	50% Exhaust Temp (deg F)
0	66,960	50,760	35,280	583	655	691
20	66,960	50,760	35,280	590	662	698
40	66,960	50,760	35,280	597	669	705
60	66,960	50,760	35,280	601	673	709
80	66,960	50,760	35,280	608	680	716
100	66,960	50,760	35,280	622	695	730

Figure 24 - Kawasaki KG-12 Engine Performance Data Table

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

Ambient Temperature (deg F)	100% Output (kW)	75% Output (kW)	50% Output (kW)	100% Heatrate (Btu/kWh, LHV)	75% Heatrate (Btu/kWh, LHV)	50% Heatrate (Btu/kWh, LHV)
10	7,500	5,625	3,750	6,784	6,964	7,418
30	7,500	5,625	3,750	6,840	7,023	7,485
50	7,500	5,625	3,750	6,895	7,081	7,551
60	7,500	5,625	3,750	6,918	7,106	7,579
80	7,500	5,625	3,750	6,965	7,155	7,635
100	7,500	5,625	3,750	7,037	7,231	7,722

Ambient Temperature (deg F)	100% Exhaust Flow (lb/hr)	75% Exhaust Flow (lb/hr)	50% Exhaust Flow (lb/hr)	100% Exhaust Temp (deg F)	75% Exhaust Temp (deg F)	50% Exhaust Temp (deg F)
0	100,440	76,140	52,920	583	655	691
20	100,440	76,140	52,920	590	662	698
40	100,440	76,140	52,920	597	669	705
60	100,440	76,140	52,920	601	673	709
80	100,440	76,140	52,920	608	680	716
100	100,440	76,140	52,920	622	695	730

Figure 25 - Kawasaki KG-18 Engine Performance Data Table

2. **2 x Heat Recovery Steam Boilers:** Both Cleaver-Brooks', Slant Series HRSGs, M/N: S-2.5-1414. Different HRSGs may be selected based on customer's competitive bid process, however, the proposed CHP system will have a minimum, total, steam production flowrate of 11,500 pph of 135 psig (Net of heat-loses.), saturated steam at 100% engine load and engine OEM's specified, maximum back-pressure. Moreover, part-load curves will be equal or greater energy efficiency than a linear relationship between Heat Input and Heat Output. The proposed HRSGs will meet applicable Local, State and Federal codes.

3. **2 x Engine NO_x & CO Emission Control Systems:** Both Emission Control Systems will meet all applicable Local, State and Federal codes and Air Quality permitting requirements approved for the specific site by the appropriate authorities.

4. **1 x Steam Turbine-Driven Chiller:** 1 x York International, Series MaxE YST, steam turbine-driven, 1,000 Ton Chiller using a condensing steam turbine-drive. A different ST CH may be selected based on customer's competitive bid process, however, the proposed ST CH will have a minimum, cooling output equal to 1,000 Tons at 100% load. Moreover, part-load curves will be equal or greater energy efficiency than provided below. The proposed ST Ch will meet applicable Local, State and Federal codes.

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

PART LOAD PERFORMANCE:

Pct Load	Capacity (TR)	Pct Steam Flow	Shaft HP (HP)	RPM	COP	Steam Flow (lb/hr)	No. Nozzle	EEFT (°F)	ELFT (°F)	CEFT (°F)	CLFT (°F)	Steam CLFT (°F)
100.0	1000.0	100.0	737.0	4424.5	1.08	9934	8	54.00	42.00	85.00	94.30	100.50
90.0	900.0	58.2	414.0	3741.2	1.62	5778	6	52.80	42.00	65.00	72.90	76.60
80.0	800.0	50.4	345.2	3558.6	1.66	5010	6	51.60	42.00	65.00	72.00	75.20
70.0	700.0	42.9	280.6	3380.5	1.71	4261	6	50.40	42.00	65.00	71.10	73.90
60.0 *	600.0	36.0	227.7	3228.6	1.74	3573	6	49.20	42.00	65.00	70.20	72.60
50.0 *	500.0	29.6	187.4	3200.0	1.76	2936	6	48.00	42.00	65.00	69.30	71.30
40.0 *	400.0	24.0	153.2	3200.0	1.73	2388	6	46.80	42.00	65.00	68.50	70.00
30.0 *	300.0	19.4	123.9	3200.0	1.61	1927	6	45.60	42.00	65.00	67.60	68.90
20.0 *	200.0	14.1	90.1	3200.0	1.47	1401	6	44.40	42.00	65.00	66.80	67.70
15.0 *	150.0	11.5	73.5	3200.0	1.35	1143	6	43.80	42.00	65.00	66.30	67.10

PART LOAD PERFORMANCE:

Pct Load	Capacity (TR)	Pct Steam Flow	Shaft HP (HP)	RPM	COP	Steam Flow (lb/hr)	No. Nozzle	EEFT (°F)	ELFT (°F)	CEFT (°F)	CLFT (°F)	Steam CLFT(°F)
100.0	1000.0	100.0	611.9	4164.1	1.27	8305	8	54.00	42.00	75.00	84.10	89.30
90.0	900.0	85.0	517.4	4001.4	1.34	7056	6	52.80	42.00	75.00	83.10	87.60
80.0	800.0	74.0	436.1	3835.0	1.37	6150	6	51.60	42.00	75.00	82.20	86.10
70.0	700.0	64.4	366.5	3692.6	1.37	5349	6	50.40	42.00	75.00	81.20	84.70
60.0	600.0	55.8	308.3	3567.5	1.36	4636	6	49.20	42.00	75.00	80.30	83.30
50.0	500.0	48.1	258.6	3518.7	1.31	3994	6	48.00	42.00	75.00	79.40	82.10
40.0 *	400.0	39.8	211.7	3461.5	1.26	3306	6	46.80	42.00	75.00	78.60	80.70
30.0 *	300.0	30.9	164.8	3421.9	1.22	2565	6	45.60	42.00	75.00	77.70	79.40
20.0 *	200.0	22.1	118.6	3411.1	1.13	1833	6	44.40	42.00	75.00	76.80	78.00
15.0 *	150.4	18.0	98.2	3491.9	1.04	1497	6	43.80	42.00	75.00	76.40	77.40

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

PART LOAD PERFORMANCE:

Pct Load	Capacity (TR)	Pct Steam Flow	Shaft HP (HP)	RPM	COP	Steam Flow (lb/hr)	No. Nozzle	EEFT (°F)	ELFT (°F)	CEFT (°F)	CLFT (°F)	Steam CLFT (°F)
100.0	1000.0	100.0	737.0	4424.5	1.08	9934	8	54.00	42.00	85.00	94.30	100.50
90.0	900.0	88.4	634.5	4239.2	1.09	8784	8	52.80	42.00	85.00	93.30	98.80
80.0	800.0	78.2	547.4	4108.2	1.10	7762	8	51.60	42.00	85.00	92.40	97.30
70.0	700.0	67.4	469.9	3983.5	1.11	6692	6	50.40	42.00	85.00	91.40	95.70
60.0	600.0	58.8	402.4	3939.0	1.09	5840	6	49.20	42.00	85.00	90.50	94.20
50.0	500.0	51.0	340.7	3903.0	1.04	5063	6	48.00	42.00	85.00	89.60	92.80
40.0	400.0	43.3	280.6	3872.3	0.98	4298	6	46.80	42.00	85.00	88.70	91.50
30.0 *	300.0	34.4	218.2	3839.0	0.92	3418	6	45.60	42.00	85.00	87.80	90.00
20.0 *	200.0	24.9	160.8	3914.0	0.85	2472	6	44.40	42.00	85.00	86.90	88.50
15.0 *	150.4	20.9	137.4	4073.1	0.76	2073	6	43.80	42.00	85.00	86.40	87.80

5. **Meters:** Customer will purchase and install (in accordance with each meter's OEMs' recommendations) utility revenue grade energy meters as required and as outlined in Milestone No.1 and related documents to monitor and record (for each engine and the total, proposed CHP system) gross electric production, corresponding engine electric parasitic loads, 135 psig steam production, ST CH steam usage and CHW production and NG usage (for each engine). At a minimum, the each meter will be able to capture hourly interval data for each of the abovementioned and the hourly interval data will be provided in the form of Time-stamped, Trend Logs in MS-Excel format or other NGrid acceptable electronic format. The proposed CHP system's control system will be capable of trending and archiving the hourly interval data for a period of one year before overwriting. During Post-Installation Inspection, customer will confirm the data collection system is installed, connected to recently calibrated metering (within six (6) months of commencing data acquisition) and properly report and archiving data.

Milestone No.2b. - Demonstration of Operability
(Completion of Milestone Nos.2A and 2b is required for the payment of 80% of the incentive.)

Yes No Confirm that the above noted equipment is installed and operational for completing Milestone 2b.

Yes No Installed and operational is defined as :

- All components of the CHP system are installed and operational.
- All equipment, piping (including flushing), electrical and control wiring is completed, so the equipment can operate in an automatic mode.

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

Yes No Yes No Yes No Yes No Yes No	▪ Interconnection to customer's NG, electrical and thermal loads are operational. Interconnection facilities are completed and accepted by Retail Connections Engineering and insurance certificates are in place. This does not absolve the customer from meeting any other jurisdictional permits or other regulatory requirements. o All instrumentation and energy meters required by MRD (as specified in Milestone No.3) are installed, calibrated within the past six (6) months and are properly working. o The CHP system is capable of continuously operating in automatic mode. o Hourly interval data will be made available to NGrid (MS-Excel or NGrid acceptable electronic format) to prove the operation of the CHP System and sub-systems matches the energy savings calculations and Technical Assistance Study. o Customer has completed its own substantial Check-Out, Start-Up and Commissioning of the full CHP system.
Post Operational Assessment	**DOCUMENTATION:** List written documentation required to train, verify, operate, or maintain the equipment being installed or controlled. This may include specification sheets, test reports, construction drawings, etc. : Provide a list of Trending Requirements required to verify proper system operation. Trends should document operational sequences, setpoints and scheduling of equipment as described in TA Study
Yes No	**Milestone No.3. (Remaining 20% of the incentive will be paid only after Milestone 3 & 4 are satisfactorily completed.)** Validate the following items: (a) O&M manuals and documentation on-site. 1. All equipment catalogs and performance specifications. O&M manuals for the following equipment: a. Each Reciprocating Engine-Generator Set; b. Each Heat Recovery Steam Generator; c. Each NOx & CO Emissions Control Systems; d. Each engine-generator sets' electric parasitic loads (i.e., pumps, motors, air compressors, fans, etc.); e. CHP System master and individual control systems; and f. Each Energy Meter (i.e., NG usage, electricity (i.e., gross & parasitic loads), 135 psig steam production and usage, HRSG feedwater flowrate and temperature, ST CH steam usage and CHW production, etc.). 2. As-Built design drawings & specifications (i.e., P&IDs, Mechanical Piping Drawings, Instrumentation List and equipment Data Sheets, etc.) are available on-site. (b) Availability of Trend Logs and confirmation of NGrid acceptable electronic format.

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
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	3. Provide 1 hour interval data for the following points as a minimum (15 minute interval data is desirable). Provide the capacity for and enable trend data archiving for a period of at least one year. a. Gross and Net kW and kWh electrical output; b. Fuel Input to CHP system (Therms or MMBtu at stated Heating Value); c. Steam generated and utilized (Therms or MMBtu); and d. ST CH steam usage and CHW generated and utilized (Tons). Other meters may be required based on the final design P&ID to measure parasitic Loads. 4. Provide ability to electronically export weekly data-files to third-party via email or FTP at all times. 5. Post operational assessment process will require functional testing of the CHP and the thermal and electrical interface to the buildings, a minimum 2 weeks and up to 6 months of concurrent 1 hour interval data for all points noted above. If equipment fails to meet expected sequences of operations and corrections are needed, an additional trend data shall be provided to confirm any seasonal changes in operations. 6. Provide meter calibration data/certification. (c) Sequence of Operation is working as outlined in MRD, TA Study and supporting energy saving calculations. The customer's full Commissioning Report is received and the remotely available performance data is reviewed by NGrid and the CHP system is operating in compliance with the proposed plant performance criteria specified in the MRD.
Post Inspection	OTHER REQUIRMENTS: Describe any requirements for demolition, removal, etc of existing equipment.
Yes No	Milestone No.4 1. Customer will have a 3-year maintenance contract (minimum) for each reciprocating engine, steam turbine-driven chiller, HRSG, air quality emissions control equipment, switchgear, instrumentation and controls to help achieve long-term, proposed operational strategies and energy cost savings. Normal planned /routine maintenance will be conducted where possible during NGrid's Off-Peak billing and Energy Efficiency Program periods. 2. Provide detailed project cost breakdown by major system components. Provide copies of all paid invoices reflecting the total Capital Cost to insure, design, permit, manage, build, check-out, start-up, test, commission and put into Commercial Operation in

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
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	accordance with all satisfied, applicable permits and electrical interconnection requirements and customer's full CHP system acceptance. 3. Provide RI State Tax Exempt Certificate. 4. Provide any and all Local, State and Federal tax credits, grants and similar financial benefits effectively reducing the Capital Cost of the proposed CHP System.

The pre-approved incentive is subject to Retail Companies' POST INSPECTION of final specifications, drawings and operation of the proposed equipment. In the event the proposed system is altered from the above description, notify the Company of the change prior to the equipment purchase and installation as the change in design and operation may impact the available incentive.

Toray Plastic (America) Authorized Signature Date

APPROVED
By Fred McKiernan at 2:24 pm, Jul 25, 2012

National Grid Authorized Signature (Division Technical Support Consultant) Date

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
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Attachment No.1
Planned Maintenance Schedules & Durations

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

Maintenance cost (Engine+Control) for KG-18

Year	Operating Hour	Maintenance Level	Expected Downtime (Days)	Main Works	Labour Man-Hour (hour)	Working hour for repair in work shop (hr)	Labour Charge by ***
1	2,000	A	1	Replacement of Spark Plug	12		
	4,000	A	1	Replacement of Spark Plug	12		
	6,000	B	2	Replacement of non-return valves	80		
	8,000	A	1	Replacement of Spark Plug ,battery	12		
2	10,000	A	1	Replacement of Spark Plug	12		
	12,000	C	12	Replacement of piston rings	600	45	
	14,000	A	1	Replacement of Spark Plug	12		
	16,000	A	1	Replacement of Spark Plug ,battery	12		
3	18,000	B	2	Replacement of non-return valves	80		
	20,000	A	1	Replacement of Spark Plug	12		
	22,000	A	1	Replacement of Spark Plug	12		
	24,000	D	14	Replacement of Crankpin and main bearings and valves,battery	1,120	18	
4	26,000	A	1	Replacement of Spark Plug	12		
	28,000	A	1	Replacement of Spark Plug	12		
	30,000	B	2	Replacement of non-return valves	80		
	32,000	A	1	Replacement of Spark Plug ,battery	12		
5	34,000	A	1	Replacement of Spark Plug	12		
	36,000	C	12	Replacement of piston rings	600	45	
	38,000	A	1	Replacement of Spark Plug	12		
	40,000	A	1	Replacement of Spark Plug ,battery	12		
6	42,000	B	2	Replacement of non-return valves	80		
	44,000	A	1	Replacement of Spark Plug	12		
	46,000	A	1	Replacement of Spark Plug	12		
	48,000	E	17	Replacement of piston crowns and thrust bearing ,battery	1,360	18	
7	50,000	A	1	Replacement of Spark Plug	12		
	52,000	A	1	Replacement of Spark Plug	12		
	54,000	B	2	Replacement of non-return valves	80		
	56,000	A	1	Replacement of Spark Plug ,battery	12		
8	58,000	A	1	Replacement of Spark Plug	12		
	60,000	C	12	Replacement of piston rings ,Cylinder controller and ignition device	600	45	
	62,000	A	1	Replacement of Spark Plug	12		
	64,000	A	1	Replacement of Spark Plug	12		
9	66,000	B	2	Replacement of non-return valves	80		
	68,000	A	1	Replacement of Spark Plug	12		
	70,000	A	1	Replacement of Spark Plug	12		
	72,000	D	14	Replacement of Crankpin and main bearings and valves ,battery	1,120	18	
10	74,000	A	1	Replacement of Spark Plug	12		
	76,000	A	1	Replacement of Spark Plug	12		
	78,000	B	2	Replacement of non-return valves	80		
	80,000	A	1	Replacement of Spark Plug ,battery	12		
11	82,000	A	1	Replacement of Spark Plug	12		
	84,000	C	12	Replacement of piston rings	600	45	
	86,000	A	1	Replacement of Spark Plug	12		
	88,000	A	1	Replacement of Spark Plug ,battery	12		
12	90,000	B	2	Replacement of non-return valves	80		
	92,000	A	1	Replacement of Spark Plug	12		
	94,000	A	1	Replacement of Spark Plug	12		
	96,000	F	17	Replacement of cylinder liners ,battery	1,360		
Sub Total					8,384	234	

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
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FORM 160.57-O2 (1105)

TABLE 6 – OPERATION / INSPECTION / MAINTENANCE REQUIREMENTS FOR YST CHILLERS

TURBINE MAINTENANCE SCHEDULE					
PROCEDURE	DAILY	WEEKLY	MONTHLY	ANNUALLY	3 YEAR
Visual Inspection (external damage, leaks)	X				
Check Oil Level in Reservoir and Governor	X				
Check for Unusual Vibration / Noise	X				
Check Oil Temperature and Pressure	X				
Observe seal steam venting	X				
Check Aux. Oil Pump Operation		X			
Check Refrigerant Levels		X			
Check Operation of all Shutdowns		X			
Check Shafts (free of Oil and Grease)		X			
Exercise Trip Valve		X			
Check Overspeed Governor			X		
Check Oil Return System Operation			X		
Check Operation of Motor Contactors in Power Panel			X		
Check Oil Heater Operation			X		
Check 3-Phase Voltage and Current Balance			X		
Verify Operation / Setting / Calibration of Safety Controls[1]			X		
Verify Condenser and Evaporator Water Flows			X		
Leak Check and Repair Leaks as Needed[1]			X		
Check Oil and Filter			X		
Remove / Clean Steam Strainer				X	
Check and Tighten All Electrical Connections				X	
Check Shaft Seals				X	
Check Thrust Bearing End Play				X	
Remove / Check Operation Sentinel Warning Valve				X	
Drain / Clean Oil Reservoir				X	
Drain / Clean Governor				X	
Perform Oil Analysis. Change as Required[1]				X	
Perform Refrigerant Analysis[1]				X	
Perform Vibration Analysis				X	
Perform Eddy Current Testing and Inspect Tubes[3]				X	
Clean Tubes				X	
Change Filter with Oil Change				X	
Check / Recalibrate Gauges				X	
Open / Inspect Turbine / Replace as Required					X
Rotor					X
Labyrinth Seals					X
Bearings					X
End Seals					X

7

NOTES:

For operating and maintenance requirements listed above, refer to appropriate service literature, contact your local YORK Service Office.

1. This procedure must be performed at the specified time interval by an Industry Certified Technician who has been trained and qualified to work on this type of YORK equipment. A record of this procedure being successfully carried out must be maintained on file by the equipment owner should prove of adequate maintenance be required at a later date for warranty validation purposes.
2. More frequent service may be required depending upon local operating conditions.
3. More frequent service may be required depending on water quality.

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
Location	50 Belver Avenue North Kingstown, RI 02852	Application No.	1999989
EEM:	1 x 7.5 MWe & 1 x 5.0 MWe nominally rated NG reciprocating engines with corresponding, individual 135 psig Steam HRSGs and Emission Control Systems, plus 1 x 1,000 Ton nominally rated Condensing Steam Turbine Centrifugal Chiller (135 psig Saturated Steam Supply).		

FORM 160.57-O2 (1105)

TABLE 6 (CON'T) – OPERATION / INSPECTION / MAINTENANCE REQUIREMENTS FOR YST CHILLERS

STEAM CONDENSER MAINTENANCE SCHEDULE						
PROCEDURE	DAILY	WEEKLY	MONTHLY	SEMI-ANNUALLY	ANNUALLY	3 YEAR
Visually Inspect for Leaks / Abnormal Noise	X					
Check Liquid Ring Seal on Relief Valve & Liquid Ring vacuum Pumps		X				
Check Condesate Pump Operation / Seals			X			
Check Hotwell Liquid Level / Pump NPSH			X			
Lubricate the Hotwell Pump Bearing				X		
Inspect / Clean Tubes with Chiller Heat Exchangers					X	
Clean and Grease vacuum Pump Bearings						X

Minimum Requirements Document

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FORM 160.75-O1 (211)

YORK

MAINTENANCE REQUIREMENTS FOR YORK YK CHILLERS

PROCEDURE	DAILY	WEEKLY	MONTHLY	YEARLY	OTHER
Record operating conditions (on applicable Log Form)	X				
Check oil levels	X				
Check refrigerant levels		X			
Check oil return system operation			X		
Check operation of motor starter			X		
Check sump heater and thermostat operation			X		
Check three-phase voltage and current balance			X		
Verify proper operation/setting/calibration of safety controls[1]			X		
Verify condenser and evaporator water flows			X		
Leak check and repair leaks as needed[1]			X		
Check and tighten all electrical connections				X	
Megohm motor windings				X	
Replace oil filter and oil return filter/drier				X	
Clean or backflush heat exchanger (VSD, SSS Applications)				X	
Replace starter coolant (VSD, SSS Applications)				X	
Replace or clean starter air filters if applicable				X[2]	
Perform oil analysis on compressor lube oil				X	
Perform refrigeration analysis[1]				X	
Perform vibration analysis				X	
Clean tubes				X[2]	
Perform eddy current testing and inspect tubes					2 - 5 Years
Lubricate motor			Refer to motor manufacturer's recommendations		

For operating and maintenance requirements listed above, refer to appropriate service literature, or contact your local YORK Service Office.

[1] This procedure must be performed at the specified time interval by an Industry Certified Technician who has been trained and qualified to work on this type of YORK equipment. A record of this procedure being successfully carried out must be maintained on file by the equipment owner should proof of adequate maintenance be required at a later date for warranty validation purposes.
[2] More frequent service may be required depending on local operating conditions.

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Attachment No.2
National Grid's Interconnection Requirements

Customer will ensure the proposed CHP System's design and construction will follow and adhere to all requirements and corresponding fees associated with and stated in Rhode Island Public Utilities Commission Tariff No.2078 – *Standards for Connecting Distributed Generation*.

Minimum Requirements Document

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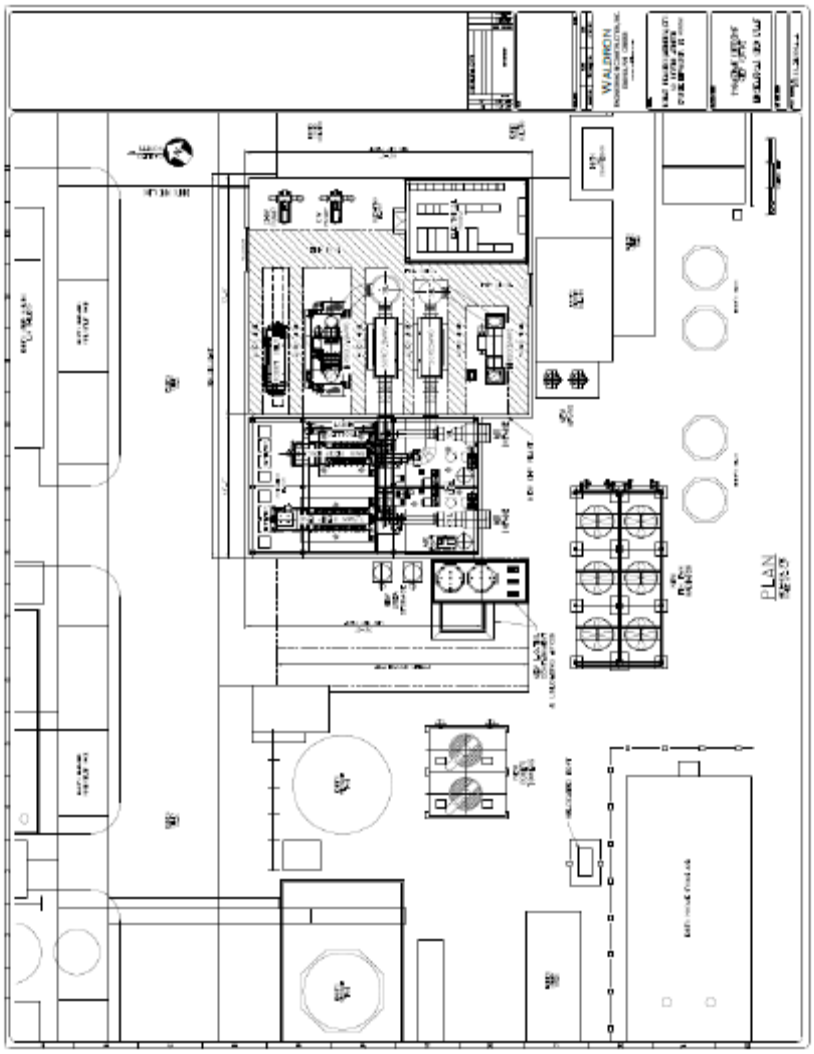
Attachment No.3
Preliminary CHP System Drawings



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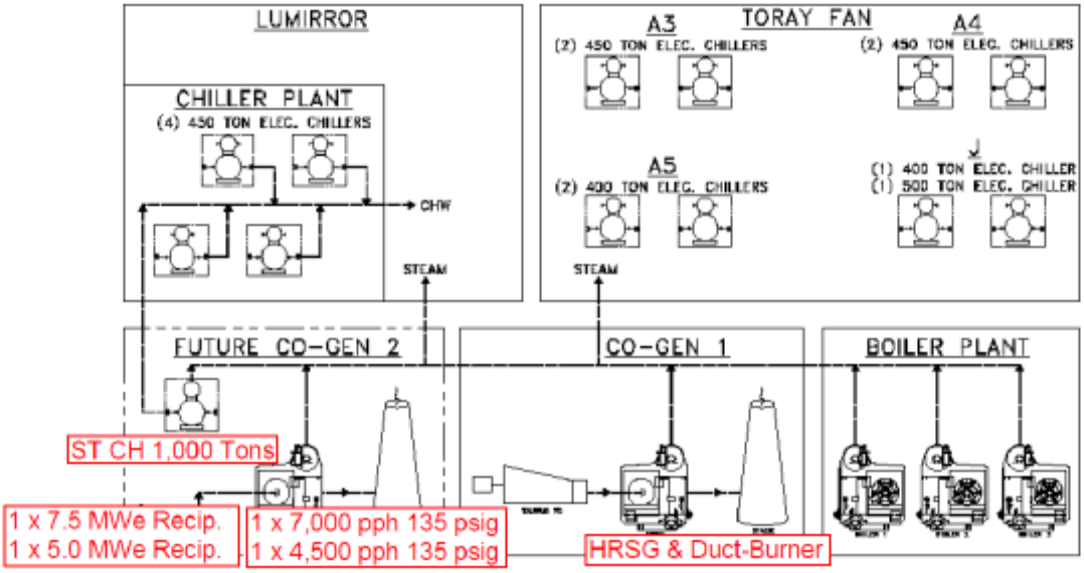

Figure 6 - Utility Infrastructure Schematic

Minimum Requirements Document

Customer Name	Toray Plastics (America), Inc.	EI or D2	EI
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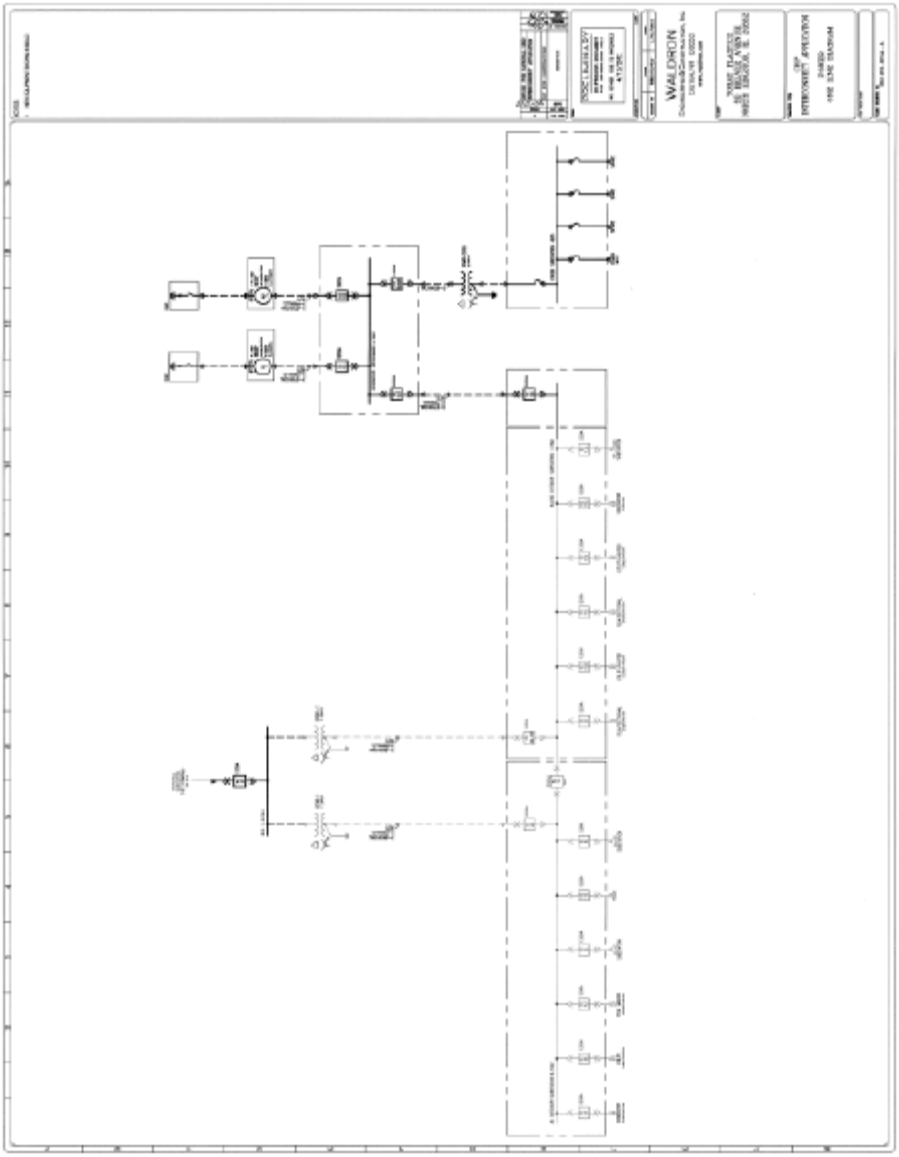

Appendix E: TA Study Proposal

(Partial)

WALDRON ENGINEERING & CONSTRUCTION, INC.

WALDRON

Proposal For

Toray Plastics (America), Inc.

CHP Conceptual Study

November 7, 2011

Waldron Engineering & Construction, Inc
37 Industrial Drive
Suite G-1
Exeter, NH 03833

WALDRON ENGINEERING & CONSTRUCTION, INC.

November 7, 2011

Charles Norman
Senior Buyer Corporate Purchasing
Toray Plastics (America), Inc.
50 Belver Ave.
North Kingston, RI 20852

RE: CHP Conceptual Study

Dear Mr. Norman:

Waldron Engineering and Construction, Inc. is pleased to submit herein our proposal to develop a CHP Study for your North Kingston facility. Waldron has developed a scope of services building on your Request for Proposals that will provide you with a complete concise analysis of the economic benefit that can be derived from installing a new CHP facility to serve the electrical loads of the Torayfan Division and the thermal loads of the site as a whole.

As you will see from this proposal, Waldron is well qualified to execute this study for Toray given our wealth of experience in the CHP market. Waldron has include the firm of ERM to our team to insure the correct scope of environmental permitting is identified in the study.

We are confident we have a solid understanding of your objectives and can deliver a quality syudy report that you can present to your management with confidence knowing that it has been based on thorough analysis and review. We thank you for this opportunity to present our proposal and hope you will select us for your project.

Sincerely,
Waldron Engineering & Construction, Inc.

Terence Waldron
Terence Waldron, P.E.
President

37 INDUSTRIAL DRIVE SUITE G-1 EXETER, NH 03833 (603) 772-7153 WALDRON.COM 2770 ELECTRIC ROAD ROANOKE VA 24018 (540) 491-9071

Waldron Engineering & Construction, Inc.

Table of Contents

Section	Description
1.	Introduction
2.	Team Organization
3.	Project Scope of Work
4.	Waldron Experience
5.	Statement of any Conflict of Interest
6.	Commercial Terms
7.	Resumes

Section 3 Project Scope of Work

- Project kick off meeting to gather data on the existing systems, points of interconnection and loads. Existing drawings will be gathered for reference material in the study. Access to the NGrid meter data for a typical year will be requires along with the boiler plant data for the same time frame.
- Develop an existing utility model that simulates the functioning of the existing Torayfan Division electrically and the entire site thermally. The model will consist of 8760 data in 15 minute intervals if available from NGrid. Verify the model against the utility bills for that year to insure accuracy.
- Compile a list of options available to serve the utilities defined in the model. Review the list with your staff prior to running up to three Future Case utility models.
- Run Future Case utility models to compare with existing for savings calculations.
- Utilize $/kw pricing to screen the options analyzed to determine if any have a strong enough business case for future consideration.
- Meet with your staff to review the findings.
- Bring one of the options forward for further refinement
- Develop a the following documentation to define the preferred option technically
    - System description with performance parameters
    - Equipment General Arrangement Drawing
    - Equipment List
    - ETAP model of the electrical system and HV one line
    - Heat and Material Balance for Winter, Summer and Spring/Fall Cases
- Identify Environmental permitting requirements
- Identify NGrid, State and Federal incentives that may be applicable
- Develop a construction cost that Toray can use as a not to exceed cost, maintenance and operations cost estimates for the final option. The construction cost estimate will be itemized for engineering, equipment, construction, commissioning, training and owners costs.
- Itemize the engineering budget into a cost proposal
- Price proposal for the NGrid Tech Analysis Study.
- Determine the simple payback and ROI using the construction, owners, maintenance, and operating cost estimates, utility savings calculated by the difference from the future case model and the existing case model, and all incentives available.
- Meet with your staff to review the detailed findings
- Compile the findings in a report to document the project.

Section 6 Commercial Terms

Waldron Engineering & Construction, Inc. will execute the scope of services listed in this proposal for a lump sum price of 38,400.

ASPEN AEROGELS
East Providence, RI

Cogeneration Feasibility Assessment

TA Study Report – Final

17 July 2015

PREPARED FOR:

National Grid

PREPARED BY:

Andelman and Lelek Engineering, Inc.
1408 Providence Highway
Norwood, MA 02062
(781) 769-8773

PROJECT CONTACT INFORMATION

Customer's Facility/Project Location		
Aspen Aerogels East Providence, RI		
Customer's Consultants:		
Robert Rose	Consulting Engineer A/Z Corporation	860-445-3469 rrose@a-zcorp.com
National Grid		
Dinesh Patel	Principal Engineer, Technical Strategy and Policy	781-907-2250 Dinesh.Patel@nationalgrid.com
Jeffrey Dunham	Lead Strategic Sales	401-527-4055 Jeffrey.Dunham@nationalgrid.com
Gerald Ferris	Lead Technical Service Consultant	401-784-7364 Gerald.Ferris@nationalgrid.com
TA Study Consultants: Andelman and Lelek Engineering, Inc.		
Michael Andelman	Principal	781-769-8773 mike@andelmanlelek.com
Neil Sen	Project Engineer	781-769-8773 neil@andelmanlelek.com

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General Cogeneration Considerations 6
Load Characterization and System Sizing 7
Proposed Cogeneration System 11
System Pricing 12
Energy and Cost Savings Analysis 13
Appendix 15

Executive Summary

A/Z Corporation and National Grid retained Andelman and Lelek Engineering, Inc. (ALE) to perform a Technical Assistance (TA) study to assess cogeneration opportunities for Aspen Aerogels in East Providence, RI.

This report presents an analysis of the savings and costs associated with adding a natural gas engine generator cogeneration system for Aspen Aerogels. The new cogeneration system would produce hot water via the engine's cooling circuits and via an engine exhaust heat exchanger. The option explored for this study was cogeneration system of approximately 1,275 kWe electric capacity. An energy analysis was performed using a custom spreadsheet calculation based on available usage records, manufacturers' performance data, and calculated values. A summary of the analysis results is shown in Table 1.

This report begins with a description of the existing facility equipment and operating sequences, followed by a general discussion of cogeneration requirements for the site. We then characterize the current electrical and thermal loads, and we present the evaluated cogeneration option along with its expected installed cost. The energy analysis calculation and important assumptions are then described.

Table 1: Savings and Costs Summary

Plant economics 1,275 kWe		
Useful electricity produced by new cogen	kWh/yr	9,946,930
Natural gas consumed by new cogen	therms/yr	972,905
Boiler fuel offset	therms/yr	501,499
Total increase in natural gas purchased	therms/yr	471,407
Total energy cost savings	$/yr	859,464
Approx. cost for complete system	$	3,600,000
Maintenance cost	$/yr	248,673
Total annual cost savings	$/yr	610,791
Simple payback (before incentives)	**yrs**	**5.9**
Annual Electrical Efficiency	**%**	**34.9**
Annual Thermal efficiency	**%**	**41.2**
Annual system efficiency	**%**	**76.1**

Facility Description

Aspen Aerogels in East Providence, RI produces industrial insulation. The manufacturing process is constant throughout the year.

Information used in this study was obtained from Aspen personnel, from documentation provided by Aspen, and from power usage information obtained from NGrid.

Existing Cogeneration Equipment

Aspen Aerogels does not have any existing cogeneration equipment.

Facility Schedule

Aspen Aerogels operates 24 hours a day, 7 days a week. The facility shuts down for one shift every month for maintenance.

General Cogeneration Considerations

Gas-fired cogeneration systems typically contain either a turbine generator or an engine generator. In gas turbine systems, heat is recovered from the turbine exhaust gases; the exhaust gas temperature is sufficient to generate steam. Exhaust heat is captured in gas engine systems and can be used to produce steam, but a significant fraction of the recoverable energy is in the form of lower-grade heat from the engine jacket and other cooling systems. Jacket heat is not suitable for steam generation; to make full use of an engine cogeneration system, the facility must have suitable hot water loads (or other end-uses of low-grade heat).

The most suitable system depends on the balance between heating and electrical loads, but generally speaking, gas engine installations are less costly than gas turbines of similar size. Further economic benefits are often conferred by engines' higher electrical efficiency.

Installed cost per kW decreases as the size of the installation rises. It is therefore advantageous to select the largest unit that can currently be accommodated at the facility; however, oversizing the unit results in significant efficiency penalties because part load performance often drops rapidly below 50% loading. If electricity demands are not large enough to operate the unit close to capacity, or if a lack of heating demand forces the unit to operate at low part load (or to dump heat), energy savings will suffer.

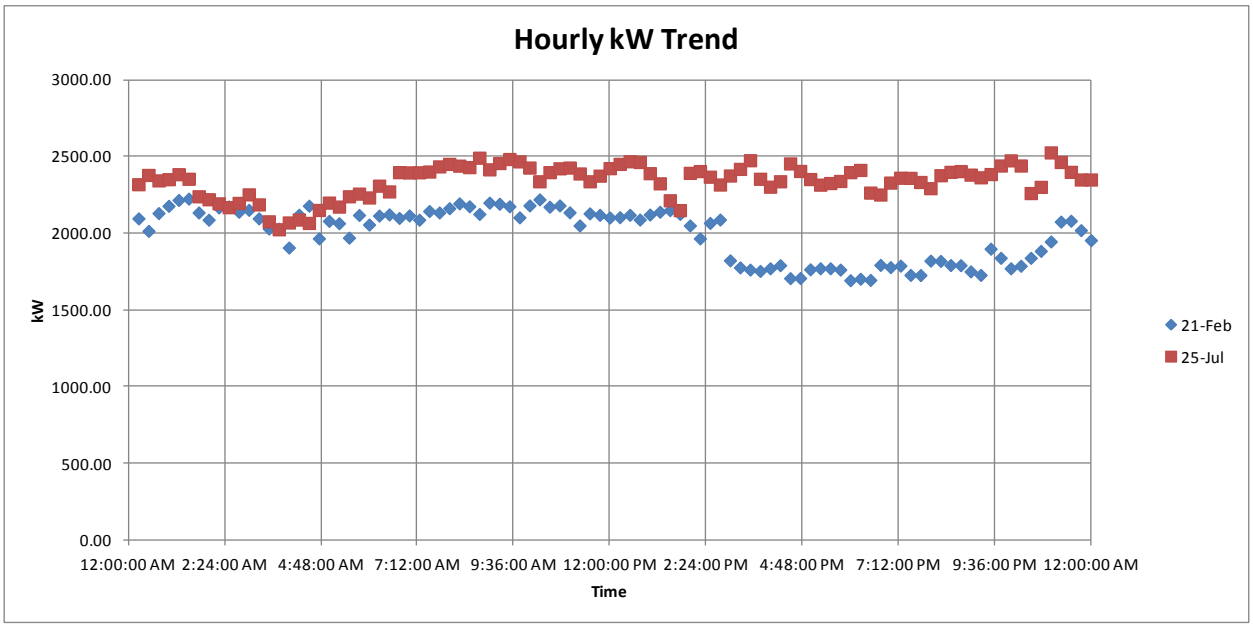
Load Characterization and System Sizing

The facility's electrical and thermal loads were characterized to determine the optimal sizing of the cogeneration system.

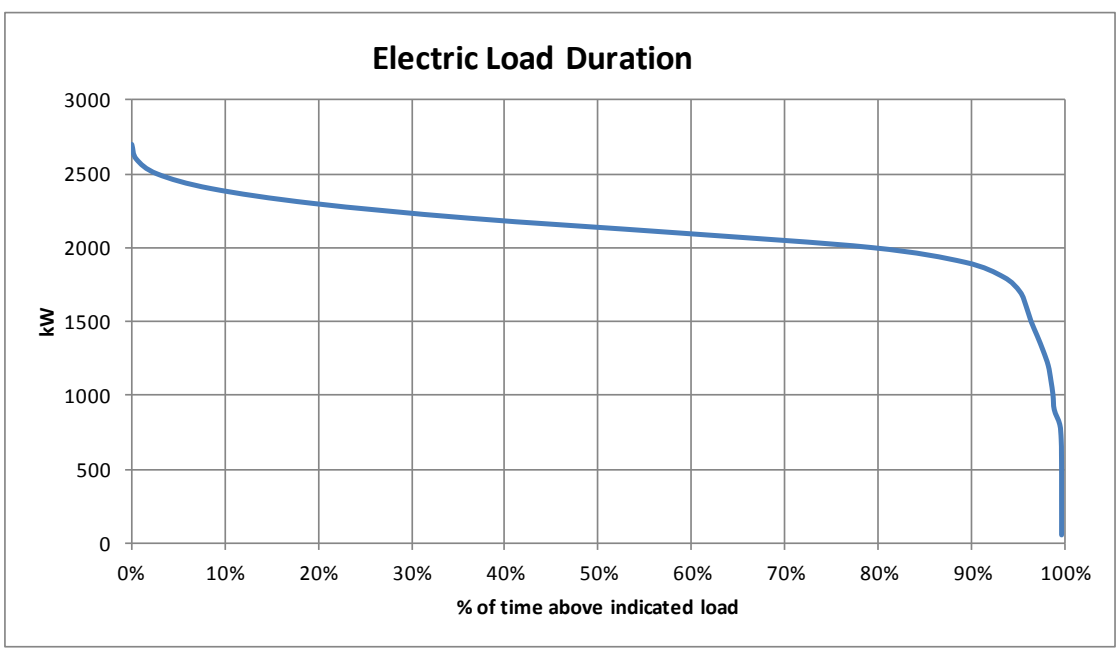
Electrical Loads

Hourly electrical data for Aspen from 2014 were obtained from National Grid. Below is a graph showing the electrical usage for one day in the winter and one day in the summer.

Electrical consumption patterns do not vary significantly with season.



The electrical load duration curve for the facility is shown below.

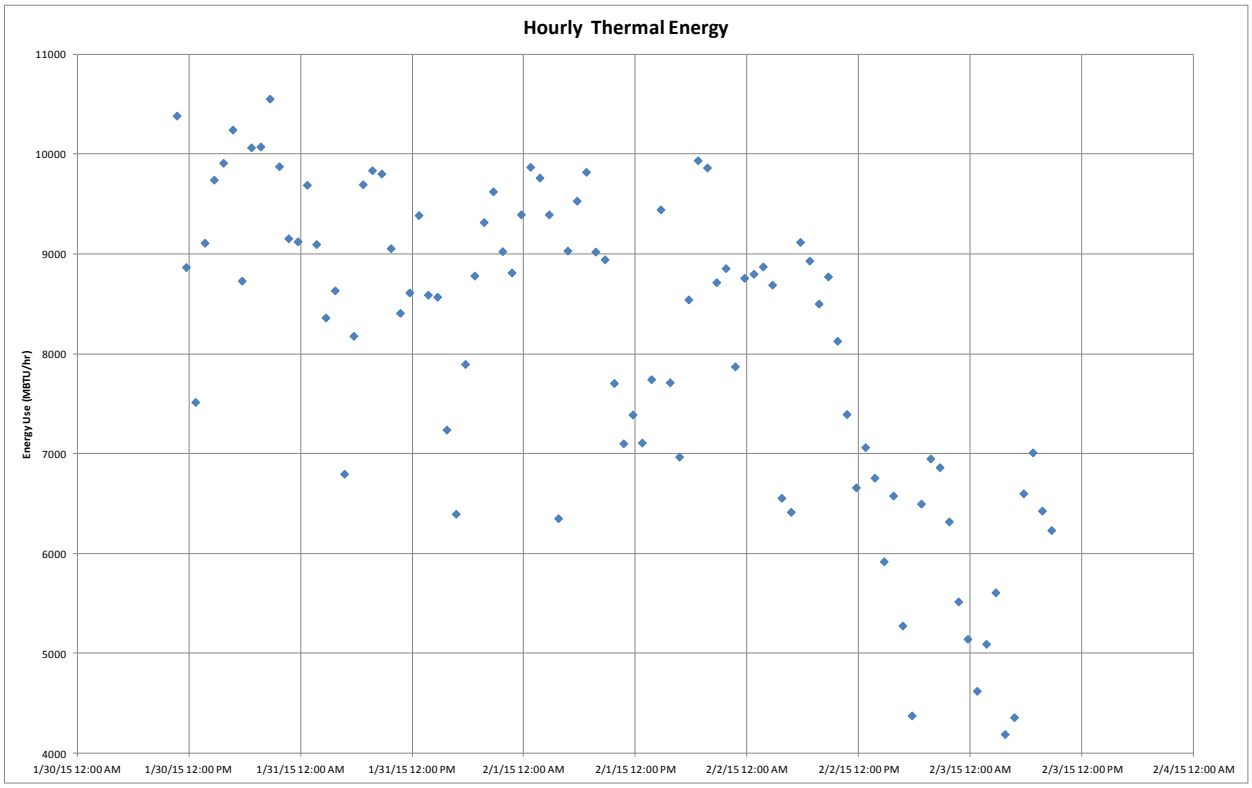


Based on the load duration curve, an approximately 1,275 kWe engine would be running at full load approximately 97% of the year.

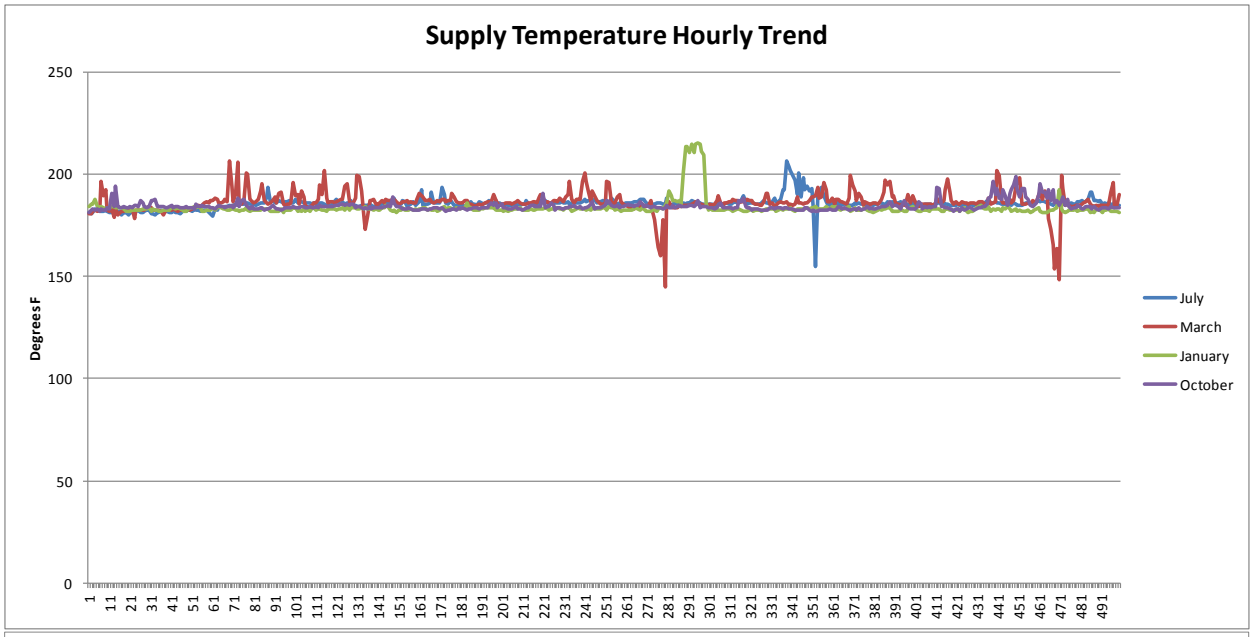
Existing Thermal Loads

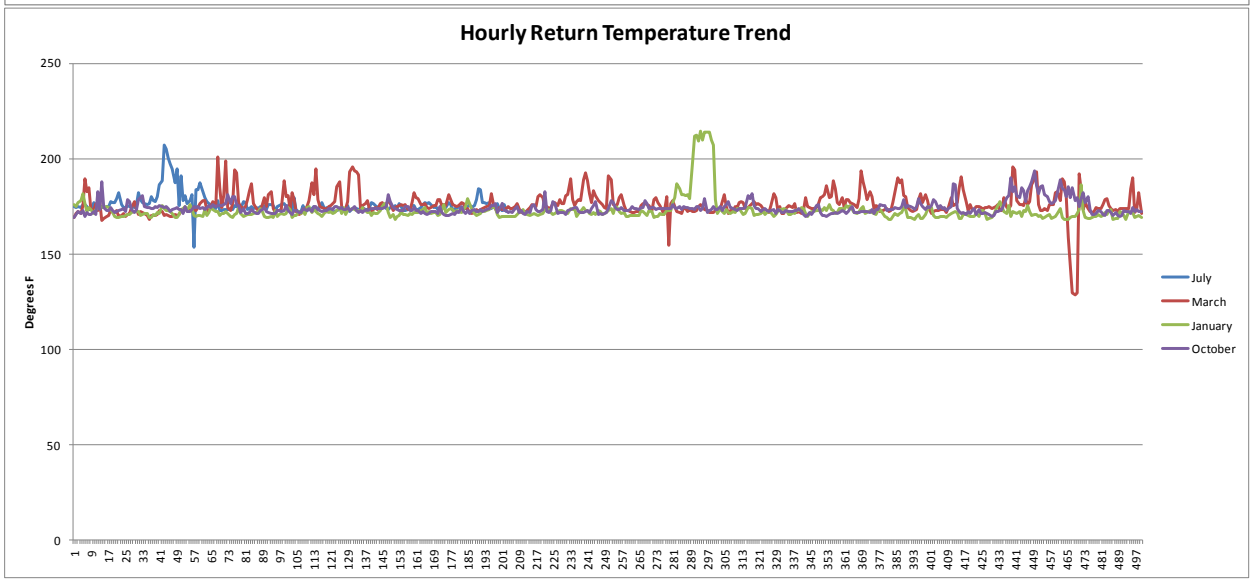
The CHP system will be used to offset loads on Aspen Aerogels' hot water system, which provides heat to their manufacturing process. The hot water system includes three boilers, of which two are normally used. Their input ratings are 80 therms/hr and 120 therms/hr. Aspen Aerogels also has a flame burner with a maximum fuel firing rate of 60 therms/hr.

From field metering data of boiler plant hot water production using an ultrasonic BTU meter, the following process hot water load profile was constructed. At its lowest point, the thermal load was a little over 40 therms/hr. The CHP system's thermal capacity, including jacket water and exhaust, is 50 therms/hr and thus the thermal load would almost always be more than 80% of the CHP system's capacity.



From temperature and pump discharge pressure data taken over three-week periods in January, March, July, and October, it is apparent that thermal loads do not vary significantly between seasons.


Supply Temperature Hourly Trend
Degrees F
250
200
150
100
50
0
July
March
January
October


Hourly Return Temperature Trend
Degrees F
250
200
150
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50
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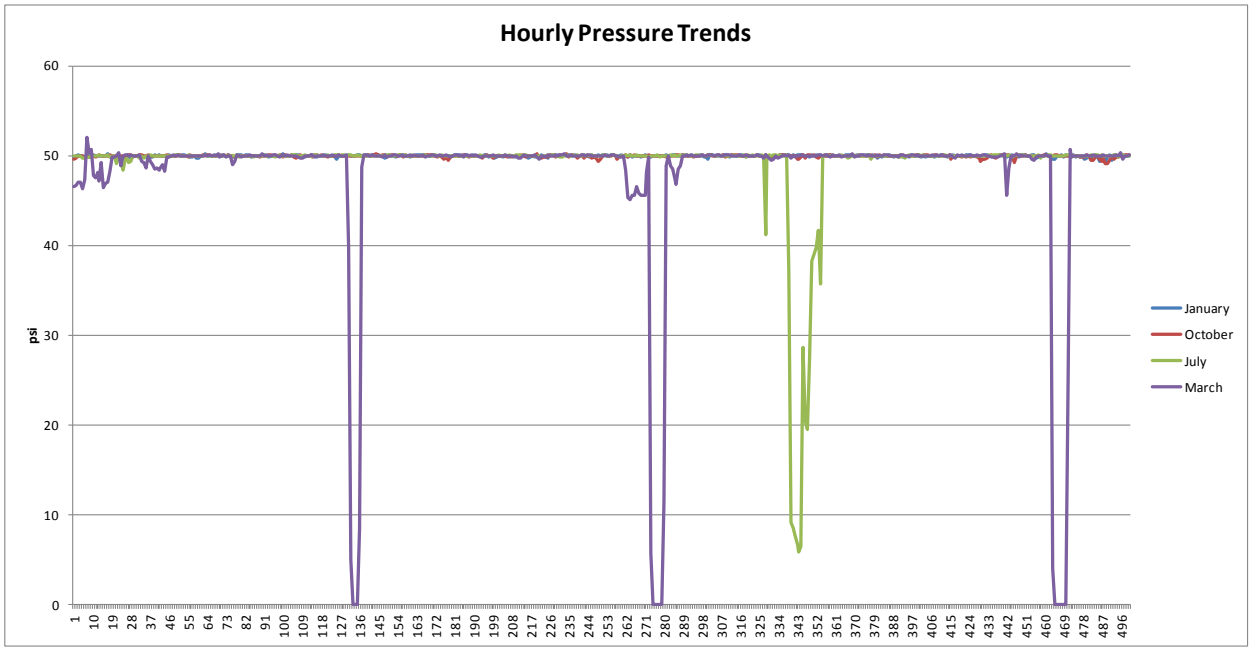
July
March
January
October


Hourly Pressure Trends
psi
60
50
40
30
20
10
0
January
October
July
March

Proposed Cogeneration System

A final selection for the proposed CHP unit is a 1,275 kWe gas engine generator. The savings calculations presented here use data obtained for a 1,275 kWe gas engine generator with high electrical efficiency.

The proposed cogeneration system package contains the following main components:

- Gas engine generator: packaged system containing the gas engine, electrical generator, and heat recovery system to produce hot water from engine cooling circuits

Table 2: Summary of Cogeneration System Properties

Gas engine generator model	Dresser-Rand HGM 560
Nominal generator capacity (kWe)	1,275
Electrical generation efficiency (HHV)	36.0%
Hot water produced via engine cooling circuits	25 therms/hr

Sequence of Operation

The CHP unit would normally operate continuously in thermal and electrical-following mode, i.e. no excess electricity would be produced and no thermal dumping would occur. Hot water would be produced via the engine's cooling circuits. The CHP unit would be controlled to operate above a minimum of 50% turndown. Based on electric and thermal load data, the unit is expected to operate above 80% capacity all operational hours (analysis assumes 93% availability).

System Pricing

The cost of the new cogeneration system was estimated based on information received from the equipment vendor. Please note that this estimate is based on initial pricing from the owner's contractor; it does not represent a guaranteed maximum price, and is not associated with a specific detailed system design.

According to Aspen Aerogels' consulting engineer, the packaged cogeneration system would have an installed cost of approximately $3,600,000.

Energy and Cost Savings Analysis

A custom cogeneration spreadsheet analysis was used to perform the energy analysis for this study. A summary of the analysis results is provided in Table 1 in the Executive Summary of this report. Details of the modeling methodology are presented below, along with information on the utility rates used in the analysis.

Calculation Methodology

The full calculation spreadsheet will be provided to National Grid for review. Notes on assumptions are provided below.

- The calculation used 15-minute interval electrical usage data for the entire year of 2014 and 1-minute interval thermal data for early 2015.
- Cogen thermal loads were determined from thermal data as described in the Load Characterization section of this report.
- For the four-week period from October 18 to November 19, adjacent days were used to approximate the hourly electrical interval data in that time as the original data were missing.
- Gas engine generator performance data (generation capacity, heat rate, thermal output, and part-load performance) were obtained from the technical properties document supplied by the vendor.
- System parasitic power (circulation pumps and radiator fan) was assumed to be 3% of full-load capacity.
- The cogeneration system was assumed have 93% availability throughout the year.
- Average electric and gas rates for 2014, which were $0.117/kWh and $0.656/therm, were used to calculate energy cost savings estimates. No additional demand charges were applied during outage periods.
- Existing boiler thermal efficiency was modeled as 80% at all times; no part load variations were modeled.
- The system was assumed to be in electrical and thermal load following mode, i.e. no excess electrical or thermal production was permitted.
- The minimum turndown for the cogen system was set to be 50%.
- Thermal process loads were assumed to be constant (24/7 schedule).

Tabulated below is the monthly increase in fuel consumption.

Table 3: Monthly Increase in Gas Usage

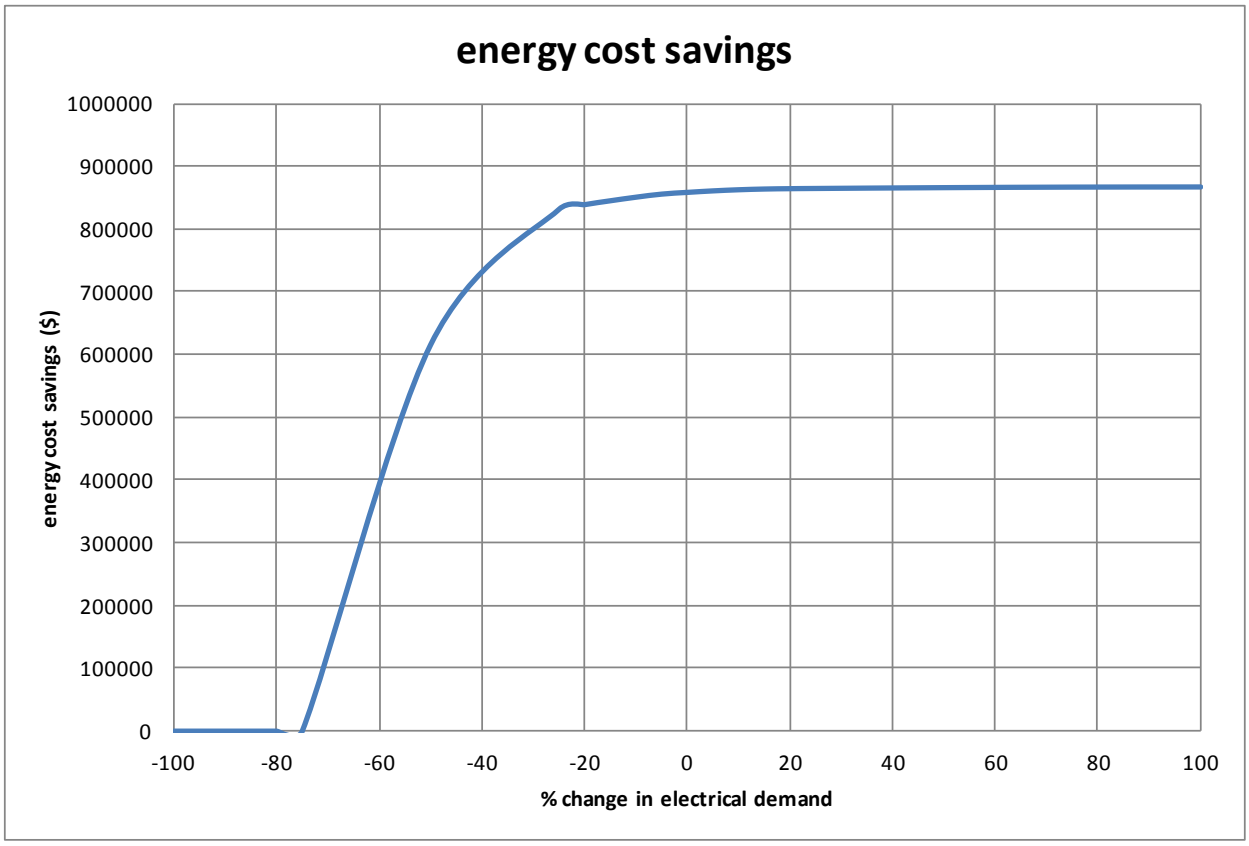
Month	Existing Load (Therms)	Generator Load (Therms)	Thermal Offset Recovery (Therms)	Increase in gas use (Therms)	Proposed Therms
January	59,834.8	89,370.4	46,045.9	40,291.8	100,126.5
February	54,235.3	80,833.5	41,647.0	36,443.4	90,678.8
March	59,893.9	89,449.5	46,080.7	40,333.0	100,226.9
April	58,385.6	85,784.6	44,228.8	38,646.9	97,032.5
May	59,922.3	88,437.2	45,616.2	39,823.5	99,745.9
June	58,033.5	86,702.2	44,663.8	39,095.8	97,129.3
July	60,245.9	89,581.5	46,147.8	40,393.4	100,639.3
August	59,922.3	89,536.9	46,128.4	40,369.9	100,292.2
September	58,033.5	84,558.7	43,673.0	38,023.7	96,057.3
October	60,245.9	88,340.4	45,511.0	39,831.4	100,077.3
November	57,833.0	85,428.6	44,012.6	38,516.8	96,349.8
December	60,174.4	88,111.5	45,490.7	39,637.3	99,811.7

The monthly increase in gas use is 93% of the difference between the monthly generator load and thermal offset recovery. The total proposed gas usage is the sum of the existing load and the increase in gas use. The months from May to September represent 42% of the increase in gas consumption after the installation of the CHP system.

Sensitivity Analysis

In this section, we explore the sensitivity of the results to changes in the facility's electrical demand.

Facility Thermal Demand



When the electrical demand decreases, it adopts three linear regimes from 0% to 25%, 25% to 45%, and 45% to 75%. The cost savings decrease more dramatically with each regime.

When the increase in energy demand exceeds 50%, the amount of money saved per year plateaus at about $868,000. On the other hand, if the percent decrease exceeds 75%, the savings sharply decrease until the savings approach $0.

Appendix

- HGM 560 Technical Description document
- Custom Cogen Calculation Spreadsheet
- Custom Screening Spreadsheet
- Aspen Aerogels MRD

nationalgrid

CROWNE PLAZA®

801 GREENWICH AVE
WARWICK, RI

Prepared for

NATIONAL GRID

Prepared by

B2Q Associates, Inc.

North Andover, MA

Revision Date

4/2/2013

Technical Assistance Study

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TECHNICAL ASSISTANCE STUDY

CROWNE PLAZA HOTEL

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EXECUTIVE SUMMARY

This technical assistance (TA) study investigates potential energy efficiency measures (EEMs) for the facility's heating, cooling, ventilation, and controls systems. The EEMs focus on upgrading existing equipment to new, higher-performance equipment, improving control to reduce energy use when it is not required, and investigating significant changes to the facility's HVAC system types.

ECM #	ECM	Electric Energy Savings	Natural Gas Savings	Total Cost Savings	Retrofit Cost	Simple Payback Before Incentive	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback After Incentive
-	-	kWh	therms	$	$	yrs	$	$	$	yrs
1	Occupancy Sensors	82,083	3,441	$11,793	$36,719	3.1	$12,035	$917	$23,767	2.0
2	Upgrade Water Source Heat Pumps	71,200	-346	$6,951	$280,302	40.3	$0	$0	$280,302	40.3
3	Upgrade Rooftop Units	72,327	0	$8,054	$72,539	9.0	$15,369	$0	$57,170	7.1
4	Upgrade Building Automation Systems	385,536	27,954	$62,284	$90,878	1.5	$21,171	$4,828	$64,879	1.0
5	Kitchen Hood Controls	5,294	1,678	$2,076	$38,603	18.6	$0	$0	$38,603	18.6
6	Install Laundry Drain Water Heat Recovery	0	1,209	$1,088	$16,176	14.9	$0	$0	$16,176	14.9
7	Upgrade Hot Water Boiler	-4,795	3,349	$2,571	$179,010	69.6	$0	$0	$179,010	69.6
8	Install VFDs on CW Pumps	127,676	-2,804	$9,711	$51,246	5.3	$20,620	$0	$30,626	3.2
9	Install VFDs on Cooling Tower Fans	35,788	0	$3,903	$17,898	4.6	$8,700	$0	$9,198	2.4
10	Low Flow Kitchen Spray Nozzle	0	1,254	$1,128	$281	0.2	$0	$0	$281	0.2
11	Install Aerators and Low Flow Shower Heads	0	7,289	$6,560	$30,168	4.6	$0	$15,084	$15,084	2.3
12	Combined Heat and Power	1,379,678	-107,222	$38,757	$643,469	16.6	-	-	-	-
13	Ground Source Heat Pump	82,657	8,767	$15,381	$967,229	62.9	$0	$0	$967,229	62.9
14	Freezer	41,273	0	$4,953	$21,858	4.4	$6,666	$0	$15,192	3.1
15	Pool Cover	33,681	-732	$2,395	$14,999	6.3	$5,439	$0	$9,560	4.0
16	Install Window Tint	149,230	-1,112	$14,167	$66,390	4.7	$24,101	$0	$42,289	3.0

Note: Costs and savings values assume a total electricity rate of $0.12 / kWh and $0.90 / therm for natural gas.

INCENTIVE PROGRAMS OVERVIEW

Incentive Programs Overview

National Grid's electric and natural gas incentive programs for medium and large business customers are fully integrated and consolidated into two (2) programs for 2012. They are the:

- Commercial New Construction Program; and the
- Large Commercial Retrofit Program.

Both programs consist of Prescriptive and Custom incentive classifications for projects saving either electricity or natural gas, but not both energy sources. Prescriptive incentives are typically for common, individual pieces of equipment and are assigned pre-determined incentive values based on their type, size and certified efficiency rating. All Prescriptive incentives are located on www.powerofaction.com under the "*What can you do?*" and "*Energy Efficiency*" menus. Custom incentives apply to complete energy systems, less common individual pieces of equipment and anything not eligible for a Prescriptive incentive. Projects simultaneously saving electricity and natural gas are classified as Custom and are specially addressed at the end of this section.

The Commercial New Construction Program (CNC) is designed for new buildings and additions to and major renovations in existing buildings. The CNC also applies to spaces changing function within existing buildings, failed equipment or equipment age exceeding 75% of their useful lifetimes. Incremental Energy Savings and Incremental Capital Costs are defined as the difference between the Rhode Island Energy Code's requirements and the proposed energy project's characteristics. All projects falling under the Custom classification must pass a Benefit-to-Cost Ratio (BCR) test to determine its incentive eligibility. In most cases, an individual electric or Natural Gas (NG) project passing its associated BCR will receive an incentive equal to the lesser of the below, respective amounts.

Incentive Determinant	Electric Incentive	Natural Gas Incentive
Incremental Capital Cost	Up to 75%	Up to 75%
Incremental Energy Savings	Up to $0.25/kWh-Y	Up to $3.00/Therm-Y
Incremental Payback Buy-Down	Down to 1.0 Year	Down to 1.0 Year

The Large Commercial Retrofit Program (LCR) is designed for existing buildings with an average, monthly demand of 200 kW or greater. The proposed project's Total Energy Savings is based on the difference between the existing, operating equipment/system relative to the proposed equipment/system. Total Capital Cost is defined as all line item costs including, but not necessarily limited to permitting, design, major equipment, installation labor and miscellaneous materials, start-up, testing, commissioning and close-out. Like the CNC, a project falling under the Custom classification must pass its BCR test to determine its incentive eligibility in the LCR. In most cases, an electric or NG project passing its associated BCR will receive an incentive equal to the lesser amount of the below, respective amounts.

Incentive Determinant	Electric Incentive	Natural Gas Incentive
Total Capital Cost	Up to 50%	Up to 50%
Total Energy Savings	Up to $0.19/kWh-Y	Up to $3.00/Therm-Y
Total Payback Buy-Down	Down to 1.0 Year	Down to 1.0 Year

For a proposed project falling under either the CNC or LCR and saving both electricity and NG, a unique BCR process determines incentive eligibility. In general, an eligible project receives an incentive equal to the larger of the individually calculated electric and NG program incentives. The electric and NG contributions to the incentive are based on the lifetime, societal benefit each energy source contributes to the proposed project.

INTRODUCTION

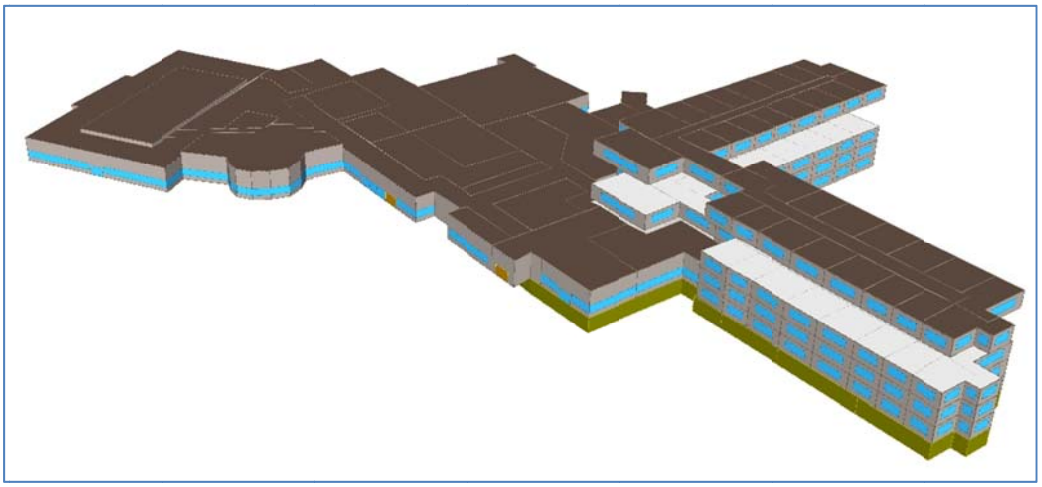
B2Q Associates (B2Q) has been retained by National Grid to prepare a technical assistance study for the Crowne Plaza Hotel facility at 801 Greenwich Ave in Warwick, RI. The energy efficiency measures (EEMs) that are being considered consist of equipment upgrades, domestic hot water savings, variable speed drives, demand control ventilation, occupancy controls, and kitchen hood controls. The measures also call for potential, significant changes in the systems that provide the heating and cooling for the facility, such as cogeneration (CHP) and groundsource heat pumps. These measures could lead to a decrease in energy use, electric demand, and fuel use. This study aims to assess and estimate the potential energy savings, costs, and simple paybacks of implementing these measures.

To analyze these changes in energy consumption, a computer model of the facility was developed and building consumption simulations were performed using the eQUEST building analysis program. eQUEST uses the latest DOE-2.2 building energy analysis software as its calculating engine. This very flexible program permits modeling of a variety of building types and components, including complex building geometry, lighting systems, HVAC systems, central plant equipment, and utility rate structures.

The eQUEST model was compiled using a reproduction of the building footprint, aerial imaging, estimated schedules for the facility based on discussions with facilities staff and general hotel facilities, and HVAC and lighting equipment based on observations from walkthroughs of the facility. Providence weather data was used in the analysis. Electric utility costs and cost savings were calculated using a rate of $0.12/kWh while thermal energy costs and cost savings employed a rate of $0.90/therm.

Utility incentives were estimated for the EEMs using National Grid's 2012 gas and electric custom screening tools. **The utility incentives included in this report must be confirmed with National Grid prior to implementation and may be subject to change.**

FACILITY DESCRIPTION



Crowne Plaza eQUEST model

Note that the new and old building wings seem to have missing floors in the eQUEST model. This is how eQUEST shows the floor multiplying function. The middle floors of the building were modeled by copying the inputs of a typical floor in order to simplify this complex model.

ARCHITECTURAL DESCRIPTION

The Crowne Plaza hotel is a six story building located at 801 Greenwich Ave, Warwick, RI. The building is approximately 250,000 square feet and houses a multitude of space types including guest rooms, offices, function/meeting rooms, ballrooms, auditoriums and dining areas.

EQUIPMENT DESCRIPTION

The Crowne Plaza Hotel was built in two phases. As a result, it has different types of HVAC systems. The new and old wing each have separate water loop heat pump systems served by a gas boiler and cooling tower. The common areas are served by rooftop units (RTUs). All of the RTUs are equipped with a gas fired furnace for heating and packaged DX coils for cooling. There are two domestic hot water (DHW) systems – one for the laundry and one for guest rooms. The RTUs and cooling towers are located on the roof, whereas the boilers, pumps, and tanks are located in mechanical rooms on the basement level.

MODEL CALIBRATION

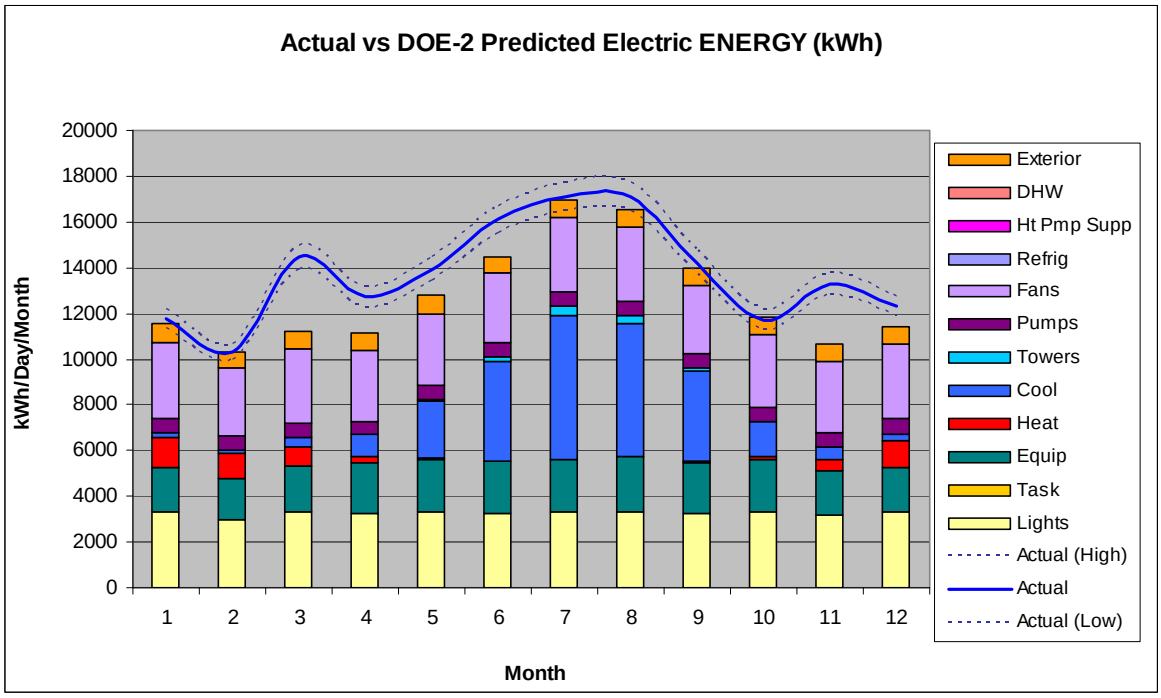
UTILITIES

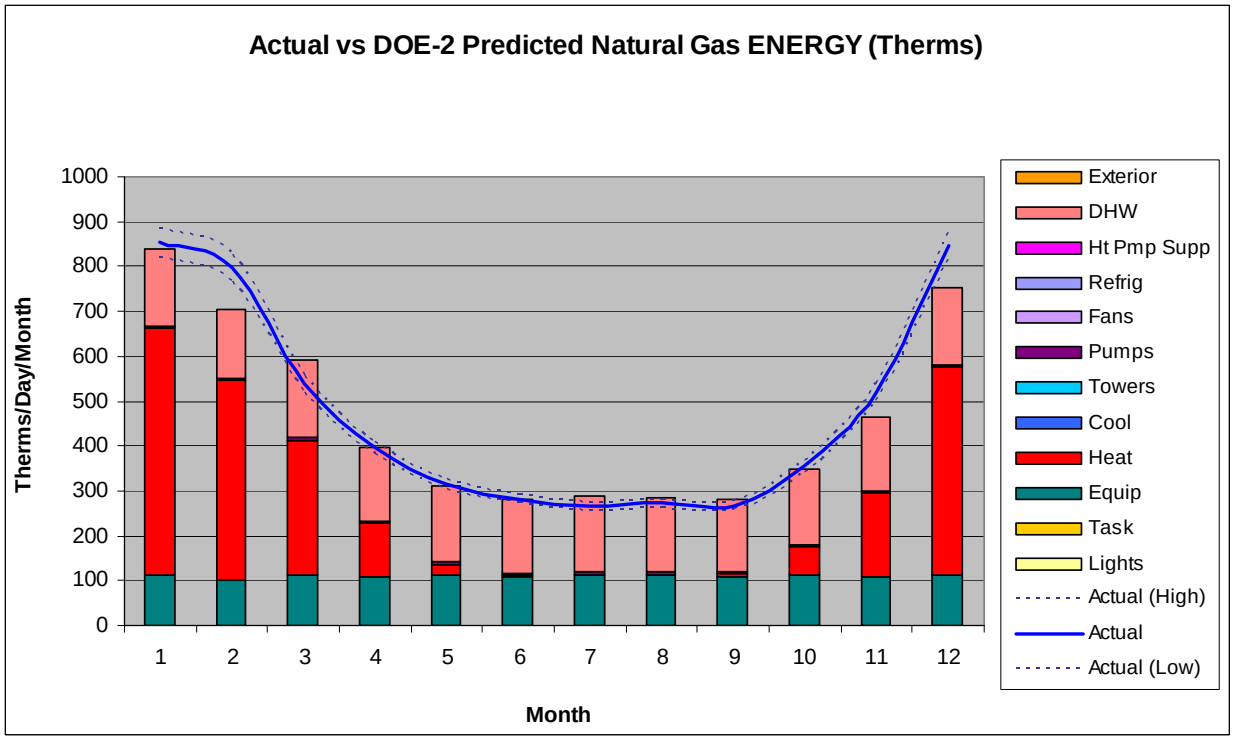
Natural Gas Delivery: National Grid
Natural Gas Supply: National Grid
Electricity Supply: National Grid (G3 rate)

GAS AND ELECTRICITY USAGE INFORMATION

The eQUEST model was built using Google Earth to draw the building footprint. Thermal zones were outlined using observation from site visits. Once done, the model is calibrated by changing the occupancy, lighting, and plug load schedules and setpoints to the data of the existing building. This was done comparing the gas and electrical consumption of 2009 and 2010 received from NGRID to the PS-E report generated by each simulation of the eQUEST model.

The monthly electrical and gas consumption charts used for the calibration are shown below. The blue curve represents the existing building consumption and the bars represent the eQUEST model output. The average of 2009 and 2010 were used for the existing building electrical use. The model output also provides the energy end use breakdown of the building.





eQUEST models DHW usage on an hour to hour basis. Using the installed data loggers' reading of the water consumption, an hourly water consumption schedule was created.

Time	Midnight-1am	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-Noon
Morning Ratio	1.0%	1.1%	1.6%	1.1%	1.1%	2.0%	15.1%	42.4%	100.0%	19.8%	20.6%	23.8%
Time	**Noon-1pm**	**1-2pm**	**2-3pm**	**3-4pm**	**4-5pm**	**5-6pm**	**6-7pm**	**7-8pm**	**8-9pm**	**9-10pm**	**10-11pm**	**11-midnight**
Afternoon Ratio	25.4%	24.1%	30.5%	35.5%	42.0%	38.3%	29.4%	20.3%	23.0%	19.0%	9.5%	7.7%

The above chart indicates the hourly percentage of the peak flow. The peak flow measured was 61.1 gpm according to the data recorded by the data loggers.

EEM 1: Guest Room Occupancy Sensors Reactivation

InnComm Guest Room Occupancy Control allows for the WSHPs serving a particular room to "setback" based on occupancy, saving energy when no occupants are detected. When the occupancy sensor detects that the guest has re-entered the room, the thermostat resets its setpoints to occupied values. The technology for this measure is already installed in most of the rooms and should be re-engaged and/or repaired.

Existing Case

The existing for this measure consists of each room being equipped with a non-programmable thermostat. The temperature setpoint for the room is manually set by the occupant. HVAC systems modulate as needed to meet that setpoint, regardless of whether the occupant is present in the space.

The assumptions made for the baseline model are the following:

- The guest room thermostat is set at a constant temperature of 72°F for cooling and 70°F for heating all year long.
- The WSHP fans are cycled on for the hour if the guest room temperature falls outside the throttling range
- The hotel has a high season from April to October and a low season from November to March. This affects the equipment load, lighting load, occupancy load, and DHW use of every space of the hotel. However, it does not affect the heating and cooling of the guest room in the baseline model. Below are shown the schedules of the occupancy, equipment load, and occupancy load of the guest rooms. Thefollowing percentages are the fraction of the maximum occupancy set for each guest room (200 ft^2/person).

Morning Schedule	Midnight-1am	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-Noon
April- October	90%	90%	90%	90%	90%	90%	65%	50%	35%	20%	20%	20%
November-March	45%	45%	45%	45%	45%	45%	35%	25%	15%	15%	15%	15%

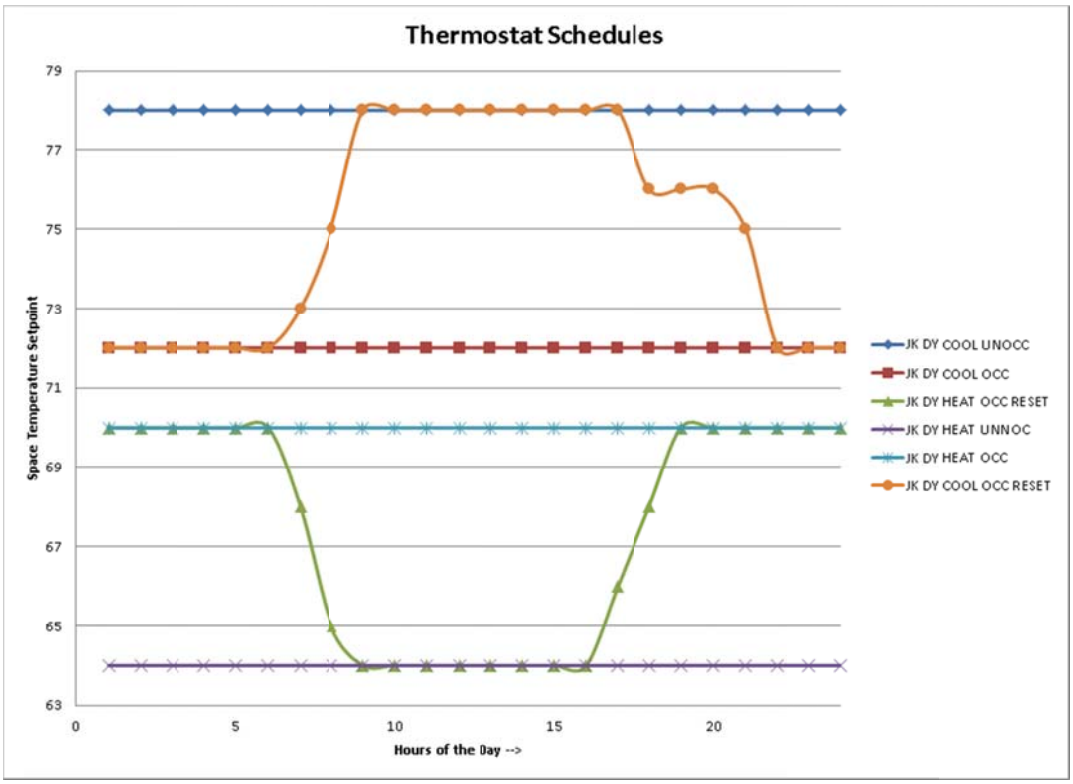
Afternoon Schedule	Noon-1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6-7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-midnight
April- October	24%	20%	20%	20%	20%	40%	45%	50%	65%	85%	85%	85%
November-March	18%	10%	10%	10%	24%	32%	32%	40%	40%	45%	45%	45%

Proposed Case

The proposed change in space temperature control is to re-activate the functioning guest room occupancy sensors and install new ones for rooms with broken or non-existent occupancy sensors. For customers to stop mistaking the InnCom guest room occupancy sensors for cameras, the proposed change is to label the sensors and thermostats with instructions, preventing the customers from deactivating the device by removing its batteries.

When the occupant leaves the space, the occupancy sensor changes the space temperature setpoint by raising the cooling setpoint temperature and lowering the heating setpoint temperature. This saves energy by reducing the heating/cooling load when the space is unoccupied. When the occupant re-

enters the space, the occupancy sensor signals the equipment to begin a specialized start-up mode, which returns the space temperature setpoint to the previously occupied value.



The graph displays the different thermostat schedules used to simulate the occupancy based temperature reset.

Energy Savings Methodology

This measure was simulated by using a parametric run of the base case model, changing the guest room thermostat set point temperature from a constant temperature of 72°F for cooling and 70°F for heating all year long to multiple thermostat schedules to model the temperature reset with repect to the time of day changes in occupancy density.

Cost Estimates

It was estimated that guest room occupancy sensor systems reactivation and labeling of the 266 rooms in the facility would cost $36,719 for the project. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	1	Occupancy Sensors				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
82,083	1.8%	$8,696	3441	2.5%	$3,097	$11,793
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$36,719	$12,035	$917	$23,767	3.1	2.0	49.6%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
11.4	19.3	20.3	19.4	8.5	111%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
64	955	287	71		105,217	

Please note that the percentage of savings which occur on-peak is greater than 100% because there is a slight energy use increase during off-peak periods.

EEM 2: Upgrade Watersource Heat Pumps (WSHPs)

The current water source heat pumps that are installed throughout the facility have reached the end of the typical service life and the units can be replaced with newer equipment which has increased efficiency and effectiveness, saving energy for the facility.

Existing Case

The base case for the upgraded WSHPs energy efficiency measure is RI code minimum efficiency heat pumps., with a coefficient of performance (COP) of 4.2 for heating and EER of 12 for cooling for each of the estimated 266 heat pumps in the facility. The efficiency curves used are the default eQUEST curves for WSHP.

Proposed Case

The proposed change is to increase the WSHP heating COP from 4.2 to 4.9 and increase the unit cooling EER from 12 to 13.5. These correspond to the efficiencies of the Trane GECE012 WSHP.

The electric savings generated by this measure can be attributed to the higher efficiency compressor. It requires less energy to extract or add heat to the condenser loop. The natural gas penalty is due to the fact that the boilers have to add the heat that the high efficiency compressors do not release into the loop.

Energy Savings Methodology

This measure was simulated using a parametric run of the base case model, changing the WSHP's COP and EER as described above, but keeping the same efficiency curves.

Cost Estimates

The incremental cost for this measure is $280,302. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	2	Upgrade Water Source Heat Pumps				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
71,200	1.5%	$7,262	-346	-0.2%	-$311	$6,951
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$280,302	$0	$0	$280,302	40.3	40.3	2.5%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
5.9	22.5	28.6	23.2	5.8	73%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
38	778	249	42		85,761	

EEM 3: Upgrade Roof Top Units (RTUs)

Several of the existing roof top units are also nearing the end of their service life. Newer models have improved efficiencies, providing energy savings for this capital replacement.

Existing Case

The base case for this measure consists of code compliant RTUs. The existing RTUs are approaching the end of their life, so the incentives for this measure were generated using the Design 2000 approach. The Design 200 (D2) is an incentive program that will pay back up to half of the incremental cost (the cost difference between a code minimum efficiency unit and the proposed unit) depending on how much less energy it will consume as compared to the code mimimum efficiency unit.

Code efficiency for each size category included in the EEM are as follows:

Capacity	Efficiency
tons	EER
3	13
5	13
15	10.8
17	10.8
25	9.5

It was assumed that each zone is attached to only one RTU, whose heating and cooling capacity corresponds to the sum of the RTUs normally attached to the zone. The temperature set points of the zones controlled by the RTUs are 68 °F for heating and 72 °F for cooling.

Proposed Case

The proposed change is to replace the code compliant RTUs, with units that have an EER of 13. This corresponds to a typical high-efficiency Carrier unit. Below is a list of the 25 year old RTUs that need to be replaced.

Served space	Location	Type	Make	Model	Capacity	Age	Quantity
Alfred's	3rd FL Roof	RTU	Trane	SFHDC254HD10C45DIA00	25 T	25	1
Lobby	3rd FL Roof	RTU	Trane	SFHDC254HD10C27D1A00	25 T	25	1
Plaza Ballroom	3rd FL Roof	RTU	Trane	BYCO60F4HOBB	5T	25	2
PlazaBallroom	3rd FL Roof	RTU	Trane	BYC036H4LOAA	3T	25	3
Restaurant - Preballroom	3rd FL Roof	RTU	Trane	BYC17OG4LOCA	15T	25	2
Hallways+restroom	3rd FL Roof	RTU	Trane	BYC200G4LOCA	17T	25	1
Restaurant - Preballroom	3rd FL Roof	RTU	Trane	BYC17OG4LOCA	15T	25	2
Hallways+restroom	3rd FL Roof	RTU	Trane	BYC200G4LOCA	17T	25	1

Energy Savings Methodology

This measure was simulated by using a parametric run of the base case model, changing RTUs efficiency from a code minimum to 13.

Cost Estimates

The incremental cost for this measure is $72,539. The total cost for code compliant RTUs is $446,095 and the total cost for high efficiency units is $518,634.

Energy Savings & Economics Summary

ECM #	3	Upgrade Rooftop Units				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
72,327	1.6%	$8,054	0	0.0%	$0	$8,054
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$72,539	$15,369	$0	$57,170	9.0	7.1	14.1%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.0	27.6	33.3	27.5	2.0	86%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
40	796	253	44		87,699	

EEM 4: Install a Building Automation System (BAS)

Installing a building automation system would allow the facility to implement advanced control strategies, such as optimal start/stop, demand control ventilation, discharge temperature reset, dual enthalpy economizer, and condenser water reset. A BAS would also give facilities staff greater control over, RTUs boilers and cooling towers, as well as giving staff more real-time information on the behavior of equipment, allowing possible issues to be identified and corrected more quickly.

Existing Case

The base case for this measure is to continue to operate the building in the same manner that it is now. These include basic equipment timers and thermostatic setpoint control of some of the major RTUs. It was assumed that:

- Min OA control setpoint is a fixed fraction of 15% of supply air.
- The discharge air temperature is currently set at 55 ^{o}F
- The RTUs serving the Grand Ballroom, the Grand Foyer, the Kitchen, Rotunda, Bristol and Tiverton are set on a schedule running from 6am to 12am
- The other RTUs are set on a 24/7 schedule

Proposed Case

The proposed changes in BAS capabilities were to implement demand control ventilation (DCV), discharge temperature setback, enthalpy economizer, optimal start/stop, and condenser water reset.

DCV is a BAS control strategy that modulates the amount of fresh air being introduced to a space based on the amount of people in the space. This measure involves installing CO_2 sensors in order to incorporate DCV for the rooftop units (RTUs) that serve large spaces, such as the plaza ballroom, the plaza foyer, the grand ballroom, the grand foyer, the lobby, the restaurant, the Atrium, Alfred's, and the Rotunda, in order to modulate the amount of outside air supplied to the spaces based on occupancy. When the space is unoccupied or has a low occupancy, less outdoor air is needed. Reducing outdoor air saves energy by reducing the amount of energy that is needed to condition the air, either for heating, cooling, or dehumidification. The way that occupancy is sensed by the DCV system is by comparing the carbon dioxide reading in the return air duct against the outside air carbon dioxide level.

Discharge air temperature reset is a control strategy that allows the discharge air to be reset based on outside air temperature. This creates energy savings by reducing the cooling load on the RTUs and the reheat load on the zone level. This control would enable the discharge air setpoint to be constantly reset by the BAS to generate energy savings. The proposed sequence calls for resetting the discharge air temperature between 55 ^{o}F to 60 ^{o}F when the worst case zone is within its deadband.

Dual-enthalpy economizer is a BAS control strategy that optimizes airside economizer operation. This strategy controls the economizer by considering the humidity in the air, as well as the sensible heat, and enables economizer mode when the outside air enthalpy is lower than the return air enthalpy. Enthalpy economizing optimizes operation and creates more effective economizer hours, creating savings by using "free cooling" and reducing the load on the condenser.

Energy Savings Methodology

An eQUEST parametric run was created to simulate the effect of DCV for the RTUs that serve large spaces.

Assumptions:

- The minimum outdoor air control method is set by the CO_2 differential between the SYSTEM return air stream and outside air intake air stream to determine the hourly outside air fraction. In eQUEST, the minimum damper position is set hourly based on the outside air CFM required per person and the hourly occupancy schedule of each zone.

An eQUEST parametric run was created to simulate the effect of resetting the discharge air temperature setpoint and was applied to all RTUs.

Assumptions:

- The supply air will reset when the worst case zone is satisfied. The discharge air will reset from 55 °F to 60 °F.

An eQUEST parametric run was created to simulate the effect of a dual-enthalpy economizer for all RTUs.

Cost Estimates

The cost for this measure is $90,878.

Energy Savings & Economics Summary

ECM #	4	Upgrade Building Automation Systems				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
385,536	8.3%	$37,125	27954	20.1%	$25,159	$62,284
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$90,878	$21,171	$4,828	$64,879	1.5	1.0	96.0%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
9.3	35.2	55.4	39.8	12.2	55%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
363	4,660	1,351	400		513,699	

EEM 5: Kitchen Hood Controls

Installing a kitchen hood control system allows the exhaust fan and makeup air unit serving the kitchen cooking area to modulate their speeds to meet the ventilation requirement throughout the occupied period. A typical constant volume kitchen hood exhausts air and supplies make up air at a constant rate. When cooking is not taking place, conditioned air from the space is exhausted and new makeup air is supplied, potentially wasting energy.

Existing Case

The kitchen hood system continues to use a constant volume exhaust fan and makeup air unit (MAU) to service the kitchen hoods. When the hood is turned on, typically scheduled for when the kitchen is occupied, the hood's exhaust fan runs at a constant speed, extracting the air from above the cook tops. The corresponding supply makeup air is provided through the MAU to maintain pressurization and condition the space.

Proposed Case

The proposed change in the kitchen hood system is to install variable speed drives on the exhaust fan and makeup air unit, as well as a smoke sensor, which senses the presence of smoke in the hood. During periods of reduced cooking activity, the hood exhaust fan will modulate down to its minimum speed (20% was assumed to be the minimum hood fan speed).

It was estimated that the kitchen's exhaust fans are extracting 37 CFM/ft^2 of hood area giving a total of 7,104 CFM. Cooking occurs each day from 6am to 8pm. It was estimated that the hood fan was equipped with a 1.5 hp motor.

Energy Savings Methodology

This measure was simulated in eQUEST by replacing the constant air extraction of 7,104 cfm from 6am to 8pm with a ratio schedule for the exhaust fan and makeup air unit. The schedule was created to run near capacity around peak cooking hours near breakfast, lunch, and dinner, while gradually decreasing to a minimum speed when there is likely to be little cooking taking place.

Time	midnight	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-Noon
Morning Ratio	0%	0%	0%	0%	0%	0%	85%	95%	85%	65%	20%	20%
Time	Noon-1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6-7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-midnight
Afternoon Ratio	85%	95%	65%	20%	75%	85%	75%	20%	0%	0%	0%	0%

Cost Estimates

It was estimated that the prescribed control upgrade to the kitchen hood would have a total project cost of approximately $55,268. See Appendix C: Cost Estimates for more information. This measure is for two hoods.

Energy Savings & Economics Summary

ECM #	5	Kitchen Hood Controls				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
5,294	0.1%	$566	1678	1.2%	$1,510	$2,076
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$55,268	$0	$0	$55,268	26.6	26.6	3.8%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.5	5.2	0.5	4.8	0.6	98%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
12	83	19	13		9,193	

EEM 6: Install Laundry Wastewater Heat Recovery Device

Installing a heat exchanger on the laundry's wastewater pipe would allow incoming water to recover some of the heat from the hot water being discharged from the laundry equipment. This heat recovery reduces the amount of heat that must be added to the incoming water to raise it to the desired temperature.

Existing Case

Currently, there is no heat recovery of the laundry waste water. When the water is discharged from the washer, it flows directly into the sewer.

Proposed Case

The proposed change to be applied for this measure consists of installing a water to water heat exchanger, harvesting heat from the laundry discharge to preheat incoming water. The heat exchanger works by using the wastewater from the laundry to heat the incoming supply water, transferring its heat and increasing the supply water temperature. Having an increased supply water temperature decreases the amount of heating energy that must be added to the supply water to meet its temperature setpoint. There will be a pumping penalty associated with this measure due to the head from the heat exchanger.

Energy Savings Methodology

The addition of laundry wastewater heat recovery was not simulated in eQUEST, as eQUEST does not have the capacity to do so. The calculations for this measure were received from Fredrick McKiernan at National Grid.

Savings were calculated using 11 days of minute interval measurements on the laundry DHW heaters and guest room DHW heaters. Below is a list of the measured data made to estimate the savings:

- Outlet temperature and flow of the laundry DHW heaters and the ones serving the guest rooms.
- It was estimated that domestic hot water daily load for the laundry room is 4,241 gal/day and 10,400 gal/day for other DHW use. The laundry DHW flow vs. total entering DHW flow ratio is constant at 29%. Please refer to the appendix for additional information on the building domestic hot water consumption.
- Temperature of the returning DHW from the guest rooms going back to the heaters.

The methodology used is described in See Appendix C: Cost Estimates.

Cost Estimates

The cost of the this measure is $16,917. See Appendix C: Cost Estimates for more information.

ENERGY SAVINGS & ECONOMICS SUMMARY

ECM #	6	Install Laundry Drain Water Heat Recovery				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
-410	0.0%	-$49	1209	0.8%	$1,088	$1,039
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$16,176	$0	$0	$16,176	15.6	15.6	6.4%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.0	0.0	0.0	0.0	0.0	0%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
6	14	-1	7		1,502	

EEM 7: Upgrade Hot Water (HW) Boilers

The current hot water boilers are near the end of their service life. New, condensing boilers can have efficiencies of 92% or higher, which is a significant improvement over the current models installed in the facility. Replacing the boilers could result in energy savings from the increased efficiency and reduced maintenance cost.

Existing Case

The base case for the upgraded boiler energy efficiency measure is to continue to use the existing hot water boilers:

- (1) Teledyne Laars Boiler (Model HL42200) with 2,200 MBH input and 1,650 MBH output serving the new wing WSHP loop (75% efficiency).
- (1) Teledyne Laars Boiler (Model HQ1466KK06B) with 1,466 MBH input and 1,143 MBH output serving the old wing WSHP loop (78% efficiency).

Proposed Case

The proposed change to be applied for this measure is to install high-efficiency condensing boilers that are 92% efficient at full load. These boilers require less natural gas in order to raise the temperature of the watersource heat pump loops to their setpoints, saving energy. The higher efficiency of condensing boilers is due to the secondary heat exchanger which extracts additional latent heat from the exhaust air vapor.

This measure was modeled with a single WSHP loop with two boilers attached. The boilers are staged so that they both operate at the same part load and ramp up and down in unison. This approach simplifies the modeling while still closely projecting the savings of replacing the boilers attached to both the new and old WSHP loops.

Energy Savings Methodology

This measure was modeled in eQUEST by adjusting the boiler efficiencies from heat input ratios (HIRs) of 1.33 and 1.28 in the base case to 1.18 for both in the proposed case. The boiler type was changed from a forced draft boiler to a condensing boiler. Hot water reset was not required in order for boiler to be fully condensing because of the relatively low temperature of the condenser loop.

Cost Estimates

It was estimated that the total project cost for installing two new condensing boilers would be $226,386. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	7	Upgrade Hot Water Boiler				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
-4,795	-0.1%	-$444	3349	2.4%	$3,015	$2,571
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$179,010	$0	$0	$179,010	69.6	69.6	1.4%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
-2.7	0.0	0.0	0.0	-1.0	55%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
15	-3	-17	17		-276	

EEM 8: Install Variable Speed Drives (VSDs) on the CW Pumps

The pumps that serve the facility's watersource heat pump loop operate at a constant speed, regardless of the demand from the facility. New inverter rated pump motors and variable speed drives will modulate the speed that the pump runs so that water is circulated at a rate that meets, but does not exceed, the requirement to adequately heat or cool the facility.

Existing Case

The base case for the variable speed drives energy efficiency measure is to continue to use constant volume condenser water pumps.

eQUEST model assumptions:

- The 4 CW circulator pumps have single speed motors.
- The pump's motors efficiency each are 88%.
- The two motors are 10 HP and two are 15 HP.
- Each pump is designed for 225 gpm and 90 ft of head.

Proposed Case

The proposed change to be applied for this measure is to replace the pumps' motors with premium-efficiency inverter duty-rated motors and install variable speed drives. The premium-efficiency inverter duty-rated motor ensures highest efficiency and compatibility with the VSD. The pumps will modulate to maintain an adjustable loop differential pressure setpoint. Overall the facility can save electric energy by decreasing the speed of the pumps, decreasing the amount of power that each draws.

Energy Savings Methodology

The variable speed drive measure was simulated in eQUEST using a parametric run that changes each unit from a single speed pump to a variable speed pump. The motors' efficiency has also been increased from 88% to 92%. In addition, the WSHPs condenser isolation valve status has been changed from no to yes. This is needed since the variable speed pump is controlled by the loop differential pressure which depends on the WSHPs isolation valves position. **Therefore, this EEM assumes that the WSHPs have been replaced as suggested in the earlier EEM.**

Cost Estimates

It was estimated that the total project cost for installing the variable speed drives would be $51,246. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	8	Install VFDs on CW Pumps				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
127,676	2.8%	$12,234	-2804	-2.0%	-$2,523	$9,711
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$51,246	$20,620	$0	$30,626	5.3	3.2	31.7%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
15.6	5.8	5.9	5.8	13.1	64%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
56	1,362	447	62		150,176	

EEM 9: Install Variable Speed Drives (VSDs) on Cooling Tower Fans

The cooling tower fans which control the amount of heat that is rejected from the condenser loop run at a fixed speed. Variable speed drives (VSDs) would allow the fans to modulate their speeds to save energy when the building load is below the design cooling capacity.

Existing Case

The base case for this measure is to continue to use constant speed cooling tower fans. It was assumed the cooling tower fans run at full speed whenever there is a cooling load on the condenser loop.

It was estimated that each fan is equipped with a 93% efficiency, 15 HP one speed motor.

Proposed Case

The proposed change to be applied for this measure is to install variable speed drives on the cooling tower fans. The motors of the two tower fans are already inverter duty-rated and do not need to be replaced. Variable speed drives allow the fans to modulate their speed to maintain a leaving condenser water temperature setpoint. This EEM will need to be coordinated with the BAS EEM, which includes resetting the condenser water loop temperature. Overall the facility can save electric energy by decreasing the speed of the fans, which decreases the amount of power that each draws.

Energy Savings Methodology

The variable speed drive measure was simulated in eQUEST using a parametric run that changes the capacity control of the two units from a single speed fan to a variable speed fan.

Cost Estimates

It was estimated that the total project cost for installing the variable speed drives would be $17,898. See Appendix C: Cost Estimates for more information. The incentive for the EEM was calculated using the rates from the Rhode Island VFD and Motor Retrofit Program prescriptive incentive application.

Energy Savings & Economics Summary

ECM #	9	Install VFDs on Cooling Tower Fans				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
35,788	0.8%	$3,903	0	0.0%	$0	$3,903
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$17,898	$8,700	$0	$9,198	4.6	2.4	42.4%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.0	17.7	38.5	19.8	1.4	79%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
20	394	125	22		43,394	

EEM 10: Low Flow Kitchen Spray Nozzle

Installing a low flow kitchen spray nozzle reduces the amount of water that is used to clean kitchen pots, dishes, etc. The specialized nozzle still provides the same effectiveness, despite the reduced flow, while the reduced flow decreases the amount of heating energy that is needed.

Existing Case

The base case for the low flow kitchen spray nozzle energy efficiency measure is to continue to use standard flow rate hot water for dish cleaning.

The kitchen is equipped with four faucets with a nozzle on each. Each of the nozzles is rated at 3 gallons per minute (GPM). Assuming each faucet will be fully running for a total of 1 hour per day, the total hot water consumption of the kitchen sinks would be 720 gallons per day.

Proposed Case

The proposed change to be applied for this measure is to install low flow rate spray nozzles for dish cleaning. The new nozzles will consume 40% less water then the existing nozzles. Each nozzle will use 1.8 GPM. The total daily water consumption of the kitchen spray nozzles will be 432 gallons. Decreasing the flow rate of the water decreases the amount of heating energy that must be added to the water in order to raise it to the required temperature. New low flow spray nozzle designs allow for maintained effectiveness in cleaning, despite the reduced flow rate meaning increased savings without a loss of performance.

Energy Savings Methodology

This measure was simulated in eQUEST by changing the main DHW heater inlet flow to reflect the reduced flow of the kitchen sinks.

Cost Estimates

It was estimated that the total project cost for installing the 4 low flow spray nozzles would be $281. This value is based on $55 per nozzle material cost and there is no labor cost, as installation can be completed by internal staff. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	10	Low Flow Kitchen Spray Nozzle				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
0	0.0%	$0	1254	0.9%	$1,128	$1,128
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$281	$0	$0	$281	0.2	0.2	401.4%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.0	0.0	0.0	0.0	0.0	0%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
7	19	0	7		2,073	

EEM 11: Install Aerators and Low Flow Shower Heads to Reduce Domestic Hot Water (DHW) Use

Aerators in sinks and low flow shower heads reduce the amount of water that is used overall by those units, without decreased effectiveness. The decreased amount of domestic hot water use as a result of these measures decreases the amount of natural gas used by the facility.

Existing Case

The base case for this measure is to continue to use standard flow sinks and shower heads in restrooms throughout the facility. There are approximately 300 standard flow rate sinks in the facility and 266 shower heads.

It was assumed that each guest room uses an average of 40 gallons per day and it was determined using the guest room occupancy list that there is in average of 130 rooms occupied throughout the entire year.

Proposed Case

The proposed change to be applied for this measure is to install aerators in standard flow rate sinks and low flow shower heads in showers with standard DHW use. Aerators are added to the existing sinks and decrease the water flow rate through the faucet. Despite the decreased flow, aerators are still equally effective for users and with decreased DHW flow, less heating energy must be added to the water to raise it to the desired temperature. Low flow shower heads accomplish a similar function, though they replace the existing shower head rather than being retrofitted onto an existing fixture. This measure proposes retrofitting 300 of the sinks in guest rooms and public restrooms with aerators and replacing 266 shower heads with new, low flow shower heads. These aerators reduce the water flow by 40%.

Energy Savings Methodology

This measure was simulated in eQUEST by changing the main DHW heater inlet flow from 5.71gpm to 3.72gpm. This is the equivalent of reducing the daily water load by 40% per room assuming each room uses 40 gallons per day. For more details, see Appendix C: Cost Estimates.

Cost Estimates

It was estimated that the total project cost for replacing and retrofitting these fixtures would be $30,168. This value is based on $50 per shower head for 266 shower heads, $15 per aerator for 300 aerators and $4,700 for the labor. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	11	Install Aerators and Low Flow Shower Heads				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
0	0.0%	$0	7289	5.2%	$6,560	$6,560
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$30,168	$0	$15,084	$15,084	4.6	2.3	43.5%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.0	0.0	0.0	0.0	0.0	0%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
39	109	0	43		12,052	

EEM 12: Combined Heat and Power (CHP)

A combined heat and power system is a large engine or turbine that creates electricity to meet the facility's electric demand, while also recovering heat generated by the unit to heat the facility. CHP units can have overall efficiencies up to 80% and significantly reduce the amount of electricity that the facility must purchase from the grid. Facilities, such as the Crowne Plaza Hotel that have high hot water loads year round can be good candidates for a CHP system.

Existing Case

The base case for the combined heat and power energy efficiency measure is to continue to use the current HVAC systems for producing heating energy and to continue to purchase all electricity from the utility.

It was assumed that the electrical base load is 250 kW and the gas base load is 6 MBH, equivalent to the total DHW gas load. Note that this does not equal the total load of the facility; rather it is an average "minimum threshold" that the facility experiences each month.

Proposed Case

The proposed change to be applied for this measure is to install a KRAFT KMGR-150-4SH Cogeneration (CHP) system that produces 150 kW of electric power from a 14.3 Therms/hr natural gas input. CHP systems are electric generators, typically either engines or gas turbines, that make use of the heat created in the exhaust and engine jacket in order to create steam or hot water for use within the facility. The CHP system proposed in this measure is a gas engine type with jacket water and exhaust heat exchangers. The total heat recovered from both heat exchangers combined is 784,012 BTU/hr. The facility can see a significant decrease in monthly electric utility bills and a decrease in heating energy that must be created by the existing facility heating system, offset by an increase in monthly natural gas bills to fuel the CHP system. The overall efficiency of this unit is 81.38%.

Energy Savings Methodology

The CHP measure was modeled in eQUEST by creating a parametric run which includes a 150kW electric generator with two heat recovery stages, one for the engine-jacket and the other one from the exhaust gas. The jacket recovers 32.9% of the generator's input energy and is used to heat the main DHW loop. The heat recovery exhaust gas recovers 21.7% of the generator's input energy and is used to heat the laundry DHW. **The higher heating value was used when calculating the efficiency of this unit.**

Cost Estimates

It was estimated that the total project cost for installing a CHP system would be $643,469. See Appendix C: Cost Estimates for more information.

ENERGY SAVINGS & ECONOMICS SUMMARY

ECM #	12	Combined Heat and Power				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
1,379,678	29.8%	$135,256	-107222	-77.2%	-$96,499	$38,757
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$643,469	-	-	-	16.6	-	-
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
157.5	157.7	157.5	178.6	160.1	45%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
198	13,568	4,822	218		1,495,630	

EEM 13: Groundsource Heat Pump

A groundsource heat pump is a system that takes advantage of the nearly constant ground water temperature throughout the year, meaning that it can serve as a heat sink in the warmer months and heat source in the colder months. Water from the facility's main loop is pumped through a heat exchanger, which exchanges heat with the ground source loop.

Existing Case

The base case for the ground source heat pump energy efficiency measure is to continue to make use of the existing condenser water loop configuration.

Proposed Case

This measure involves drilling standing column wells with a heat rejection/extraction capacity of 395 tons while providing 55 °F +/- 5 °F water year-round. The system will have pumps to draw water out of the standing column well and run it through a water-to-water heat exchanger where heat is rejected or extracted by the condenser water loop. The advantage of using geothermal is that it eliminates the need for cooling towers and supplementary boilers.

Energy Savings Methodology

The GSHP was modeled in eQUEST by creating another eQUEST model, which is identical to the base model except for the boiler and cooling tower of the WLHP which are replaced by a ground loop heat exchanger and standing column wells. The well field will be compromised of (11) 1000 ft deep wells. Each well has a heat rejection capacity of approximately 35 tons.

Cost Estimates

It was estimated that the total project cost for installing a ground source heat pump would be $1,223,211. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	13	Ground Source Heat Pump				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
82,657	1.8%	$7,490	8767	6.3%	$7,891	$15,381
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$967,229	$0	$0	$967,229	62.9	62.9	1.6%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
8.8	41.9	55.3	19.8	-66.6	82%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
93	1,041	290	102		114,721	

EEM 14: Freezer

The savings and cost estimates for this EEM were provided by Nationall Resource Management. Refer to Appendix A for their report.

Existing Case

Crowne Plaza has seven walk-in freezers and coolers. The total wattage load for all of the freezers is 2.0873 kW. The freezers are not equipped with destratification fans, ECM motors, or economizers.

Proposed Case

NRM proposes installing ECM motors for the evaporator fans, installing destratification fans inside the freezers, installing a wall-mount economizer (NRM-500), installing a roof-mount economizer (NRM-1000), and installing additional controls.

Energy Savings Methodology

The savings were calculated by NRM.

Cost Estimates

The cost for this measure is $21,858 and was provided by NRM.

Energy Savings & Economics Summary

ECM #	14	Freezer				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
41,273	0.9%	$4,953	0	0.0%	$0	$4,953
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$21,858	$6,666	$0	$15,192	4.4	3.1	32.6%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
1.4	1.4	1.4	1.4	1.4	0%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
23	454	144	25		50,045	

EEM 15: Pool Cover

The current indoor pool is heated everyday throughout the year. The heated water evaporates into the space, cooling the pool down. An automatic pool cover can cover the pool while it is not being used to limit pool evaporation. In addition, pool covers also reduce the need to ventilate the room with outdoor air, meaning more energy can be saved by reducing the outdoor air flow when the pool is covered.

Existing Case

The base case for the pool cover energy efficiency measure is to continue to use the standard pool heater. The existing pool is heated by a 15 kW three-phase electric heater to keep the pool at an average water temperature of 85°F all year long, while the room temperature is between 62 °F and 64 °F. The pool is 225 ft^2 and open to customers from 8 am to 7 pm every day of the year.

To simulate the baseline model, it was assumed that the swimming pool electric water heater is running at the same rate 24/7 throughout the year, using 79,300 kWh per year. This electric use was calculated using the following assumptions:

- pool water temperature is 85 °F,
- room temperature is 63 °F,
- pool area is 225 ft^2,
- pool perimeter of 60 ft,
- room relative humidity of 60%.

See Appendix C: Cost Estimates for more information. This electric use was then simulated in eQUEST by adding a 9.3 kW electric load for the pool heater running 100% on a 24/7 schedule.

Proposed Case

The proposed change is to install an automatic pool cover to limit pool evaporation when the pool is not used. Evaporating water absorbs tremendous amounts of energy and is by far the largest source of the pool energy loss. In addition, pool covers also reduce the need to ventilate the room with outdoor air meaning more energy can be saved by reducing the outdoor air flow when the pool is covered.

Energy Savings Methodology

The pool cover measure was simulated in eQUEST using a parametric run that changes the pool heater schedule from a 100% 24/7 to 100% from 8 am to 7 pm and 30% from 7 pm to 8 am. This schedule matches the opening schedule of the pool facility. It was assumed that the heater runs at 30% because the cooling load is reduced when the pool cover decreases the amount of heat released from the pool via latent heat of vaporization.

Cost Estimates

It was estimated that the total cost for installing an automatic pool cover is $14,999. This value is based on the price per square foot of $40 given by the vendor for an L shaped pool. The estimates were obtained from COVERTECH LLC. See Appendix C: Cost Estimates for more information.

Energy Savings & Economics Summary

ECM #	15	Pool Cover				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
33,681	0.7%	$3,054	-732	-0.5%	-$659	$2,395
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$14,999	$5,439	$0	$9,560	6.3	4.0	25.1%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
0.0	0.2	0.2	0.2	0.2	40%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
15	360	118	16		39,629	

EEM 16: Application of Vista Window Film

Base Case

Crowne Plaza has 11,219 square feet of glazing and 212 sliding glass doors that do not have a window film applied. The solar heat gain coefficient (SHGC) of the clear double hung windows and the double hung sliding doors was assumed to be 0.48.

Proposed Case

A window tint will be applied to the 11,219 square feet of double hung glazing and the 212 sliding glass doors. The window tint will reduce the SHGC to 0.30. The reduction in the SHGC will reduce the load on the heat pumps during cooling operation. There will be a slight heating penalty as the film reduces the amount of passive solar heating during heating operation. The savings are attributed to reduced compressor run hours in the heat pumps, reduced CW loop pump run hours, and reduced cooling tower fan run hours.

Energy Savings Methodology

An eQUEST model was created. The model was created using information gather during previous site visits, as well as an aerial image that was traced in AutoCAD to create a realistic envelope geometry. The model was calibrated to historical electrical and natural gas consumption that was obtained from NGRID. The base case building was modeled to existing conditions. The proposed case was run by modifying the window SHGC 'parametrically'.

Cost Estimates

The cost for this measure was obtained by Crowne Plaza from Solar Tint. The cost for this measure is $66,390.

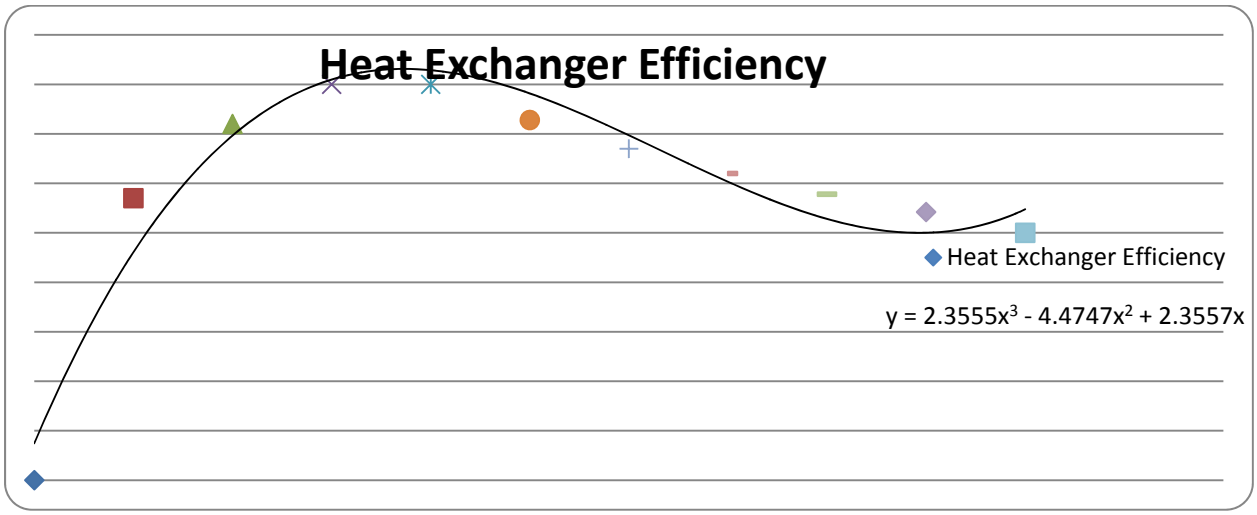
ENERGY SAVINGS & ECONOMICS SUMMARY

ECM #	16	Install Window Tint				
Electric Energy Savings	Electric Energy Savings	Electric Cost Savings	Natural Gas Energy Savings	Natural Gas Energy Savings	Natural Gas Cost Savings	Total Cost Savings
kWh	%	$	therms	%	$	$
149,230	3.2%	$15,168	-1112	-0.8%	-$1,001	$14,167
Retrofit Cost	Electric Incentive	Natural Gas Incentive	Net Cost	Simple Payback Before Incentive	Simple Payback After Incentive	Return on Investment After Incentive
$	$	$	$	yrs	yrs	%
$66,390	$24,101	$0	$42,289	4.7	3.0	33.5%
January Peak Demand Savings	June Peak Demand Savings	July Peak Demand Savings	August Peak Demand Savings	December Peak Demand Savings	Percentage of Savings On-Peak	Other Savings
kW	kW	kW	kW	kW	%	$
8.6	38.5	50.1	38.7	12.7	76%	$0
CO_2 Savings	NO_x Savings	SO_x Savings	Equivalent Trees Savings		Equivalent Gasoline Savings	
metric tons	lbs	lbs	trees		gallons	
77	1,625	522	85		179,108	

APPENDIX A: CALCULATIONS

EEM #6: Laundry Drain Water Heat Recovery

Below, the efficiency of the Exergy 23 series, model 00540-2 heat exchanger with a fixed temperature difference between hot and cold water depending on the Hot water to Cold water flow ratio. For example, for a 20% ratio, 20% of the total flow is hot water and 80 % is cold water.



Below, the assumptions made to calculate savings:

Assumptions		
Delay between Laundry income water vs drain	10	min
City water temp before heat recovery	52	F
Laundry Drain water temp	105	F
Heat exchanger efficiency (x=ratio between HW vs CW)	2.3555x3 - 4.4747x2 + 2.3557x	
Water Heater efficiency	80%	

Below, a section of the 11 day onsite measured data:

Laundry		Guest room					
Time (hh.mm)	City water Demand Flow (gpm)	Time (hh.mm)	City water Demand Flow (gpm)	Total Flow gpm	City water temp after heat recovery (F)	Heat gain in city water Btu/min	Gas Savings Btu/min
17.21	0.0	17.21	3.1	3.1	61.7	248.1	310.2
17.22	0.0	17.22	3.8	3.8	52.0	0.0	0.0
17.23	0.0	17.23	2.9	2.9	56.7	113.1	141.4
17.24	7.9	17.24	3.0	10.9	52.0	4.1	5.1
17.25	7.9	17.25	4.4	12.3	61.2	949.0	1186.3
17.26	0.2	17.26	2.9	3.2	52.0	0.0	0.0
17.27	11.9	17.27	4.5	16.4	52.0	0.0	0.0
17.28	9.8	17.28	5.2	15.1	52.0	0.0	0.0
17.29	14.9	17.29	5.2	20.0	58.2	1041.1	1301.3

Savings per year (therms)	**1208.5**

Measured data:

- Laundry City water demand flow
- Guest room City water demand flow was calculated by deducting all other know flows, leaving only the guest room water consumption.

Calculated data formulas:

- **Total flow** = Laundry City water demand flow + Guest room City water demand flow
- **City water temp after heat recovery=** City_water_temp + ((City_water_temp *City_water_flow+Laundry_Drain_water_temp*Drain_water_flow)/ (City_water_flow+Drain_water_flow) -City_water_temp) *Heat_Exchanger_efficiency
- **Heat gain in city water =** 8.35 * Total flow * (City water temp after heat recovery - City water temp before heat recovery)
- **Gas Savings =** Heat gain in city water - Water Heater efficiency

Low Flow Kitchen Spray Nozzle:

Time	Midnight - 1am	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-Noon
Morning Ratio	60.5%	60.4%	52.7%	49.1%	48.7%	53.1%	58.5%	62.8%	87.9%	100.0%	83.4%	85.6%
Time	Noon-1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6-7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-midnight
Afternoon Ratio	81.3%	69.8%	61.9%	69.6%	64.9%	64.9%	58.8%	63.5%	59.5%	54.9%	62.0%	66.0%

Average hourly ratio	65.8%	
eQUEST Input flow	5.7	gpm
Total water use	5,420	Gal/day
Daily water load per nozzle	180	gal/day
Number of nozzle	4	rooms
Kitchen water load	720	gal/day
Aerator savings	50%	
Proposed daily usage	5060.1	gal
Proposed case eQUEST input flow	5.34	gpm

Shower Aerator calculations:

Time	Midnight - 1am	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-Noon
Morning Ratio	60.5%	60.4%	52.7%	49.1%	48.7%	53.1%	58.5%	62.8%	87.9%	100.0%	83.4%	85.6%
Time	Noon-1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6-7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-midnight
Afternoon Ratio	81.3%	69.8%	61.9%	69.6%	64.9%	64.9%	58.8%	63.5%	59.5%	54.9%	62.0%	66.0%

Average hourly ratio	65.8%	
eQUEST Input flow	5.7	gpm
Total water use	5,420	gal/day
daily water load per room	40	gal/day
Average occupied room per day	130	rooms
Total guest room load	5200	gal/day
Aerator savings	40%	
Proposed daily usage	3340.1	gal
Proposed case eQUEST input flow	3.52	gpm

EEM #14: Freezer

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EXHIBIT A

Customer: Crowne Plaza #3446-BP
Address: 801 Greenwich Ave., Warwick, RI 02886
Telephone: 401-732-6000 x7878
Contact: Deidra Tart
Utility Company: National Grid
Account Number: 0000-000-0000 Install: 7TC6DH1FH16ECM1SDK

PAYBACK ANALYSIS

Economizer & Walk-In Cooler/Freezer Evaporator Fan and Door Heater Controls

Material Code	Quantity	Description	Unit Cost	Total Cost
E NRM-500	0	NRM-500 Economizers Wall Mount	$1,900.00	$0.00
E NRM-1000	0	NRM-1000 Economizers Roof/Wall Mount	$6,600.00	$0.00
CCS 1EV	1	Controls for Temp, Evap Fan, Defrost	$1,450.00	$1,450.00
CCS-2+EV	6	Controls per Additional Cooler/Freezer	$840.00	$5,040.00
A DESTR-1000	0	Destratifier fan units	$210.00	$0.00
CCS-1DH	1	Cooler Door Heater Control Option	$700.00	$700.00
CCS-1FH	1	Freezer Door Heater Control Option	$700.00	$700.00
CCS-2+DH	4	Additional Cooler Door Heater Circuits	$525.00	$2,100.00
CCS 2+FH	0	Additional Freezer Door Heater Circuits	$525.00	$0.00
SD Control	1	Smart Defrost Kit on Walk-in Freezers	$700.00	$700.00
1/20 HP ECM	16	ECM Evaporator Fan Motor Replacement for 1/20HP	$165.00	$2,640.00
1/4 HP ECM	0	ECM Evaporator Fan Motor Replacement for 1/4HP	$290.00	$0.00
C VCOOL SCTS	0	NRM-Switched Receptacle Control System	$180.00	$0.00
		MATERIAL SUBTOTAL		$13,330.00
		Sales Tax @ 7%		$933.10
		TOTAL MATERIAL COSTS		$14,263.10
		Cooler Retrofit Labor Cost		$3,215.00
		Economizer Installation Labor Cost		$0.00
		Destratifier Fan Installation Labor Cost		$0.00
		Cooler Door Heater Retrofit Labor Cost		$1,025.00
		Freezer Door Heater Retrofit Labor Cost		$445.00
		SDK Smart Electric Defrost Control Labor Cost		$350.00
		ECM Evaporator Fan Motor Replacement Labor Cost		$1,760.00
		Novelty Cooler Control Labor Cost		$0.00
		LABOR SUBTOTAL		$7,595.00
	2 YR	Warranty on CoolTrol Products		
	1 YR	Warranty on Electric Defrost Control and ECM's		
Total PROJECT COST				**$21,858.10**

PROJECT ECONOMIC SUMMARY

Estimated KWH Savings/yr		41,273
Energy savings/yr @ $0.13/KWH	$0.160	$6,603.61
Simple Payback Period Before Incentive		**3.31 YRS**
PAYBACK ANALYSIS		
ESTIMATED National Grid Incentive	50% of CoolTrol and ECMs	**$10,929.05**
Net cost to customer		**$10,929.05**
Simple Payback Period With Incentive		**1.66 YRS**

Prepared by National Resource Management, Inc. (800)[illegible] 2011 CoolTrol and ECM's Large CI - MA, NH, RI (coolmcs).xls COST-ROI

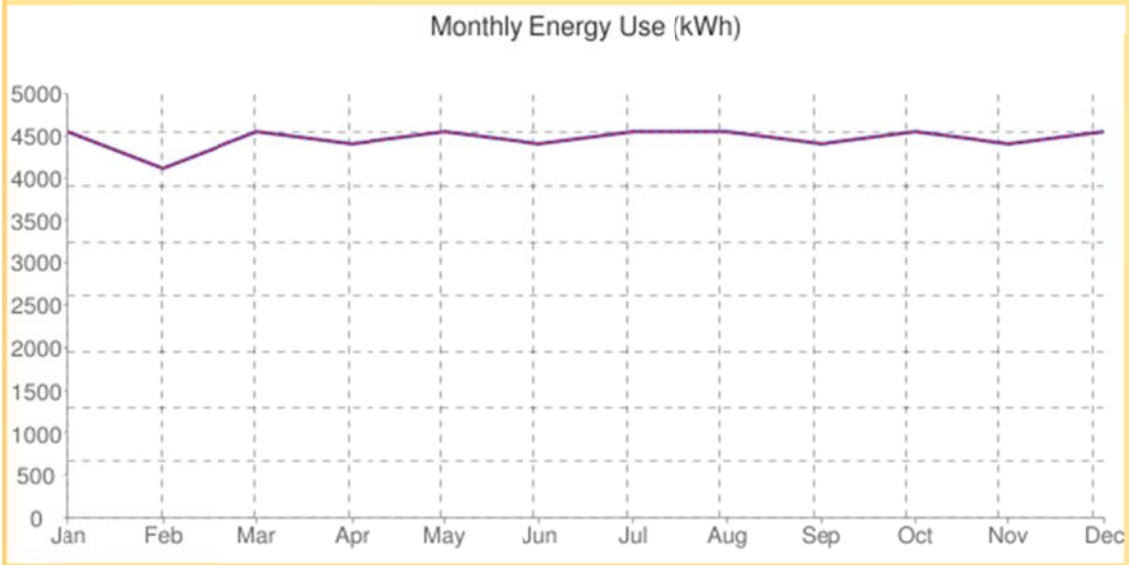
EEM #15: Pool Cover

Pool energy consumption calculation using the following online software:

http://www.energyexperts.org/CalculatorsTools/PoolEnergyUseCalculator.aspx

Intro | Step 1: Basic Info | Step 2: Schedules | Step 3: View Results

Energy Loss	Current Pool	
	Energy Use (kWh/yr)	Cost
Evaporation:	61,372	$ 9,206
Radiation to Night Sky:	00	$ 00
Radiation to Ambient:	13,446	$ 2,017
Convection:	2,794	$ 419
Solar Gain:	00	$ 00
Refill:	1,759	$ 264
Total:	79,371	$ 11,906



EEM #16: Vista Window Film

SOLAR TINT

225B George Waterman Road - Johnston, Rhode Island 02919
(401) 233-0075 800-649-0767 Fax (401) 233-0086
Email: solartintri@verizon.net • www.solartintri.com

PROPOSAL SUBMITTED TO: CROWNE PLAZA
PHONE: 732-6000
DATE: 6-1-12
STREET: 801 GREENWICH AVE.
JOB NAME: GUEST ROOMS & COMMON AREAS
CITY, STATE AND ZIP CODE: WARWICK, RI 02886
JOB LOCATION:
ARCHITECT:
DATE OF PLANS:
EMAIL:
FAX:

We hereby submit specifications and estimate for:

THE FOLLOWING ROOMS AND AREAS TINTED WITH VISTA V33B WINDOW FILM

(A) FRONT - EAST : 60 SLIDING DOORS & 216 LITES OF GLASS 3700 SF.

(B) FRONT - EAST FOYERS - 48 LITES OF GLASS 500 SF

(C) REAR - WEST - 52 SLIDING DOORS & 135 LITES OF GLASS 2465 SF

(D) ADDITION - NORTH - 26 SLIDING DOORS & 146 LITES OF GLASS 2350 SF

(E) ADDITION - SOUTH - 26 SLIDING DOORS & 140 LITES OF GLASS 2280 SF

We Propose hereby to furnish material and labor - complete in accordance with above specifications, for the sum of:

SIXTY-THREE THOUSAND, FIVE-HUNDRED dollars $ 63,500.00

Tax 2,890.00

TOTAL: 66,390.00

Payment to be made as follow:

TERMS TO BE DISCUSSED

All material is guaranteed to be as specified. All work to be completed in a substantial workmanlike manner according to specifications submitted, per standard practices. Any alteration or deviation from above specifications involving extra costs will be executed only upon written orders, and will become an extra charge over and above the estimate. Our workers are fully covered by Workmen's Compensation Insurance.

Authorized Signature

Note: This proposal may be withdrawn by us if not accepted within 30 days.

Acceptance of Proposal The above prices, specifications and conditions are satisfactory and are hereby accepted. You are authorized to do the work as specified. Payment will be made as outlined above.

Date of Acceptance

Signature

Signature

CHART 19: Dual-Pane, 1/8 Inch (3mm) Panes, Exterior Pane High Performance Low-E on #2 Surface, Clear Interior Pane

VISTA WINDOW FILM

	(1) % Total Solar Transmittance	(2) % Total Solar Reflectance	(3) % Total Solar Absorptance	(4) % Visible Transmittance	(5) % Visible Reflectance (exterior)	(6) % Visible Reflectance (interior)	(7) % UV Rejected	(8) Winter U-value	(10) Shading Coefficient	(11) % Total Solar Energy Rejected	(12) Solar Heat Gain Coefficient (SHGC)	(13) Emissivity	(14) Light to Solar Heat Gain Ratio (LSG)	Compared to window w/o film: (15) % Summer Solar Heat Gain Reduction	(16) % Winter Heat Loss Reduction	(17)% Glare Reduction
Window without film applied:	38	35	27	72	11	12	84	0.30	0.48	58	0.42	0.04	1.71	-	-	-
Window with film applied:																
NEUTRALS																
V33 SR CDF	14	39	47	27	20	20	99.9	0.29	0.38	67	0.33	0.04	0.82	21%	3%	63%
V45 SR CDF	18	37	45	35	16	14	99.9	0.30	0.41	64	0.36	0.04	0.97	15%	0%	51%
V58 SR CDF	24	36	40	46	13	11	99.9	0.30	0.44	62	0.38	0.04	1.21	8%	0%	36%
DUAL REFLECTIVES																
V14 SR CDF	5	47	48	9	39	24	99.9	0.30	0.27	77	0.23	0.04	0.39	44%	0%	88%
V18 SR CDF	8	43	49	16	31	21	99.9	0.30	0.32	73	0.27	0.04	0.59	33%	0%	78%
V28 SR CDF (PS8)	10	42	48	21	29	22	99.9	0.29	0.33	72	0.28	0.04	0.75	31%	3%	71%
V38 SR CDF (PS8)	16	39	45	32	20	17	99.9	0.30	0.38	67	0.33	0.04	0.97	21%	0%	56%
V48 SR CDF	19	36	45	37	15	11	99.9	0.30	0.42	64	0.36	0.04	1.03	13%	0%	49%
V33 BR SR CDF	14	42	44	29	22	19	99.9	0.29	0.34	70	0.30	0.04	0.97	29%	3%	60%
HARMONY SERIES																
V31 SR CDF	12	35	53	28	10	9	99.9	0.29	0.42	64	0.36	0.04	0.78	13%	3%	61%
V40 SR CDF	18	35	47	35	11	9	99.9	0.29	0.43	63	0.37	0.04	0.95	10%	3%	51%
V41 SR CDF	18	35	47	38	10	8	99.9	0.29	0.43	63	0.37	0.04	1.03	10%	3%	47%
V50 SR CDF	21	36	43	43	12	10	99.9	0.28	0.42	63	0.37	0.04	1.16	13%	7%	40%
V51 SR CDF	20	35	45	43	10	9	99.9	0.29	0.43	63	0.37	0.04	1.16	10%	3%	40%
LOW-E SERIES																
VE35 SR CDF	11	46	43	22	36	36	99.9	0.26	0.27	77	0.23	0.04	0.96	44%	13%	69%
VE50 SR CDF	20	40	40	40	22	27	99.9	0.26	0.36	68	0.32	0.04	1.25	25%	13%	44%
EXTERIOR																
VRE20 ER HPR	9	65	26	13	65	60	99.9	0.30	0.13	88	0.12	0.04	1.08	73%	0%	82%
VNE35 ER HPR	29	19	52	34	20	21	99.9	0.30	0.41	65	0.35	0.04	0.97	15%	0%	53%
ENERLOGIC																
VEP35 SR CDF	12	46	42	26	36	29	99	0.22	0.26	77	0.23	0.04	1.13	46%	27%	64%
VEP70 SR CDF	27	35	38	56	11	6	99	0.23	0.42	63	0.37	0.04	1.51	13%	23%	22%
SPECTRALLY SELECTIVE																
VS60 SR CDF	22	36	42	49	11	11	99.9	0.29	0.43	63	0.37	0.04	1.32	10%	3%	32%
VS61 SR CDF	25	38	37	50	18	20	99.9	0.29	0.41	65	0.35	0.04	1.43	15%	3%	31%
VS70 SR CDF	25	35	40	56	11	10	99.9	0.28	0.44	62	0.38	0.04	1.47	8%	7%	22%
VS80BL SR CDF	26	35	39	61	11	11	99.9	0.30	0.45	61	0.39	0.04	1.56	6%	0%	15%

Chart 19-V IGU-3mm-LowE 2 Prepared by Solutia Performance Films 1/17/2012 Page 1 of 1

APPENDIX B: BEN-COST SCREENING

EEM1 - Occupancy Sensors 11/15/2012

National Grid Electric 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Occupancy Sensors
Existing or Base Case	Exising Occupancy Sensors are deactivated
Proposed Case:	Existing Occupancy Sensors are activated

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Time Period	Energy (kWH) Reduction per Period	Hours Per Period	Average Demand Reduction
Winter			
December 5pm-7pm M-F	357.00	42	8.50
January 5pm-7pm M-F	478.80	42	11.40
February	-	-	0.00
Summer			
June 1pm-5pm M-F	1,621.20	84	19.30
July 1pm-5pm M-F	1,705.20	84	20.30
August 1pm-5pm M-F	1,784.80	92	19.40
September	-	-	0.00

Measure Code:		EMSB10
Measure Description:		EMS & HVAC controls - 10yrs
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	28,358.08
Est Incremental Labor Costs	$	-

Total Est Annual kWH Savings		233,330
Average Cost per kWh	$	0.0849
Est annual Energy Cost Savings	$	19,809.72
Percent OnPeak Energy Savings		62%

Calculated Incentive	$	8,548
Authorized Incentive	$	8,548

Customer Cost	$	19,810

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Gas Heating	-	(therms)
Gas Non Heating	-	(therms)
Gas All	-	(therms)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($) value not currently
Lifetime Value of Benefits	-	($)

Pk Win kW Rd	9.95	kW
Pk Sum kW Rd	19.67	kW

Payback Without Incentive	1.43	years
Payback With Incentive	1.00	years

EEM1 - Occupancy Sensors 11/15/2012

National Grid Gas 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Deecription	Occupancy Sensors
Existing or Base Case	Exising Occupancy Sensors are deactivated
Proposed Case:	Existing Occupancy Sensors are activated

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Measure Category:		EMSB10
Measure Deecription:		EMS & HVAC controls - 10yrs
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	4,340.92
Est Incremental Labor Costs	$	-

Total Est Annual Therm Savings		3,441
Average Cost per therm	$	1.15
Est annual Gas Cost Savings	$	3,957.15

Calculated Incentive	$	384
Authorized Incentive	$	379

Customer Cost	$	3,962

Payback Without Incentive	1.10	years
Payback With Incentive	1.00	years

Gas Savings

Gas Heating	3,441.00	therms
Gas Non Heating	-	therms
Gas All	-	therms

Energy Savings

Total Est Annual kWH Savings	-	kWh

Demand Savings

Pk Win kW Rd	-	kW
Pk Sum kW Rd	-	kW

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

EEM4 - BAS 5/13/2013

National Grid Electric 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Building Automation System
Existing or Base Case	No BAS exists
Proposed Case:	A BAS will be installed and all equipment will be controlled centrally

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Time Period	Energy (kWH) Reduction per Period	Hours Per Period	Average Demand Reduction
Winter			
December 5pm-7pm M-F	512.40	42	12.20
January 5pm-7pm M-F	390.60	42	9.30
February	-	-	0.00
Summer			
June 1pm-5pm M-F	2,956.80	84	35.20
July 1pm-5pm M-F	4,653.60	84	55.40
August 1pm-5pm M-F	3,624.80	92	39.40
September	-	-	0.00

Measure Code:		EMSB10
Measure Description:		EMS & HVAC controls - 10yrs
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	53,902.66
Est Incremental Labor Costs	$	-

Total Est Annual kWH Savings		385,536
Average Cost per kWh	$	0.0849
Est annual Energy Cost Savings	$	32,732.01
Percent OnPeak Energy Savings		55%

Calculated Incentive	$	21,171
Authorized Incentive	$	21,171

Customer Cost	$	32,732

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Gas Heating	-	(therms)
Gas Non Heating	-	(therms)
Gas All	-	(therms)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

value not currently

Pk Win kW Rd	10.75	kW
Pk Sum kW Rd	43.33	kW

Payback Without Incentive	1.65	years
Payback With Incentive	1.00	years

EEM4 - BAS 5/13/2013

National Grid Gas 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Building Automation System
Existing or Base Case	No BAS exists
Proposed Case:	A BAS will be installed and all equipment will be controlled centrally

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Measure Category:		EMSB10
Measure Description:		EMS & HVAC controls - 10yrs
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	36,975.34
Est Incremental Labor Costs	$	-

Total Est Annual Therm Savings		27,954
Average Cost per therm	$	1.15
Est annual Gas Cost Savings	$	32,147.10

Calculated Incentive	$	4,828
Authorized Incentive	$	4,828

Customer Cost	$	32,147

Payback Without Incentive	1.15	years
Payback With Incentive	1.00	years

Gas Savings		
Gas Heating	-	therms
Gas Non Heating	-	therms
Gas All	27,954.00	therms

Energy Savings		
Total Est Annual kWH Savings	-	kWh

Demand Savings		
Pk Win kW Rd	-	kW
Pk Sum kW Rd	-	kW

Results		
Oil	-	(mmbtu)
Propane	-	(mmbtu)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

EEM9 - VFD CT 11/16/2012

National Grid Electric 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Heat Rejection
Existing or Base Case	The CTs are not equipped with VFDs
Proposed Case:	The CTs are equipped with VFDs

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Time Period	Energy (kWH) Reduction per Period	Hours Per Period	Average Demand Reduction
Winter			
December 5pm-7pm M-F	58.80	42	1.40
January 5pm-7pm M-F	-	42	0.00
February	-	-	0.00
Summer			
June 1pm-5pm M-F	1,344.00	84	16.00
July 1pm-5pm M-F	3,225.60	84	38.40
August 1pm-5pm M-F	1,784.80	92	19.40
September	-	-	0.00

Measure Code:		VSDH10
Measure Description:		Drives on HVAC systems - 10Yrs
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	17,898.00
Est Incremental Labor Costs	$	-

Total Est Annual kWH Savings		35,788
Average Cost per kWh	$	0.0849
Est annual Energy Cost Savings	$	3,038.40
Percent OnPeak Energy Savings		7900%

Calculated Incentive	$	5,780
Authorized Incentive	$	24,101

Customer Cost	$	(6,203)

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Gas Heating	-	(therms)
Gas Non Heating	-	(therms)
Gas All	-	(therms)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

value not currently

Pk Win kW Rd	0.70	kW
Pk Sum kW Rd	24.60	kW

Payback Without Incentive	5.89	years
Payback With Incentive	(2.04)	years

EEM11 - Install Aerators 11/16/2012

National Grid Gas 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Reduce HW consumption
Existing or Base Case	Fixtures and shower heads are standard flow
Proposed Case:	Fixtures and showers heads will be retrofitted with low flow heads and aerators.

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Measure Category:		DHW10
Measure Description:		Domestic/Service Water Systems
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	30,168.00
Est Incremental Labor Costs	$	-

Total Est Annual Therm Savings		7,289
Average Cost per therm	$	1.15
Est annual Gas Cost Savings	$	8,382.35

Calculated Incentive	$	15,084
Authorized Incentive	$	15,084

Customer Cost	$	15,084

Payback Without Incentive	3.60	years
Payback With Incentive	1.80	years

Gas Savings

Gas Heating	-	therms
Gas Non Heating	-	therms
Gas All	7,289.00	therms

Energy Savings

Total Est Annual kWH Savings	-	kWh

Demand Savings

Pk Win kW Rd	-	kW
Pk Sum kW Rd	-	kW

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

EEM15 - Pool Cover 11/16/2012

National Grid Electric 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Freezer
Existing or Base Case	Evaporator fans do not cycle
Proposed Case:	Evaporators fans will cycle

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Time Period	Energy (kWH) Reduction per Period	Hours Per Period	Average Demand Reduction
Winter			
December 5pm-7pm M-F	-	42	0.00
January 5pm-7pm M-F	-	42	0.00
February	-	-	0.00
Summer			
June 1pm-5pm M-F	-	84	0.00
July 1pm-5pm M-F	-	84	0.00
August 1pm-5pm M-F	-	92	0.00
September	-	-	0.00

Measure Code:		REFG10
Measure Description:		nercial Refrigeration Equip - 10Yrs
Measure Life:		10
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	21,858.00
Est Incremental Labor Costs	$	-

Total Est Annual kWH Savings		41,273
Average Cost per kWh	$	0.0849
Est annual Energy Cost Savings	$	3,504.08
Percent OnPeak Energy Savings		1%

Calculated Incentive	$	6,666
Authorized Incentive	$	6,666

Customer Cost	$	15,192

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Gas Heating	-	(therms)
Gas Non Heating	-	(therms)
Gas All	7,289.00	(therms)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

value not currently

Pk Win kW Rd	-	kW
Pk Sum kW Rd	-	kW

Payback Without Incentive	1.84	years
Payback With Incentive	1.28	years

EEM15 - Pool Cover 11/16/2012

National Grid Electric 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Pool Cover
Existing or Base Case	The pool is not covered
Proposed Case:	The pool will have a cover

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Time Period	Energy (kWH) Reduction per Period	Hours Per Period	Average Demand Reduction
Winter			
December 5pm-7pm M-F	8.40	42	0.20
January 5pm-7pm M-F	-	42	0.00
February	-	-	0.00
Summer			
June 1pm-5pm M-F	16.80	84	0.20
July 1pm-5pm M-F	16.80	84	0.20
August 1pm-5pm M-F	18.40	92	0.20
September	-	-	0.00

Measure Code:		HTGO
Measure Description:		Heating Other
Measure Life:		15
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	14,999.00
Est Incremental Labor Costs	$	-

Total Est Annual kWH Savings		33,681
Average Cost per kWh	$	0.0849
Est annual Energy Cost Savings	$	2,859.52
Percent OnPeak Energy Savings		1%

Calculated Incentive	$	5,439
Authorized Incentive	$	5,439

Customer Cost	$	9,560

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Gas Heating	-	(therms)
Gas Non Heating	-	(therms)
Gas All	(732.00)	(therms)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

value not currently

Pk Win kW Rd	0.10	kW
Pk Sum kW Rd	0.20	kW

Payback Without Incentive	7.43	years
Payback With Incentive	4.74	years

EEM16 - Install Window Tint 11/16/2012

National Grid Electric 2012 Custom Screening Tool	
Customer Name	Crowne Plaza
Project Description	Windows
Existing or Base Case	The windows do not have a tint film
Proposed Case:	The windows will be equipped with a window film to reduces SHGC

Utility Contact	0
Program	Retrofit
State	RI

Phone Number	0
App Number	0
Funding Type	0

Time Period	Energy (kWH) Reduction per Period	Hours Per Period	Average Demand Reduction
Winter			
December 5pm-7pm M-F	533.40	42	12.70
January 5pm-7pm M-F	361.20	42	8.60
February	-	-	0.00
Summer			
June 1pm-5pm M-F	3,234.00	84	38.50
July 1pm-5pm M-F	4,208.40	84	50.10
August 1pm-5pm M-F	3,560.40	92	38.70
September	-	-	0.00

Measure Code:		BSHL
Measure Description:		Building Shell (Insul & Windows)
Measure Life:		25
Base Costs		
Proposed Costs		
Est Incremental Costs		
Est Incremental Equip Costs	$	66,390.00
Est Incremental Labor Costs	$	-

Total Est Annual kWH Savings		149,230
Average Cost per kWh	$	0.0849
Est annual Energy Cost Savings	$	12,669.63
Percent OnPeak Energy Savings		76%

Calculated Incentive	$	24,101
Authorized Incentive	$	24,101

Customer Cost	$	42,289

Results

Oil	-	(mmbtu)
Propane	-	(mmbtu)
Gas Heating	-	(therms)
Gas Non Heating	-	(therms)
Gas All	(1,112.00)	(therms)
Water	-	(gallons)
Waste Water	-	(gallons)
Other Annual Benefits	-	($)
Other One Time Benefits	-	($)
Lifetime Value of Benefits	-	($)

value not currently

Pk Win kW Rd	10.65	kW
Pk Sum kW Rd	42.43	kW

Payback Without Incentive	5.83	years
Payback With Incentive	3.71	years

APPENDIX C: COST ESTIMATES

OPINION OF PROBABLE COST

Guest room occupancy sensor

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install guest room occupancy sensor

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	3	Label									$200
2	3	Smart Digital Thermostat - E527	ea	$180	133	$23,940	$50.00	60	$3,000		$26,940
2	3	Batteries									$266

Sub-Total		**$27,406**
Contingency	10.0%	$2,741
Overhead & Profit	10.0%	$3,015
Engineering	8.0%	$2,653
Eng Commissioning	2.0%	$603
Construction Management	1.0%	$301
Total Cost with Mark-up		**$36,719**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

WSHP

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Upgrade WSHPs

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	quote	WSHP equipment + instalation	ea	$1,475	266	$392,350	$115.00	2128	$244,720		$637,070
									Sub-Total		**$637,070**
									Contingency	10.0%	$63,707
									Overhead & Profit	10.0%	$70,078
									Engineering	15.0%	$115,628
									Eng Commissioning	10.0%	$70,078
									Construction Management	15.0%	$105,117
									Total Cost with Mark-up		**$1,061,677**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Upgrade BAS

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Upgrade BAS

CONTACT:
B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Cost per point	# of Units	# of Points/Unit	total # of points	Labor Cost	Item Cost
1	3	Install BAS Program	-	-	-	-	$20,000	$20,000
2	3	Cooling towers	$650	2	6	12	Included	$7,800
3	3	WSHP loop	$650	1	4	4	Included	$2,600
4	3	RTU	$650	48	9	432	Included	$280,800
5	3	Boiler	$650	6	6	36	Included	$23,400
6	3	Pump	$650	8	2	16	Included	$10,400
7	3	Miscelaneous points	$650	1	4	4	Included	$2,600
8	3	Commissioning					$31,200	$31,200

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

Sub-Total		**$378,800**
Contingency	5.0%	$18,940
Overhead & Profit	10.0%	$39,774
Engineering	10.0%	$43,751
Eng Commissioning	10.0%	$39,774
Construction Management	5.0%	$19,887
tal Cost with Mark-up		**$540,926**

OPINION OF PROBABLE COST

Kitchen Hood Controls

CLIENT: Crown Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install kitchen smoke detector

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	2	Install Kitchen smoke dertector, VSDs and inverter rated motor on Make up and exhaust air	ea	$10,000	2	$20,000					$20,000
2	3	Programming	ea	$0	2	$0	$100.00	24	$2,400		$2,400
4		Control Wiring	lf	$4	200	$764	inc. in material cost				$764

Sub-Total		**$23,164**
Contingency	10.0%	$2,316
Overhead & Profit	10.0%	$2,548
Engineering	15.0%	$4,204
Eng Commissioning	10.0%	$2,548
Construction Management	15.0%	$3,822
Total Cost with Mark-up		**$38,603**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included. Vendor quote from previous project.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Laundry waste water

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install Laundry waste water

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	1	Exergy 23 series, model 00540-2 heat exchanger	lf	$9	100	$1,160	$46.85	20	$937		$2,097
2	1	Allocation 90 deg elbow	ea	$11	6	$64	$46.85	4.8	$225		$289
3	3	Allocation for GFX	ea	$500	1	$500	$100.00	4	$400		$900
4	1	Allocation for Circulation Pump	ea	$1,025	1	$1,025	$46.85	3.2	$150		$1,175
5	3	Allocation for Additional Piping Components				$0	$0.00		$0		$2,500
6	3	Allocation for Controls				$0	$0.00		$0		$2,000
7	1	Allocation for Valving		$335	2	$670	$51.90	1.454	$75		$745
									Sub-Total		**$9,706**
									Contingency	10.0%	$971
									Overhead & Profit	10.0%	$1,068
									Engineering	15.0%	$1,762
									Eng Commissioning	10.0%	$1,068
									Construction Management	15.0%	$1,602
									Total Cost with Mark-up		**$16,176**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Boiler

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/27/2012
ESTIMATED BY: RE
CHECKED BY: RA

Description: Upgrade Boiler

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	3	Allowance for removal of old Gas Boilers	ea	$1,500	2	$3,000	$100.00	24	$2,400		$5,400
2	3	Gas condensing Boiler, 1.466 MBH, Circulator,		$15,442	1	$15,442	$100.00	170	$17,000		$32,442
3	3	Gas Condensing Boiler, 2.2 MBH, Circulator,	ea	$24,675	1	$24,675	$100.00	180	$18,000		$42,675
4	3	Expansion Tank, 60 gal capacity	ea	$645	2	$1,290	$61.00	8	$488		$1,778
5	3	Allowance for boiler Demolition					$100.00	96	$9,600		$9,600
6	3	Breeching/Penetration/Flues	lf	$20	100	$2,000	$255.00	10	$2,550		$4,550
7	3	Allowance for piping, Sch 40	lf	$27	100	$2,700	$300.00	10	$3,000		$5,700
8	3	Allowance for Pipe Covering	lf	$7	100	$700	$100.00	5	$500		$1,200
9	3	Allowance for Fittings, Valves	ea	$500	16	$8,000	$130.00	40	$5,200		$13,200
10	3	Allowance for Air Separator	ea	$2,500	1	$2,500	$350.00	8	$2,800		$5,300
11	3	Allowance for Electrical									$5,000
12	3	Allowance for masonry									$6,000
13	3	Allowance for rigging									$3,000

Sub-Total		**$135,845**
Contingency	5.0%	$6,792
Overhead & Profit	5.0%	$7,132
Engineering	10.0%	$14,977
Eng Commissioning	5.0%	$7,132
Construction Management	5.0%	$7,132
Total Cost with Mark-up		**$179,010**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Pump Variable Speed Drive

CLIENT: Crown Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install VSD on Water loop pump

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	3	High efficiency 10 HP motor	ea	$710	2	$1,420	$100.00	10	$1,000.00		$2,420
2	3	High efficiency 15 HP motor	ea	$935	2	$1,870	$100.00	10	$1,000.00		$2,870
3	3	Single VSD for 10 HP motor	ea	$2,335	2	$4,670	$100.00	20	$2,000.00		$6,670
4	3	Single VSD for 15 HP motor	ea	$2,620	2	$5,240	$100.00	20	$2,000.00		$7,240
5	3	Pump Differential Pressure Sensor and VSD controls	ea	$860	4	$3,440	$100.00	16	$1,600.00		$5,040
6	3	Control Wiring	lf	$3.82	200	$764	$115.00	8	$920.00		$1,684
7	3	Ball Valve for Wet Tap	ea	$121	2	$241	$100.00	2	$200.00		$441
8	3	Wet Tap - 4" size, 5/16" Probe dia	ea	$942	2	$1,884	$100.00	24	$2,400.00		$4,284

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

Sub-Total		**$30,649**
Contingency	10.0%	$3,065
Overhead & Profit	10.0%	$3,371
Engineering	20.0%	$7,417
Eng Commissioning	10.0%	$3,371
Construction Management	10.0%	$3,371
Total Cost with Mark-up		**$51,246**

OPINION OF PROBABLE COST

Variable Speed Drive on CT fan

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install VSD on cooling towers

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	1	VSD for 15hp fan motor	ea	$2,620	2	$5,240	$100.00	20	$2,000		$7,240
2	3	Programming and Control Point							$3,500		$3,500

Sub-Total		**$10,740**
Contingency	10.0%	$1,074
Overhead & Profit	10.0%	$1,181
Engineering	15.0%	$1,949
Eng Commissioning	10.0%	$1,181
Construction Management	15.0%	$1,772
Total Cost with Mark-up		**$17,898**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Kitchen DHW savings

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Description: Install low flow nozzles

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	3	Install low flow nozzle	ea	$40	4	$160	$50.00	1	$50		$210

		Sub-Total	**$210**
	Contingency	10.0%	$21
	Overhead & Profit	10.0%	$23
	Engineering	8.0%	$20
	Eng Commissioning	2.0%	$5
	Construction Management	1.0%	$2
	Total Cost with Mark-up		**$281**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Bathroom DHW savings

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install low flow shower heads and faucets

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	3	Install low flow shower Heads	ea	$50	266	$13,300	$50.00	44	$2,217		$15,517
2	3	Install low flow aerator on faucets	ea	$15	300	$4,500	$50.00	50	$2,500		$7,000

Sub-Total		**$22,517**
Contingency	10.0%	$2,252
Overhead & Profit	10.0%	$2,477
Engineering	8.0%	$2,180
Eng Commissioning	2.0%	$495
Construction Management	1.0%	$248
Total Cost with Mark-up		**$30,168**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

CHP

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install CHP

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	3	150 KW CHP package	ea	$197,419.80	1	$197,419.80			$0		$197,419.80
2	3	Engine/Generator Controls	incl above	$0.00	0	$0.00			$0		$0.00
3	3	Sound Attenuating Enclosure	incl above	$0.00	0	$0.00			$0		$0.00
4	3	Exhaust Flue	incl above	$0.00	0	$0.00			$0		$0.00
5	3	Waste Heat "Dump" Radiator &	incl above	$0.00	0	$0.00			$0		$0.00
6	3	Piping to/from dump radiator	incl above	$0.00	0	$0.00			$0		$0.00
7	3	Additional emissions reduction system	incl above	$0.00	0	$0.00			$0		$0.00
8	3	Demo, site work, concrete	ls	$17,100.00	1	$17,100.00			$0		$17,100.00
9	3	Rigging	ls	$3,900.00	1	$3,900.00			$0		$3,900.00
10	3	Process Controls Interface	ls	$15,000.00	1	$15,000.00			$0		$15,000.00
11	3	Mechanical	ls	$60,000.00	1	$60,000.00			$0		$60,000.00
12	3	Fuel Piping & Fittings from source to	incl above	$0.00	0	$0.00			$0		$0.00
13	3	Electrical: See attached	ea	$52,200.00	1	$52,200.00			$0		$52,200.00
14	3	Add for net metering	allow	$30,000.00	1	$30,000.00			$0		$30,000.00
15	3	General Construction	incl above	$0.00	0	$0.00			$0		$0.00
16	3	DEP Permitting	allow	$3,000.00	1	$3,000.00			$0		$3,000.00
17	3	Construction Permits	allow	$3,000.00	1	$3,000.00					$3,000.00
17	3	Contr Start-up and commissioning	allow	$4,500.00	1	$4,500.00					$4,500.00

Sub-Total		**$386,120**
Contingency	10.0%	$38,611.98
Overhead & Profit	10.0%	$42,473.18
Engineering	15.0%	$70,080.74
Eng Commissioning	10.0%	$42,473.18
Construction Management	15.0%	$63,709.77
Total Cost with Mark-up		**$643,469**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Ground Water loop

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install ground water loop

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	2	Drilling 8" diameter, 1500ft deep wells on arenite	lf	$56	12000	$672,000			$0		$672,000
2	incl above	Cement & cementing services	incl above	$0	0	$0			$0		$0
3	incl above	Casing tools services	incl above	$0	0	$0			$0		$0
4	incl above	Well Piping	incl above	$0	0	$0			$0		$0
5	incl above	Labor	incl above	$0	0	$0			$0		$0
6	incl above	Insurance	incl above	$0	0	$0			$0		$0
7	3	Pump + Motor +VSD + controls	ea	$22,500	2	$45,000			$0		$45,000
8	3	Demo, site work	ea	$2,500	1	$2,500	$100.00	25	$2,500		$5,000
9	3	Extra piping to connect to water loop	ea	$5,000	1	$5,000	$100.00	50	$5,000		$10,000
10	3	Permits & Geological Surveys	ls	$2,000	1	$2,000			$0		$2,000
									Sub-Total		**$734,000**
									Contingency	10.0%	$73,400
									Overhead & Profit	10.0%	$80,740
									Engineering	15.0%	$133,221
									Eng Commissioning	10.0%	$80,740
									Construction Management	15.0%	$121,110
									Total Cost with Mark-up		**$1,223,211**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Freezer

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Freezer Controls

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	2	A quote from National Resource Management (NRM) (dated 2/28/2012)									$21,858

		Sub-Total	**$21,858**
	Contingency	10.0%	Included
	Overhead & Profit	10.0%	Included
	Engineering	15.0%	Included
	Eng Commissioning	10.0%	Included
	Construction Management	15.0%	Included
	Total Cost with Mark-up		**$21,858**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

OPINION OF PROBABLE COST

Pool

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION DATE: 11/16/2012
ESTIMATED BY: RB
CHECKED BY: RA

Description: Install Drycooler

CONTACT: B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	Material Cost	Labor Rate	Hours	Labor Cost	Equipment Cost	Item Cost
1	2	Automaticool pool cover	sf	$40	225	$9,000			Included		$9,000
		Gas Heater?									$0
											$0

Sub-Total		**$9,000**
Contingency	10.0%	$900
Overhead & Profit	10.0%	$990
Engineering	15.0%	$1,634
Eng Commissioning	10.0%	$990
Construction Management	15.0%	$1,485
Total Cost with Mark-up		**$14,999**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

Window Tint

CLIENT: Crowne Plaza Hotel
CUSTOMER: National GRID
LOCATION: Warwick, RI

REVISION 11/16/2012
ESTIMATE RB
CHECKED RA

Description: Apply Window Film

CONTACT B2Q Associates, Inc.
146 Main Street
North Andover, MA 01845
pbanks@b2qassociates.com
978-208-0609 phone
978-719-6339 fax

Item #	Source	Description	Unit	Unit Cost	Qty	aterial Co	Labor Rate	Hours	Labor Cos	uipment C	Item Cost
1	2	A quote from Solar Tint									$66,390

Sub-Total		**$66,390**
Contingency	10.0%	Included
Overhead & Profit	10.0%	Included
Engineering	15.0%	Included
Eng Commissioning	10.0%	Included
Construction Management	15.0%	Included
Total Cost with Mark-up		**$66,390**

Sources:
1) Means
2) Vendor Quote
3) Engineering Est.

NOTE: State Sales Tax not included.

DISCLAIMER: B2Q does not expressly warrant or represent the accuracy of the above cost estimates due to unforeseeable factors in the construction industry, including price volatility of labor and materials

APPENDIX D: SIMULATION OUTPUT

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:26:38 BDL RUN 42

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	32422.	1049850.	44480.	218432.	1325284.	0.	1.	0.	0.	4553928.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	60068.	0.	0.	1889.	0.	0.	0.	42251.	0.	135417.

TOTAL ELECTRICITY	4553928.	KWH	17.952	KWH	/SQFT-YR GROSS-AREA	17.952 KWH	/SQFT-YR NET-AREA
TOTAL NATURAL-GAS	135417.	THERM	0.534	THERM	/SQFT-YR GROSS-AREA	0.534 THERM	/SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.99
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 174
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:15:50 BDL RUN 36

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	41740.	1015668.	45958.	217384.	1360601.	0.	1.	0.	0.	4564810.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	63856.	0.	0.	1888.	0.	0.	0.	42251.	0.	139204.

TOTAL ELECTRICITY 4564810. KWH 17.995 KWH /SQFT-YR GROSS-AREA 17.995 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 139204. THERM 0.549 THERM /SQFT-YR GROSS-AREA 0.549 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:17:23 BDL RUN 37

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48345.	1004472.	47215.	219590.	1360602.	0.	1.	0.	0.	4563683.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	63510.	0.	0.	1888.	0.	0.	0.	42251.	0.	138857.

TOTAL ELECTRICITY 4563683. KWH 17.990 KWH /SQFT-YR GROSS-AREA 17.990 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 138857. THERM 0.547 THERM /SQFT-YR GROSS-AREA 0.547 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:23:56 BDL RUN 41

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48598.	851326.	89990.	224680.	1167348.	0.	1.	0.	0.	4265401.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	35653.	0.	0.	1925.	0.	0.	0.	42251.	0.	111038.

TOTAL ELECTRICITY 4265401. KWH 16.814 KWH /SQFT-YR GROSS-AREA 16.814 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 111038. THERM 0.438 THERM /SQFT-YR GROSS-AREA 0.438 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 4.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 123
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 233

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:06:33 BDL RUN 32

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48345.	1074365.	47215.	219590.	1357739.	0.	1.	0.	0.	4630715.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	61831.	0.	0.	1889.	0.	0.	0.	42251.	0.	137180.

TOTAL ELECTRICITY 4630715. KWH 18.255 KWH /SQFT-YR GROSS-AREA 18.255 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 137180. THERM 0.541 THERM /SQFT-YR GROSS-AREA 0.541 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.54
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 93
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 480

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:05:01 BDL RUN 31

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	49549.	1076798.	47218.	223180.	1360600.	0.	1.	0.	0.	4640807.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	60161.	0.	0.	1888.	0.	0.	0.	42251.	0.	135508.

TOTAL ELECTRICITY 4640807. KWH 18.294 KWH /SQFT-YR GROSS-AREA 18.294 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 135508. THERM 0.534 THERM /SQFT-YR GROSS-AREA 0.534 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:11:45 BDL RUN 34

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48752.	1076584.	47805.	91128.	1360605.	0.	1.	0.	0.	4508335.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	66314.	0.	0.	1888.	0.	0.	0.	42251.	0.	141661.

TOTAL ELECTRICITY 4508335. KWH 17.772 KWH /SQFT-YR GROSS-AREA 17.772 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 141661. THERM 0.558 THERM /SQFT-YR GROSS-AREA 0.558 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:28:11 BDL RUN 43

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48345.	1076798.	9389.	221629.	1360602.	0.	1.	0.	0.	4600223.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	63510.	0.	0.	1888.	0.	0.	0.	42251.	0.	138857.

TOTAL ELECTRICITY 4600223. KWH 18.134 KWH /SQFT-YR GROSS-AREA 18.134 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 138857. THERM 0.547 THERM /SQFT-YR GROSS-AREA 0.547 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:08:10 BDL RUN 33

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48345.	1076798.	47215.	219590.	1360602.	0.	1.	0.	0.	4636010.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	63510.	0.	0.	1888.	0.	0.	0.	40997.	0.	137604.

TOTAL ELECTRICITY 4636010. KWH 18.275 KWH /SQFT-YR GROSS-AREA 18.275 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 137604. THERM 0.542 THERM /SQFT-YR GROSS-AREA 0.542 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:13:15 BDL RUN 35

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	48345.	1076798.	47215.	219590.	1360602.	0.	1.	0.	0.	4636010.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	63510.	0.	0.	1888.	0.	0.	0.	34962.	0.	131568.

TOTAL ELECTRICITY 4636010. KWH 18.275 KWH /SQFT-YR GROSS-AREA 18.275 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 131568. THERM 0.519 THERM /SQFT-YR GROSS-AREA 0.519 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:20:25 BDL RUN 39

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	869878.	0.	441442.	29858.	798242.	35901.	149675.	931336.	0.	1.	0.	0.	3256332.
FM1 NATURAL-GAS													
THERM	36436.	0.	50279.	65303.	27025.	1098.	8671.	41647.	0.	0.	15620.	0.	246079.

TOTAL ELECTRICITY 3256332. KWH 12.837 KWH /SQFT-YR GROSS-AREA 12.837 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 246079. THERM 0.970 THERM /SQFT-YR GROSS-AREA 0.970 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/27/2012 17:09:13 BDL RUN 1

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	33922.	1045065.	0.	200214.	1390009.	0.	684.	0.	0.	4553355.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	54658.	0.	0.	1889.	0.	0.	0.	42335.	0.	130090.

TOTAL ELECTRICITY 4553355. KWH 17.950 KWH /SQFT-YR GROSS-AREA 17.950 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 130090. THERM 0.513 THERM /SQFT-YR GROSS-AREA 0.513 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 31.14
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 227
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 2638

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:21:54 BDL RUN 40

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	608828.	48345.	1072510.	47215.	219607.	1360384.	0.	1.	0.	0.	4602328.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	64244.	0.	0.	1887.	0.	0.	0.	42251.	0.	139590.

TOTAL ELECTRICITY 4602328. KWH 18.143 KWH /SQFT-YR GROSS-AREA 18.143 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 139590. THERM 0.550 THERM /SQFT-YR GROSS-AREA 0.550 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 6.06
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 441

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

Crown Plaza RB DOE-2.2-47h2 11/09/2012 15:29:45 BDL RUN 44

REPORT- BEPU Building Utility Performance WEATHER FILE- Providence RI TMY2

	LIGHTS	TASK LIGHTS	MISC EQUIP	SPACE HEATING	SPACE COOLING	HEAT REJECT	PUMPS & AUX	VENT FANS	REFRIG DISPLAY	HT PUMP SUPPLEM	DOMEST HOT WTR	EXT USAGE	TOTAL
EM1 ELECTRICITY													
KWH	1245437.	0.	638023.	47967.	1018586.	41874.	207685.	1287204.	0.	1.	0.	0.	4486782.
FM1 NATURAL-GAS													
THERM	0.	0.	31208.	64626.	0.	0.	1885.	0.	0.	0.	42251.	0.	139970.

TOTAL ELECTRICITY 4486782. KWH 17.687 KWH /SQFT-YR GROSS-AREA 17.687 KWH /SQFT-YR NET-AREA
TOTAL NATURAL-GAS 139970. THERM 0.552 THERM /SQFT-YR GROSS-AREA 0.552 THERM /SQFT-YR NET-AREA

PERCENT OF HOURS ANY SYSTEM ZONE OUTSIDE OF THROTTLING RANGE = 7.32
PERCENT OF HOURS ANY PLANT LOAD NOT SATISFIED = 0.00
HOURS ANY ZONE ABOVE COOLING THROTTLING RANGE = 90
HOURS ANY ZONE BELOW HEATING THROTTLING RANGE = 552

NOTE: ENERGY IS APPORTIONED HOURLY TO ALL END-USE CATEGORIES.

National Grid
Rhode Island
Alternative Gas Technology Program
Financial Analysis

Inputs for IRP Financial Analysis

Date:	02/17/2013
Customer Name:	Toray Plastics
Address:	Belver Road
Account # :	
Equipment Type	2 x NG (only) Reciprocating Engines 12.5 MWe (Gross).
Equipment Life (years)	20
Current gas load saved due to heat recovery (Th)	
MADQ - Current:	26,266 Th
- Proposed:	40,743 Th

	Gas Project	Alternate Project
Capital Cost	$22,700,000	$0
Operating Cost	-$1,612,053	$0

Results of Analysis

Incremental Distribution Margin per Year	$ 475,261	
Net Present Value based on equipment life	$ 4,274,289	
Rebate based on 75% of NPV	$ 2,774,813	= REBATE
Rebate based on 75% of Capital Cost Difference	$ 16,775,518	
Rebate resulting in 1.5 year Simple Payback	$ 20,032,439	

Rate Classification:

Current: EXTRA LARGE HIGH LOAD FACTOR
Proposed: EXTRA LARGE HIGH LOAD FACTOR

Month	Current Load (Th)	Proposed Load (Th)	Adjustment to current for Heat Recovery	Adjusted
Jan	814,239	1,263,044		448,805
Feb	713,326	1,128,997		415,671
Mar	771,750	1,258,293		486,543
Apr	635,224	1,112,689		477,465
May	631,286	1,211,862		580,576
Jun	637,478	1,226,560		589,082
Jul	625,631	1,268,664		643,033
Aug	625,898	1,243,527		617,629
Sep	594,280	1,179,193		584,913
Oct	596,348	1,109,531		513,183
Nov	620,901	1,110,803		489,902
Dec	704,221	1,206,836		502,615
TOTAL	7,970,582	14,319,999	0	6,349,417
			Net Incremental Load	**6,349,417**

Proposed MADQ			
Nov	1,110,803	30	37,027
Dec	1,206,836	31	38,930
Jan	1,263,044	31	40,743
Feb	1,128,997	28	40,321
Mar	1,258,293	31	40,590
Apr	1,112,689	30	37,090
			40,743

Current MADQ			
Nov	620,901	30	20,697
Dec	704,221	31	22,717
Jan	814,239	31	26,266
Feb	713,326	28	25,476
Mar	771,750	31	24,895
Apr	635,224	30	21,174
			26,266

AGT REBATE ANALYSIS

MARGIN CALCULATION

Firm Sales Service

	Rates for Effect Dec 1, 2008	Customer Charge (Monthly)	Demand Rate (MADQ Th)	Distribution $ Head (Th)	Distribution $ Tail (Th)	Embedded Gas Cost	Head Margin (per Th)	Tail Margin (per Th)
1	**SMALL LOW LOAD FACTOR**	$ 22.00	$ -	$ 0.5431	$ 0.2242	$ -	$ 0.5431	$ 0.2242
2	**SMALL HIGH LOAD FACTOR**	$ 22.00	$ -	$ 0.5431	$ 0.2242	$ -	$ 0.5431	$ 0.2242
3	**MEDIUM LOW LOAD FACTOR**	$ 70.00	$ 1.3000	$ 0.1865	$ -	$ -	**$ 0.1865**	
4	**MEDIUM HIGH LOAD FACTOR**	$ 70.00	$ 1.3000	$ 0.1865	$ -	$ -	**$ 0.1865**	
5	**LARGE LOW LOAD FACTOR**	$ 175.00	$ 1.3000	$ 0.1727	$ -	$ -	**$ 0.1727**	
6	**LARGE HIGH LOAD FACTOR**	$ 175.00	$ 1.8000	$ 0.1007	$ -	$ -	**$ 0.1007**	
7	**EXTRA LARGE LOW LOAD FACTOR**	$ 425.00	$ 1.3000	$ 0.0328	$ -	$ -	**$ 0.0328**	
8	**EXTRA LARGE HIGH LOAD FACTOR**	$ 425.00	$ 1.8000	$ 0.0256	$ -	$ -	**$ 0.0256**	

Calculation of Current Distribution Margin

MADQ-Current (Th)	26,266	Customer	Demand	Distribution $			TOTAL
Month	Current (Th)	Charge		M, L, XL	Small Low	Small High	MARGIN
Jan	814,239	$ 425	$ 47,278	$ 20,845	-	-	$ 68,548
Feb	713,326	$ 425	$ 47,278	$ 18,261	-	-	$ 65,965
Mar	771,750	$ 425	$ 47,278	$ 19,757	-	-	$ 67,460
Apr	635,224	$ 425	$ 47,278	$ 16,262	-	-	$ 63,965
May	631,286	$ 425	$ 47,278	$ 16,161	-	-	$ 63,864
Jun	637,478	$ 425	$ 47,278	$ 16,319	-	-	$ 64,023
Jul	625,631	$ 425	$ 47,278	$ 16,016	-	-	$ 63,720
Aug	625,898	$ 425	$ 47,278	$ 16,023	-	-	$ 63,726
Sep	594,280	$ 425	$ 47,278	$ 15,214	-	-	$ 62,917
Oct	596,348	$ 425	$ 47,278	$ 15,267	-	-	$ 62,970
Nov	620,901	$ 425	$ 47,278	$ 15,895	-	-	$ 63,598
Dec	704,221	$ 425	$ 47,278	$ 18,028	-	-	$ 65,731
TOTAL	7,970,582	$ 5,100	$ 567,341	$ 204,047	$ 0	$ 0	$ 776,488

average distribution margin / Th $ 0.097

Small C/I Breaks (Th)	Peak	Off Peak
Small Low Load	135	20
Small High Load	65	30

Off Peak=May-Oct 3,710,921 Rate Classification 8 EXTRA LARGE HIGH LOAD FACTOR
Off Peak / Total 47% Load Factor 1

Calculation of Proposed Distribution Margin

MADQ-Proposed (Th)	40,743	Customer	Demand	Distribution $			TOTAL	
Month	Proposed (Th)	Charge		M, L, XL	Small Low	Small High	MARGIN	
Jan	1,263,044	$ 425	$ 73,338	$ 32,334	-	-	$ 106,097	
Feb	1,128,997	$ 425	$ 73,338	$ 28,902	-	-	$ 102,665	
Mar	1,258,293	$ 425	$ 73,338	$ 32,212	-	-	$ 105,975	
Apr	1,112,689	$ 425	$ 73,338	$ 28,485	-	-	$ 102,248	
May	1,211,862	$ 425	$ 73,338	$ 31,024	-	-	$ 104,787	
Jun	1,226,560	$ 425	$ 73,338	$ 31,400	-	-	$ 105,163	
Jul	1,268,664	$ 425	$ 73,338	$ 32,478	-	-	$ 106,241	
Aug	1,243,527	$ 425	$ 73,338	$ 31,834	-	-	$ 105,597	
Sep	1,179,193	$ 425	$ 73,338	$ 30,187	-	-	$ 103,950	
Oct	1,109,531	$ 425	$ 73,338	$ 28,404	-	-	$ 102,167	
Nov	1,110,803	$ 425	$ 73,338	$ 28,437	-	-	$ 102,200	
Dec	1,206,836	$ 425	$ 73,338	$ 30,895	-	-	$ 104,658	
TOTAL	14,319,999	$ 5,100	$ 880,056	$ 185,327	$ 0	$ 0	$ 1,251,748	$ 475,261

average distribution margin / Th $ 0.087

Off Peak=May-Oct (Th) 7,239,337 Rate Classification 8 EXTRA LARGE HIGH LOAD FACTOR
Off Peak / Total 51% Load Factor 1.00

Rate= 0.1005

Incremental Distribution Margin per year $ 475,261
Equipment Life (years) 20 No Deduct
Net Present Value of Margin over Equipment Life: $4,274,289

NPV1-20 $4,032,393
NPVremaining $4,032,393
75% of above $3,024,295
Less: Construction $ **$249,482**
$2,774,813

Year	
1	$ 475,261
2	$ 475,261
3	$ 475,261
4	$ 475,261
5	$ 475,261
6	$ 475,261
7	$ 475,261
8	$ 475,261
9	$ 475,261
10	$ 475,261
11	$ 475,261
12	$ 475,261
13	$ 475,261
14	$ 475,261
15	$ 475,261
16	$ 475,261
17	$ 475,261
18	$ 475,261
19	$ 475,261
20	$ 475,261

Calculation of Customer Bill

Total Customer Bill

Firm Sales Service

	Rates Eff. May 1, 2005	Customer Charge (Monthly)	Demand Rate (MADQ Ccf)	Distribution $ Head Block (Th)	Distribution $ Tail Block (Th)	GCR (Th)
1	**SMALL LOW LOAD FACTOR**	$ 22.00	$ -	$ 0.5431	$ 0.2242	$ 0.6725
2	**SMALL HIGH LOAD FACTOR**	$ 22.00	$ -	$ 0.5431	$ 0.2242	$ 0.6725
3	**MEDIUM LOW LOAD FACTOR**	$ 70.00	$ 1.3000	$ 0.1865	$ -	$ 0.6725
4	**MEDIUM HIGH LOAD FACTOR**	$ 70.00	$ 1.3000	$ 0.1865	$ -	$ 0.6725
5	**LARGE LOW LOAD FACTOR**	$ 175.00	$ 1.3000	$ 0.1727	$ -	$ 0.6725
6	**LARGE HIGH LOAD FACTOR**	$ 175.00	$ 1.8000	$ 0.1007	$ -	$ 0.6240
7	**EXTRA LARGE LOW LOAD FACTOR**	$ 425.00	$ 1.3000	$ 0.0328	$ -	$ 0.6725
8	**EXTRA LARGE HIGH LOAD FACTOR**	$ 425.00	$ 1.8000	$ 0.0256	$ -	$ 0.6240

Calculation of Current Bill

MADQ-Current (Th)	26,266	Customer	Demand	Distribution $			GCR	TOTAL
Month	Current (Th)	Charge		M, L, XL				BILL
Jan	814,239	$ 425	$ 47,278	$ 20,845	-	-	$ 508,085	$ 576,633
Feb	713,326	$ 425	$ 47,278	$ 18,261	-	-	$ 445,115	$ 511,080
Mar	771,750	$ 425	$ 47,278	$ 19,757	-	-	$ 481,572	$ 549,032
Apr	635,224	$ 425	$ 47,278	$ 16,262	-	-	$ 396,380	$ 460,345
May	631,286	$ 425	$ 47,278	$ 16,161	-	-	$ 393,922	$ 457,787
Jun	637,478	$ 425	$ 47,278	$ 16,319	-	-	$ 397,786	$ 461,809
Jul	625,631	$ 425	$ 47,278	$ 16,016	-	-	$ 390,394	$ 454,113
Aug	625,898	$ 425	$ 47,278	$ 16,023	-	-	$ 390,560	$ 454,287
Sep	594,280	$ 425	$ 47,278	$ 15,214	-	-	$ 370,831	$ 433,748
Oct	596,348	$ 425	$ 47,278	$ 15,267	-	-	$ 372,121	$ 435,091
Nov	620,901	$ 425	$ 47,278	$ 15,895	-	-	$ 387,442	$ 451,041
Dec	704,221	$ 425	$ 47,278	$ 18,028	-	-	$ 439,434	$ 505,165
TOTAL	7,970,582	$ 5,100	$ 567,341	$ 204,047	$ 0	$ 0	$ 4,973,643	$ 5,750,131
							average charge / Th	$ 0.721

Off Peak=May-Oct	3,710,921	Rate Classification	8	EXTRA LARGE HIGH LOAD FACTOR
Off Peak / Total	47%	Load Factor	1	

Calculation of Proposed Bill

MADQ-Proposed (Th)	40,743	Customer	Demand	Distribution $	Distribution Charges		GCR	TOTAL
Month	Proposed (Th)	Charge		M, L, XL	Small Low	Small High		BILL
Jan	1,263,044	$ 425	$ 73,338	$ 32,334	-	-	$ 788,139	$ 894,236
Feb	1,128,997	$ 425	$ 73,338	$ 28,902	-	-	$ 704,494	$ 807,159
Mar	1,258,293	$ 425	$ 73,338	$ 32,212	-	-	$ 785,175	$ 891,150
Apr	1,112,689	$ 425	$ 73,338	$ 28,485	-	-	$ 694,318	$ 796,566
May	1,211,862	$ 425	$ 73,338	$ 31,024	-	-	$ 756,202	$ 860,989
Jun	1,226,560	$ 425	$ 73,338	$ 31,400	-	-	$ 765,373	$ 870,536
Jul	1,268,664	$ 425	$ 73,338	$ 32,478	-	-	$ 791,646	$ 897,887
Aug	1,243,527	$ 425	$ 73,338	$ 31,834	-	-	$ 775,961	$ 881,558
Sep	1,179,193	$ 425	$ 73,338	$ 30,187	-	-	$ 735,816	$ 839,767
Oct	1,109,531	$ 425	$ 73,338	$ 28,404	-	-	$ 692,347	$ 794,514
Nov	1,110,803	$ 425	$ 73,338	$ 28,437	-	-	$ 693,141	$ 795,341
Dec	1,206,836	$ 425	$ 73,338	$ 30,895	-	-	$ 753,066	$ 857,724
TOTAL	14,319,999	$ 5,100	$ 880,056	$ 366,592	$ 0	$ 0	$ 8,935,679	$ 10,187,428
							average charge / Th	$ 0.711

Off Peak=May-Oct	7,239,337	Rate Classification	8	EXTRA LARGE HIGH LOAD FACTOR
Off Peak / Total	51%	Load Factor	1	

AGT Rebate Calculations based on:

- 75% of the difference in Capital Cost and
-An amount resulting in a 1.5 year Simple Payback

75% of the difference between the Base and Alternate Energy Projects' capital costs

= ($22,700,000) - ($0) x 75%

= **$17,025,000** - $249,482 = **$16,775,518**
Constr Cost

An amount resulting in a simple payback of 1.5 years

= ($22,700,000 - $0) / ($0 - -$1,612,053)

= $22,700,000 / $1,612,053

= 14.0814229 years = Simple payback of Base Energy Project

Rebate Amount
= (14.0814229 - 1.5) x ($0 - -$1,612,053)

= 12.5814229 x $1,612,053

= **$20,281,921** - $249,482 = **$20,032,439**
Constr Cost

=

AGT FINANCIAL ANALYSIS

Miscellaneous notes on the AGT Financial Analysis for Applications Falling in the Small, Medium, Large or Extra Large Rate Classificaiton

1 Model is set up for Customers in the Small, Medium, Large and Extra Large Rate classifications both on a current basis and with the added AGT Program load

2 Heat Recovery:
- If the proposed application will have heat recovery which displaces existing gas heat, the displaced therms will be factored into the margin calculation.
- The model distributes the displaced Ccf in the same relationship to when the proposed load uses gas since that is when the heat is generated

3 Bill Calculation
- The bill calculation sheet can be used to get a gas energy cost for the customer.

4 Separate meter:
- If the application is to be separately metered run model with no current load to get the right rate calculation for the new account and see Pricing for help with loss of existing margin due to heat recovery from new application.

New England Gas Company
Rhode Island
Demand Side Management Program
Financial Analysis

Inputs for IRP Financial Analysis

Date:		
Customer Name:	Aspen Aeorgels	
Address:	East Providence, RI	
Account # :		
Equipment Type	CHP Engine	
Equipment Life (years)		20
Current gas load saved due to heat recovery (Ccf)		
MADQ - Current:	1,946 Th	
- Proposed:	3,239 Th	

	CHP Project	Base	
Capital Cost	$3,600,000	$0.00	
Operating Cost	$772,524	$1,631,988.20	$859,463.90

Results of Analysis

Incremental Distribution Margin Year 1	$ 45,727	
Net Present Value based on equipment life	$ 464,749	
Rebate based on 75% of NPV	$ 330,288	
Rebate based on 75% of Capital Cost Difference	$ 2,700,000	
Rebate resulting in 1.5 year Simple Payback	$ 2,310,804	
	$ 330,288	= REBATE

Rate Classification:
Current:
Proposed:

Month	CY 2014 Proposed Load (Th)	Current Base Load (Th)	Adjustment to current for Heat Recovery	**Proposed Adjusted**	
Jan	100,127	59,835		40,292	
Feb	90,679	54,235		36,444	
Mar	100,227	59,894		40,333	
Apr	97,033	58,386		38,647	
May	99,746	59,922		39,824	*
Jun	97,129	58,034		39,096	*
Jul	100,639	60,246		40,393	*
Aug	100,292	59,922		40,370	*
Sep	96,057	58,034		38,024	*
Oct	100,077	60,246		39,831	
Nov	96,350	57,833		38,517	
Dec	99,812	60,174		39,637	
TOTAL	1,178,168	**706,760**	**0**	**471,407**	

New England Gas Company
Rhode Island
Demand Side Management Program
Financial Analysis

Inputs for IRP Financial Analysis

Date:
Customer Name: Crowne Plaza
Address: Warwick, RI
Account # :

Equipment Type CHP Engine
Equipment Life (years) 20
Current gas load saved due to heat recovery (Ccf)
MADQ - Current: 1,078 Th
- Proposed: 1,170 Th

	CHP Project	Base	
Capital Cost	$424,000	$0.00	
Operating Cost	$78,065	$0.00	-$78,064.88

Results of Analysis

Incremental Distribution Margin Year 1	$ 8,446
Net Present Value based on equipment life	$ 85,843
Rebate based on 75% of NPV	$ 64,382
Rebate based on 75% of Capital Cost Difference	$ 318,000
Rebate resulting in 1.5 year Simple Payback	$ 306,903
	$ 64,382 = REBATE

Rate Classification:
Current:
Proposed:

Month	CY 2014 Proposed Load (Th)	Current Base Load (Th)	Adjustment to current for Heat Recovery	**Proposed Adjusted**
Jan	22,175	19,278	0	2,897
Feb	32,762	30,188	0	2,574
Mar	31,059	28,205	0	2,854
Apr	24,513	21,683	0	2,830
May	21,073	18,616	0	2,457
Jun	14,611	12,479	0	2,132
Jul	12,466	10,383	0	2,083
Aug	11,031	8,948	0	2,083
Sep	10,534	8,519	0	2,015
Oct	11,024	8,380	0	2,644
Nov	16,085	13,222	0	2,863
Dec	19,665	16,786	0	2,879
TOTAL	226,998	**196,687**	**0**	**30,311**

Redacted

Division 1-2

Request:

Re: The Direct Testimony of Witness Ann E. Leary at page 7, line 12, though page 8, line 10, please provide a list of each project presently being considered by the Company for inclusion in the AGT program and provide:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes for the proposed facility;

c. The dollar amount of anticipated AGT funding for the project by year;

d. Description of the advanced technology that would be utilized;

e. Any workpapers, studies and analyses relied upon to support the Company's assessment of the proposed project.

Response:

a) [redacted] is the only customer currently working towards an offering of an AGT rebate. The Company has also discussed the Advanced Gas Technology (AGT) program with other customers, including two manufacturing facilities, but the Company has not studied their proposed gas usages as of yet to see how and if they would qualify to accept such applications.

b) [redacted] projected annual gas increase in volume is [redacted] therms.

c) The Company will offer the [redacted] project a rebate of [redacted] The Company used the table provided in Attachment DIV 1-2-1 to determine the offer to the customer. The gas usage qualifies for 55 percent and at a rate of $0.63 for an Extra High Load Factor customer.

d) The advanced technology that would be used is combined heat and power.

e) In support of the project's rebate, please see the attached AGT table provided in Attachment DIV 1-2-1 and the applicable Technical Assistance Study provided in Confidential Attachment DIV 1-2-2.

Prepared by or under the supervision of: David M. Moreira

REDACTED

therms non heat	total therms Increase	% consumed	$ Actual offered	$ Proposed Table	CHP size

[redacted]

Incremental Therms estimated during May-Oct months times $/therms

Percent Consumed in May-Oct Months

Rate	31%	35%	40%	45%	50%	55%	60%	65%	70%+
SMALL LOW LOAD FACTOR	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00	$ 2.13	$ 2.25
SMALL HIGH LOAD FACTOR	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00	$ 2.13	$ 2.25
MEDIUM LOW LOAD FACTOR	$ 1.00	$ 1.13	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00
MEDIUM HIGH LOAD FACTOR	$ 1.00	$ 1.13	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00
LARGE LOW LOAD FACTOR	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00	$ 1.13	$ 1.25
LARGE HIGH LOAD FACTOR	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00	$ 1.13	$ 1.25
EXTRA LARGE LOW LOAD FACTOR	$ 0.25	$ 0.25	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00
EXTRA LARGE HIGH LOAD FACTOR	$ 0.25	$ 0.25	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00

TECHNOLOGY	APPLICATION
Air Compressor	Product cooling or movement
Compressed Natural Gas	Personal or fleet cars and trucks
Engine-Driven Pump	Municipal water pumping
Convection Oven & Burner	Curing, drying and forming
Absorption/Engine Driven Chiller	Office air conditioning or process cooling
Desiccant Dehumidifier	Office or process dehumidification
Engine-Driven Generator	Cogeneration
Catalytic Infra-Red Heater	Curing, drying and forming
Incinerator	Solid waste or air pollutant destruction
Boiler & Burner	Process heating (i.e., steam, hot water, etc.)

Attachment DIV 1-2-2

REDACTED

Prepared by or under the supervision of: David M. Moreira

Division 1-3

Request:

Re: The Direct Testimony of Witness Ann E. Leary at page 7, line 12, though page 8, line 10, please provide a list of each project during the last three years that have applied for but been denied rebates under the AGT program including:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes for the proposed facility;

c. Description of the advanced technology that would be utilized;

d. Reason for project denial;

e. Requested Rebate amount.

Response:

Over the last three years, no customers have applied for a rebate under the Advanced Gas Technology program and been denied.

Division 1-4

Request:

Re: The Direct Testimony of Witness Ann E. Leary at page 29, lines 4 though 8, please:

a. Provide the detail of the forecast from which the referenced 39,347,340 Dths of forecasted throughput;

b. Provide actual throughput by month for the current DAC year and for each of the three immediately preceding DAC years.

Response:

a. To clarify, the forecasted throughput referenced in the August 1, 2018 direct testimony of Company witness Ann E. Leary at page 29, lines 4 through 8, is 39,668,606 dekatherms (Dth), rather than 39,347,340 Dth indicated in this request. In addition, in the August 31, 2018 supplemental testimony of Ms. Leary at page 10, the Company increased the annual forecast by 18,426 Dth, for a total of 39,687,032 Dth. Please see Attachment DIV 1-4(a) for the monthly throughput by rate classification for the period November 2018 through October 2019. Please note this information was also provided in the Company's 2018 Gas Cost Recovery filing, Docket No. 4872, filed on August 31, 2018 at Attachment AEL-1, Page 12. The forecast presented in this filing was prepared by Company witness, Theodore E. Poe.

b. Please see Attachment DIV 1-4(b) for the actual monthly throughput for the each of the Distribution Adjustment Charge years during November 2014 through July 2018. The Company previously provided the actual monthly throughput for the period November 2014 through October 2017 in Schedule 6 of the October Monthly Deferred Reports filed on November 20, 2015 in Docket No. 4520; November 18, 2016 in Docket No. 4576; and November 20, 2017 in Docket No. 4647. The Company also provided the monthly throughput data for the period November 2017 through July 2018 in Schedule 6 of the July Monthly Deferred Report filed on August 17, 2018 in Docket No. 4719.

Prepared by or under the supervision of: Theodore E. Poe and Ann E. Leary

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Forecasted Throughput (Dth)

	Rate Class	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	SALES													
(1)	Residential Non-Heating	22,227	35,614	47,291	40,666	38,648	37,807	26,709	21,502	16,823	16,284	17,571	16,077	337,218
(2)	Residential Heating	1,271,942	2,396,453	3,427,224	3,653,832	3,123,499	2,122,108	1,225,830	619,954	435,361	397,039	439,559	532,719	19,645,520
(3)	Small C&I	125,069	293,293	453,403	454,861	389,113	258,015	116,773	65,276	40,925	36,380	48,446	52,987	2,334,542
(4)	Medium C&I	200,308	392,753	606,014	526,512	452,808	383,665	197,339	125,789	98,066	94,334	97,543	110,966	3,286,097
(5)	Large LLF	44,361	92,278	119,512	130,436	117,009	85,027	49,006	18,991	11,143	9,807	13,893	16,841	708,304
(6)	Large HLF	19,715	23,207	31,558	27,637	23,504	22,820	19,033	15,521	13,976	13,402	16,077	16,190	242,642
(7)	Extra Large LLF	2,541	5,897	5,728	7,685	6,516	3,854	3,652	1,426	342	84	293	847	38,865
(8)	Extra Large HLF	9,650	4,484	-	4,654	1,128	-	8,824	6,431	5,706	6,321	5,860	8,592	61,651
(9)	**Total Sales**	1,695,814	3,243,979	4,690,730	4,846,283	4,152,227	2,913,296	1,647,166	874,890	622,341	573,652	639,241	755,220	26,654,839
	TRANSPORTATION													
(10)	FT- Small	12,566	20,010	25,711	27,397	23,943	17,207	11,753	5,273	2,876	2,532	2,898	6,015	158,180
(11)	FT- Medium	173,197	315,865	411,364	369,590	342,996	260,713	155,362	95,839	75,553	73,024	76,357	92,379	2,442,238
(12)	FT- Large LLF	176,854	296,272	358,609	352,261	309,727	189,270	115,275	50,934	34,456	32,191	43,742	83,995	2,043,586
(13)	FT- Large HLF	72,228	99,002	112,191	98,705	100,840	78,821	67,676	59,185	50,762	58,565	58,743	59,808	916,525
(14)	FT- Extra Large LLF	122,430	178,864	194,162	182,450	157,144	96,228	62,805	27,050	21,711	20,914	29,069	80,905	1,173,733
(15)	FT- Extra Large HLF	561,571	629,875	608,190	524,520	597,555	475,819	466,687	479,539	493,717	517,144	445,471	497,844	6,297,932
(16)	**Total FT Transportation**	1,118,847	1,539,888	1,710,227	1,554,923	1,532,205	1,118,057	879,557	717,819	679,075	704,370	656,281	820,946	13,032,193
	Total THROUGHPUT													
(17)	Residential Non-Heating	22,227	35,614	47,291	40,666	38,648	37,807	26,709	21,502	16,823	16,284	17,571	16,077	337,218
(18)	Residential Heating	1,271,942	2,396,453	3,427,224	3,653,832	3,123,499	2,122,108	1,225,830	619,954	435,361	397,039	439,559	532,719	19,645,520
(19)	Small C&I	137,635	313,303	479,114	482,258	413,056	275,222	128,526	70,548	43,801	38,912	51,344	59,002	2,492,721
(20)	Medium C&I	373,505	708,618	1,017,378	896,102	795,805	644,377	352,701	221,628	173,618	167,358	173,900	203,345	5,728,335
(21)	Large LLF	221,214	388,549	478,120	482,697	426,737	274,298	164,280	69,925	45,599	41,998	57,635	100,837	2,751,890
(22)	Large HLF	91,944	122,209	143,749	126,342	124,344	101,641	86,709	74,706	64,738	71,967	74,820	75,997	1,159,166
(23)	Extra Large LLF	124,972	184,761	199,890	190,135	163,660	100,082	66,456	28,476	22,053	20,999	29,362	81,753	1,212,598
(24)	Extra Large HLF	571,222	634,359	608,190	529,174	598,683	475,819	475,511	485,970	499,423	523,465	451,331	506,436	6,359,583
(25)	**Total Throughput**	2,814,661	4,783,867	6,400,956	6,401,206	5,684,431	4,031,353	2,526,723	1,592,708	1,301,416	1,278,022	1,295,522	1,576,166	39,687,032

Actual Dth Usage for Filing

	THROUGHPUT (Dth)	Nov-17 Actual (a)	Dec-17 Actual (b)	Jan-18 Actual (c)	Feb-18 Actual (d)	Mar-18 Actual (e)	Apr-18 Actual (f)	May-18 Actual (g)	Jun-18 Actual (h)	Jul-18 Actual (i)	Total (m)
	Rate Class										
1	**SALES**										
2	Residential Non-Heating	25,799	36,375	54,883	49,588	42,810	41,610	30,778	20,876	17,267	**319,985**
3	Residential Non-Heating Low Income	506	908	1,479	1,192	1,139	1,176	992	550	458	**8,399**
4	Residential Heating	1,049,547	2,123,640	3,918,609	3,156,062	2,437,110	2,449,113	1,306,376	501,624	399,062	**17,341,142**
5	Residential Heating Low Income	85,126	174,014	295,095	237,817	192,552	191,545	117,403	50,413	40,182	**1,384,149**
6	Small C&I	111,854	277,727	585,108	440,831	334,818	319,554	154,805	52,206	43,437	**2,320,339**
7	Medium C&I	195,033	383,557	650,534	533,358	424,687	414,692	234,444	118,691	99,018	**3,054,013**
8	Large LLF	32,729	77,403	145,182	120,731	101,572	99,605	52,679	10,910	15,118	**655,929**
9	Large HLF	19,260	22,406	29,939	26,984	24,449	27,181	21,738	20,612	15,327	**207,897**
10	Extra Large LLF	1,662	7,001	9,784	6,318	10,337	11,137	5,738	1,636	966	**54,580**
11	Extra Large HLF	9,191	7,841	5,969	3,560	3,292	3,705	4,618	5,200	5,396	**48,773**
12	**Total Sales**	1,530,707	3,110,872	5,696,582	4,576,441	3,572,766	3,559,318	1,929,572	782,719	636,232	**25,395,207**
13	**TSS**										
14	Small	26	327	1,270	1,577	928	895	409	5	0	**5,437**
15	Medium	1,986	6,054	11,692	11,398	12,266	11,034	8,187	27	234	**62,877**
16	Large LLF	501	5,293	10,605	10,619	8,970	8,523	4,065	0	0	**48,576**
17	Large HLF	0	464	629	4,300	771	(164)	2,302	0	0	**8,301**
18	Extra Large LLF	0	0	0	0	0	0	0	0	0	**0**
19	Extra Large HLF	0	0	0	0	0	0	0	0	0	**0**
20	**Total TSS**	2,513	12,138	24,197	27,895	22,935	20,288	14,962	31	234	**125,192**
21	**Sales & TSS THROUGHPUT**										
22	Residential Non-Heating	25,799	36,375	54,883	49,588	42,810	41,610	30,778	20,876	17,267	**319,985**
23	Residential Non-Heating Low Income	506	908	1,479	1,192	1,139	1,176	992	550	458	**8,399**
24	Residential Heating	1,049,547	2,123,640	3,918,609	3,156,062	2,437,110	2,449,113	1,306,376	501,624	399,062	**17,341,142**
25	Residential Heating Low Income	85,126	174,014	295,095	237,817	192,552	191,545	117,403	50,413	40,182	**1,384,149**
26	Small C&I	111,880	278,053	586,379	442,408	335,746	320,449	155,214	52,211	43,437	**2,325,776**
27	Medium C&I	197,019	389,610	662,226	544,756	436,953	425,727	242,631	118,718	99,252	**3,116,891**
28	Large LLF	33,230	82,697	155,787	131,351	110,543	108,127	56,744	10,910	15,118	**704,505**
29	Large HLF	19,260	22,871	30,568	31,285	25,220	27,017	24,039	20,612	15,327	**216,199**
30	Extra Large LLF	1,662	7,001	9,784	6,318	10,337	11,137	5,738	1,636	966	**54,580**
31	Extra Large HLF	9,191	7,841	5,969	3,560	3,292	3,705	4,618	5,200	5,396	**48,773**
32	**Total Sales & TSS Throughput**	1,533,220	3,123,009	5,720,779	4,604,335	3,595,701	3,579,606	1,944,533	782,750	636,465	**25,520,398**
33	**FT-1 TRANSPORTATION**										
	FT-1 Small	0	0	0	0	0	0	0	0	0	**0**
34	FT-1 Medium	30,639	60,057	94,202	106,674	70,928	79,406	56,114	28,324	22,817	**549,159**
35	FT-1 Large LLF	34,759	97,785	156,615	188,114	117,763	131,498	92,626	28,406	18,764	**866,328**
36	FT-1 Large HLF	32,023	38,641	51,303	58,673	41,269	46,793	38,856	32,470	28,689	**368,716**
37	FT-1 Extra Large LLF	48,732	127,674	194,739	224,079	151,917	171,030	126,757	46,116	25,013	**1,116,058**
38	FT-1 Extra Large HLF	433,197	494,103	573,189	623,062	499,034	544,355	492,894	435,486	425,787	**4,521,106**
39	Default	4,332	9,934	11,836	12,359	9,199	10,571	8,376	1,824	1,291	**69,721**
40	**Total FT-1 Transportation**	583,682	828,194	1,081,884	1,212,960	890,109	983,653	815,622	572,624	522,361	**7,491,089**
41	**FT-2 TRANSPORTATION**										
42	FT-2 Small	6,121	14,942	30,920	23,834	18,268	17,792	9,661	3,132	1,963	**126,633**
43	FT-2 Medium	115,362	220,831	362,383	302,105	252,568	225,062	142,061	67,418	55,558	**1,743,348**
44	FT-2 Large LLF	60,802	159,214	267,279	214,763	179,315	174,043	107,417	33,875	20,295	**1,217,001**
45	FT-2 Large HLF	36,322	47,803	63,254	59,154	50,624	53,196	39,633	30,068	27,451	**407,505**
46	FT-2 Extra Large LLF	126	2,476	4,034	3,026	2,441	2,597	1,203	0	0	**15,902**
47	FT-2 Extra Large HLF	47,318	52,276	60,012	46,226	43,247	46,933	39,757	42,217	31,497	**409,482**
48	**Total FT-2 Transportation**	266,050	497,542	787,882	649,107	546,463	519,623	339,732	176,710	136,764	**3,919,872**
49	**Total THROUGHPUT**										
50	Residential Non-Heating	25,799	36,375	54,883	49,588	42,810	41,610	30,778	20,876	17,267	**319,985**
51	Residential Non-Heating Low Income	506	908	1,479	1,192	1,139	1,176	992	550	458	**8,399**
52	Residential Heating	1,049,547	2,123,640	3,918,609	3,156,062	2,437,110	2,449,113	1,306,376	501,624	399,062	**17,341,142**
53	Residential Heating Low Income	85,126	174,014	295,095	237,817	192,552	191,545	117,403	50,413	40,182	**1,384,149**
54	Small C&I	118,001	292,995	617,299	466,242	354,014	338,241	164,875	55,343	45,400	**2,452,409**
55	Medium C&I	343,020	670,498	1,118,811	953,535	760,448	730,194	440,806	214,459	177,627	**5,409,398**
56	Large LLF	128,791	339,695	579,680	534,227	407,621	413,668	256,787	73,190	54,177	**2,787,835**
57	Large HLF	87,605	109,315	145,125	149,112	117,113	127,007	102,528	83,150	71,467	**992,420**
58	Extra Large LLF	50,519	137,151	208,557	233,422	164,695	184,765	133,699	47,753	25,980	**1,186,540**
59	Extra Large HLF	489,706	554,220	639,171	672,847	545,573	594,993	537,269	482,903	462,680	**4,979,361**
60	Default	4,332	9,934	11,836	12,359	9,199	10,571	8,376	1,824	1,291	**69,721**
61	**Total Throughput**	2,382,952	4,448,745	7,590,544	6,466,403	5,032,272	5,082,882	3,099,887	1,532,085	1,295,590	**36,931,360**

Actual Dth Usage for Filing

	THROUGHPUT (Dth)	Nov-16 Actual (a)	Dec-16 Actual (b)	Jan-17 Actual (c)	Feb-17 Actual (d)	Mar-17 Actual (e)	Apr-17 Actual (f)	May-17 Actual (g)	Jun-17 Actual (h)	Jul-17 Actual (i)	Aug-17 Actual (j)	Sep-17 Actual (k)	Oct-17 Actual (l)	Total (m)
	Rate Class													
1	**SALES**													
2	Residential Non-Heating	27,860	38,287	50,638	50,625	47,073	44,256	29,336	24,258	19,200	17,698	18,669	16,470	**384,370**
3	Residential Non-Heating Low Income	708	1,220	1,697	1,646	1,406	1,429	1,005	683	486	438	1,424	(624)	**11,518**
4	Residential Heating	1,105,743	2,028,011	2,935,054	2,884,975	2,623,389	2,276,588	986,291	656,511	414,665	369,201	375,999	385,111	**17,041,537**
5	Residential Heating Low Income	99,712	178,044	250,781	238,178	213,710	194,021	100,127	67,120	43,824	38,781	40,198	37,443	**1,501,938**
6	Small C&I	116,386	260,153	412,737	405,424	368,672	313,479	104,811	66,481	43,307	37,212	39,181	39,210	**2,207,054**
7	Medium C&I	202,328	353,053	502,001	473,805	444,548	395,382	189,716	140,530	97,779	93,200	95,519	101,259	**3,089,120**
8	Large LLF	38,117	70,274	111,810	100,523	94,633	80,576	30,177	20,339	10,256	9,086	10,365	10,185	**586,342**
9	Large HLF	17,053	21,083	26,215	26,803	24,099	20,948	19,724	17,792	12,615	15,096	16,358	14,763	**232,549**
10	Extra Large LLF	3,267	6,464	12,229	9,417	10,069	10,129	4,291	2,883	1,059	479	336	607	**61,229**
11	Extra Large HLF	10,464	5,556	6,078	3,679	3,582	3,762	7,836	10,647	7,815	6,744	5,843	8,751	**80,755**
12	**Total Sales**	1,621,637	2,962,145	4,309,240	4,195,075	3,831,181	3,340,569	1,473,313	1,007,242	651,008	587,934	603,893	613,175	**25,196,411**
13	**TSS**													
14	Small	1	820	1,643	1,720	1,352	1,660	341	93	74	33	12	17	**7,767**
15	Medium	1,651	2,542	5,657	6,588	6,566	8,327	4,570	75	134	118	1,024	806	**38,058**
16	Large LLF	1,104	2,207	5,122	5,623	8,641	7,726	1,932	(99)	150	204	0	586	**33,195**
17	Large HLF	360	986	(7,763)	781	852	1,594	987	0	0	0	0	0	**(2,204)**
18	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	**0**
19	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	**0**
20	**Total TSS**	3,116	6,555	4,658	14,712	17,411	19,307	7,830	68	359	355	1,036	1,409	**76,816**
21	**Sales & TSS THROUGHPUT**													
22	Residential Non-Heating	27,860	38,287	50,638	50,625	47,073	44,256	29,336	24,258	19,200	17,698	18,669	16,470	**384,370**
23	Residential Non-Heating Low Income	708	1,220	1,697	1,646	1,406	1,429	1,005	683	486	438	1,424	(624)	**11,518**
24	Residential Heating	1,105,743	2,028,011	2,935,054	2,884,975	2,623,389	2,276,588	986,291	656,511	414,665	369,201	375,999	385,111	**17,041,537**
25	Residential Heating Low Income	99,712	178,044	250,781	238,178	213,710	194,021	100,127	67,120	43,824	38,781	40,198	37,443	**1,501,938**
26	Small C&I	116,387	260,972	414,380	407,145	370,024	315,140	105,153	66,574	43,381	37,246	39,193	39,228	**2,214,821**
27	Medium C&I	203,978	355,596	507,658	480,393	451,114	403,709	194,286	140,604	97,914	93,318	96,543	102,065	**3,127,178**
28	Large LLF	39,221	72,481	116,932	106,146	103,274	88,301	32,109	20,239	10,406	9,289	10,365	10,771	**619,536**
29	Large HLF	17,413	22,069	18,451	27,584	24,951	22,542	20,711	17,792	12,615	15,096	16,358	14,763	**230,345**
30	Extra Large LLF	3,267	6,464	12,229	9,417	10,069	10,129	4,291	2,883	1,059	479	336	607	**61,229**
31	Extra Large HLF	10,464	5,556	6,078	3,679	3,582	3,762	7,836	10,647	7,815	6,744	5,843	8,751	**80,755**
32	**Total Sales & TSS Throughput**	1,624,752	2,968,700	4,313,898	4,209,787	3,848,592	3,359,876	1,481,143	1,007,310	651,366	588,289	604,928	614,584	**25,273,226**
33	**FT-1 TRANSPORTATION**													
	FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	**0**
34	FT-1 Medium	15,039	57,778	91,539	92,513	76,349	87,997	45,854	33,455	23,293	21,970	23,698	23,592	**593,076**
35	FT-1 Large LLF	30,674	85,561	138,218	139,766	118,745	139,253	64,270	39,180	19,071	15,474	16,660	18,918	**825,791**
36	FT-1 Large HLF	3,130	34,229	46,585	45,978	41,018	46,755	30,869	28,414	28,075	25,530	30,959	30,186	**391,729**
37	FT-1 Extra Large LLF	49,729	116,405	178,743	179,983	159,841	186,388	98,443	62,497	28,207	20,162	21,762	25,305	**1,127,465**
38	FT-1 Extra Large HLF	26,686	491,114	557,480	552,086	489,501	569,383	456,839	434,173	437,754	445,240	452,915	391,880	**5,305,050**
39	Default	1,315	5,384	7,861	7,933	6,877	8,043	8,305	4,092	2,507	2,189	2,196	2,326	**59,028**
40	**Total FT-1 Transportation**	126,573	790,470	1,020,427	1,018,260	892,330	1,037,818	704,581	601,811	538,906	530,565	548,191	492,207	**8,302,140**
41	**FT-2 TRANSPORTATION**													
42	FT-2 Small	5,763	12,400	19,816	18,921	18,027	14,840	5,565	4,962	2,460	2,299	2,308	2,343	**109,702**
43	FT-2 Medium	113,132	196,524	277,630	266,892	257,186	228,063	111,699	79,934	51,690	51,122	50,384	54,721	**1,738,976**
44	FT-2 Large LLF	90,345	164,245	224,090	204,116	189,418	154,331	66,850	31,676	39,593	18,450	19,167	27,361	**1,229,642**
45	FT-2 Large HLF	36,219	43,989	56,893	59,620	56,196	46,493	33,574	32,303	25,720	24,257	26,620	27,286	**469,169**
46	FT-2 Extra Large LLF	1,374	4,987	7,574	6,675	5,895	6,478	2,108	1,453	936	423	(782)	142	**37,264**
47	FT-2 Extra Large HLF	42,225	46,991	50,604	47,994	55,613	50,379	37,837	40,363	36,026	34,521	41,438	36,599	**520,588**
48	**Total FT-2 Transportation**	289,058	469,135	636,607	604,218	582,335	500,584	257,632	190,691	156,426	131,072	139,134	148,452	**4,105,341**
49	**Total THROUGHPUT**													
50	Residential Non-Heating	27,860	38,287	50,638	50,625	47,073	44,256	29,336	24,258	19,200	17,698	18,669	16,470	**384,370**
51	Residential Non-Heating Low Income	708	1,220	1,697	1,646	1,406	1,429	1,005	683	486	438	1,424	(624)	**11,518**
52	Residential Heating	1,105,743	2,028,011	2,935,054	2,884,975	2,623,389	2,276,588	986,291	656,511	414,665	369,201	375,999	385,111	**17,041,537**
53	Residential Heating Low Income	99,712	178,044	250,781	238,178	213,710	194,021	100,127	67,120	43,824	38,781	40,198	37,443	**1,501,938**
54	Small C&I	122,150	273,372	434,196	426,066	388,051	329,980	110,717	71,536	45,841	39,544	41,501	41,570	**2,324,523**
55	Medium C&I	332,149	609,897	876,827	839,797	784,649	719,769	351,839	253,994	172,897	166,411	170,625	180,378	**5,459,230**
56	Large LLF	160,240	322,287	479,241	450,028	411,438	381,885	163,229	91,095	69,071	43,213	46,193	57,051	**2,674,969**
57	Large HLF	56,763	100,288	121,930	133,181	122,164	115,789	85,154	78,509	66,410	64,883	73,937	72,235	**1,091,242**
58	Extra Large LLF	54,369	127,856	198,546	196,075	175,805	202,996	104,842	66,833	30,203	21,064	21,316	26,054	**1,225,958**
59	Extra Large HLF	79,375	543,661	614,162	603,758	548,696	623,524	502,512	485,182	481,595	486,504	500,195	437,230	**5,906,393**
60	Default	1,315	5,384	7,861	7,933	6,877	8,043	8,305	4,092	2,507	2,189	2,196	2,326	**59,028**
61	**Total Throughput**	2,040,383	4,228,306	5,970,932	5,832,264	5,323,257	4,898,277	2,443,356	1,799,812	1,346,698	1,249,926	1,292,254	1,255,243	**37,680,707**

Actual Dth Usage for Filing

	THROUGHPUT (Dth)	Nov-15 Actual (a)	Dec-15 Actual (b)	Jan-16 Actual (c)	Feb-16 Actual (d)	Mar-16 Actual (e)	Apr-16 Actual (f)	May-16 Actual (g)	Jun-16 Actual (h)	Jul-16 Actual (i)	Aug-16 Actual (j)	Sep-16 Actual (k)	Oct-16 Actual (l)	Total (m)
	Rate Class													
1	**SALES**													
2	Residential Non-Heating	37,092	60,224	75,729	89,222	67,317	60,019	39,167	28,743	18,658	16,187	16,103	19,867	**528,325**
3	Residential Non-Heating Low Income	1,316	2,434	3,160	3,548	2,537	2,941	1,956	1,023	327	259	277	392	**20,168**
4	Residential Heating	894,673	1,774,748	2,309,007	2,862,444	2,537,120	1,778,181	1,062,089	573,872	392,213	337,357	341,248	470,510	**15,333,461**
5	Residential Heating Low Income	93,503	177,183	227,988	271,102	173,668	152,450	100,566	55,710	40,021	33,305	34,078	46,179	**1,405,751**
6	Small C&I	103,351	234,087	316,821	424,123	362,345	236,605	124,634	68,665	47,017	41,144	34,719	46,769	**2,040,278**
7	Medium C&I	172,404	312,683	395,600	482,261	433,570	310,734	195,493	122,262	92,582	92,842	91,211	118,506	**2,820,147**
8	Large LLF	32,833	66,156	87,518	113,350	106,251	77,000	38,092	17,590	8,111	9,003	7,444	14,885	**578,234**
9	Large HLF	17,530	18,358	18,187	20,408	17,020	14,204	15,349	19,350	15,912	10,345	14,381	17,352	**198,396**
10	Extra Large LLF	3,781	6,963	9,313	9,683	14,539	8,303	5,409	3,332	1,167	1,113	283	744	**64,630**
11	Extra Large HLF	14,656	20,385	8,705	6,141	10,751	6,283	4,488	5,453	5,653	5,410	6,275	7,588	**101,786**
12	**Total Sales**	1,371,138	2,673,220	3,452,028	4,282,281	3,725,117	2,646,719	1,587,241	896,000	621,661	546,964	546,017	742,792	**23,091,177**
13	**TSS**													
14	Small	30	63	190	273	237	101	55	14	1	0	1	3	**968**
15	Medium	11,278	16,740	20,111	23,975	22,576	17,296	10,629	427	871	692	666	738	**125,999**
16	Large LLF	4,405	7,416	7,166	8,188	7,877	5,738	3,350	7,452	470	406	(7,506)	71	**45,033**
17	Large HLF	1,797	2,093	2,336	3,181	3,174	2,679	2,702	294	0	221	1,580	6,129	**26,187**
18	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	**0**
19	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	**0**
20	**Total TSS**	17,510	26,312	29,803	35,617	33,863	25,815	16,736	8,187	1,342	1,320	(5,259)	6,941	**198,187**
21	**Sales & TSS THROUGHPUT**													
22	Residential Non-Heating	37,092	60,224	75,729	89,222	67,317	60,019	39,167	28,743	18,658	16,187	16,103	19,867	**528,325**
23	Residential Non-Heating Low Income	1,316	2,434	3,160	3,548	2,537	2,941	1,956	1,023	327	259	277	392	**20,168**
24	Residential Heating	894,673	1,774,748	2,309,007	2,862,444	2,537,120	1,778,181	1,062,089	573,872	392,213	337,357	341,248	470,510	**15,333,461**
25	Residential Heating Low Income	93,503	177,183	227,988	271,102	173,668	152,450	100,566	55,710	40,021	33,305	34,078	46,179	**1,405,751**
26	Small C&I	103,381	234,149	317,012	424,396	362,582	236,705	124,688	68,679	47,017	41,144	34,720	46,772	**2,041,246**
27	Medium C&I	183,682	329,423	415,711	506,235	456,146	328,031	206,121	122,689	93,453	93,534	91,877	119,244	**2,946,146**
28	Large LLF	37,238	73,573	94,684	121,538	114,128	82,739	41,442	25,042	8,581	9,409	(62)	14,956	**623,267**
29	Large HLF	19,327	20,451	20,523	23,589	20,194	16,883	18,051	19,644	15,912	10,566	15,961	23,481	**224,583**
30	Extra Large LLF	3,781	6,963	9,313	9,683	14,539	8,303	5,409	3,332	1,167	1,113	283	744	**64,630**
31	Extra Large HLF	14,656	20,385	8,705	6,141	10,751	6,283	4,488	5,453	5,653	5,410	6,275	7,588	**101,786**
32	**Total Sales & TSS Throughput**	1,388,648	2,699,532	3,481,832	4,317,898	3,758,980	2,672,534	1,603,977	904,187	623,002	548,284	540,759	749,733	**23,289,364**
33	**FT-1 TRANSPORTATION**													
	FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	**0**
34	FT-1 Medium	63,644	68,106	75,898	132,048	80,921	50,248	46,317	16,972	12,658	23,275	19,597	25,082	**614,765**
35	FT-1 Large LLF	90,987	108,704	113,907	224,428	122,228	70,276	54,505	4,166	(6,639)	15,268	12,755	21,342	**831,926**
36	FT-1 Large HLF	42,174	44,422	39,881	66,915	44,249	36,833	33,922	28,372	31,907	24,836	26,008	28,244	**447,761**
37	FT-1 Extra Large LLF	128,795	147,186	149,215	255,433	164,414	106,626	93,152	12,455	(19,882)	16,867	16,137	27,896	**1,098,294**
38	FT-1 Extra Large HLF	465,126	508,134	512,954	600,196	496,037	410,300	485,818	417,435	478,958	424,379	489,409	401,651	**5,690,396**
39	Default	4,805	8,633	5,044	8,588	5,343	4,502	4,208	102	527	1,411	1,527	2,003	**46,693**
40	**Total FT-1 Transportation**	795,530	885,185	896,900	1,287,608	913,192	678,786	717,920	479,501	497,528	506,036	565,433	506,217	**8,729,834**
41	**FT-2 TRANSPORTATION**													
42	FT-2 Small	3,168	7,148	11,801	16,262	13,677	8,922	4,864	2,660	1,939	1,894	1,805	2,711	**76,850**
43	FT-2 Medium	101,345	171,161	219,040	264,594	227,758	180,341	117,208	72,110	51,904	45,212	44,845	62,395	**1,557,911**
44	FT-2 Large LLF	65,164	126,421	166,758	196,312	191,012	124,706	75,799	25,923	15,596	13,724	15,849	28,855	**1,046,117**
45	FT-2 Large HLF	30,668	19,443	47,289	51,672	44,457	39,401	32,801	27,650	21,669	21,990	26,358	24,907	**388,303**
46	FT-2 Extra Large LLF	4,340	7,674	9,285	12,583	11,869	9,132	6,423	3,574	2,469	2,001	475	818	**70,642**
47	FT-2 Extra Large HLF	40,295	44,082	45,454	47,875	50,114	40,735	36,244	36,123	35,144	32,540	38,843	37,476	**484,926**
48	**Total FT-2 Transportation**	244,979	375,929	499,627	589,297	538,887	403,236	273,340	168,039	128,721	117,359	128,175	157,161	**3,624,750**
49	**Total THROUGHPUT**													
50	Residential Non-Heating	37,092	60,224	75,729	89,222	67,317	60,019	39,167	28,743	18,658	16,187	16,103	19,867	**528,325**
51	Residential Non-Heating Low Income	1,316	2,434	3,160	3,548	2,537	2,941	1,956	1,023	327	259	277	392	**20,168**
52	Residential Heating	894,673	1,774,748	2,309,007	2,862,444	2,537,120	1,778,181	1,062,089	573,872	392,213	337,357	341,248	470,510	**15,333,461**
53	Residential Heating Low Income	93,503	177,183	227,988	271,102	173,668	152,450	100,566	55,710	40,021	33,305	34,078	46,179	**1,405,751**
54	Small C&I	106,549	241,297	328,813	440,658	376,259	245,627	129,552	71,339	48,956	43,038	36,525	49,483	**2,118,097**
55	Medium C&I	348,671	568,689	710,649	902,877	764,825	558,619	369,646	211,771	158,015	162,022	156,319	206,721	**5,118,822**
56	Large LLF	193,388	308,698	375,350	542,278	427,367	277,720	171,746	55,130	17,537	38,400	28,542	65,153	**2,501,309**
57	Large HLF	92,168	84,316	107,694	142,175	108,900	93,117	84,774	75,665	69,488	57,392	68,327	76,631	**1,060,647**
58	Extra Large LLF	136,916	161,823	167,814	277,699	190,821	124,061	104,983	19,361	(16,246)	19,981	16,895	29,458	**1,233,566**
59	Extra Large HLF	520,078	572,601	567,112	654,211	556,902	457,318	526,550	459,011	519,756	462,329	534,527	446,715	**6,277,108**
60	Default	4,805	8,633	5,044	8,588	5,343	4,502	4,208	102	527	1,411	1,527	2,003	**46,693**
61	**Total Throughput**	2,429,157	3,960,645	4,878,358	6,194,802	5,211,058	3,754,555	2,595,237	1,551,727	1,249,252	1,171,679	1,234,367	1,413,111	**35,643,948**

Actual Dth Usage for Filing

	THROUGHPUT (Dth)	Nov-14 Actual (a)	Dec-14 Actual (b)	Jan-15 Actual (c)	Feb-15 Actual (d)	Mar-15 Actual (e)	Apr-15 Actual (f)	May-15 Actual (g)	Jun-15 Actual (h)	Jul-15 Actual (i)	Aug-15 Actual (j)	Sep-15 Actual (k)	Oct-15 Actual (l)	Total (m)
	Rate Class													
1	**SALES**													
2	Residential Non-Heating	56,635	74,913	97,349	123,153	116,760	83,622	45,364	29,503	23,827	21,194	20,827	24,491	**717,638**
3	Residential Non-Heating Low Income	2,753	2,976	4,006	4,900	4,353	4,329	2,015	1,051	787	728	593	828	**29,320**
4	Residential Heating	954,909	2,132,202	2,877,504	3,747,011	3,449,650	2,298,799	1,005,002	502,341	400,977	346,347	343,276	450,190	**18,508,206**
5	Residential Heating Low Income	100,792	213,885	282,745	352,717	318,259	247,469	109,620	61,630	49,907	40,759	40,160	50,642	**1,868,584**
6	Small C&I	113,249	292,468	439,525	597,057	549,888	338,002	125,776	58,890	47,382	43,390	42,914	52,565	**2,701,105**
7	Medium C&I	178,359	381,774	521,529	651,611	613,387	408,835	197,016	114,481	88,610	76,911	82,998	101,609	**3,417,120**
8	Large LLF	33,489	86,758	120,493	141,284	147,542	101,589	45,229	11,989	10,474	25,083	11,388	11,263	**746,580**
9	Large HLF	15,270	18,169	24,633	22,930	25,819	31,088	15,252	19,782	8,379	11,266	11,420	19,984	**223,991**
10	Extra Large LLF	5,189	9,565	16,279	19,829	11,954	12,084	(4,815)	14,341	1,735	(628)	1,821	2,420	**89,774**
11	Extra Large HLF	(152,203)	160,465	108,923	59,429	53,908	47,657	23,721	31,883	23,815	17,991	16,165	14,386	**406,140**
12	**Total Sales**	1,308,441	3,373,175	4,492,986	5,719,920	5,291,519	3,573,474	1,564,179	845,891	655,892	583,040	571,562	728,379	**28,708,459**
13	**TSS**													
14	Small	301	854	1,327	1,920	2,089	1,345	378	220	185	192	0	56	**8,866**
15	Medium	9,178	21,446	29,294	38,027	37,104	25,222	11,865	10,534	6,483	5,923	3,175	10,365	**208,615**
16	Large LLF	2,777	5,722	7,098	13,537	8,055	8,378	3,976	2,274	1,144	1,112	628	1,018	**55,719**
17	Large HLF	2,532	2,704	4,072	3,674	3,313	2,402	1,277	1,687	1,357	1,310	1,478	1,574	**27,379**
18	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	**0**
19	Extra Large HLF	264	532	743	837	769	616	245	218	159	125	0	0	**4,509**
20	**Total TSS**	15,052	31,258	42,532	57,995	51,330	37,964	17,740	14,933	9,328	8,662	5,281	13,013	**305,088**
21	**Sales & TSS THROUGHPUT**													
22	Residential Non-Heating	56,635	74,913	97,349	123,153	116,760	83,622	45,364	29,503	23,827	21,194	20,827	24,491	**717,638**
23	Residential Non-Heating Low Income	2,753	2,976	4,006	4,900	4,353	4,329	2,015	1,051	787	728	593	828	**29,320**
24	Residential Heating	954,909	2,132,202	2,877,504	3,747,011	3,449,650	2,298,799	1,005,002	502,341	400,977	346,347	343,276	450,190	**18,508,206**
25	Residential Heating Low Income	100,792	213,885	282,745	352,717	318,259	247,469	109,620	61,630	49,907	40,759	40,160	50,642	**1,868,584**
26	Small C&I	113,550	293,321	440,852	598,976	551,977	339,347	126,153	59,110	47,568	43,581	42,914	52,622	**2,709,971**
27	Medium C&I	187,537	403,220	550,823	689,638	650,491	434,057	208,882	125,015	95,093	82,834	86,173	111,974	**3,625,735**
28	Large LLF	36,266	92,480	127,590	154,821	155,597	109,967	49,205	14,263	11,618	26,195	12,016	12,281	**802,299**
29	Large HLF	17,802	20,873	28,704	26,603	29,132	33,491	16,528	21,469	9,736	12,576	12,898	21,558	**251,371**
30	Extra Large LLF	5,189	9,565	16,279	19,829	11,954	12,084	(4,815)	14,341	1,735	(628)	1,821	2,420	**89,774**
31	Extra Large HLF	(151,939)	160,997	109,666	60,266	54,678	48,274	23,965	32,101	23,974	18,116	16,165	14,386	**410,649**
32	**Total Sales & TSS Throughput**	1,323,493	3,404,433	4,535,518	5,777,914	5,342,849	3,611,438	1,581,919	860,825	665,221	591,702	576,843	741,392	**29,013,547**
33	**FT-1 TRANSPORTATION**													
	FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	**0**
34	FT-1 Medium	57,966	96,104	100,233	135,188	122,498	75,806	21,313	6,857	21,051	24,285	24,512	24,527	**710,339**
35	FT-1 Large LLF	85,682	189,184	184,327	260,376	175,201	90,860	33,587	33,587	17,758	16,211	11,575	20,511	**1,118,857**
36	FT-1 Large HLF	44,200	22,241	61,570	68,016	59,201	45,155	24,369	25,331	33,188	26,564	31,062	34,626	**475,524**
37	FT-1 Extra Large LLF	90,099	219,158	190,733	271,669	152,936	112,130	41,421	41,421	3,936	18,237	19,300	26,775	**1,187,815**
38	FT-1 Extra Large HLF	387,524	526,905	485,557	1,114,383	199,614	595,745	354,609	415,032	428,859	457,334	452,386	408,034	**5,825,983**
39	Default	19,277	5,635	11,253	12,896	13,353	7,386	195	261	835	(1,362)	5,248	165	**75,141**
40	**Total FT-1 Transportation**	684,748	1,059,227	1,033,672	1,862,528	722,803	927,081	475,494	522,488	505,627	541,270	544,083	514,638	**9,393,658**
41	**FT-2 TRANSPORTATION**													
42	FT-2 Small	2,128	4,905	8,211	16,127	14,606	7,807	3,208	1,627	1,503	1,431	1,445	1,686	**64,684**
43	FT-2 Medium	112,126	178,320	249,026	302,723	291,842	204,857	107,703	60,396	49,330	46,825	45,603	58,466	**1,707,215**
44	FT-2 Large LLF	77,258	143,077	207,088	238,144	233,339	114,024	62,983	29,165	11,198	13,175	15,590	25,658	**1,170,700**
45	FT-2 Large HLF	32,198	45,275	50,064	52,770	67,514	50,722	35,421	37,616	27,338	31,531	21,841	24,725	**477,015**
46	FT-2 Extra Large LLF	5,357	4,119	11,008	13,007	15,952	8,322	3,613	1,404	1,094	833	435	839	**65,983**
47	FT-2 Extra Large HLF	13,412	16,035	16,606	16,189	21,989	16,367	26,776	17,265	22,552	19,024	37,093	31,609	**254,918**
48	**Total FT-2 Transportation**	242,480	391,730	542,002	638,960	645,241	402,099	239,705	147,473	113,016	112,819	122,007	142,982	**3,740,514**
49	**Total THROUGHPUT**													
50	Residential Non-Heating	56,635	74,913	97,349	123,153	116,760	83,622	45,364	29,503	23,827	21,194	20,827	24,491	**717,638**
51	Residential Non-Heating Low Income	2,753	2,976	4,006	4,900	4,353	4,329	2,015	1,051	787	728	593	828	**29,320**
52	Residential Heating	954,909	2,132,202	2,877,504	3,747,011	3,449,650	2,298,799	1,005,002	502,341	400,977	346,347	343,276	450,190	**18,508,206**
53	Residential Heating Low Income	100,792	213,885	282,745	352,717	318,259	247,469	109,620	61,630	49,907	40,759	40,160	50,642	**1,868,584**
54	Small C&I	115,678	298,227	449,062	615,104	566,582	347,154	129,362	60,737	49,071	45,013	44,359	54,307	**2,774,655**
55	Medium C&I	357,629	677,643	900,081	1,127,548	1,064,830	714,720	337,898	192,267	165,473	153,944	156,287	194,967	**6,043,288**
56	Large LLF	199,207	424,741	519,005	653,341	564,137	314,850	145,774	77,015	40,575	55,581	39,181	58,450	**3,091,857**
57	Large HLF	94,200	88,389	140,338	147,390	155,847	129,368	76,319	84,416	70,262	70,672	65,801	80,908	**1,203,909**
58	Extra Large LLF	100,645	232,842	218,020	304,505	180,842	132,536	40,220	57,165	6,765	18,441	21,557	30,034	**1,343,572**
59	Extra Large HLF	248,997	703,937	611,829	1,190,838	276,281	660,386	405,351	464,398	475,385	494,475	505,645	454,030	**6,491,551**
60	Default	19,277	5,635	11,253	12,896	13,353	7,386	195	261	835	(1,362)	5,248	165	**75,141**
61	**Total Throughput**	2,250,721	4,855,391	6,111,192	8,279,403	6,710,893	4,940,618	2,297,118	1,530,785	1,283,863	1,245,791	1,242,933	1,399,012	**42,147,720**

Division 1-5

Request:

Re: The Direct Testimony of Witness Ann E. Leary Schedule AEL-7, please provide the workpapers, including electronic spreadsheet files, used in the development of the Company's RDM reconciliations, customer transfer adjustments, and normalizations.

Response:

The Company provided the Division of Public Utilities and Carriers (Division) with Excel files associated with the Revenue Decoupling Mechanism (RDM) reconciliation filing on June 29, 2018, and again in the Distribution Adjustment Charge (DAC) filing on August 1, 2018 and the Supplemental DAC filing on August 31, 2018. Please note that, as indicated in the RDM testimony of Ann E. Leary submitted on June 29, 2018 at Page 6 of 8 (and also included in Schedule AEL-7, Page 11 of 19 of the August 1, 2018 DAC filing), the Company did not make any adjustments to reflect customer transfers and normalizations because the Company has identified all Residential Heating customers who were incorrectly on the Residential Non-Heating rate class during the rate year February 2013 through January 2014, so no further adjustments were needed. Please see the Excel version of Attachment DIV 1-5, which is the same electronic spreadsheet provided on August 31, 2018, with additional detail supporting the actual revenues and customer counts used to compute the RDM adjustment.

Prepared by or under the supervision of: Ann E. Leary

Division 1-6

Request:

Re: The August 1, 2018 Direct Testimony of Witness Ann E. Leary at page 15, lines 11, through 21, please provide:

a. The Witness' definition of Distribution Adjustment Charge related bad debt;

b. The Witness' definition of energy efficiency related bad debt;

c. The amount of Distribution Adjustment Charge related bad debt for each of the last three years;

d. The amount of energy efficiency related bad debt for each of the last three years.

Response:

a. The Distribution Adjustment Charge (DAC)-related bad debt referenced in the direct testimony of Ann E. Leary on Page 15 is the revenue associated with the uncollectible component of the DAC. In each DAC filing, the Company adjusts the DAC (excluding the Revenue Decoupling Adjustment factor) by the uncollectible percentage approved in the Company's most recent rate proceeding, pursuant to the Company's tariff, RIPUC NG-GAS No. 101, Section 3, Schedule A, Item 2.0.

b. The energy efficiency-related bad debt referenced in Ms. Leary's direct testimony on Page 15 is the revenue associated with the uncollectible component of the Energy Efficiency Surcharge (EES). In each Energy Efficiency Program filing, the Company adjusts the EES by the uncollectible percentage approved in the Company's most recent rate proceeding, pursuant to the Company's tariff, RIPUC NG-GAS No. 101, Section 1, Schedule C, Item 4.0.

c. Please see Attachment DIV1-6 (c) for the uncollectible revenues associated with the DAC for the past three years. Please note that while preparing this response, the Company discovered that the amount shown in Schedule AEL-6, Page 2, Line (3) should have been $1,204,071, and not $1,165,424. This small revision will increase the Total Allowable Bad Debt in Schedule AEL-6, Page 2, Line (5)

Prepared by or under the supervision of: Ann E. Leary

Division 1-6, page 2

d. to $11,237,878, which is still higher than the Actual Net Charge Off in Schedule AEL-6, Page 2, Line (6), therefore, precluding the Company from recovering any of the costs associated with the participants who successfully completed the Arrearage Management Program.

e. Please see Attachment DIV1-6 (d) for the uncollectible collections associated with energy efficiency for the past three years.

Prepared by or under the supervision of: Ann E. Leary

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
DAC Uncollectible Collections														
(1)	2014	$23,052	$23,621	$21,893	$10,982	$14,181	$7,553	$5,731	$5,870	$5,679	$8,133	$10,977	$16,319	$153,990
(2)	2015	$20,009	$25,078	$23,598	$35,117	$38,414	$15,854	$13,817	$12,626	$12,656	$15,340	$33,302	$64,697	$310,507
(3)	2016	$83,489	$105,464	$89,729	$76,392	$62,835	$33,061	$23,718	$21,648	$21,916	$28,520	$64,772	$125,733	$737,277
(4)	2017	$180,995	$173,718	$157,062	$156,235	$83,108	$56,683	$38,308	$35,351	$37,273	$36,884	$84,249	$164,203	$1,204,071

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4846
Attachment DIV 1-6 (c)
Page 1 of 1

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Energy Efficiency Uncollectible Collections														
(1)	2014	$97,663	$120,231	$110,191	$84,556	$43,592	$25,608	$9,126	$33,693	$15,456	$33,389	$38,505	$85,812	$697,823
(2)	2015	$100,591	$190,788	$157,043	$117,042	$52,421	$31,185	$28,354	$27,461	$27,376	$31,514	$54,650	$89,870	$908,296
(3)	2016	$107,098	$118,392	$103,519	$76,282	$49,932	$29,378	$22,801	$21,087	$22,268	$27,080	$52,449	$86,471	$716,758
(4)	2017	$133,419	$157,782	$134,353	$129,211	$55,406	$43,680	$32,225	$30,972	$32,281	$32,603	$63,428	$121,491	$966,849

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4846
Attachment DIV 1-6 (d)
Page 1 of 1

Division 1-7

Request:

Re: The August 1, 2018 Direct Testimony of Witness Ann E. Leary at page 17, lines 5 though 9, please provide:

a. The referenced July 31, 2018, FY 2018 Annual Service Quality Report;

b. The referenced June 22, 2018, request for relief.

Response:

a. Please refer to Attachment DIV 1-7 (a) for a copy of the Company's Fiscal Year 2018 Annual Report on Service Quality Plan filed on July 31, 2018 in Docket No. 3476.

b. Please refer to Attachment DIV 1-7 (b) for a copy of the Company's Request for Relief from Penalty Because of Exogenous and/or Force Majeure Event filed on June 22, 2018 in Docket No. 3476.

Prepared by or under the supervision of: Ann E. Leary

nationalgrid

Robert J. Humm
Senior Counsel

July 31, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: <u>Docket 3476 – Fiscal Year 2018 Annual Report on Service Quality Plan</u>

Dear Ms. Massaro:

Enclosed for filing are 10 copies of National Grid's[1] annual performance results for fiscal year (FY) 2018[2] for its gas operations in Rhode Island under the Service Quality Plan established in the above-referenced docket. The enclosed annual report covers the period of July 1, 2017 through June 30, 2018. The annual report also establishes updated benchmarks to be used in measuring performance for FY 2019, which covers the period of July 1, 2018 through June 30, 2019.

Attachment 1, Page 2 provides a summary of the Service Quality performance for both the fourth quarter and overall FY 2018, while Attachment 2 provides month-by-month details for each measure. As shown on Attachment 1, Page 2, Column (8), National Grid's fourth quarter performance was within one standard deviation of the established benchmarks in all areas. In addition, as shown on Attachment 1, Page 2, Column (12), National Grid's FY 2018 performance was within one standard deviation of the established benchmarks in all areas except for On-Cycle Meter Reads. On June 22, 2018, National Grid filed with the Public Utilities Commission (PUC) a request for relief from the penalty associated with its FY 2018 On-Cycle Meter Reads performance as a result of an exogenous and/or force majeure event. At the time of this filing, the PUC has not ruled on the Company's request for relief from the penalty. On July 30, 2018, the Division of Public Utilities and Carriers (Division) filed a Memorandum recommending the approval of the Company's request for relief from the penalty.

The benchmark for Meter Testing is based on a calendar year basis, and was revised in October 2012 to reflect the Division's Rules and Regulations Prescribing Standards for Gas Utilities, Master Meter Systems, and Jurisdictional Propane Systems. National Grid has tested a total of 8,291 meters during the period of January 2018 through June 2018, as shown on Attachment 1, Page 2. National Grid will report the final calendar year results for this measure in

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

[2] The fiscal year in Docket No. 3476 runs from July 1 through June 30.

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its second quarter report for FY 2019. In addition, the After Business Hours benchmarks were modified effective January 1, 2013 and continue to be fixed at a mean of 95.27%, with a penalty threshold of 94.38%.

As noted above, National Grid has also updated the performance benchmarks for FY 2019 to incorporate the results of the most recent 12 months of data. Attachment 3 summarizes the benchmarks that will be used to measure performance for the period from July 1, 2018 through June 30, 2019. Attachment 4 provides National Grid's monthly statistics used to calculate the new benchmarks based on the most recent 36 months of data. Please note that National Grid completed 100% of the customer-requested meter tests within 15 days during the 36 months of the benchmark period, generating a standard deviation of zero and a benchmark of 100%. Establishing a benchmark of 100%, however, would not be reasonable or practical. Accordingly, for this measure only (customer-requested meter tests), National Grid proposes to continue use a mean benchmark of 99.60% with a penalty threshold of 94.04%, as it has used in prior years.

Finally, please note that the figure for Scheduled Meters to be read for July 2017 has been updated from the figure previously reported in the first quarter report. As a result, the On-Cycle Meter Reads metrics for that month have been updated for this annual report. The overall FY 2018 performance reflects the most up-to-date figures.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosures

cc: Docket 3476 Service List
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NATIONAL GRID - GAS OPERATIONS
SERVICE QUALITY PERFORMANCE
FISCAL YEAR 2018 - FOURTH QUARTER REPORT (2nd Quarter CY2018) *

SERVICE QUALITY MEASURES	Apr-18	May-18	Jun-18	Total or Weighted Average	Benchmark	Penalty Threshold
CALL CENTER RESPONSIVENESS						
Total Calls Answered	47,681	51,900	45,836	145,417		
Abandoned Calls	1,125	1,458	1,074	3,657		
Total Calls Offered	48,806	53,358	46,910	149,074		
% Abandoned Calls	2.31%	2.73%	2.29%	**2.45%**	3.68%	6.59%
Answered in 60 Seconds	42,676	44,475	40,356	127,507		
% Calls Answered in 60 Seconds	87.44%	83.35%	86.03%	**85.53%**	82.40%	71.60%
METER READS						
Scheduled Meters	278,913	278,928	279,140	836,981		
Meters Read	275,587	275,629	275,869	827,085		
% On-Cycle Meter Reads	98.81%	98.82%	98.83%	**98.82%**	98.70%	98.53%
METER TESTING**					CALENDAR YTD	CY2018 GOAL
<= 500 Cfh*** (180 month test interval	1,680	1,526	1,296	**4,502**	7,389	31,701
> 500 Cfh (120 month test interval)	221	156	144	**521**	902	3,091
Meters Not Tested (Attempts Exhausted)					21,677	
Inactive Meters					1,629	
Total					**31,597**	**34,792**
CUSTOMER REQUESTED TESTS						
Customer Requested Tests	0	0	1	1		
Tests Completed in 15 Days	0	0	1	1		
% Completed in 15 Days	100.00%	100.0%	100.0%	**100.0%**	99.60%	94.04%
SERVICE APPOINTMENTS						
Scheduled Service Appointments	3,078	3,369	3,071	9,518		
Completed Service Appointments	2,913	3,141	2,951	9,005		
% Service Appointments Met	94.64%	93.23%	96.09%	**94.61%**	95.00%	93.40%
SAFETY						
Leak-Call Response:						
Normal Business Hours:						
- Total Calls	389	373	318	1,080		
- Response in 30 Minutes or Less	372	354	307	1,033		
% in 30 Minutes or Less	95.63%	94.91%	96.54%	**95.65%**	95.28%	93.96%
After Business Hours**:**						
- Total Calls	298	274	268	840		
- Response in 45 Minutes or Less	289	262	256	807		
% in 45 Minutes or Less	96.98%	95.62%	95.52%	**96.07%**	95.27%	94.38%

* Note: Docket No. 3476 fiscal year runs July 1 through June 30.

** The meter testing measure is compiled on a calendar year basis. The final calendar year results will be adjusted to reflect the total of attempted periodic tests of meters and will l provided at calendar year end.

*** The definition of commercial and residential meters changed in October 2012 to reflect the revised Division 2006 Regulations. Under those regulations, meters with a capacity greater than 500 cubic feet per hour (Cfh) are classified as commercial, and meters with a capacity less than or equal to 500 Cfh are classified as residential.

**** The After Business Hours benchmarks were modified effective January 1, 2013 and are now fixed at a mean 95.27% with a penalty threshold of 94.38%.

NATIONAL GRID - GAS OPERATIONS
SERVICE QUALITY PERFORMANCE
FISCAL YEAR 2018 - FOURTH QUARTER REPORT

Service Quality Measures	Benchmarks & Penalties					Quarterly Performance				Annual Performance			
	Benchmark (Mean) (1)	Standard Deviation (2)	Penalty Threshold (3)	Penalty Weight (4)	Maximum Penalty (5)	4th Quarter Performance (6)	Variance from Mean (7)	# Standard Deviations (8)	Penalty (9)	Fiscal YTD Performance (10)	Variance from Mean (11)	# Standard Deviations (12)	Penalty (13)
Customer Service and Billing:													
Abandoned Calls	3.68%	2.91%	6.59%	12%	$150,000	2.45%	1.23%	0.4216	$0	2.04%	1.64%	0.5634	$0
Calls Answered in 60 Seconds	82.40%	10.80%	71.60%	12%	$150,000	85.53%	3.13%	0.2901	$0	88.62%	6.22%	0.5764	$0
On-Cycle Meter Reads	98.70%	0.17%	98.53%	6%	$75,000	98.82%	0.12%	0.6921	$0	97.37%	-1.33%	7.8416	$75,000
Meter Testing[14]				6%	$75,000				$0				$0
Total Meters <=500 Cfh Tested (180 month test interval)	31,701					4,502				7,389			
Total Meters >500 Cfh Tested (120 month test interval)	3,091					521				902			
Customer Requested Meter Tests	99.60%	5.56%	94.04%	4%	$50,000	100.00%	0.40%	0.0719	$0	100.00%	0.40%	0.0719	$0
Service Appointments Met	95.00%	1.60%	93.40%	12%	$150,000	94.61%	-0.39%	0.2436	$0	94.47%	-0.53%	0.3288	$0
Safety - Leak Call Response:													
Normal Business Hours-30 min or less	95.28%	1.32%	93.96%	24%	$300,000	95.65%	0.37%	0.2789	$0	95.26%	-0.02%	0.0150	$0
After Business Hours[15]-45 min or less	95.27%	0.89%	94.38%	24%	$300,000	96.07%	0.80%	0.9005	$0	95.91%	0.64%	0.7206	$0
				100%	$1,250,000				**$0**				**$75,000**

Notes:

(1)-(5) Submitted in the Annual Service Quality Report filed on July 31, 2017 (see Attachment 3, Cols. (1) - (3) for fiscal year (FY) 2018 Benchmark, Standard Deviation, and Penalty Threshold data).
(6) Fourth quarter of FY 2018 performance data.
(7) Calculated as (6) plus or minus (1), where positive results reflect above-average performance.
(8) Calculated as (7) divided by (2).
(9) Penalties are assessed when performance exceeds one standard deviation from the mean, with the maximum penalty assessed at two standard deviations from the mean. Only the penalties related to the safety measures are assessed quarterly.
(10) Year-to-date performance data for FY 2018 (i.e., July 2017 - June 2018) except Meter Testing. See Note (14).
(11) Calculated as (10) plus or minus (1), where positive results reflect above-average performance.
(12) Calculated as (11) divided by (2).
(13) Penalties are assessed when performance exceeds one standard deviation from the mean, with the maximum penalty assessed at two standard deviations from the mean. At the time of this filing, the Company's request for relief from the On-Cycle Meter Reads penalty as a result of an exogenous and/or force majeure event is pending in Docket No. 3476.
(14) The meter testing measure is compiled on a calendar year basis. Therefore, the FY 2018 Report reflects activity between January 2018 through June 2018. The final calendar year results will be adjusted to reflect the total of attempted periodic tests of meters and will be provided at calendar year end.
(15) The After Business Hours benchmarks were modified effective January 1, 2013 and are now fixed at a mean of 95.27% with a penalty threshold of 94.38%.

National Grid - Gas
RIPUC Docket No. 3476
Service Quality Report
Attachment 2

NATIONAL GRID - GAS OPERATIONS
SERVICE QUALITY PERFORMANCE
FISCAL YEAR 2018 - ANNUAL PERFORMANCE DATA

SERVICE QUALITY MEASURES	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total or Weighted Average
CALL CENTER RESPONSIVENESS													
Total Calls Answered	33,766	36,777	35,203	39,408	41,512	38,843	45,543	40,946	46,737	47,681	51,900	45,836	504,152
Abandoned Calls	1,242	475	532	509	955	490	862	867	912	1,125	1,458	1,074	10,501
Total Calls Offered	35,008	37,252	35,735	39,917	42,467	39,333	46,405	41,813	47,649	48,806	53,358	46,910	514,653
% Abandoned Calls	3.55%	1.28%	1.49%	1.28%	2.25%	1.25%	1.86%	2.07%	1.91%	2.31%	2.73%	2.29%	**2.04%**
Answered in 60 Seconds	27,288	34,344	32,960	37,281	37,514	36,639	41,823	37,933	42,822	42,676	44,475	40,356	456,111
% Calls Answered in 60 Seconds	77.95%	92.19%	92.23%	93.40%	88.34%	93.15%	90.13%	90.72%	89.87%	87.44%	83.35%	86.03%	**88.62%**
METER READS													
Scheduled Meters	278,541	277,635	277,635	277,798	278,026	278,470	298,194	278,698	280,524	278,913	278,929	279,140	3,362,503
Meters Read	274,489	273,488	273,679	273,698	231,236	275,015	294,679	275,240	275,356	275,587	275,630	275,869	3,273,966
% On-Cycle Meter Reads	98.55%	98.51%	98.58%	98.52%	83.17%	98.76%	98.82%	98.76%	98.16%	98.81%	98.82%	98.83%	**97.37%**
METER TESTING*													
<= 500 Cfh** (180 month test interval)	1,252	945	856	925	761	296	542	1,138	1,207	1,680	1,526	1,296	12,424
> 500 Cfh (120 month test interval)	97	78	105	132	50	57	113	122	146	221	156	144	1,421
Total Meters Tested*	1,349	1,023	961	1,057	811	353	655	1,260	1,353	1,901	1,682	1,440	**13,845**
CUSTOMER REQUESTED TESTS													
Customer Requested Tests	1	2	0	0	0	0	0	0	1	0	0	1	5
Tests Completed in 15 Days	1	2	0	0	0	0	0	0	1	0	0	1	5
% Completed in 15 Days	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	**100.0%**
SERVICE APPOINTMENTS													
Scheduled Service Appointments	2,656	2,946	2,804	2840	3206	2198	2533	2591	2891	3,078	3,369	3,071	34,183
Completed Service Appointments	2,528	2,749	2,619	2665	3014	2086	2376	2503	2749	2,913	3,141	2,951	32,294
% Service Appointments Met	95.18%	93.31%	93.40%	93.84%	94.01%	94.90%	93.80%	96.60%	95.09%	94.64%	93.23%	96.09%	**94.47%**
SAFETY													
Leak-Call Response:													
Normal Business Hours:													
- Total Calls	389	465	445	512	632	561	570	380	367	389	373	318	5,401
- Response in 30 Minutes or Less	360	449	435	485	608	525	535	364	351	372	354	307	5,145
% in 30 Minutes or Less	92.54%	96.56%	97.75%	94.73%	96.20%	93.58%	93.86%	95.79%	95.64%	95.63%	94.91%	96.54%	**95.26%**
After Business Hours*:**													
- Total Calls	307	333	304	359	489	513	561	317	355	298	274	268	4,378
- Response in 45 Minutes or Less	295	317	284	343	471	490	539	310	343	289	262	256	4,199
% in 45 Minutes or Less	96.09%	95.20%	93.42%	95.54%	96.32%	95.52%	96.08%	97.79%	96.62%	96.98%	95.62%	95.52%	**95.91%**

* The Meter Testing measure is compiled on a calendar year basis.

** The definition of commercial and residential meters changed in October 2012 to reflect the revised Division 2006 Regulations. Under those regulations, meters with a capacity greater than 500 cubic feet per hour (Cfh) are classified as commercial, and meters with a capacity less than or equal to 500 Cfh are classified as residential.

*** The After Business Hours benchmarks were modified effective January 1, 2013 and are now fixed at a mean of 95.27% with a penalty threshold of 94.38%.

National Grid - Gas
RIPUC Docket No. 3476
Service Quality Report
Attachment 3

NATIONAL GRID - GAS OPERATIONS
REVISED SERVICE QUALITY BENCHMARKS
FISCAL YEAR 2019

Measures	**Benchmark (Mean) FY19**	**Standard Deviation (+/-)**	**Penalty Threshold**
Customer Service and Billing:			
Abandoned Calls	2.93%	2.55%	5.48%
Calls Answer in 60 Seconds	85.62%	8.80%	76.82%
On-Cycle Meter Reads	98.26%	2.59%	95.67%
Meter Testing*	**CY2018 GOAL**		
<= 500 Cfh (180 month test interval)	31,701		
> 500 Cfh (120 month test interval)	3,091		
Customer Requested Meter Tests**	99.60%	5.56%	94.04%
Service Appointments Met	94.94%	1.41%	93.53%
Safety - Leak Call Response:			
Normal Business Hours-30 min or less	95.33%	1.23%	94.10%
After Business Hours***-45 min or less	95.27%	0.89%	94.38%

*The Meter Testing measure is compiled on a calendar year basis. The final calendar year results will be adjusted to reflect the total of attempted periodic tests of meters and will be provided at calendar year

**Most recent 36 months of data generate an unpractical benchmark of 100%. National Grid proposes to use a mean benchmark of 99.60% with a penalty threshold of 94.04%, as in prior years.

***The After Business Hours benchmarks were modified effective January 1, 2013 and are now fixed at a mean of 95.27% with a penalty threshold of 94.38%.

NATIONAL GRID - GAS OPERATIONS
SERVICE QUALITY BENCHMARKS

SERVICE QUALITY MEASURES	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16
CALL CENTER RESPONSIVENESS													
Total Calls Answered	47,802	43,996	45,864	52,438	38,240	38,341	39,291	41,455	46,218	41,094	40,521	38,276	32,562
Abandoned Calls	450	1,146	2,075	1,894	1,157	623	1,122	1,105	933	865	3,028	3,233	5,307
Total Calls Offered	48,252	45,142	47,939	54,332	39,397	38,964	40,413	42,560	47,151	41,959	43,549	41,509	37,869
% Abandoned Calls	0.93%	2.54%	4.33%	3.49%	2.94%	1.60%	2.78%	2.60%	1.98%	2.06%	6.95%	7.79%	14.01%
Answered in 60 Seconds	45,792	38,271	37,683	43,882	33,170	35,835	34,058	37,584	41,916	37,378	31,042	27,936	21,724
% Calls Answered in 60 Seconds	94.90%	84.78%	78.61%	80.77%	84.19%	91.97%	84.27%	88.31%	88.90%	89.08%	71.28%	67.30%	57.37%
METER READS													
Scheduled Meters	274,835	274,808	274,786	275,005	275,492	275,870	276,227	278,952	276,430	276,211	277,260	278,137	276,243
Meters Read	271,547	270,776	271,308	271,635	272,323	272,678	273,062	276,028	273,566	273,263	273,973	274,643	272,548
% On-Cycle Meter Reads	98.80%	98.53%	98.73%	98.77%	98.85%	98.84%	98.85%	98.95%	98.96%	98.93%	98.81%	98.74%	98.66%
METER TESTING*													
<= 500 Cfh (180 month test interval)	124	142	195	173	215	114	716	188	424	397	534	334	192
> 500 Cfh (120 month test interval)	59	78	45	65	52	116	71	101	122	94	95	80	57
Total Meters Tested	183	220	240	238	267	230	787	289	546	491	629	414	249
Customer Requested Tests	0	2	1	0	1	1	0	0	0	0	1	0	0
Tests Completed in 15 Days	0	2	1	0	1	1	0	0	0	0	1	0	0
% Completed in 15 Days	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
SERVICE APPOINTMENTS													
Scheduled Service Appointments	1,709	1,562	1,883	2504	2230	2232	1812	1512	1990	1,687	1,652	1,743	1,411
Completed Service Appointments	1,634	1,456	1,773	2342	2083	2177	1758	1453	1922	1,649	1,600	1,685	1,367
% Service Appointments Met	95.61%	93.21%	94.16%	93.53%	93.41%	97.54%	97.02%	96.10%	96.58%	97.75%	96.85%	96.67%	96.88%
SAFETY													
Leak-Call Response:													
Normal Business Hours:													
- Total Calls	392	372	405	581	591	515	510	434	398	340	342	365	322
- Response in 30 Minutes or Less	380	354	391	552	561	493	489	408	378	323	331	347	304
% in 30 Minutes or Less	96.94%	95.16%	96.54%	95.01%	94.92%	95.73%	95.88%	94.01%	94.97%	95.00%	96.78%	95.07%	94.41%
After Business Hours:**													
- Total Calls	308	370	317	530	482	433	519	476	306	292	269	248	235
- Response in 45 Minutes or Less	298	356	308	510	460	417	504	438	299	283	251	243	228
% in 45 Minutes or Less	96.75%	96.22%	97.16%	96.23%	95.44%	96.30%	97.11%	92.02%	97.71%	96.92%	93.31%	97.98%	97.02%

*The definition of commercial and residential meters changed in October 2012 to reflect the revised Division 2006 Regulations. Under those regulations, meters with a capacity greater than 500 cubic feet per hour (Cfh) are classified as commercial, and meters with a capacity less than or equal to 500 Cfh are classified as residential. This measure is compiled on a calendar year basis.

**The After Business Hours benchmarks were modified effective January 1, 2013 and are now fixed at a mean of 95.27% with a penalty threshold of 94.38%.

NATIONAL GRID - GAS OPERATIONS
SERVICE QUALITY BENCHMARKS

SERVICE QUALITY MEASURES	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17
CALL CENTER RESPONSIVENESS												
Total Calls Answered	40,735	34,541	40,143	36,196	36,514	38,881	35,880	42,893	37,937	45,202	39,183	33,766
Abandoned Calls	1,444	494	379	411	285	740	928	869	671	1,813	3,187	1,242
Total Calls Offered	42,179	35,035	40,522	36,607	36,799	39,621	36,808	43,762	38,608	47,015	42,370	35,008
% Abandoned Calls	3.42%	1.41%	0.94%	1.12%	0.77%	1.87%	2.52%	1.99%	1.74%	3.86%	7.52%	3.55%
Answered in 60 Seconds	35,737	32,917	38,893	34,704	35,330	34,937	30,555	38,656	34,489	37,028	28,409	27,288
% Calls Answered in 60 Seconds	84.73%	93.95%	95.98%	94.80%	96.01%	88.18%	83.01%	88.33%	89.33%	78.76%	67.05%	77.95%
METER READS												
Scheduled Meters	276,302	276,315	279,383	276,880	282,457	299,485	279,335	281,014	278,658	281,522	278,158	278,541
Meters Read	272,380	272,163	275,384	272,986	278,065	295,734	275,757	277,300	274,875	277,617	273,922	274,489
% On-Cycle Meter Reads	98.58%	98.50%	98.57%	98.59%	98.45%	98.75%	98.72%	98.68%	98.64%	98.61%	98.48%	98.55%
METER TESTING*												
<= 500 Cfh (180 month test interval)	333	578	1,056	398	371	450	837	1,521	1,830	2,036	1,140	1,252
> 500 Cfh (120 month test interval)	41	65	63	23	33	103	139	137	250	203	102	97
Total Meters Tested	374	643	1,119	421	404	553	976	1,658	2,080	2,239	1,242	1,349
Customer Requested Tests	2	0	1	0	0	0	0	0	0	0	0	1
Tests Completed in 15 Days	2	0	1	0	0	0	0	0	0	0	0	1
% Completed in 15 Days	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
SERVICE APPOINTMENTS												
Scheduled Service Appointments	1,748	2,412	2960	2493	2417	2190	2620	3855	3,165	3,175	3,079	2,656
Completed Service Appointments	1,652	2,316	2791	2324	2249	2099	2515	3672	3,031	3,034	2,887	2,528
% Service Appointments Met	94.51%	96.02%	94.29%	93.22%	93.05%	95.84%	95.99%	95.25%	95.77%	95.56%	93.76%	95.18%
SAFETY												
Leak-Call Response:												
Normal Business Hours:												
- Total Calls	453	442	516	515	591	497	362	384	384	437	491	389
- Response in 30 Minutes or Less	438	412	495	480	564	475	346	377	364	417	467	360
% in 30 Minutes or Less	96.69%	93.21%	95.93%	93.20%	95.43%	95.57%	95.58%	98.18%	94.79%	95.42%	95.11%	92.54%
After Business Hours:**												
- Total Calls	311	269	385	389	534	437	371	391	294	300	294	307
- Response in 45 Minutes or Less	305	261	372	378	506	421	361	359	289	290	283	295
% in 45 Minutes or Less	98.07%	97.03%	96.62%	97.17%	94.76%	96.34%	97.30%	91.82%	98.30%	96.67%	96.26%	96.09%

NATIONAL GRID - GAS OPERATIONS
SERVICE QUALITY BENCHMARKS

SERVICE QUALITY MEASURES	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	36 Month Average	Standard Deviation	Penalty Threshold	Maximum Penalty
CALL CENTER RESPONSIVENESS															
Total Calls Answered	36,777	35,203	39,408	41,512	38,843	45,543	40,946	46,737	47,681	51,900	45,836	41,065			
Abandoned Calls	475	532	509	955	490	862	867	912	1,125	1,458	1,074	1,241			
Total Calls Offered	37,252	35,735	39,917	42,467	39,333	46,405	41,813	47,649	48,806	53,358	46,910	42,306			
% Abandoned Calls	1.28%	1.49%	1.28%	2.25%	1.25%	1.86%	2.07%	1.91%	2.31%	2.73%	2.29%	**2.93%**	2.55%	5.48%	8.03%
Answered in 60 Seconds	34,344	32,960	37,281	37,514	36,639	41,823	37,933	42,822	42,676	44,475	40,356	36,223			
% Calls Answered in 60 Seconds	92.19%	92.23%	93.40%	88.34%	93.15%	90.13%	90.72%	89.87%	87.44%	83.35%	86.03%	**85.62%**	8.80%	76.82%	68.02%
METER READS															
Scheduled Meters	277,635	277,635	277,798	278,026	278,470	298,194	278,698	280,524	278,913	278,929	279,140	278,952			
Meters Read	273,488	273,679	273,698	231,236	275,015	294,679	275,240	275,356	275,587	275,630	275,869	274,097			
% On-Cycle Meter Reads	98.51%	98.58%	98.52%	83.17%	98.76%	98.82%	98.76%	98.16%	98.81%	98.82%	98.83%	**98.26%**	2.59%	95.67%	93.08%
METER TESTING*															
<= 500 Cfh (180 month test interval)	945	856	925	761	296	542	1,138	1,207	1,680	1,526	1,296	8,907			
> 500 Cfh (120 month test interval)	78	105	132	50	57	113	122	146	221	156	144	1,205			
Total Meters Tested	1,023	961	1,057	811	353	655	1,260	1,353	1,901	1,682	1,440	**10,112**			
Customer Requested Tests	2	0	0	0	0	0	0	1	0	0	1	0			
Tests Completed in 15 Days	2	0	0	0	0	0	0	1	0	0	1	0			
% Completed in 15 Days	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	**100.00%**	0.00%	100.00%	100.00%
SERVICE APPOINTMENTS															
Scheduled Service Appointments	2,946	2,804	2,840	3,206	2,198	2,533	2,591	2,891	3,078	3,369	3,071	2,451			
Completed Service Appointments	2,749	2,619	2,665	3,014	2,086	2,376	2,503	2,749	2,913	3,141	2,951	2,327			
% Service Appointments Met	93.31%	93.40%	93.84%	94.01%	94.90%	93.80%	96.60%	95.09%	94.64%	93.23%	96.09%	**94.94%**	1.41%	93.53%	92.12%
SAFETY															
Leak-Call Response:															
Normal Business Hours:															
- Total Calls	465	445	512	632	561	570	380	367	389	373	318	446			
- Response in 30 Minutes or Less	449	435	485	608	525	535	364	351	372	354	307	425			
% in 30 Minutes or Less	96.56%	97.75%	94.73%	96.20%	93.58%	93.86%	95.79%	95.64%	95.63%	94.91%	96.54%	**95.33%**	1.23%	94.10%	92.87%
After Business Hours:**															
- Total Calls	333	304	359	489	513	561	317	355	298	274	268	365			
- Response in 45 Minutes or Less	317	284	343	471	490	539	310	343	289	262	256	351			
% in 45 Minutes or Less	95.20%	93.42%	95.54%	96.32%	95.52%	96.08%	97.79%	96.62%	96.98%	95.62%	95.52%	**96.05%**	1.52%	94.53%	93.01%

nationalgrid

Robert J. Humm
Senior Counsel

June 22, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 3476 – Quarterly Report on Service Quality Plan
Request for Relief from Penalty Because of Exogenous and/or Force Majeure Event

Dear Ms. Massaro:

On behalf of National Grid,[1] I am enclosing the Company's request for relief from a penalty under the Gas Service Quality Plan (the Service Quality Plan) as a result of an exogenous and/or force majeure event. Pursuant to Rhode Island Public Utilities Commission (PUC) Order No. 17605 (November 21, 2003) regarding the Service Quality Plan in Docket No. 3476, if the Company "contends that an exogenous event or a force majeure occurred, it must seek relief from the Commission and the burden of proof will be on [the Company]." The Company's November 2017 performance for On-Cycle Meter Reads fell below the penalty threshold established in Order No. 17605 as a result of an exogenous and/or force majeure event, namely the October 29-30, 2017 wind and rain storm (the October Storm). The October Storm required the reallocation of the Company's meter reading workforce to provide emergency wires down support during the week of October 30, during which the Company responded to more than 5,000 wires down calls. As a result of the five days of estimated meter reads incurred during the Company's response to the October Storm, the Company will not be able to achieve the annual On-Cycle Meter Reads target under the Service Quality Plan. Accordingly, the Company requests relief from the PUC from the On-Cycle Meter Reads penalty as a result of the exogenous and/or force majeure event.

This request is supported by the pre-filed direct testimony of Gary Bennett, Director of Customer Meter Services, New England South and West.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosure

cc: Docket 3476 Service List
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7415 ■ robert.humm@nationalgrid.com ■ www.nationalgrid.com

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PRE-FILED DIRECT TESTIMONY

OF

GARY BENNETT

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I. Introduction

Q. Please state your name and business address.

A. My name is Gary Bennett. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. (Service Company) as Director of Customer Meter Services, New England South and West. In this role, I manage the Customer Meter Services department in Rhode Island and Southern and Western Massachusetts. Among other responsibilities, I oversee the work performed for the gas and electric service quality measures set forth in The Narragansett Electric Company's (the Company) service quality plans, including the execution of meter reading.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Marine Engineering from Massachusetts Maritime Academy in 1982. In 1987, I earned a Master's degree in Business Administration from Rensselaer Polytechnic Institute. Before working at National Grid, I worked at General Dynamics as a Nuclear Test Engineer from 1982 to 1988, and at LTXX as a Manufacturing Supervisor from 1988 to 1991. In 1991, I began working at National Grid – namely, its predecessor companies Boston Gas Company (Boston Gas)

and KeySpan Corporation (KeySpan). At Boston Gas, I held the following positions: Budget Analyst in the Field Customer Service department; Field Coordinator for the Distribution department; and Supervisor of Gas Dispatch. At KeySpan Home Energy Services, a division of KeySpan, I held the position of Manager of Field Operations and Director of Support Services. I also held the position of Director of Call Center and Billing at KeySpan. After National Grid merged with KeySpan, I held the following positions: Director of Customer Meter Services, New England North; Director of Dispatch; Director of Performance and Reporting; and my current position as Director of Customer Meter Services, New England South and West. I assumed my current position in 2016.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commission?

A. I have not previously testified before the PUC. However, in 2008, I testified before the New Hampshire Public Utilities Commission as part of EnergyNorth Natural Gas, Inc. d/b/a National Grid NH's rate case filing in Docket DG 08-009.

II. <u>Purpose and Structure of Testimony</u>

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

A. The purpose of my testimony is to describe the Company's fiscal year (FY) 2018 On-Cycle Meter Reads performance as part of the overall Gas Service Quality Plan (the

Service Quality Plan). In particular, my testimony will demonstrate that the Company's On-Cycle Meter Reads performance fell below the penalty threshold established by the PUC in the Service Quality Plan in Docket No. 3476 as a result of an exogenous and/or force majeure event, namely the October 29-30, 2017 wind and rain storm (the October Storm). Accordingly, my testimony requests relief from the PUC, pursuant to Order No. 17605 in Docket No. 3476, from the On-Cycle Meter Reads penalty as a result of the exogenous and/or force majeure event.

Q. How is the testimony structured?

A. Section I of my testimony presents the Introduction. Section II describes the purpose and structure of my testimony. Section III presents the Company's request for relief from the PUC as a result of the occurrence of an exogenous and/or force majeure event, including the background and reasons for the request. Section IV is the conclusion of my testimony.

III. <u>Request for Relief from Penalty Because of Exogenous and/or Force Majeure Event</u>

Q. What is the purpose of the Service Quality Plan?

A. The purpose of the Service Quality Plan is to ensure that the Company's gas customers receive a reasonable level of service. The Service Quality Plan is comprised of the following five key aspects: service measures, benchmark standards, a penalty amount for not meeting the benchmark standards, the penalty weight for each measure, and the time

period for measuring performance to assess a penalty. To meet these standards, the Company's Service Quality Plan includes the following eight service quality measures to monitor the quality of service to customers: Abandoned Call Rate; Average Speed of Answer; On-Cycle Meter Reads; Testing of Meters; Customer Requested Meter Tests Completed; Service Appointments Met as Scheduled; Leak Call Responsiveness – Normal Business Hours; and Leak Call Responsiveness – After Normal Business Hours.

Q. What is the On-Cycle Meter Reads service quality measure?

A. The On-Cycle Meter Reads percentage measures the ratio of actual meter reads to the number of meters assigned to be read.

Q. What is the current service quality benchmark for On-Cycle Meter Reads, and how was that benchmark established?

A. The current service quality benchmark for On-Cycle Meter Reads is 98.70 percent over the Service Quality Plan fiscal year,[1] with a penalty threshold of 98.53 percent. When the PUC established the Service Quality Plan in 2003, the PUC originally set a benchmark of 94.52 percent for On-Cycle Meter Reads, with a penalty threshold of 93.30 percent, based on a three-year meter reading performance utilizing one standard deviation as a means to set the penalty threshold. The Company has consistently achieved and/or

[1] The Service Quality Plan fiscal year is July 1 through June 30, as set forth in Docket No. 3476.

exceeded the On-Cycle Meter Reads benchmark each year since its inception. As a result, the On-Cycle Meter Reads benchmark has increased to its current level of 98.70 percent with a much narrower penalty threshold.

Q. Please describe the process for how the Company completes the On-Cycle Meter Reads?

A. The Company reads all of its approximately 795,000 gas and electric meters in Rhode Island each month, including approximately 278,000 gas meters each month.[2] The gas meter reading schedule is divided into 20 cycles per month. The Company uses two methods to read gas meters. First, more than 99 percent of the gas meters are read by an Automated Meter Reading process. Automated Meter Reading uses an Encoded Receiver Transmitter device installed on the meter that transmits a radio signal to a meter reading application located on a Company vehicle as the vehicle passes by the meter. Second, the remaining meters are read through an Electronic Meter Reading process. Under the Electronic Meter Reading process, a pedestrian meter reader manually reads a meter and enters the information into a handheld meter reading device. Gas meters must be read within three days of their scheduled reading date before the window is closed for customer billing. Any meter that is not read within the three day window will be

[2] The same Company employees read both gas and electric meters.

provided an estimated read on a customer's bill. The Company uses between 15 and 17 employees to read all gas and electric meters each month.

Q. During week of October 30, 2017, how many gas meters were assigned to be read and how many actual meter reads occurred?

A. The table below sets forth the schedule of gas meters assigned to be read, and actual meter reads, during the week of October 30, 2017:

Date	Meters Assigned to be Read	Actual # of Meters Read
October 30 (Cycle 20)	9,974 meters assigned	0 meters read
October 31 (Cycle 1)	20,183 meters assigned	0 meters read
November 1 (Cycle 2)	10,448 meters assigned	0 meters read
November 2 (Cycle 3)	21,697 meters assigned	0 meters read
November 3 (Cycle 4)	12,379 meters assigned	0 meters read

Thus, none of the gas meters scheduled to be read during the week of the October Storm were actually read.

Q. Why did the Company not read any of the scheduled meters during the week of the October Storm?

A. The October Storm required the reallocation of the Company's Customer Meter Services department, including the meter reading workforce, to provide emergency wires down support during the week of October 30, 2017. "Emergency wires down support" consists of dispatching a qualified person to respond to electric wires on the ground that could potentially pose a public safety hazard and to take appropriate action to make the area

safe, including guarding the fallen wire until a qualified crew can be dispatched to remediate the wires down issue. During the week of October 30, the Company responded to more than 5,000 wires down calls. As a result of the five days of estimated meter reads incurred during the Company's response to the October Storm, the Company will not be able to achieve the annual On-Cycle Meter Reads target.

Q. How does the Company's performance during the week of October 30, 2017 affect the Service Quality Plan annual benchmark for On-Cycle Meter Reads?

A. As a result of the five days the Company was unable to read meters because of the October Storm, the Company will not be able to achieve its required annual benchmark of 98.70 percent or annual penalty threshold of 98.53 percent, even if the Company were to achieve an On-Cycle Meter Reads rate of 100 percent for the remainder of the Service Quality Plan fiscal year.

Q. Why is the Company making this request for relief from the penalty?

A. Pursuant to Order No. 17605 in Docket No. 3476, if the Company "contends that an exogenous event or a force majeure occurred, it must seek relief from the Commission and the burden of proof will be on [the Company]." The October Storm is an exogenous and force majeure event. As such, the Company seeks relief from the penalty associated with not meeting the annual benchmark for the On-Cycle Meter Reads, which is the direct result of the impact of the October Storm.

Q. Why is the October Storm an exogenous and force majeure event?

A. The October Storm was a major wind and rain event that severely impacted the Company's infrastructure throughout its service territory. Contrary to the forecasts, the October Storm brought strong, hazardous wind gusts that affected the majority of the Northeast during the night on Sunday, October 29 through Monday, October 30, 2017. The October Storm impacted a total of approximately 176,247 customers in the Company's Rhode Island service territory, with approximately 144,144 customers impacted at the October Storm's peak. The Company experienced interruptions in all 38 communities it serves, with more than 200 distribution feeders affected and more than 5,000 wires down calls throughout the state. In fact, the October Storm impacted more customers than Hurricane Sandy in 2012 and produced more physical damage to the Company's poles than Tropical Storm Irene in 2011. Overall, the October Storm posed significant challenges for the Company, as the weather rapidly escalated to a very severe event beyond the expected forecasts, and impacted all of the Company's communities within a very short timeframe.

Q. But for the five-day period during the October Storm, would the Company have incurred a penalty for its On-Cycle Meter Reads performance?

A. No. To put the impact of the October Storm into context, the Company's inability to read meters on November 1, 2, and 3 during the week of October 30, 2017 resulted in a November 2017 meter read rate of 83.17 percent, comprised of 278,026 meters scheduled

to be read and 231,236 meters actually read. In comparison, for the past five years, the Company had averaged an annual meter reading rate of approximately 98.70 percent. Assuming the June 2018[3] results are in line with historical experience, a typical meter reading rate for the impacted week in November 2017 would have resulted in an annual performance rate above the penalty threshold for the year. The last time the Company fell below even a 98 percent annual On-Cycle Meter Reads rate for any one month was in July 2013 (97.8 percent), which was still well above the annual benchmark and penalty threshold at the time.

IV. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

[3] The Company expects the June 2018 data will be available in mid-July 2018.

Division 1-8

Request:

Re: The August 1, 2018 Direct Testimony of Witness Ann E. Leary at page 18, lines 11 through 13, please provide:

a. The current benchmark Target Revenue-Per-Customer for both Residential Heating and Residential Non-Heating rate classes;

b. The benchmark Target Revenue-Per-Customer for both Residential Heating and Residential Non-Heating rate classes for each of the past three years;

c. The benchmark Target Revenue-Per-Customers for both Residential Heating and Residential Non-Heating rate classes established in 4323;

d. All workpapers, documents, and supporting calculations for the development of the current benchmark Target Revenue-Per-Customer for both the Residential Heating and Residential Non-Heating rate classes.

Response:

a. Please see Attachment DIV 1-8(a) for the current benchmark Target Revenue-Per-Customer for both Residential Heating and Residential Non-Heating rate classes. Please note these are the same benchmarks approved in Docket No. 4708.

b. Please see Attachment DIV 1-8(b) for the benchmark Target Revenue-Per-Customer for both Residential Heating and Residential Non-Heating rate classes for each of the past three years.

c. Please see Attachment DIV 1-8(c) for the requested benchmarks established pursuant to the Settlement Agreement in Docket No. 4323 (2012 Rate Case). Please note that the Company provided the benchmark Target Revenue-Per-Customer in Docket No. 4514 in accordance with the approved Settlement Agreement in the 2012 Rate Case. Pursuant to Article III, Section C.4 of the Settlement Agreement in the 2012 Rate Case, the actual average rate year customer count and actual growth capital investment from the end of the test year to the end of the rate year was used for purposes of establishing the Revenue-Per-Customer targets used in the calculation of the Company's annual Revenue Decoupling Mechanism for the period commencing February 1, 2013, which was the effective date for the new base distribution rates in the 2012 Rate Case.

Prepared by or under the supervision of: Ann E. Leary

Division 1-8, page 2

d. Please see the Excel version of Attachment DIV 1-8(d), which includes the workpapers used to develop the current benchmark Target Revenue-Per-Customer, as well as the benchmark Target Revenue-Per-Customer for the past three years and benchmarks established in Docket No. 4323, for both Residential Heating and Residential Non-Heating rate classes.

Prepared by or under the supervision of: Ann E. Leary

Gas Revenue Decoupling Targets Reflected in Docket No. 4846

		Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(1)	Residential Non-Heat (incl Low-Income)													
(2)	Number of Customers	26,197	26,140	26,085	26,015	25,964	25,969	25,980	26,058	26,107	26,125	26,234	26,255	
(3)	Number of Accounts Transferred Nov 2014	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	
(4)	Number of Accounts Transferred Jun 2015	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	
(5)	Number of Accounts Transferred Jul 2016	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	
(6)	Number of Customers	21,943	21,886	21,831	21,761	21,710	21,715	21,726	21,804	21,853	21,871	21,980	22,001	
(7)	Final Revenue Requirement	$551,147	$480,518	$440,626	$421,958	$404,421	$411,267	$425,590	$468,132	$543,736	$608,707	$619,002	$604,058	$5,979,163
(8)	**RPC**	$25.12	$21.96	$20.18	$19.39	$18.63	$18.94	$19.59	$21.47	$24.88	$27.83	$28.16	$27.46	
(9)	Residential Heating (incl Low-Income)													
(10)	Number of Customers	206,526	205,560	204,853	204,218	203,713	203,918	204,929	206,779	208,036	208,864	206,524	206,734	
(11)	Number of Accounts Transferred Nov 2014	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	
(12)	Number of Accounts Transferred Jun 2015	970	970	970	970	970	970	970	970	970	970	970	970	
(13)	Number of Accounts Transferred Jul 2016	684	684	684	684	684	684	684	684	684	684	684	684	
(14)	Number of Customers	210,780	209,814	209,107	208,472	207,967	208,172	209,183	211,033	212,290	213,118	210,778	210,988	
(15)	Final Revenue Requirement	$11,157,590	$7,202,607	$5,097,052	$4,502,584	$4,237,221	$4,306,645	$4,692,464	$7,051,595	$11,560,624	$14,908,187	$15,552,475	$14,470,701	$104,739,746
(16)	**RPC**	$52.93	$34.33	$24.38	$21.60	$20.37	$20.69	$22.43	$33.41	$54.46	$69.95	$73.79	$68.59	
(17)	Small													
(18)	Number of Customers	18,697	18,524	18,381	18,270	18,221	18,243	18,367	18,680	18,856	18,995	18,800	18,800	
(19)	Final Revenue Requirement	$1,457,117	$928,852	$615,286	$579,616	$538,554	$536,429	$588,115	$875,201	$1,472,999	$2,206,366	$1,901,912	$1,957,612	$13,658,058
(20)	**RPC**	$77.93	$50.14	$33.47	$31.72	$29.56	$29.40	$32.02	$46.85	$78.12	$116.16	$101.17	$104.13	
(21)	Medium C&I													
(22)	Number of Customers	4,702	4,691	4,694	4,684	4,665	4,678	4,700	4,734	4,758	4,773	4,696	4,705	
(23)	Final Revenue Requirement	$1,838,057	$1,438,900	$1,215,685	$1,068,436	$1,004,164	$1,064,655	$1,178,537	$1,510,387	$1,910,148	$2,404,616	$2,432,687	$2,334,238	$19,400,509
(24)	**RPC**	$390.91	$306.74	$258.99	$228.10	$215.25	$227.59	$250.75	$319.05	$401.46	$503.80	$518.03	$496.12	

Gas Revenue Decoupling Targets Reflected in Docket No. 4708

		Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(1)	Residential Non-Heat (incl Low-Income)													
(2)	Number of Customers	26,197	26,140	26,085	26,015	25,964	25,969	25,980	26,058	26,107	26,125	26,234	26,255	
(3)	Number of Accounts Transferred Nov 2014	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	
(4)	Number of Accounts Transferred Jun 2015	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	
(5)	Number of Accounts Transferred Jul 2016	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	
(6)	Number of Customers	21,943	21,886	21,831	21,761	21,710	21,715	21,726	21,804	21,853	21,871	21,980	22,001	
(7)	Final Revenue Requirement	$551,147	$480,518	$440,626	$421,958	$404,421	$411,267	$425,590	$468,132	$543,736	$608,707	$619,002	$604,058	$5,979,163
(8)	**RPC**	$25.12	$21.96	$20.18	$19.39	$18.63	$18.94	$19.59	$21.47	$24.88	$27.83	$28.16	$27.46	
(9)	Residential Heating (incl Low-Income)													
(10)	Number of Customers	206,526	205,560	204,853	204,218	203,713	203,918	204,929	206,779	208,036	208,864	206,524	206,734	
(11)	Number of Accounts Transferred Nov 2014	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	
(12)	Number of Accounts Transferred Jun 2015	970	970	970	970	970	970	970	970	970	970	970	970	
(13)	Number of Accounts Transferred Jul 2016	684	684	684	684	684	684	684	684	684	684	684	684	
(14)	Number of Customers	210,780	209,814	209,107	208,472	207,967	208,172	209,183	211,033	212,290	213,118	210,778	210,988	
(15)	Final Revenue Requirement	$11,157,590	$7,202,607	$5,097,052	$4,502,584	$4,237,221	$4,306,645	$4,692,464	$7,051,595	$11,560,624	$14,908,187	$15,552,475	$14,470,701	$104,739,746
(16)	**RPC**	$52.93	$34.33	$24.38	$21.60	$20.37	$20.69	$22.43	$33.41	$54.46	$69.95	$73.79	$68.59	
(17)	Small													
(18)	Number of Customers	18,697	18,524	18,381	18,270	18,221	18,243	18,367	18,680	18,856	18,995	18,800	18,800	
(19)	Final Revenue Requirement	$1,457,117	$928,852	$615,286	$579,616	$538,554	$536,429	$588,115	$875,201	$1,472,999	$2,206,366	$1,901,912	$1,957,612	$13,658,058
(20)	**RPC**	$77.93	$50.14	$33.47	$31.72	$29.56	$29.40	$32.02	$46.85	$78.12	$116.16	$101.17	$104.13	
(21)	Medium C&I													
(22)	Number of Customers	4,702	4,691	4,694	4,684	4,665	4,678	4,700	4,734	4,758	4,773	4,696	4,705	
(23)	Final Revenue Requirement	$1,838,057	$1,438,900	$1,215,685	$1,068,436	$1,004,164	$1,064,655	$1,178,537	$1,510,387	$1,910,148	$2,404,616	$2,432,687	$2,334,238	$19,400,509
(24)	**RPC**	$390.91	$306.74	$258.99	$228.10	$215.25	$227.59	$250.75	$319.05	$401.46	$503.80	$518.03	$496.12	

Gas Revenue Decoupling Targets Reflected in Docket No. 4634

		Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(1)	Residential Non-Heat (incl Low-Income)													
(2)	Number of Customers	26,197	26,140	26,085	26,015	25,964	25,969	25,980	26,058	26,107	26,125	26,234	26,255	
(3)	Number of Accounts Transferred Nov 2014	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	
(4)	Number of Accounts Transferred Jun 2015	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	
(5)	Number of Customers	22,627	22,570	22,515	22,445	22,394	22,399	22,410	22,488	22,537	22,555	22,664	22,685	
(6)	Final Revenue Requirement	$551,147	$480,518	$440,626	$421,958	$404,421	$411,267	$425,590	$468,132	$543,736	$608,707	$619,002	$604,058	$5,979,163
(7)	**RPC**	$24.36	$21.29	$19.57	$18.80	$18.06	$18.36	$18.99	$20.82	$24.13	$26.99	$27.31	$26.63	
(8)	Residential Heating (incl Low-Income)													
(9)	Number of Customers	206,526	205,560	204,853	204,218	203,713	203,918	204,929	206,779	208,036	208,864	206,524	206,734	
(10)	Number of Accounts Transferred Nov 2014	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	
(11)	Number of Accounts Transferred Jun 2015	970	970	970	970	970	970	970	970	970	970	970	970	
(12)	Number of Customers	210,096	209,130	208,423	207,788	207,283	207,488	208,499	210,349	211,606	212,434	210,094	210,304	
(13)	Final Revenue Requirement	$11,157,590	$7,202,607	$5,097,052	$4,502,584	$4,237,221	$4,306,645	$4,692,464	$7,051,595	$11,560,624	$14,908,187	$15,552,475	$14,470,701	$104,739,746
(14)	**RPC**	$53.11	$34.44	$24.46	$21.67	$20.44	$20.76	$22.51	$33.52	$54.63	$70.18	$74.03	$68.81	
(15)	Small													
(16)	Number of Customers	18,697	18,524	18,381	18,270	18,221	18,243	18,367	18,680	18,856	18,995	18,800	18,800	
(17)	Final Revenue Requirement	$1,457,117	$928,852	$615,286	$579,616	$538,554	$536,429	$588,115	$875,201	$1,472,999	$2,206,366	$1,901,912	$1,957,612	$13,658,058
(18)	**RPC**	$77.93	$50.14	$33.47	$31.72	$29.56	$29.40	$32.02	$46.85	$78.12	$116.16	$101.17	$104.13	
(19)	Medium C&I													
(20)	Number of Customers	4,702	4,691	4,694	4,684	4,665	4,678	4,700	4,734	4,758	4,773	4,696	4,705	
(21)	Final Revenue Requirement	$1,838,057	$1,438,900	$1,215,685	$1,068,436	$1,004,164	$1,064,655	$1,178,537	$1,510,387	$1,910,148	$2,404,616	$2,432,687	$2,334,238	$19,400,509
(22)	**RPC**	$390.91	$306.74	$258.99	$228.10	$215.25	$227.59	$250.75	$319.05	$401.46	$503.80	$518.03	$496.12	

Gas Revenue Decoupling Targets Reflected in Docket No. 4573

		Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(1)	Residential Non-Heat (incl Low-Income)													
(2)	Number of Customers	26,197	26,140	26,085	26,015	25,964	25,969	25,980	26,058	26,107	26,125	26,234	26,255	
(3)	Number of Accounts Transferred Nov 2014	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	(2,600)	
(4)	Adjusted Number of Customers	23,597	23,540	23,485	23,415	23,364	23,369	23,380	23,458	23,507	23,525	23,634	23,655	
(5)	Final Revenue Requirement	$551,147	$480,518	$440,626	$421,958	$404,421	$411,267	$425,590	$468,132	$543,736	$608,707	$619,002	$604,058	$5,979,163
(6)	**RPC**	$23.36	$20.41	$18.76	$18.02	$17.31	$17.60	$18.20	$19.96	$23.13	$25.87	$26.19	$25.54	
(7)	Residential Heating (incl Low-Income)													
(8)	Number of Customers	206,526	205,560	204,853	204,218	203,713	203,918	204,929	206,779	208,036	208,864	206,524	206,734	
(9)	Number of Accounts Transferred Nov 2014	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	
(10)	Adjusted Number of Customers	209,126	208,160	207,453	206,818	206,313	206,518	207,529	209,379	210,636	211,464	209,124	209,334	
(11)	Final Revenue Requirement	$11,157,590	$7,202,607	$5,097,052	$4,502,584	$4,237,221	$4,306,645	$4,692,464	$7,051,595	$11,560,624	$14,908,187	$15,552,475	$14,470,701	$104,739,746
(12)	**RPC**	$53.35	$34.60	$24.57	$21.77	$20.54	$20.85	$22.61	$33.68	$54.88	$70.50	$74.37	$69.13	
(13)	Small													
(14)	Number of Customers	18,697	18,524	18,381	18,270	18,221	18,243	18,367	18,680	18,856	18,995	18,800	18,800	
(15)	Final Revenue Requirement	$1,457,117	$928,852	$615,286	$579,616	$538,554	$536,429	$588,115	$875,201	$1,472,999	$2,206,366	$1,901,912	$1,957,612	$13,658,058
(16)	**RPC**	$77.93	$50.14	$33.47	$31.72	$29.56	$29.40	$32.02	$46.85	$78.12	$116.16	$101.17	$104.13	
(17)	Medium C&I													
(18)	Number of Customers	4,702	4,691	4,694	4,684	4,665	4,678	4,700	4,734	4,758	4,773	4,696	4,705	
(19)	Final Revenue Requirement	$1,838,057	$1,438,900	$1,215,685	$1,068,436	$1,004,164	$1,064,655	$1,178,537	$1,510,387	$1,910,148	$2,404,616	$2,432,687	$2,334,238	$19,400,509
(20)	**RPC**	$390.91	$306.74	$258.99	$228.10	$215.25	$227.59	$250.75	$319.05	$401.46	$503.80	$518.03	$496.12	

Gas Revenue Decoupling Targets Reflected in Docket No. 4514

Gas Revenue Decoupling Targets[1]

Line No.		Feb-13 (a)	Mar-13 (b)	Apr-13 (c)	May-13 (d)	Jun-13 (e)	Jul-13 (f)	Aug-13 (g)	Sep-13 (h)	Oct-13 (i)	Nov-13 (j)	Dec-13 (k)	Jan-14 (l)	Total Feb 13 - Jan 14 (m)
	Residential Non-Heat													
1	Residential Non-Heat (incl Low-Income)													
2	Number of Customers	26,234	26,255	26,197	26,140	26,085	26,015	25,964	25,969	25,980	26,058	26,107	26,125	
3	Actual Revenue	$ 619,002	$ 604,058	$ 551,147	$ 480,518	$ 440,626	$ 421,958	$ 404,421	$ 411,267	$ 425,590	$ 468,132	$ 543,736	$ 608,707	$ 5,979,163
4	**RPC**	$ 23.60	$ 23.01	$ 21.04	$ 18.38	$ 16.89	$ 16.22	$ 15.58	$ 15.84	$ 16.38	$ 17.97	$ 20.83	$ 23.30	
5	Residential Heating (incl Low-Income)													
6	Number of Customers	206,524	206,734	206,526	205,560	204,853	204,218	203,713	203,918	204,929	206,779	208,036	208,864	
7	Actual Revenue	$ 15,552,475	$ 14,470,701	$ 11,157,590	$ 7,202,607	$ 5,097,052	$ 4,502,584	$ 4,237,221	$ 4,306,645	$ 4,692,464	$ 7,051,595	$ 11,560,624	$ 14,908,187	$ 104,739,746
8	**RPC**	$ 75.31	$ 70.00	$ 54.03	$ 35.04	$ 24.88	$ 22.05	$ 20.80	$ 21.12	$ 22.90	$ 34.10	$ 55.57	$ 71.38	
9	Small													
10	Number of Customers	18,800	18,800	18,697	18,524	18,381	18,270	18,221	18,243	18,367	18,680	18,856	18,995	
11	Actual Revenue	$ 1,901,912	$ 1,957,612	$ 1,457,117	$ 928,852	$ 615,286	$ 579,616	$ 538,554	$ 536,429	$ 588,115	$ 875,201	$ 1,472,999	$ 2,206,366	$ 13,658,058
12	**RPC**	$ 101.17	$ 104.13	$ 77.93	$ 50.14	$ 33.47	$ 31.72	$ 29.56	$ 29.40	$ 32.02	$ 46.85	$ 78.12	$ 116.16	
13	Medium C&I													
14	Number of Customers	4,696	4,705	4,702	4,691	4,694	4,684	4,665	4,678	4,700	4,734	4,758	4,773	
15	Actual Revenue	$ 2,432,687	$ 2,334,238	$ 1,838,057	$ 1,438,900	$ 1,215,685	$ 1,068,436	$ 1,004,164	$ 1,064,655	$ 1,178,537	$ 1,510,387	$ 1,910,148	$ 2,404,616	$ 19,400,509
16	**RPC**	$ 518.03	$ 496.12	$ 390.91	$ 306.74	$ 258.99	$ 228.10	$ 215.25	$ 227.59	$ 250.75	$ 319.05	$ 401.46	$ 503.80	

1 Actual revenue allocations from Schedule SLN-4 pg. 2

Base Revenue Requirement and Revenue Allocator

Line No.		Reference	Feb-13 (a)	Mar-13 (b)	Apr-13 (c)	May-13 (d)	Jun-13 (e)	Jul-13 (f)	Aug-13 (g)	Sep-13 (h)	Oct-13 (i)	Nov-13 (j)	Dec-13 (k)	Jan-14 (l)	Total Feb 13 - Jan 14 (m)
1	Residential Non-Heat														
2	Base Revenue		$ 603,913	$ 588,968	$ 538,932	$ 470,726	$ 433,857	$ 415,672	$ 398,638	$ 405,354	$ 419,298	$ 459,766	$ 531,921	$ 595,623	$ 5,862,669
3	Allocator	(2) / (2, Col m)	10%	10%	9%	8%	7%	7%	7%	7%	7%	8%	9%	10%	100%
4	Low Income Residential Non-Heat														
5	Base Revenue		$ 13,947	$ 13,940	$ 11,320	$ 9,098	$ 6,354	$ 5,908	$ 5,445	$ 5,566	$ 5,915	$ 7,808	$ 10,956	$ 12,137	$ 108,393
6	Adjusted Base Revenue[2]	(5) / .9	$ 15,497	$ 15,489	$ 12,578	$ 10,109	$ 7,060	$ 6,564	$ 6,050	$ 6,184	$ 6,572	$ 8,675	$ 12,173	$ 13,486	$ 120,436
7	Allocator	(6) / (6, Col m)	13%	13%	10%	8%	6%	5%	5%	5%	5%	7%	10%	11%	100%
8	Residential Non-Heat (incl Low-Income)														
9	Base Revenue		$ 617,861	$ 602,908	$ 550,252	$ 479,824	$ 440,210	$ 421,580	$ 404,083	$ 410,920	$ 425,213	$ 467,574	$ 542,877	$ 607,760	$ 5,971,062
10	Allocator	(2)+(6) / (2+6, Col m)	10%	10%	9%	8%	7%	7%	7%	7%	7%	8%	9%	10%	100%
11	Residential Heating														
12	Base Revenue		$ 14,020,146	$ 12,954,125	$ 9,943,653	$ 6,404,239	$ 4,506,389	$ 3,987,699	$ 3,769,512	$ 3,829,208	$ 4,180,136	$ 6,300,411	$ 10,350,245	$ 13,468,008	$ 93,713,771
13	Allocator	(12) / (12, Col m)	15%	14%	11%	7%	5%	4%	4%	4%	4%	7%	11%	14%	100%
14	Low Income Residential Heating														
15	Base Revenue		$ 1,408,471	$ 1,392,249	$ 1,113,617	$ 732,135	$ 541,223	$ 471,900	$ 428,941	$ 437,828	$ 469,958	$ 689,384	$ 1,111,176	$ 1,324,319	$ 10,121,201
16	Adjusted Base Revenue[2]	(15) / .9	$ 1,564,968	$ 1,546,944	$ 1,237,352	$ 813,484	$ 601,359	$ 524,333	$ 476,601	$ 486,475	$ 522,176	$ 765,982	$ 1,234,640	$ 1,471,465	$ 11,245,779
17	Allocator	(16) / (16, Col m)	14%	14%	11%	7%	5%	5%	4%	4%	5%	7%	11%	13%	100%
18	Residential Heating (incl Low-Income)														
19	Base Revenue		$ 15,428,617	$ 14,346,375	$ 11,057,270	$ 7,136,374	$ 5,047,612	$ 4,459,599	$ 4,198,453	$ 4,267,036	$ 4,650,094	$ 6,989,795	$ 11,461,421	$ 14,792,327	$ 103,834,972
20	Allocator	(12)+(16) / (12+16, Col m)	15%	14%	11%	7%	5%	4%	4%	4%	4%	7%	11%	14%	100%
21	Small														
22	Base Revenue		$ 1,905,339	$ 1,961,140	$ 1,459,743	$ 930,525	$ 616,395	$ 580,660	$ 539,524	$ 537,396	$ 589,175	$ 876,778	$ 1,475,654	$ 2,210,342	$ 13,682,672
23	Allocator	(22) / (22, Col m)	14%	14%	11%	7%	5%	4%	4%	4%	4%	6%	11%	16%	100%
24	Medium C&I														
25	Base Revenue		$ 2,434,281	$ 2,335,767	$ 1,839,262	$ 1,439,843	$ 1,216,481	$ 1,069,136	$ 1,004,822	$ 1,065,352	$ 1,179,309	$ 1,511,377	$ 1,911,399	$ 2,406,191	$ 19,413,220
26	Allocator	(25) / (25, Col m)	13%	12%	9%	7%	6%	6%	5%	5%	6%	8%	10%	12%	100%

Allocated Actual Revenue

		Reference	Feb-13 (a)	Mar-13 (b)	Apr-13 (c)	May-13 (d)	Jun-13 (e)	Jul-13 (f)	Aug-13 (g)	Sep-13 (h)	Oct-13 (i)	Nov-13 (j)	Dec-13 (k)	Jan-14 (l)	Total Feb 13 - Jan 14 (m)	Actual Revenue Requirement[3] (n)
27	Residential Non-Heat (incl Low-Income)															
28	Actual Revenue Requirement	(28, Col n) * (10)	$ 619,002	$ 604,058	$ 551,147	$ 480,518	$ 440,626	$ 421,958	$ 404,421	$ 411,267	$ 425,590	$ 468,132	$ 543,736	$ 608,707	$ 5,979,163	$5,979,163
29	Residential Heating (incl Low-Income)															
30	Actual Revenue Requirement	(30, Col n) * (20)	$ 15,552,475	$ 14,470,701	$ 11,157,590	$ 7,202,607	$ 5,097,052	$ 4,502,584	$ 4,237,221	$ 4,306,645	$ 4,692,464	$ 7,051,595	$ 11,560,624	$ 14,908,187	$ 104,739,746	$104,739,746
31	Small															
32	Actual Revenue Requirement	(32, Col n) * (23)	$ 1,901,912	$ 1,957,612	$ 1,457,117	$ 928,852	$ 615,286	$ 579,616	$ 538,554	$ 536,429	$ 588,115	$ 875,201	$ 1,472,999	$ 2,206,366	$ 13,658,058	$13,658,058
33	Medium C&I															
34	Actual Revenue Requirement	(34, Col n) * (26)	$ 2,432,687	$ 2,334,238	$ 1,838,057	$ 1,438,900	$ 1,215,685	$ 1,068,436	$ 1,004,164	$ 1,064,655	$ 1,178,537	$ 1,510,387	$ 1,910,148	$ 2,404,616	$ 19,400,509	$19,400,509

1 Base revenue requirement from Docket 4323 ("2012 Rate Case"), Book 2, Compliance Attachment 8C, Schedule PMN-7, page 4 of 5.
2 Low Income Residential Heat and Low Income Residential Non Heat revenues are adjusted to remove the 10% discount.
3 Actual Revenue Requirement Feb'13-Jan'14, source: Schedule MAL-1.

The Narragansett Electric Company
d/b/a National Grid
Computation of Class RDM Revenue per Customer
Rate Year Ending January 31, 2014

Line No.		Settled Rate Designed Class Rev Requirement Col A	Settled Growth Capital Rev Requirement Col B	Actual Growth Capital Revenue Requirement Col C	Actual Rate Year Rev Target Col D = A - B + C	Actual Avg. Rate Year Number of Customers Col E	Annual RDM Target Col F = D/E
	RDM Classes						
1	Res Non HT (incl Low Income)	$5,983,105	$82,829	$78,887	$5,979,163	26,094	$229.14
2	Res HT (incl Low Income)	$104,959,550	$1,453,041	$1,233,238	$104,739,746	205,888	$508.72
3	C&I Small	$13,682,672	$189,420	$164,807	$13,658,058	18,570	$735.51
4	C&I Medium	$19,413,220	$268,753	$256,043	$19,400,509	4,707	$4,121.92
5							
6	Sub-Total RDM	$144,038,546	$1,994,044	$1,732,975	$143,777,477	255,258	

Column Notes

Column A - Per Settlement Agreement Rate Design without Low Income discount.
Column B - RDM Class related Growth Capital revenue requirement per Settlement from Page 2 Column E. Line 6 equals Page 2, Line 3E + Line 7E.
Column C - Actual RDM Class related Growth Capital revenue requirement for the Rate Year ending 1/31/14 from Page 3 Column E.
Column E - Actual Average number of customers for the Rate Year ending January 31, 2014 from Page 3 Column F.