Somerset Power LLC
1606 Riverside Avenue
Somerset, MA 02726-2805

Phone: 508.235.2000
Fax: 508.235.2085

July 1, 2010

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

Re: Renewable Energy Resources Eligibility Form – Somerset Station Unit 6

On behalf of Somerset Power LLC ("Somerset Power") the attached Renewable Energy Eligibility Application Form (the "Application") is submitted to the public utility commission, pursuant to the Rhode Island Renewable Energy Standard Act Section 39-26-1 et.seq. of the General Laws of Rhode Island. The enclosed application is for the use of Eligible Biomass Fuels in the Plasma Gasification project being proposed to re-fuel Somerset Station Unit No. 6 in Somerset, Massachusetts. Plasma gasification of solid fuels represents a first of a kind application of advanced low emission technology.

The Massachusetts Department of Environmental Protection ("MassDEP") has issued a Conditional Approval for the Plasma Gasification re-fueling of Somerset Unit 6 and Boiler No. 8 from a solid fuel (coal) to clean synthesis gas ("syngas") fuel fired boiler. The Conditional Approval allows the use of up to 35% solid biomass as a gasifier feedstock, and to combust up to an additional 10% liquid bio diesel fuel for flame stabilization in the boiler. While the Conditional Approval also allows the use of up to 35% IPP paper cubes or Construction & Demolition ("C&D") wood, we are only requesting certification for clean wood biomass and neat bio diesel.

This proposed technology is unique from any other utility scale power generation method currently in use or anticipated within the scope of the Massachusetts RPS. The proposed Plasma Gasification System is a stand-alone system that converts solid fuel feedstock to a gaseous fuel similar to landfill gas. The feedstock (including biomass) is not combusted or "fired" in the gasification train; rather it is heated to high temperature in the absence of oxygen to disassociate the carbon and hydrogen molecules into a synthesis gaseous fuel.

The syngas train itself does not require a DEP Air Permit, since it has no air emissions nor vents to atmosphere.

The gaseous fuel produced in the Plasma Gasification process will then be piped to Boiler No. 8, where it will be combusted within the re-fueled boiler. The modifications needed to convert Boiler No. 8 to syngas firing will employ the equivalent of Best Available Control Technology ("BACT") for this type of process.

The permitted emissions unit, re-fueled Boiler No. 8, will no longer be a solid fuel fired boiler nor a wood fired boiler, but rather a gas fired boiler. The proposed Plasma Gasification re-fueling project is a first of a kind, and represents innovative advanced technology for commercial power generation. The new, refueled air emission unit employs BACT and represents a "low-emission advanced biomass power conversion technology." This is further substantiated by the Conditional Approval issued by MassDEP. Somerset Power believes that Somerset Unit 6 qualifies as a New Renewable Generation Unit under Section 39-26-1of the General Laws of Rhode Island. Since the re-fueled boiler No. 8 will also be capable of firing up to 10% liquid fuels (Low Sulfur No. 6 fuel oil or biodiesel), we are requesting a "co-firing with ineligible fuels waiver" under the same Section.

In order to facilitate the approval process, Somerset Power welcomes the opportunity to meet with you at your convenience to review the attached application and answer any of your questions.

Sincerely,

Fred Wass

Fredrick W. Wass
Manager, Assets
Somerset Power LLC

cc:

Luly E. Massaro, State of Rhode Island Public Utilities Commission Clerk
Bob Henry, NRG Energy, Inc.
Alan Sawyer, NRG Energy, Inc.
Robert Fraser, AEcom

RIPUC Use Only Date Application Received: __ __/__ __/__ __ Date Review Completed: __ __/__ __/__ __ Date Commission Action: __ __/__ __/__ __ Date Commission Approved: __ __/__ __/__ __

GIS Certification #: ____________________

RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM

The Standard Application Form
Required of all Applicants for Certification of Eligibility of Renewable Energy Resource
(Version 7 – June 11, 2010)

STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISSION
Pursuant to the Renewable Energy Act
Section 39-26-1 et. seq. of the General Laws of Rhode Island

NOTICE:

When completing this Renewable Energy Resources Eligibility Form and any applicable Appendices, please refer to the State of Rhode Island and Providence Plantations Public Utilities Commission Rules and Regulations Governing the Implementation of a Renewable Energy Standard (RES Regulations, Effective Date: January 1, 2006), and the associated RES Certification Filing Methodology Guide. All applicable regulations, procedures and guidelines are available on the Commission's web site: www.ripuc.org/utilityinfo/res.html. Also, all filings must be in conformance with the Commission's Rules of Practice and Procedure, in particular, Rule 1.5, or its successor regulation, entitled "Formal Requirements as to Filings."

• Please complete the Renewable Energy Resources Eligibility Form and Appendices using a typewriter or black ink.

• Please submit one original and three copies of the completed Application Form, applicable Appendices and all supporting documentation to the Commission at the following address:

Rhode Island Public Utilities Commission
89 Jefferson Blvd
Warwick, RI 02888
Attn: Renewable Energy Resources Eligibility

In addition to the paper copies, electronic/email submittals are required under Commission regulations. Such electronic submittals should be sent to: Luly E. Massaro, Commission Clerk at lmassaro@puc.state.ri.us

• In addition to filing with the Commission, Applicants are required to send, electronically or electronically and in paper format, a copy of the completed Application including all attachments and supporting documentation, to the Division of Public Utilities and Carriers and to all interested parties. A list of interested parties can be obtained from the Commission's website at www.ripuc.org/utilityinfo/res.html.

• Keep a copy of the completed Application for your records.

• The Commission will notify the Authorized Representative if the Application is incomplete.

• Pursuant to Section 6.0 of the RES Regulations, the Commission shall provide a thirty (30) day period for public comment following posting of any administratively complete Application.

• Please note that all information submitted on or attached to the Application is considered to be a public record unless the Commission agrees to deem some portion of the application confidential after consideration under section 1.2(g) of the Commission's Rules of Practice and Procedure.

• In accordance with Section 6.2 of the RES Regulations, the Commission will provide prospective reviews for Applicants seeking a preliminary determination as to whether a facility would be eligible prior to the formal certification process described in Section 6.1 of the RES Regulations. Please note that space is provided on the Form for applicant to designate the type of review being requested.

• Questions related to this Renewable Energy Resources Eligibility Form should be submitted in writing, preferably via email and directed to: Luly E. Massaro, Commission Clerk at lmassaro@puc.state.ri.us

SECTION I: Identification Information

1.1 Name of Generation Unit (sufficient for full and unique identification):
SOMERSET – UNIT 6

1.2 Type of Certification being requested (check one):

☐ Standard Certification ☑ Prospective Certification (Declaratory Judgment)

1.3 This Application includes: (Check all that apply)[1]

- ☐ APPENDIX A: Authorized Representative Certification for Individual Owner or Operator
- ☑ APPENDIX B: Authorized Representative Certification for Non-Corporate Entities Other Than Individuals
- ☐ APPENDIX C: Existing Renewable Energy Resources
- ☐ APPENDIX D: Special Provisions for Aggregators of Customer-sited or Off-grid Generation Facilities
- ☐ APPENDIX E: Special Provisions for a Generation Unit Located in a Control Area Adjacent to NEPOOL
- ☑ APPENDIX F: Fuel Source Plan for Eligible Biomass Fuels

1.4 Primary Contact Person name and title: FRED W. WASS, MANAGER, ASSETS

1.5 Primary Contact Person address and contact information:
Address: 211 CARNEGIE CENTER
PRINCETON, NJ 08540

Phone: 609.524.5125 Fax: 609.524.4941
Email: FRED.WASS@NRGENERGY.COM

1.6 Backup Contact Person name and title: ALAN SAWYER
DIRECTOR, ASSET MANAGEMENT

1.7 Backup Contact Person address and contact information:
Address: 211 CARNEGIE CENTER
PRINCETON, NJ 08540

Phone: 609.524.4677 Fax: 609.524.4941
Email: ALAN.SAWYER@NRGENERGY.COM

[1] Please note that all Applicants are required to complete the Renewable Energy Resources Eligibility Standard Application Form and all of the Appendices that apply to the Generation Unit or Owner or Operator that is the subject of this Form. Please omit Appendices that do not apply.

1.8 Name and Title of Authorized Representative (*i.e.*, the individual responsible for certifying the accuracy of all information contained in this form and associated appendices, and whose signature will appear on the application):
J. ANDREW MURPHY, PRESIDENT

Appendix A or B (as appropriate) completed and attached? ☑ Yes ☐ No ☐ N/A

1.9 Authorized Representative address and contact information:
Address: 211 CARNEGIE CENTER
PRINCETON, NJ 08540

Phone: 609.524.5115 Fax: 609.524.4149
Email: DREW.MURPHY@NRGENERGY.COM

1.10 Owner name and title: SOMERSET POWER LLC

1.11 Owner address and contact information:
Address: 211 CARNEGIE CENTER
PRINCETON, NJ 08540

Phone: 609.524.5115 Fax: 609.524.5160
Email:

1.12 Owner business organization type (check one):
- ☐ Individual
- ☐ Partnership
- ☐ Corporation

☑ Other: LIMITED LIABILITY COMPANY

1.13 Operator name and title: SOMERSET POWER LLC .

1.14 Operator address and contact information:
Address: 211 CARNEGIE CENTER
PRINCETON, NJ 08540

Phone: 508.235.2000 X 5364 Fax: 609.524.4149
Email: JEFF.ARAUJO@NRGENERGY.COM

1.15 Operator business organization type (check one):
- ☐ Individual
- ☐ Partnership
- ☐ Corporation

☑ Other: LIMITED LIABILITY COMPANY

SECTION II: Generation Unit Information, Fuels, Energy Resources and Technologies

2.1 ISO-NE Generation Unit Asset Identification Number or NEPOOL GIS Identification Number (either or both as applicable): 577

2.2 Generation Unit Nameplate Capacity: 120 MW

2.3 Maximum Demonstrated Capacity: 120 MW

2.4 Please indicate which of the following Eligible Renewable Energy Resources are used by the Generation Unit: (Check ALL that apply) – *per RES Regulations Section 5.0*

- ☐ Direct solar radiation
- ☐ The wind
- ☐ Movement of or the latent heat of the ocean
- ☐ The heat of the earth
- ☐ Small hydro facilities
- ☑ Biomass facilities using Eligible Biomass Fuels and maintaining compliance with all aspects of current air permits; Eligible Biomass Fuels may be co-fired with fossil fuels, provided that only the renewable energy fraction of production from multi-fuel facilities shall be considered eligible.
- ☐ Biomass facilities using unlisted biomass fuel
- ☐ Biomass facilities, multi-fueled or using fossil fuel co-firing
- ☐ Fuel cells using a renewable resource referenced in this section

2.5 If the box checked in Section 2.4 above is "Small hydro facilities", please certify that the facility's aggregate capacity does not exceed 30 MW. – *per RES Regulations Section 3.32*

☐ ← check this box to certify that the above statement is true

☑ N/A or other (please explain) ______

2.6 If the box checked in Section 2.4 above is "Small hydro facilities", please certify that the facility does not involve any new impoundment or diversion of water with an average salinity of twenty (20) parts per thousand or less. – *per RES Regulations Section 3.32*

☐ ← check this box to certify that the above statement is true

☑ N/A or other (please explain) ______

2.7 If you checked one of the Biomass facilities boxes in Section 2.1 above, please respond to the following:

A. Please specify the fuel or fuels used or to be used in the Unit: SEE LIST ATTACHED

B. Please complete and attach Appendix F, Eligible Biomass Fuel Source Plan.

Appendix F completed and attached? ☑ Yes ☐ No ☐ N/A

2.8 Has the Generation Unit been certified as a Renewable Energy Resource for eligibility in another state's renewable portfolio standard?

❑ Yes ☑ No If yes, please attach a copy of that state's certifying order.

Copy of State's certifying order attached? ❑ Yes ❑ No ☑ N/A

SECTION III: Commercial Operation Date

Please provide documentation to support all claims and responses to the following questions:

3.1 Date Generation Unit first entered Commercial Operation: 0 6 / 0 1 / 1 3 at the site. (ESTIMATED C.O.D.

3.2 Is there an Existing Renewable Energy Resource located at the site of Generation Unit?

❑ Yes

☑ No

3.3 If the date entered in response to question 3.1 is earlier than December 31, 1997 or if you checked "Yes" in response to question 3.2 above, please complete Appendix C.

Appendix C completed and attached? ❑ Yes ❑ No ❑ N/A

3.4 Was all or any part of the Generation Unit used on or before December 31, 1997 to generate electricity at any other site?

☑ Yes

❑ No

3.5 If you checked "Yes" to question 3.4 above, please specify the power production equipment used and the address where such power production equipment produced electricity (attach more detail if the space provided is not sufficient):
SEE ATTACHED COMMENTS

SECTION IV: Metering

4.1 Please indicate how the Generation Unit's electrical energy output is verified (check all that apply):

☑ ISO-NE Market Settlement System

❑ Self-reported to the NEPOOL GIS Administrator

❑ Other (please specify below and see Appendix D: Eligibility for Aggregations):

Appendix D completed and attached? ❑ Yes ❑ No ☑ N/A

SECTION V: Location

5.1 Please check one of the following that apply to the Generation Unit:

- ☑ Grid Connected Generation
- ❑ Off-Grid Generation (not connected to a utility transmission or distribution system)
- ❑ Customer Sited Generation (interconnected on the end-use customer side of the retail electricity meter in such a manner that it displaces all or part of the metered consumption of the end-use customer)

5.2 Generation Unit address: 1606 RIVERSIDE AVE.
SOMERSET, MA 02726

5.3 Please provide the Generation Unit's geographic location information:

A. Universal Transverse Mercator Coordinates: ____________

B. Longitude/Latitude: 71,68,20W / 41,44,00N

5.4 The Generation Unit located: (please check the appropriate box)

- ☑ In the NEPOOL control area
- ❑ In a control area adjacent to the NEPOOL control area
- ❑ In a control area other than NEPOOL which is not adjacent to the NEPOOL control area ← *If you checked this box, then the generator does not qualify for the RI RES – therefore, please do not complete/submit this form.*

5.5 If you checked "In a control area adjacent to the NEPOOL control area" in Section 5.4 above, please complete Appendix E.

Appendix E completed and attached? ❑ Yes ❑ No ☑ N/A

SECTION VI: Certification

6.1 Please attach documentation, using one of the applicable forms below, demonstrating the authority of the Authorized Representative indicated in Section 1.8 to certify and submit this Application.

Corporations

If the Owner or Operator is a corporation, the Authorized Representative shall provide **either**:

(a) Evidence of a board of directors vote granting authority to the Authorized Representative to execute the Renewable Energy Resources Eligibility Form, **or**

(b) A certification from the Corporate Clerk or Secretary of the Corporation that the Authorized Representative is authorized to execute the Renewable Energy Resources Eligibility Form or is otherwise authorized to legally bind the corporation in like matters.

Evidence of Board Vote provided? ☐ Yes ☐ No ☑ N/A

Corporate Certification provided? ☐ Yes ☐ No ☑ N/A

Individuals

If the Owner or Operator is an individual, that individual shall complete and attach APPENDIX A, or a similar form of certification from the Owner or Operator, duly notarized, that certifies that the Authorized Representative has authority to execute the Renewable Energy Resources Eligibility Form.

Appendix A completed and attached? ☐ Yes ☐ No ☑ N/A

Non-Corporate Entities

(Proprietorships, Partnerships, Cooperatives, etc.) If the Owner or Operator is not an individual or a corporation, it shall complete and attach APPENDIX B or execute a resolution indicating that the Authorized Representative named in Section 1.8 has authority to execute the Renewable Energy Resources Eligibility Form or to otherwise legally bind the non-corporate entity in like matters.

Appendix B completed and attached? ☑ Yes ☐ No ☐ N/A

6.2 Authorized Representative Certification and Signature:

I hereby certify, under pains and penalties of perjury, that I have personally examined and am familiar with the information submitted herein and based upon my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate and complete. I am aware that there are significant penalties, both civil and criminal, for submitting false information, including possible fines and punishment. My signature below certifies all information submitted on this Renewable Energy Resources Eligibility Form. The Renewable Energy Resources Eligibility Form includes the Standard Application Form and all required Appendices and attachments. I acknowledge that the Generation Unit is obligated to and will notify the Commission promptly in the event of a change in a generator's eligibility status (including, without limitation, the status of the air permits) and that when and if, in the Commission's opinion, after due consideration, there is a material change in the characteristics of a Generation Unit or its fuel stream that could alter its eligibility, such Generation Unit must be re-certified in accordance with Section 9.0 of the RES Regulations. I further acknowledge that the Generation Unit is obligated to and will file such quarterly or other reports as required by the Regulations and the Commission in its certification order. I understand that the Generation Unit will be immediately de-certified if it fails to file such reports.

Signature of Authorized Representative:

SIGNATURE: ______________________ DATE: 7/6/10

J. ANDREW MURPHY

PRESIDENT

GIS Certification #: ____

APPENDIX A
(Required When Owner or Operator is An Individual)

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISION

RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM
Pursuant to the Renewable Energy Act
Section 39-26-1 et. seq. of the General Laws of Rhode Island

I, John Andrew Murphy, as Owner or Operator of the Generation Unit named in Section 1.1 of the attached Renewable Energy Resources Eligibility Form, under the pains and penalties of perjury, hereby certify that ____________________, named in Section 1.8 of the attached Application, is authorized to execute this Renewable Energy Resource Eligibility Form.

SIGNATURE: ____________________ DATE: 7/6/10

President
(Title)

State: New Jersey

County: Mercer

(TO BE COMPLETED BY NOTARY) I, Lisa Marie Harding as a notary public, certify that I witnessed the signature of the above named John Andrew Murphy and said individual verified his/her identity to me on this date: 7/6/10.

SIGNATURE: Lisa Marie Harding

My commission expires on: Nov. 17, 2014 NOTARY SEAL:

LISA MARIE HARDING
NOTARY PUBLIC
STATE OF NEW JERSEY
My Commission Expires Nov. 17, 2014
ID# 2391124

GIS Certification #:
____

APPENDIX F
(Revised 6/11/10)
Eligible Biomass Fuel Source Plan
(Required of all Applicants Proposing to Use An Eligible Biomass Fuel)

STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISION
Part of Application for Certificate of Eligibility
RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM
Pursuant to the Renewable Energy Act
Section 39-26-1 et. seq. of the General Laws of Rhode Island

Note to Applicants: Please refer to the RES Certification Filing Methodology Guide posted on the Commission's web site (www.ripuc.org/utilityinfo/res.html) for information, templates and suggestions regarding the types and levels of detail appropriate for responses to specific application items requested below. Also, please see Section 6.9 of the RES Regulations for additional details on specific requirements.

The phrase "Eligible Biomass Fuel" (per RES Regulations Section 3.7) means fuel sources including brush, stumps, lumber ends and trimmings, wood pallets, bark, wood chips, shavings, slash, yard trimmings, site clearing waste, wood packaging, and other clean wood that is not mixed with other unsorted solid wastes[5]; agricultural waste, food and vegetative material; energy crops; landfill methane[6] or biogas[7], provided that such gas is collected and conveyed directly to the Generation Unit without use of facilities used as common carriers of natural gas; or neat bio-diesel and other neat liquid fuels that are derived from such fuel sources.

In determining if an Eligible Biomass Generation Unit shall be certified, the Commission will consider if the fuel source plan can reasonably be expected to ensure that only Eligible Biomass Fuels will be used, and in the case of co-firing ensure that only that proportion of generation attributable to an Eligible Biomass Fuel be eligible. Certification will not be granted to those Generation Units with fuel source plans the Commission deems inadequate for these purposes.

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[5] Generation Units using wood sources other than those listed above may make application, as part of the required fuel source plan described in Section 6.9 of the RES Regulations, for the Commission to approve a particular wood source as "clean wood." The burden will be on the applicant to demonstrate that the wood source is at least as clean as those listed in the legislation. Wood sources containing resins, glues, laminates, paints, preservatives, or other treatments that would combust or off-gas, or mixed with any other material that would burn, melt, or create other residue aside from wood ash, will not be approved as clean wood.

[6] Landfill gas, which is an Eligible Biomass Fuel, means only that gas recovered from inside a landfill and resulting from the natural decomposition of waste, and that would otherwise be vented or flared as part of the landfill's normal operation if not used as a fuel source.

[7] Gas resulting from the anaerobic digestion of sewage or manure is considered to be a type of biogas, and therefore an Eligible Biomass Fuel that has been fully separated from the waste stream.

F.1 The attached Fuel Source Plan includes a detailed description of the type of Eligible Biomass Fuel to be used at the Generation Unit.

Detailed description attached? ☑ Yes ❑ No ❑ N/A

Comments: ____

____

F.2 If the proposed fuel is "other clean wood," the Fuel Source Plan should include any further substantiation to demonstrate why the fuel source should be considered as clean as those clean wood sources listed in the legislation.

Further substantiation attached? ❑ Yes ❑ No ☑ N/A

Comments: ____

____

F.3 In the case of co-firing with ineligible fuels, the Fuel Source Plan must include a description of (a) how such co-firing will occur; (b) how the relative amounts of Eligible Biomass Fuel and ineligible fuel will be measured; and (c) how the eligible portion of generation output will be calculated. Such calculations shall be based on the energy content of all of the proposed fuels used.

Description attached? ☑ Yes ❑ No ❑ N/A

Comments: ____

____

F.4 The Fuel Source Plan must provide a description of what measures will be taken to ensure that only the Eligible Biomass Fuel are used, examples of which may include: standard operating protocols or procedures that will be implemented at the Generation Unit, contracts with fuel suppliers, testing or sampling regimes.

Description provided? ☑ Yes ❑ No ❑ N/A

Comments: ____

____

F.5 Please include in the Fuel Source Plan an acknowledgement that the fuels stored at or brought to the Generation Unit will only be either Eligible Biomass Fuels or fossil fuels used for co-firing and that Biomass Fuels not deemed eligible will not be allowed at the premises of the certified Generation Unit. And please check the following box to certify that this statement is true.

☑ ← check this box to certify that the above statement is true

❑ N/A or other (please explain) ______________________________

____

F.6 If the proposed fuel includes recycled wood waste, please submit documentation that such fuel meets the definition of Eligible Biomass Fuel and also meets material separation, storage, or handling standards acceptable to the Commission and furthermore consistent with the RES Regulations.

Documentation attached? ☐ Yes ☐ No ☐ N/A

Comments: ____

____

F.7 Please certify that you will file all reports and other information necessary to enable the Commission to verify the on-going eligibility of the renewable energy generators pursuant to Section 6.3 of the RES Regulations. Specifically, RES Regulations Section 6.3(i) states that Renewable Energy Resources of the type that combust fuel to generate electricity must file quarterly reports due 60 days after the end of each quarter on the fuel stream used during the quarter. Instructions and filing documents for the quarterly reports can be found on the Commissions website or can be furnished upon request.

☑ ← check this box to certify that the above statement is true

☐ N/A or other (please explain) ______________________________

____

F.8 Please attach a copy of the Generation Unit's Valid Air Permit or equivalent authorization.

Valid Air Permit or equivalent attached? ☑ Yes ☐ No ☐ N/A

Comments: ____

____

F.9 Effective date of Valid Air Permit or equivalent authorization:

12/08/08

F.10 State or jurisdiction issuing Valid Air Permit or equivalent authorization: COMMONWEALTH OF MASSACHUSETTS

Somerset Power LLC – Unit 6
Attachment to the Standard Application Form
State of Rhode Island Public Utilities Commission
Pursuant to the Renewable Energy Act
Section 39-26-1 et.sq.of the General Laws of Rhode island

Appendix F

F1. Detailed description of the type of Eligible Biomass Fuel to be used at the Generation Unit.

Eligible Renewable Solid Biomass

1. Forest Residue – tops, branches, stumps, slash, forest thinning,
2. Pulpwood – harvested tree chips
3. Urban Wood Residue – land clearing residue (e.g. tree chips, branches, tops, logs, stumps, brush, bark, and mixed wood), tree trimmings,
4. Manufacturing Residue – bark, sawdust, tailings, woodchips, shavings,
5. Roundwood – whole trees in long log form
6. wood pallets
7. energy crops – switchgrass, poplar, cane, corn stover,

Other Solid Biomass

8. Clean C&D wood "positive pick" – clean wood positive picked from C&D waste; with DEP BUD if required
9. Clean C&D wood "negative pick" – clean wood remaining after removing non clean wood materials from C&D waste; with DEP BUD if required
10. CDW bulk – chipped C&D organic residue derived after separation and recycling of common non-organic materials (metals, rocks, road debris, plaster, masonry, aluminum, etc.); with DEP BUD (required)
11. Paper cubes – non-recycled paper derived fuel cubes (manufactured by IPP)

Eligible Renewable Liquid Biomass

12. B100 Biodiesel – manufactured from vegetable oils, recycled cooking greases or oils, or animal fats
13. Biodiesel blends – blend of B100 and diesel fuel, qualified to the percent of B100 in the blend (typical blends include B80, B20, B5)
14. Algal based Biodiesel (i.e. GreenFuel emission fed algae)

Solid Fossil Feedstock

15. Coal – generic domestic and international coal sources
16. Coke – metallurgical or foundry coke
17. Lime – a non heat producing fluxing agent

Liquid Fossil Fuels

18. Low Sulfur (0.3%) No. 6 oil

Somerset Power LLC – Unit 6
Attachment to the Standard Application Form
State of Rhode Island Public Utilities Commission
Pursuant to the Renewable Energy Act
Section 39-26-1 et.sq.of the General Laws of Rhode island

Somerset Power - Fuel Supply Plan
Anticipated - November 2007

Feedstock / fuel source	heat btu/lb	Minimum Renewable Usage quantity TPH	mmbtu/hr	%	MW	RECs	Maximum Renewable Usage quantity TPH	mmbtu/hr	%	MW	RECs	Expected Renewable Usage quantity TPH	mmbtu/hr	%	MW	RECs
Solid Biomass																
Forest Residue	4,625	0		0%	-	-	6	60	5%	6	5.6	6	60	5%	6	5.6
Urban Wood Resic	4,625	0		0%	-	-	25	230	18%	21	21.5	25	230	18%	21	21.5
Pulpwood	4,625	0		0%	-	-	-		0%	-	-	-		0%	-	-
Round wood	4,625	0		0%	-	-	7	65	5%	6	6.1	7	65	5%	6	6.1
Pallets	6,125	0		0%	-	-	6	70	5%	7	6.5	6	70	5%	7	6.5
Mfgr Residue	6,125	0		0%	-	-	2	25	2%	2	2.3	2	25	2%	2	2.3
Energy crops	4,500	0		0%	-	-	-		0%	-	-	-		0%	-	-
Clean C&D wood	6,125	5	61	5%	6	-	-		0%	-	-	-		0%	-	-
CDW Bulk	6,000	31	372	29%	35	-	-		0%	-	-	-		0%	-	-
Paper Cubes	9,000	1	18	1%	2	-	-		0%	-	-	-		0%	-	-
Liquid Biofuels					-					-					-	
B100	15,800	0		0%	-	-	4	128	10%	12	12.0	-		0%	-	-
B20	18,100	0		0%	-	-	-		0%	-	-	4	128	10%	12	2.4
Fossil Fuels										-					-	
Coal / Coke	11,000	32	705	55%	65	-	32	706	55%	66	-	32	706	55%	66	-
LS No 6	18,659	3	128	10%	12	-	-		0%	-	-	-		0%	-	-
Total			1284	100%	120	0		1284	100%	120	54.0		1284	100%	120	44.4

F3. Description of (a) how co-firing will occur; (b) how relative amounts of Eligible Biomass Fuel and ineligible fuel will be measured; and (c) how the eligible portion of the generation output will be calculated.

Somerset Power will maintain feedstock and fuel receiving procedures to measure and record the following:

- Quantity of biomass feedstock received in tons (all trucks will be weighed before and after unloading biomass)
- Heat content of delivered biomass feedstock will be measured / calculated (samples from each biomass truck will be collected and analyzed on a periodic basis) to determine the average stockpile heat content on a first in first out basis.
- Coal and Coke heat quantity and heat content will be measured for each shipment. The average coal and coke stockpile heat content will be calculated on a first in last out basis.
- Liquid fuel, both biodiesel and No. 6 oil will be supplied with a heat content analysis. The average heat content and amount of B100 blend (if any) will be calculated for liquid fuel storage volumes.
- All feedstock flow to the gasifiers will be measured to determine quantity deliverd on a daily basis. Net heat content for a) Eligible Renewable Biomass, b) other biomass, or c) coal / coke will be determined on a daily basis.
- The portion of the total electrical energy output that qualifies as New Renewable Generation in a given time period shall be equal to the ratio of the net heat content of the Eligible Biomass Fuels consumed to the net heat content of all fuels consumed in that time period.

F4. Measures that will be taken to ensure that only Eligible Biomass Fuel is used including standard operating protocols and procedures, contracts with fuel suppliers, testing and sampling regimes.

Somerset Power will maintain feedstock and fuel receiving procedures to measure and record the following:

- The quality of all biomass received will be analyzed on vendor by vendor basis to ensure the quality of all shipments (truckloads) to verify adherence with the RPS Eligible Biomass fuel requirements.
- No other fuel utilized at this Unit, including “paper cubes,” materials derived from construction and demolition, or any “organic refuse-derived fuel,” will be considered to be an Eligible Biomass Fuel without the prior, express, written consent of the Division, except that fossil fuels and materials derived from fossil fuels shall not be so considered.
- The Owner of the Unit will draft and submit for approval by the Division, in consultation with the RI DEP, a detailed Plan and format for monthly

recording of the quantities and heat content of all fuels and fuel feedstock received, fed into the gasifier, and fed into the combustion unit. No electrical energy output of the Unit shall qualify as New Renewable Generation until the Division has approved said plan and format.

- A statement that the Owner of the Unit will maintain and, upon request, submit to the Division, records of all fuel feedstock that are received at the Unit, organized by shipments within each month, and that are fed into both the gasifier and the combustion unit, organized on a daily and monthly basis.

F8. Generation Units' Valid Air Permit (attached)

Other Attachments:

1) Somerset- Unit 6 Conditional Approval from MADEP
2) Draft Approval for MADEP Statement of qualification

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY AND ENVIRONMENTAL AFFAIRS
DIVISION OF ENERGY RESOURCES

Draft Statement of Qualification

Pursuant to the Renewable Energy Portfolio Standard 225 CMR 14.00

This Statement of Qualification, provided by the Massachusetts Division of Energy Resources (the Division), signifies that the Generation Unit identified below meets the requirements for eligibility as a New Renewable Generation Unit, pursuant to the Renewable Energy Portfolio Standard 225 CMR 14.05, as of the approval date of the Application for Statement of Qualification, this 23rd **day of May 2008**.

Generation Unit Name, Capacity, and Location:	**Somerset – Unit 6** 120 MW Somerset, MA
Authorized Representative's Name and Address:	John Ragan President Somerset PowerLLC 211 Carnegie Center Princeton, NJ 08540

This New Renewable Generation Unit is assigned a unique Massachusetts RPS Identification Number, listed below. Please include MA RPS ID #s on all correspondence with DOER.

MA RPS ID #: BM-1075-08

The Unit's NEPOOL GIS Identification Number is:

MSS-577

This Statement of Qualification is contingent on compliance with the following provisions:

1. The Owner or Operator shall operate the Unit as described in its Statement of Qualification Application (SQA) dated November 27, 2007, as supplemented by an attachment submitted on December 10, 2007, and shall comply with the provisions of the Massachusetts RPS Regulations at 225 CMR 14.00, including relevant RPS Guidelines and this Statement of Qualification (SQ).
2. Each report to the Division (and, if required herein, to the Massachusetts Department of Environmental Protection, Mass DEP) on emission monitoring results or concerning other documentation required under this SQ shall include a cover letter that states the nature and purpose of the report, identifies any attachments, summarizes the information detailed in any attachments, and provides the Certification required in the RPS Regulations at 225 CMR 14.10(1). Any attached documentation shall be provided only by an electronic medium (e-mail or compact disk), with an appropriately brief descriptive title, including the time period or date of its data.

3. Eligible Biomass Fuels.
The Eligible Biomass Fuels for this Unit shall be limited to the following:

a. Forest residue – tops, branches, stumps, slash, and forest thinning;

b. Pulpwood – harvested tree chips;

c. Urban wood residue – land clearing residue (whole tree chips, branches, tops, logs, stumps, brush, bark, and mixed wood) and tree trimmings;

d. Manufacturing woody residues – bark, sawdust, tailings, woodchips, shavings; trimmings and scraps;

e. Roundwood – whole trees in long log form;

f. Wood pallets;

g. Energy crops – harvested switchgrass, poplar, cane, corn stover; willow, crop byproducts;.or

h. Neat biodiesel (e.g., B100 or B99) or other liquid bio-fuels, which may be derived from vegetable oils, yellow grease, animal fats, algae, or other contemporaneous biological sources, and which may be the neat biodiesel portion (on a heat content basis, the qualified portion of which shall be calculated as stated in Provision 6, below) of a blend that includes petroleum-derived diesel (e.g., B20), except that the qualification of any blended biodiesel or other liquid bio-fuel is contingent on prior, express, written consent by the Division after review of its consistency with the Commonwealth's policy on liquid bio-fuel.

4. Other Fuels.
No other fuel utilized at this Unit, including "paper cubes," materials derived from construction and demolition, or any "organic refuse-derived fuel," will be considered to be an Eligible Biomass Fuel without the prior, express, written consent of the Division, except that fossil fuels and materials derived from fossil fuels shall not be so considered.

5. Fuel Supply Plan.
The Owner or Operator of the Unit will draft and submit for approval by the Division, in consultation with the MassDEP, a detailed Plan and format for monthly recording of the quantities and heat content of all fuels and fuel feedstocks received, fed into the gasifier, and fed into the combustion unit. No electrical energy output of the Unit shall qualify as New Renewable Generation until the Division has approved said plan and format. The Division may require changes in said Plan and format at any time, and the Owner or Operator of the Unit may propose to the Division changes in said Plan and format, which shall not be implemented until approved in writing by the Division. The Division may, at its sole discretion, require submission of a quarterly report documenting compliance with the approved plan. The Plan and format shall include at least the following components unless otherwise approved by the Division:

a. A statement that the Owner or Operator of the Unit will maintain and, upon request, submit to the Division, records of all fuel feedstocks that are received at the Unit, organized by shipments within each month, and that are fed into both the gasifier and the combustion unit, organized on a daily and monthly basis.

b. A statement that the Owner or Operator of the Unit will measure the heat content of each type of solid fuel on a daily consumed basis, and the average for each month will be calculated on a weighted average basis. The heat content of each type of liquid fuel will be supplied and certified by the vendors for all deliveries and the Owner or Operator of the Unit will calculate the heat content for liquid fuel consumed.

c. Forms that will be used to record this data.

d. The sampling, analysis and calibration procedures that will be followed.

6. Co-firing Calculation
The portion of the total electrical energy output that qualifies as New Renewable Generation in a given time period shall be equal to the ratio of the net heat content of the Eligible Biomass Fuels consumed to the net heat content of all fuels consumed in that time period. The calculation of the qualifying portion of output that qualifies in each month shall be performed in the manner provided on page 4 of the Attachment to the SQA, as submitted to the Division in revised form on December 10, 2007, or as subsequently proposed by the Owner or Operator of the Unit and approved in writing by the Division.

7. Quarterly Co-firing and Fuel Report.
The Owner or Operator of the Unit will submit to the Division a quarterly report in a format to be approved by the Division that includes for each month a calculation of the quantity of electrical energy output that qualifies as New Renewable Generation under Provision 6, and, if required by the Division, a summary of the information listed in Provision 5. The report for each calendar quarter will be submitted no later than thirty days after the end of the quarter.

8. Emission Requirements and Onset of RPS Qualification.
Commencement of the qualification of the portion of the electrical energy output of the Unit from Eligible Biomass Fuels as New Renewable Generation shall commence on the day after the date on which Owner/Operator first demonstrates to DOER satisfaction, in consultation with the MassDEP, that the Unit meets both of the emission limits specified in the Table under this Provision. Such demonstration of compliance shall include the following:

   a. certification of the Continuous Emissions Monitoring System (CEMS) for nitrogen oxides (NOx);

   b. documentation that emissions data were obtained from the CEMS and recorded for at least 90% of the time that the Unit was using qualified biomass in the plasma gasifier, except for periods of calibration checks, zero span adjustment, preventive maintenance, and any other exceptions provided in the Unit's Operating Permit;

   c. documentation that the emissions of NOx recorded by CEMS met the limits specified in the Table, averaged over the month; and

   d. documentation that the required stack test for particulate matter (PM) also met the limits.

DOER will notify the NEPOOL GIS Administrator of the date as of which the electrical energy output of the Unit first qualifies as New Renewable Generation under the RPS Regulations at 225 CMR 14.00. Qualification as New Renewable Generation after such initial qualification shall be contingent on meeting the requirements of the Table and all other provisions of this SQ and the RPS Regulations at 225 CMR 14.00, including relevant RPS Guidelines. This SQ incorporates by reference here the *Guideline on the RPS Eligibility of Biomass Generation Units* issued by the Division on November 8, 2007.

EMISSION REQUIREMENTS TABLE

Pollutant	Emission Limit	Method of Determination
PM	0.015 lbs/MMBtu (1-hr Avg.)	Annual stack test and as detailed in Provision 9
NOx	0.07 lbs/MMBtu	CEMS – monthly average

9. Monitoring and Testing Methods.
Owner/Operator shall monitor and test the emissions of NOx and PM by the methods specified in

the Unit's Amended ECP Final Approval and Conditional Approval from the MassDEP, both dated January 25, 2008, or in any Approval or Title V Operating Permit that supersedes those Approvals. A CO limit shall act as a surrogate for complying with the PM monthly average emission limit, as follows. If the monthly average CO concentration exceeds 200 ppm @ 3% O2, the Unit shall be considered to be in non-compliance with the PM emission limit. A PM Compliance Assurance Monitoring Plan may be substituted for the CO surrogate if approved by the Division, in consultation with the MassDEP.

10. <u>RPS Quarterly Low-Emissions Reports</u>.
Owner/Operator shall submit to DOER and to the MassDEP the quarterly reports required for this Unit by the *Guideline on the RPS Eligibility of Biomass Generation Units* issued by the Division on November 8, 2007, or, if notified by DOER, by any subsequent version of that *Guideline*. In addition, a summary page of the results of any compliance stack testing for PM, NOx, or CO conducted shall be submitted to DOER no later than 30 days after the end of the calendar quarter in which such testing occurred or at the same time the report is submitted to the MassDEP in the event that the test was conducted within 30 days of the end of the calendar quarter. Such report shall accompany the RPS Quarterly Low-Emissions Report for that quarter. Each RPS Quarterly Low-Emissions Report shall include a summary that shows the calculation of the monthly average emissions of NOx and, by a method to be specified by the MassDEP, PM. The format of such quarterly reports shall be proposed by Owner/Operator and approved by DOER.

11. <u>Emission Exceedances</u>.
If DOER finds that the Generation Unit did exceed the emission limit for NOx contained in the Emission Requirements Table, above, averaged over a calendar month, or if sufficient data to satisfy the requirements of the Approvals or superseding Title V Operating Permit is not collected, or if a PM stack test demonstrates exceedance of the limit for PM in the Emission Requirements Table, DOER shall notify the NEPOOL GIS Administrator to void the Massachusetts New Renewable Generation Attribute for all certificates produced by the Generation Unit during that calendar month. Qualification of the Unit's output will resume when compliance with the limits in the Emission Requirements Table are again demonstrated to the Division in the manner required by the MassDEP.

Pursuant to 225 CMR 14.06, the Owner or Operator of the New Renewable Generation Unit is responsible for notifying the Division of any changes in the characteristics of the Generation Unit that could affect its eligibility status. The Owner or Operator of the Generation Unit is also responsible for notifying the Division of any changes in the Unit's ownership, generation capacity, or contact information. The Division may suspend or revoke this Statement of Qualification if the Owner or Operator of a New Renewable Generation Unit fails to comply with 225 CMR 14.00, including the provisions of this Statement of Qualification.

____ Date: ________________
Philip Giudice
Commissioner
Division of Energy Resources

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY & ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SOUTHEAST REGIONAL OFFICE
20 RIVERSIDE DRIVE, LAKEVILLE, MA 02347 508-946-2700

DEVAL L. PATRICK
Governor

TIMOTHY P. MURRAY
Lieutenant Governor

IAN A. BOWLES
Secretary

LAURIE BURT
Commissioner

December 8, 2008

Leonard J. Ariagno
Somerset Power LLC
Somerset Operations, Inc.
1606 Riverside Avenue
Somerset, Massachusetts 02726

RE: **<u>CONDITIONAL APPROVAL</u>**
Application for: BWP AQ 02
Non-Major Comprehensive Plan Applications
310 CMR 7.02 Plan Approval and Emission Limitations
Transmittal No.: W101376
Application No.: 4B06046
Source Number: 0060

AT: Somerset Power LLC
1606 Riverside Avenue
Somerset, Massachusetts 02726

Dear Mr. Ariagno:

On January 25, 2008, the Department of Environmental Protection issued the Conditional Approval for the above-referenced application. A request for an adjudicatory hearing on the Conditional Approval was filed with the Department (DEP Docket No. 2008-054) and Commissioner Laurie Burt rendered a Final Decision dated August 19, 2008 and a Final Decision on the Motion for Reconsideration dated November 26, 2008. The Department is hereby re-issuing that approval in accordance with the Final Decision and the Final Decision on the Motion for Reconsideration. Accordingly, this Conditional Approval supersedes the January 25, 2008 Conditional Approval.

The Department of Environmental Protection (the Department or MassDEP), Bureau of Waste Prevention (BWP), has reviewed the Non-Major Comprehensive Plan Application (NMCPA), submitted by Somerset Power LLC (the Applicant), for proposed modifications to Unit

6/Boiler 8 of the Somerset Station (Facility) located at 1606 Riverside Avenue, Somerset, Massachusetts. This letter approves, with conditions, the Somerset Power LLC NMCPA.

The modifications in the Applicant's NMCPA are intended to demonstrate compliance with emission limitations and compliance schedules for the control of certain designated pollutants contained in 310 CMR 7.29, "Emission Standards for Power Plants." 310 CMR 7.29 regulates the state's largest power plants for nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg) and carbon dioxide (CO_2). Both the NMCPA and the Amended Emission Control Plan (ECP) filed pursuant to 310 CMR 7.29 include emission limits for NO_x, SO_2 and Hg more stringent than the requirements of 310 CMR 7.29. The NMCPA Conditional Approval includes these limits as enforceable permit requirements.

In addition, based on comments received during the public comment period and hearing on the draft approvals, and commitments made by Somerset Power LLC in a January 4, 2008 letter to Secretary Ian Bowles of the Executive Office of Energy and Environmental Affairs, the Conditional Approval includes limitations on the CO_2 emissions significantly more stringent than the 310 CMR 7.29 requirements. Upon the date that Somerset Power LLC notifies ISO New England, Inc. that Unit 6/Boiler 8 is released for commercial generation dispatch with synthetic gas (syngas) conversion equipment in continuous operation, but no later than 180 days after initial burning of syngas, the Conditional Approval reduces Somerset Power LLC's CO_2 emissions limit from non-renewable fuels combusted in Unit 6/Boiler 8 from its historical actual emissions of 916,586 tons per calendar year to its more recent actual average of 860,708 tons per calendar year. Any emissions of CO_2 from Unit 6/Boiler 8 and the emergency syngas flare (Syngas Flare) above that limit can only come from on-site use of eligible biomass or other zero net carbon alternative(s), or any emission of CO_2 from Unit 6/Boiler 8 and the Syngas Flare above 860,708 tons that are not from on-site use of eligible biomass or other zero net carbon alternative(s) must be sequestered. The Department will review and approve or deny proposals for sequestered CO_2 emissions.

NMCPA BACKGROUND

Proposed modifications to the Somerset Station include alterations to existing Unit 6/Boiler 8 coal fired electric utility generating unit. The proposed modifications will convert Boiler 8 from a conventional pulverized coal-fired boiler to a synthetic gas (syngas) fired boiler. Syngas will be produced by plasma gasification of coal and/or biomass feed stocks followed by a syngas cleanup train. The project will include the physical removal of Boiler 8 existing coal burners and pulverizers.

The application was prepared by ENSR and bears the seal and signature of Michael Kravett, P.E. No. 46489.

On April 2, 2007 Somerset Power LLC submitted an Amended 310 Code of Massachusetts Regulations (CMR) 7.29 Emission Control Plan (ECP) application (4B07009) for the proposed conversion of Unit 6/Boiler 8 from coal to syngas pursuant to 310 CMR 7.29(6)(h). On January 25, 2008, the Department issued the Amended ECP Final Approval of ECP application (4B07009) and as reissued in a Amended ECP Final Approval dated December 8, 2008.

The Unit 6/Boiler 8 syngas fuel conversion project does not constitute "Repowering" as defined in 310 CMR 7.00 Definitions and 310 CMR 7.29(2) even though the burning of syngas will realize significant emission reductions and require substantive modifications to Unit 6/Boiler 8. However, the Department recognizes the Applicant's right to propose amendments to the approved ECP pursuant to 310 CMR 7.29(6)(h).

Currently, Somerset Power LLC operates a natural gas reburn system to meet the emission limits contained in the ECP Final Approval (4B01043) dated June 7, 2002, issued pursuant to 310 CMR 7.29 Emissions Standards for Power Plants. On February 24, 2003, the Department issued a Conditional Approval (4B02023) for the construction and operation of the natural gas reburn system pursuant to 310 CMR 7.02 Plan Approval and Emission Limitations. The Conditional Approval (4B02023), including shutdown provisions, will remain in effect in the event that the Unit 6/Boiler 8 project to convert from a conventional pulverized coal-fired boiler to a syngas fired boiler does not go forward.

On December 22, 2006, Somerset Power LLC submitted the NMCPA (4B06046) in accordance with 310 CMR 7.02. The Department is of the opinion that the NMCPA is in conformance with the current Massachusetts Air Pollution Control Regulations and hereby issues this **CONDITIONAL APPROVAL** for the proposed alterations of the facility, subject to the conditions and provisions stated herein. The Department's review has been limited to compliance with applicable Air Pollution Control Regulations and does not relieve you of the obligation to comply with all other permitting requirements contained in other regulations or statutes.

This CONDITIONAL APPROVAL combines and includes: the 310 CMR 7.02 Comprehensive Plan Approval; the 310 CMR 7.00: Appendix A: Emission Offsets and Nonattainment Review analysis; and the Code of Federal Regulations (CFR), Title 40, Part 52.21 Prevention of Significant Deterioration (PSD) analysis, and hereby incorporates the NMCPA submitted by the Applicant by reference, including the Amended ECP application and Amended ECP Final Approval (4B07009) dated December 8, 2008.

On August 21, 2007, the Department issued for public comment a Proposed Conditional Approval. A Public Notice on the Proposed Conditional Approval was published in the Fall River Herald News on August 23, 2007 and in The Spectator on August 29, 2007. The Department also held a public hearing on the Proposed Conditional Approval on October 1, 2007 at the Somerset Public Library, Somerset, Massachusetts at which it received public comment both orally and in writing. The Department considered these comments in issuing this Conditional Approval. In addition, Somerset Power LLC in a letter dated January 4, 2008 to the Executive Office of Energy and Environmental Affairs proposed an additional commitment to reduce CO_2 emissions from non-renewable fuels.

The CONDITIONAL APPROVAL allows for commencement of proposed construction and/or alterations of the facility and its operation, and provides information on the project description, emission control systems, facility limits, continuous emission monitors, record keeping, reporting and testing requirements. A list of the submitted information pertinent to the application is delineated on page 29 of 30.

Should you have any questions concerning this matter, please feel free to contact the undersigned at (508) 946-2779.

Very truly yours,

This final document copy is being provided to you electronically by the Department of Environmental Protection. A signed copy of this document is on file at the DEP office listed on the letterhead.

John K. Winkler, Chief
Permit Section
Bureau of Waste Prevention

cc: Brendan McCahill
U.S. EPA Region I – Air Permits
One Congress St., (CAP)
Boston, MA 02114

ecc: Alan Sawyer, NRG Energy, Inc., Princeton, NJ
Bob Fraser, ENSR, Westford, MA
Board of Selectman, Somerset, MA
Board of Health, Somerset, MA
Fire Department, Somerset, MA
Cynthia Luppi, Clean Water Action, Boston, MA
Shanna Cleveland, Esq., CLF, Boston, MA
Seth Kaplan, Esq., CLF, Boston, MA
Frank Gorke, MASSPIRG, Boston, MA
David Dionne, Westport, MA
Gary Moran, MassDEP/CO-Boston
Sharon Weber, MassDEP/CO-Boston
Marilyn Levenson, Esq., MassDEP/OGC-Boston
James Colman, MassDEP/BWP-Boston
Nancy Seidman, MassDEP/BWP-Boston Marc
Wolman, MassDEP/BWP-Boston
Patricio Silva, MassDEP/BWP-Boston
Yi Tian, MassDEP/BWP-Boston
William Lamkin, MassDEP/BWP-NERO
David Johnston, MassDEP-SERO
Laurel Carlson, MassDEP/BWP-SERO
Laura Patriarca, MassDEP/BWP-SERO

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List of Abbreviations

BACT....................Best Available Control Technology
Btu/kWh................British Thermal Units per kilowatt hour
Btu/lb....................British Thermal Units per pound
BWP.....................Bureau of Waste Prevention
CEM.....................continuous emission monitor
CFR.....................Code of Federal Regulations
CMR.....................Code of Massachusetts Regulations
COM.....................continuous opacity monitor
CO.......................carbon monoxide
CO_2......................carbon dioxide
dB(A).....................decibels (A-weighted sound level)
ECP.....................Emission Control Plan
EPA.....................U.S. Environmental Protection Agency
ESP.....................electrostatic precipitator
FF........................fabric filter
Hg.......................mercury
HAP.....................Hazardous Air Pollutant
HCl......................hydrochloric acid
HHV.....................higher heating value
H_2SO_4..................sulfuric acid
lb/GWh..................pounds per gigawatt hour
lb/hr.....................pound per hour
lb/MMBtu..............pound per million British Thermal Units
lb/MWh.................pound per megawatt hour
LAER...................lowest achievable emission rate
MARAMA............Mid-Atlantic Regional Air Management Association
MassDEP...............Massachusetts Department of Environmental Protection
MCR....................maximum continuous rating
MMBtu/hr.............Million British Thermal Units per hour
MW.....................megawatt
NA......................nonattainment
NAAQS................National Ambient Air Quality Standards
NH_3.....................ammonia
NMCPA...............Non-Major Comprehensive Plan Application
NO_2.....................nitrogen dioxide
NO_x......................nitrogen oxides
NSPS....................New Source Performance Standards
NSR.....................New Source Review
O_3........................ozone
OGC....................Office of General Counsel
ppm_{vd} @ 3% O_2.......parts per million volume dry corrected to three percent oxygen
Pb........................lead
PM.......................particulate matter
PM_{10}.....................particulate matter less than or equal to 10 microns in diameter
$PM_{2.5}$....................particulate matter less than or equal to 2.5 microns in diameter
psig......................pounds per square inch gauge
PTE.....................potential to emit
RACT..................Reasonably Available Control Technology
RATA..................Relative Accuracy Test Audit
RBLC..................RACT/BACT/LAER Clearinghouse
SNCR..................selective non-catalytic reduction
SO_2.....................sulfur dioxide

SO_3........................sulfur trioxide
SO_x........................sulfur oxides
SOMP..................Standard Operating and Maintenance Procedures
tpy......................tons per year
VOC....................volatile organic compound

I. FACILITY DESCRIPTION

A. Site Description

The Somerset Power LLC site consists of approximately 40 acres of land situated in a mixed use area of Somerset, Massachusetts consisting of residential and commercial properties. The existing Somerset Power site includes approximately 140 megawatts (MW) net of coal, residual oil and jet fuel-fired electric power generation equipment. The site is bordered by County Street and Riverside Avenue to the west, the Taunton River to the east, residential properties and Annette Avenue to the north, and Stevens Street, a residential property and the Taunton River to the south.

The neighboring community consists of a mix of commercial and residential properties. The nearest residential areas are directly adjacent to the site to the north and south, and along the west side of Riverside Avenue.

B. Project Description

Somerset Power LLC Somerset Station is subject to 310 CMR 7.29 Emissions Standards for Power Plants that were promulgated on May 11, 2001 and amended effective June 4, 2004, October 6, 2006 and June 29, 2007. These regulations impose facility-wide annual emission limits for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2); and calendar month emission limits for NO_x and SO_2, in units of pounds per megawatt hour (lb/MWh), and annual emission limits for mercury (Hg) in units of pounds per gigawatt hour (lb/GWh) or a minimum Hg removal efficiency. These regulations do not impose carbon monoxide (CO) and fine particulate matter ($PM_{2.5}$) emission standards at this time, but development of such emission standards is reserved. These regulations required applicable power plants to submit an Emission Control Plan (ECP) that defined how the facility would comply with the 310 CMR 7.29 requirements. On June 7, 2002, the Department issued to Somerset Power LLC a Final Approval of the ECP and advised Somerset Power LLC of the requirement to receive a Plan Approval pursuant to 310 CMR 7.02 for the construction of the natural gas reburn project. On August 5, 2002, the Department received Somerset Power LLC's application requesting Plan Approval (4B02023) of the natural gas reburn project. In addition, although not required by 310 CMR 7.29, Somerset Power LLC submitted an application (4B02003) pursuant to 310 CMR 7.02 for modifications to the coal pile and construction of a fixed sound barrier along Riverside Avenue. On February 24, 2003, the Department issued Conditional Approvals (4B02003 and 4B02023) of the proposed natural gas reburn project and the fixed sound barrier and coal pile modifications.

On April 3, 2007, the Department received the Applicant's amended ECP application (4B06046) that requested approval to discontinue burning pulverized coal in Boiler 8 and to convert Unit 6/Boiler 8 to burn syngas. Revisions to the amended ECP application were received on April 13, 2007, and May 8, 2007. In addition, Somerset Power LLC in a letter dated January 4, 2008 to the Executive Office of Energy and Environmental Affairs proposed to further reduce CO_2 emissions from non-renewable fuels (fossil fuels). On January 25, 2008, the Department issued an Amended Emission Control Plan Final Approval of ECP application (4B07009) and as reissued in an Amended ECP Final Approval dated December 8, 2008.

Proposed modifications to the Somerset Station include alterations to existing Unit 6/Boiler 8 coal fired electric utility generating unit. The proposed modifications will convert Boiler 8 from a conventional pulverized coal-fired boiler to a synthetic gas (syngas) fired boiler. Syngas will be produced by plasma gasification of coal and/or biomass feed stocks followed by a syngas cleanup train. The project will include the physical removal of the existing coal burners and pulverizers. Conversion of Unit 6/Boiler 8 to burn syngas will not result in any increase in potential to emit of any criteria air pollutant, and will significantly reduce annual emissions of NO_x, SO_2, PM (Particulate Matter), PM_{10} (Particulate Matter less than or equal to 10 microns in diameter) and $PM_{2.5}$ (Particulate Matter less than or equal to 2.5 microns in diameter) and lead (Pb). The conversion to syngas will result in reduced potential emissions of non-criteria air pollutants: hydrochloric acid (HCl), sulfuric acid (H_2SO_4), ammonia (NH_3) and Hg, and no increase in Hg emissions above the baseline in 310 CMR 7.02(3)(o)2: Table A. The project will also eliminate the production of bottom ash and fly ash, (which will be replaced by a saleable inert slag byproduct). A potential collateral increase in actual emissions of CO and VOC emissions may result from operation of the boiler after conversion to syngas; however, the applicant has demonstrated that any such increase would be less than "significant" emission thresholds under federal New Source Review (NSR) regulations. Although the rate of CO_2 (lb/MW-hr) from firing syngas is expected to be lower than the current emissions rate associated with pulverized coal combustion, a potential collateral increase in actual CO_2 emissions may result from the operation of the boiler after conversion to syngas if unit capacity factor were to increase in the future (CO_2 emissions estimates have been provided by the applicant at both current capacity factor and based on a hypothetical 10% increase in capacity factor from historical operations). The project does, however, have the potential for an overall reduced CO_2 footprint insofar as it proposes to use certain biomass (renewable) feedstocks in place of coal (fossil fuel). With the conversion to syngas, the calendar year CO_2 emissions from non-renewable fuels will not exceed 860,708 tons per year (2004/2005 average actual annual emissions), a reduction of 55,878 tons per year of CO_2 emissions will be realized in comparison to the 916,586 tons per year (1997/1998/2000 average actual annual emissions) allowed by the ECP Final Approval dated June 7, 2002. A NO_x/CO/VOC optimization program after startup is proposed to ensure that the lowest overall emission levels will be achieved.

Somerset Power also proposes to construct an enclosed flare that will be used to vent syngas during emergency upset conditions and shutdowns, and for testing. Operation of the flare will be limited to not more than 500 hours per year after the project enters commercial operation (and no more than 1,000 hours per year during commissioning). Air emissions from the proposed emergency flare are addressed in the Best Available Control Technology (BACT) analysis section of this Conditional Approval.

The major components of the plasma gasification equipment, with the exception of the syngas emergency flare, will be located within the existing building. Limestone and coke will be stored in the existing coal storage area, and biomass will be stored in a converted existing oil tank or new enclosed storage building. The Applicant proposes to comply with 310 CMR 7.03(22) Conveyors, and Dry Material Storage (except silos) concerning biomass material storage and transfer conveyors.

C. Actual Emission Change Estimates

The construction/alteration of Unit 6/Boiler 8 to burn syngas (with or without the emergency flare emissions) are projected to reduce actual annual emissions of NO_x, SO_2, PM, PM_{10}, $PM_{2.5}$,

H_2SO_4, Pb, CO_2, HCl, Hg and NH_3, and are projected to increase actual annual emissions of CO and VOC. The estimated actual emission changes are defined in Tables 1 through 3. Table 1 includes 1000 hours of flare operation, the limit for the first year of operation. Table 2 includes 500 hours of flare operation, the limit for all subsequent years. Table 3 includes no operation hours for the flare and reflects maximum projected boiler operation.

Table 1: ACTUAL EMISSION CHANGE ESTIMATES
(1st Year of Operation Including Maximum 1,000 hours of Flare Operation)

		Baseline Emissions	Projected Actual Annual Emissions at Present Capacity Factor, Boiler plus 1,000 hrs Flare[1]		Projected Actual Annual Emissions at Hypothetical 10% Increased Capacity Factor, Boiler plus 1,000 hrs Flare[1]	
		2004/05 Average	Projected Future	Net Change	Projected Future	Net Change
Fuel	MMBtu/yr	8,368,118	8,379,277	+11,159	9,217,205	+849,087
Net Output	kWh	795,587,000	749,719,685[2]	-45,867,315	824,691,653[2]	+29,104,654
Heat Rate	Btu/kWh	10,520	10,500[2]	-20	10,500[2]	-20
NO_x	tpy	962	299	-663	326	-636
CO	tpy	74.4	140	+65.6	153	+78.6
VOC	tpy	9.8	27.4	+17.6	30.4	+20.3
SO_2	tpy	4369	348	-4021	380	-3989
PM	tpy	100.5	64.4	-36.1	70.4	-30.1
PM_{10}	tpy	68.2	60.4	-7.8	66.4	-1.8
$PM_{2.5}$	tpy	68.2	60.4	-7.8	66.4	-1.8
H_2SO_4	tpy	43.1	13.5	-29.6	14.7	-28.4
Pb[3]	tpy	2.2	1.6	-0.6	1.9	-0.3
CO_2	tpy	860,708	856,326	-4,382	941,959	+81,251
Hg[3]	tpy	0.01	0.00089	-0.0091	0.00099	-0.0090
HCl[3]	tpy	188.3	38.4	-149.9	42.0	-146.3
NH_3	tpy	52.4	41.1	-11.3	44.0	-8.4

Notes:
1 - Includes Unit 6/Boiler 8 with 1,000 hours of operation for the Emergency Syngas Flare
2 - Net Output and Heat Rate are for Unit 6/Boiler 8 only; the emergency flare generates no electricity
3 - HAP emission

Table 2: ACTUAL EMISSION CHANGE ESTIMATES
(2nd Year and All Subsequent Years of Operation Including Maximum 500 Hours of Flare Operation)

		Baseline Emissions	Projected Actual Annual Emissions at Present Capacity Factor, Boiler plus 500 hrs Flare[1]		Projected Actual Annual Emissions at Hypothetical 10% Increased Capacity Factor, Boiler plus 500 hrs Flare[1]	
		2004/05 Average	Projected	Net Change	Projected	Net Change
Fuel	MMBtu/yr	8,368,118	8,632,887	+264,769	9,496,176	+1,128,058
Net Output	kWh	795,587,000	798,026,366[2]	+2,439,366	877,829,003[2]	+82,242,003
Heat Rate	Btu/kWh	10,520	10,500[2]	-20	10,500[2]	-20
NO_x	tpy	962	304	-658	334	-628

CO	tpy	74.4	142	+67.6	156	+81.6
VOC	tpy	9.8	26.2	+16.4	28.2	+18.4
SO_2	tpy	4369	356	-4013	390	-3979
PM	tpy	100.5	65.2	-35.3	71.2	-29.3
PM_{10}	tpy	68.2	61.2	-7.0	67.2	-1.0
$PM_{2.5}$	tpy	68.2	61.2	-7.0	67.2	-1.0
H_2SO_4	tpy	43.1	13.4	-29.7	14.7	-28.4
Pb[3]	tpy	2.2	1.6	-0.6	1.9	-0.3
CO_2	tpy	860,708	856,326	-4,382	941,959	+81,251
Hg[3]	tpy	0.01	0.00094	-0.0091	0.00104	-0.0090
HCl[3]	tpy	188.3	39.2	-149.1	43.0	-145.2
NH_3	tpy	52.4	40.5	-11.9	44.5	-7.9

Notes:
1 - Includes Unit 6/Boiler 8 with 500 hours of operation for the Emergency Syngas Flare
2 - Net Output and Heat Rate are for Unit 6/Boiler 8 only; the emergency flare generates no electricity
3 - HAP emission

Table 3: ACTUAL EMISSION CHANGE ESTIMATES
(No Flare Operation)

		Baseline Emissions	Projected Actual Annual Emissions at Present Capacity Factor[1]		Projected Actual Annual Emissions at Hypothetical 10% Increased Capacity Factor[1]	
		2004/05 Average	Projected	Net Change	Projected	Net Change
Fuel	MMBtu/yr	8,368,118	8,886,497	+518,379	9,775,147	+1,407,029
Net Output	kWh	795,587,000	846,333,047	+50,746,047	930,966,351	+135,379,351
Heat Rate	Btu/kWh	10,520	10,500	-20	10,500	-20
NO_x	tpy	962	311	-651	342	-620
CO	tpy	74.4	144.6	+70.2	159.1	+84.7
VOC	tpy	9.8	24.2	+14.4	26.7	+16.9
SO_2	tpy	4369	364	-4,005	400	-3,969
PM	tpy	100.5	65.7	-34.8	72.3	-28.2
PM_{10}	tpy	68.2	61.3	-6.9	67.4	-0.8
$PM_{2.5}$	tpy	68.2	61.3	-6.9	67.4	-0.8
H_2SO_4	tpy	43.1	13.4	-29.7	14.7	-28.4
Pb[2]	tpy	2.2	1.6	-0.6	1.9	-0.3
CO_2	tpy	860,708	856,326	-4,382	941,959	+81,251
Hg[2]	tpy	0.01	0.00095	-0.0091	0.00104	-0.0090
HCl[2]	tpy	188.3	40.1	-148.2	44.1	-144.2
NH_3	tpy	52.4	40.3	-12.1	44.3	-8.1

Notes:
1 - Annual operation of Unit 6/Boiler 8, assuming no Flare Events
2 - HAP emission

D. Description of Proposed Alteration/Construction

The Applicant proposes construction/alterations to convert Unit 6/Boiler 8 to syngas as follows:

Unit 6/Boiler 8

Unit 6/Boiler 8 is a single reheat, pulverized coal-fired, balanced draft base load unit with a nominal 120 MW net output (132 MW gross output) generator capacity that began commercial operation in 1959. The actual net output of the Unit 6 turbine-generator has ranged to as low as 104 MW due in part to the fuel changes in order to comply with air pollution control regulations. There will be no modifications to the existing Unit 6 generator as part of the syngas fuel conversion project.

Boiler 8 is a tangentially fired, Combustion Engineering boiler that currently utilizes pulverized coal as the primary fuel and No. 6 fuel oil as a secondary fuel. Boiler 8 is presently limited to 1,186 million Btu per hour (MMBtu/hr) heat input. The boiler is capable of supplying 800,000 pounds of steam per hour at 1,925 pounds per square inch gauge (psig) and 1,000 °F to Unit 6 turbine-generator. Boiler 8 is equipped with a natural gas reburn system and NOX-OUT Selective Non-catalytic Reduction (SNCR) post combustion NO_x emission controls that operates in conjunction with the natural gas reburn system to reduce NO_x emissions. Boiler 8 is also equipped with an electrostatic precipitator (ESP) for the control of particulate matter. Products of combustion are released to the ambient air from a stack 310 feet above ground level with an inside diameter of 156 inches.

Boiler 8 will be converted to burn syngas as the primary fuel. The existing coal pulverizers and burners will be removed and new low NO_x design syngas burners will be installed with a new burner management system. Substantial economizer, superheater, and likely waterwall modifications will be required to optimize heat transfer and heat adsorption when burning syngas to match the steam capacity of the Unit 6 turbine-generator and to optimize efficiency. These modifications are necessary since syngas burns with a bluish transparent flame at temperatures much lower than pulverized coal combustion and heat transfer will be primarily convective, versus primarily radiant heat transfer with pulverized coal burning that produces a hotter white-yellow flame. Up to 10% of the boiler heat input will be provided by oil (or biodiesel) having a sulfur content of 0.3% by weight or less, to ensure flame stabilization and system safety.

The existing natural gas reburn system and existing ESPs will be removed or abandoned in place; the existing SNCR system will be retained and operated as needed for NO_x emission control; and the existing stack will be retained. In addition, existing Boilers 1 through 6 and ancillary equipment will be removed as required to create indoor space for the plasma gasification equipment and syngas cleanup train.

Plasma Gasification Equipment

Westinghouse Plasma Corporation (or equivalent) gasification system technology will be utilized and it will represent the first known commercial application of direct coal plasma gasification. The plasma system will consist of up to four gasifiers. Each gasifier consists of a steel and ceramic cupola with plasma torches (typically six per cupola) that will create a very high temperature plasma zone in the bottom of the cupola. Up to 10% of the heat input to the gasifier will be in the form of metallurgical coke, which will establish a bed of carbon at the bottom of the gasifier to support the gasification zone of coal and/or biomass gasification feedstocks. Up to 35% of the annual feedstock consumption may be biomass feedstocks consisting of wood, wood chips, agricultural solid products, and/or "other biomass derived feedstock" [non-recyclable paper (paper cubes) and/or processed construction and demolition derived feedstock, etc.]. Prior to utilizing "other biomass derived feedstock" a Beneficial Use Determination (BUD) application will need to be submitted to the Department and receive written approval pursuant to 310 CMR 19.060. The BUD application will need to include an air toxics assessment that demonstrates that the Massachusetts Threshold Effects Exposure Limits (TELs) and Allowable Ambient Limits (AALs) will not be exceeded. Air (air blown or oxygen enriched) will be blown through the plasma torches heating it to approximately 10,000 °F converting the air to a plasma state. This plasma is injected into the gasification bed that will operate at approximately 6,000 °F. The gaseous stream rises to the top of the cupola almost completely dissociating the feedstock (coal, biomass and coke) into two streams: gaseous organic material and inorganic liquid (melted ash). Limestone is fed to the gasifiers as needed to flux the liquid slag; however it is otherwise an inert material. The main combustible constituents of the syngas consist primarily of carbon monoxide (CO) and hydrogen (H_2). The inorganic liquid stream is an inert vitrified mineral slag consisting of melted ash constituents. The vitrified mineral slag will be maintained in a hot molten state and will be drained via a port on the bottom of the cupola to a water quench, where it will harden and shatter to an inert solid material similar to crushed glass.

The gasifiers will operate under a slight negative pressure to preclude any fugitive emissions. Syngas will exit the gasifier at approximately 1,900 °F at a low velocity in order to minimize carry over of solid particulate to the syngas cleanup train.

<u>Synthetic Gas (Syngas) Cleanup Train</u>
The syngas cleanup train will consist of a syngas cooler, wet quench scrubber, baghouse, polishing wet scrubber, carbon filters and aqueous contactors/bioreactors. There will be no syngas bypasses installed on any component of the syngas cleanup train.

The syngas cooler will consist of one heat exchanger that will reduce syngas temperature to approximately 500 °F. Steam produced will be used in the Unit 6/Boiler 8 steam and/or feedwater cycle. The cooled syngas will enter a wet quench spray scrubber designed to remove HCl, SO_2 and NH_3 and to further cool the syngas prior to entering a baghouse (fabric filter) for fine particulate removal. The baghouse is designed with nitrogen pulse bag cleaning and particulate captured is recycled back to the cupolas. Syngas exiting the baghouse passes through a polishing wet scrubber to further condense aerosols and remove residual acid gases, filterable particulate and condensable particulate. Syngas then passes through a syngas blower prior to entering a two-stage fixed bed activated carbon filter for elemental Hg removal. A Hg sampling location will be provided between the two carbon beds to periodically monitor for Hg break-through that will identify the need to replace carbon in the lead bed. It is estimated that one carbon bed saturated with Hg will need to be changed out and disposed every other year. Syngas exiting the carbon beds passes through a Shell Paques (or equivalent) system for H_2S removal consisting of one or more packed-bed scrubbers that uses an aqueous soda solution containing thiobacillus bacteria. The soda solution absorbs the H_2S and is then circulated through one or more aerated atmospheric bioreactor tanks where the bacteria will convert the scrubbed H_2S to elemental sulfur. The sulfur solution is dewatered and may be reused for agricultural fertilizer or a high quality (99%+) sulfur cake may be produced for sale. The clean syngas exiting the packed bed scrubbers is ducted to the Boiler 8 syngas burners, or in case of an upset condition, such as a Boiler 8 emergency burner trip, the clean syngas will be diverted to the emergency syngas flare to shutdown the process. The syngas is expected to have a higher heating value of approximately 150 Btu/ft^3.

Emergency Syngas Flare

An enclosed syngas flare will combust residual clean syngas during an upset condition such as an emergency burner trip. Products of combustion will be released to the ambient air from a stack 80 feet above ground level (96.4 feet above sea level) with an inside diameter of 32 feet. The base of the syngas flare will include a masonry sound barrier to reduce sound impacts when the flare is in operation.

II. EMISSIONS

A. Background

Boiler 8 currently burns coal and No. 6 fuel oil and will in the future burn syngas with up to 10% oil (or biodiesel) having a sulfur content of 0.3% by weight or less. Emissions to the ambient air from Boiler 8 operation include the criteria air contaminants PM, PM_{10}, $PM_{2.5}$, SO_2, CO, NO_x, Pb and VOC and the non-criteria air contaminants H_2SO_4, HCl, Hg, NH_3 and CO_2. With the conversion of Boiler 8 to syngas firing, all air contaminant potential to emit (PTE) emission rates to the ambient air will decrease.

B. New Emission Limits

1. Unit 6/Boiler 8 shall not exceed the emission limits as specified in Table 4:

Table 4: UNIT 6/BOILER 8 EMISSION LIMITS

Emission	lb/MMBtu		ppmvd @ 3% O_2		lb/hr	tpy[f]
	1-hr Avg.	30-day avg.[c]	1-hr avg.	30-day avg.[c]		
NO_x[a]	0.367	0.07	255	54.7	471	393.7
CO[a]	0.083	0.033	95	37.2	107	183.0
VOC[a,b]	0.0073	0.005	14.6	11.2	9.37	30.7
SO_2[a]	1.2	0.08	-	-	1541	460.0
PM	0.015	-	-	-	103	83.1
PM_{10}	0.014	-	-	-	103	77.5
$PM_{2.5}$	0.014	-	-	-	103	77.5
H_2SO_4	0.003	-	-	-	3.85	16.9
Pb[g]	0.00039	-	-	-	0.501	2.2
Hg[d,e,g]	2.4E-07	2.4E-07	-	-	3.1E-04	1.3E-03
HCl[g]	0.0090	-	-	-	11.6	44.1
NH_3	0.0091	-	17	-	10.1	50.9
CO_2	-	-	-	-	-	860,708[h]

Notes:

a - Based upon stack compliance emission testing per 40 CFR 60.8, or as otherwise approved by the Department, and continuous

emission monitor (CEM) data
b - Based upon CO CEM emission data correlated to VOC emissions
c - Based on a 30-day rolling average
d - Hg emissions will meet the MA 7.29 requirements – 7.5 x 10^{-6} lb/MWh (7.1 x 10^{-7} lb/MMBtu) during the first year and prior to commercial operation which is prior to the date the Applicant notifies ISO New England, Inc. that Unit 6/Boiler 8 is released for commercial generation dispatch with the syngas conversion equipment in continuous operation.
e - Based on 95% reduction from typical Hg in coal and EPA AP42 factors.
f - tpy is tons per consecutive twelve month period.
g - HAP emission
h - tons per year from non-renewable fuels on a calendar year basis, including Syngas Flare emissions. Any CO_2 emissions above 860,708 tons per calendar year emission limit shall be derived from on-site use of eligible biomass or other zero (0) net carbon alternative; or, any CO_2 emissions generated from Unit 6/Boiler 8 and the Syngas Flare above 860,708 tons per calendar year not from the use of eligible biomass or other zero (0) net carbon alternative must be sequestered.

2. Unit 6/Boiler 8 shall not exceed the emission limits/standards as specified in Table 5:

Table 5: EMISSION LIMITS/STANDARDS[a]	
NO_x	0.735 lb/MWh (calculated over any 12 month period, recalculated monthly) 0.735 lb/MWh (calculated over any individual month)
SO_2	0.84 lb/MWh (calculated over any 12 month period, recalculated monthly) 0.84 lb/MWh (calculated over any individual month)
Hg	95% control or 0.0025 lb/GWh (calculated over any 12 month period, recalculated monthly)[b]

Notes:
a - Methodology to demonstrate compliance shall be in accordance with procedures contained in 310 CMR 7.29 Emissions Standards for Power Plants or alternative monitoring as approved by the Department.
b - Unit 6/Boiler 8 shall achieve the 2012 310 CMR 7.29 limits upon achieving commercial operation.

3. Somerset Power LLC shall perform a NO_x/CO/VOC optimization/minimization program prior to compliance emission testing.
4. The Department reserves the right to reduce CO and/or VOC emission limits to less than the above based upon compliance emission test results achieved, the optimization/minimization program and CEM data.
5. The Unit 6/Boiler 8 start up requirements pertaining to NO_x and CO emissions contained in Section VI – Special Conditions of the September 29, 1998 NO_x Reasonably Available Control Technology (RACT) ECP Approval (4B95165) remain in effect.
6. Unit 6/Boiler 8 and the Emergency Syngas Flare shall not exceed 20 percent opacity for a period or aggregate period of time in excess of two minutes during any one hour provided that, at no time during the said two minutes shall the opacity exceed 40%.

7. The Emergency Syngas Flare shall not exceed the emission limits as specified in Table 6:

Table 6: EMERGENCY SYNGAS FLARE EMISSION LIMITS				
Emission	**lb/MMBtu[a]**	**lb/hr[a]**	**tpy[b,c,e]**	**tpy[b,d,e]**
NO_x	0.07	89.9	22.5	11.2
CO	0.037	47.5	11.9	5.9
VOC	0.02	25.7	6.4	3.2
SO_2	0.08	103	25.7	12.8
PM	0.02	25.7	6.4	3.2
PM_{10}	0.02	25.7	6.4	3.2
$PM_{2.5}$	0.02	25.7	6.4	3.2

Notes:

a - Based upon stack emission testing per 40 CFR 60.8, or as otherwise approved by the Department, and based on the average of three 1-hr tests. Lb/MMBtu and lb/hr limits for the emergency flare are based on maximum 1-hr emission levels, assuming operation at 1284 MMBtu/hr for an entire hour.

b - tpy is tons per consecutive twelve month period, and are based on average syngas flow rate over each shutdown event of 642 MMBtu/hr (1,284 MMBtu / 2).

c - Prior to commercial operation - maximum 1,000 hr/yr and 642,000 MMBtu/yr input

d - Post commercial operation - maximum 500 hr/yr and 321,000 MMBtu/yr input

e – tpy is tons per consecutive twelve month period.

8. Unit 6/Boiler 8 and the Emergency Syngas Flare will become subject to Table 4: Unit 6/Boiler 8 Emission Limits, Table 5: Unit 6/Boiler 8 Emission Limits/Standards, and Table 6: Emergency Syngas Flare Emission Limits as of the date specified in Section XI.4.e., but not later than 180 days after initial burning of syngas.

III. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW

A. Background

The federal government under the jurisdiction of the Environmental Protection Agency (EPA) established National Ambient Air Quality Standards (NAAQS) for seven air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2, PM_{10}, $PM_{2.5}$, NO_2, CO, ozone (O_3), and Pb.

One of the basic goals of federal and state air regulations is to ensure that ambient air quality, including the impact of existing and new sources, complies with ambient standards. Towards this end, EPA classified all areas of the country as "attainment," "nonattainment" or "unclassified" with respect to the NAAQS.

New major stationary sources of regulated air pollutants or major modifications to existing major stationary sources of regulated air pollutants that are located in areas classified as either "attainment" or "unclassified" are subject to 40 CFR Section 52.21 Prevention of Significant Deterioration of Air Quality (PSD) regulations. Pursuant to 40 CFR 52.21(b)(1)(i)(a), a source is considered "major" if it has the potential to emit 100 tpy or more of any regulated NSR pollutant and is listed as one of the 28 designated PSD stationary source categories, and a modification is considered a "major modification" if the physical change or change in the method of operation of a "major" stationary source would result in a significant net emission increase.

Effective July 1, 1982, the PSD program was implemented, by the Department, in accordance with the Department's "Procedures for Implementing Federal Prevention of Significant Deterioration Regulations." Somerset Power LLC, Unit 6/Boiler 8, steam to electric power generation unit is rated at 1,284 MMBtu/hr heat input. Thus, Somerset Station is one of the 28 designated PSD stationary source categories, namely a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input and is an existing major stationary source of regulated air pollutants.

Effective March 3, 2003, the Department notified US EPA Region 1 that Massachusetts would no longer implement the PSD program and returned delegation of the PSD program to the US EPA. Therefore, the US EPA Region 1 has the responsibility to determine PSD applicability for this project.

B. General Information

The Applicant is proposing to alter Unit 6/Boiler 8 at its electric utility steam generating facility in Somerset, Massachusetts. The facility is located in an area that is in either "attainment" or "unclassified" for SO_2, NO_2, CO, Pb, PM_{10} and $PM_{2.5}$. Therefore, the facility is located in a PSD area for these pollutants.

IV. EMISSION OFFSETS AND NONATTAINMENT REVIEW

A. Background

The entire Commonwealth of Massachusetts is designated "moderate" nonattainment (NA) for the pollutant O_3 NAAQS. NO_x and VOCs emissions are precursors to the formation of O_3.

New major stationary sources of regulated air pollutants or major modifications to existing major stationary sources of regulated air pollutants that are located in areas classified as "nonattainment" are subject to 310 CMR 7.00: Appendix A Emission Offsets and Nonattainment Review. Pursuant to 310 CMR 7.00: Appendix A(2), a source is considered "major" if it has a potential to emit 50 tpy or more of NO_x or VOC, and a modification is considered a "major modification" if the physical change or change in method of operation of a "major" stationary source would result in a significant net emission increase. A significant net emission increase for applications received after November 15, 1992 is defined as 25 tpy of either VOC or NO_x emissions.

Applicable requirements for any proposed new major stationary source of NO_x and/or VOC require the source to meet Lowest Achievable Emission Rate (LAER) and obtain emission offsets.

B. General Information

Alteration of Unit6/Boiler 8 is not categorized as a "major modification" to an existing major source since the alteration would not result in a representative actual annual emissions increase in excess of the NSR significant emission increase thresholds.

2004-2005 Average Past Actual Baseline

For the alterations proposed in NMCPA (4B06046) submitted on December 22, 2006, the NO_x and VOC net emission change estimates for Unit 6/Boiler 8 for emissions subject to Nonattainment review are defined in Table 7.

Table 7: NONATTAINMENT REVIEW

		Actual Emissions		Baseline Emissions	Projected Emissions with Syngas[a]	Net Emission Change		
		Emissions 2004	Emissions 2005	2004/05 Average	Representative Actual Annual Emissions	(Projected) -(Baseline)	NA Significance Threshold	NA Significant (Y/N)
NO_x	tpy	972.5	951.4	962	334	-628	25	No
VOC	tpy	9.9	9.6	9.8	28[b]	+18.2[b]	25	No

Notes:
a - Includes Unit 6/Boiler 8 and the Emergency Syngas Flare
b - 1st year of syngas operation 30 tpy and a +20.2 tpy net emission change

The syngas conversion project, based on comparing past actual annual emissions to future representative actual annual emissions, will result in significant NO_x emission reductions, and less than a significant net increase in representative actual emissions of VOC. Unit 6/Boiler 8 collateral VOC representative actual emissions increase will not adversely affect NAAQS for O_3 due to the substantial reductions of NO_x emissions.

C. Conclusion

The proposed Unit 6/Boiler 8 alteration, based on current information and pursuant to 310 CMR 7.00: Appendix A(2), is not considered a "major modification" to an existing major stationary source. Based on current information, LAER and Offsets, pursuant to 310 CMR 7.00: Appendix A, are not required for the alterations/construction. Refer to Section X and XI for emission record keeping and reporting requirements.

V. NEW SOURCE PERFORMANCE STANDARDS

A. Background

The New Source Performance Standards (NSPS) for fossil fuel-fired steam generators and electric utility steam generating units, are contained in Title 40 Part 60 Subpart D and Subpart Da, respectively. Unit 6/Boiler 8 is considered to be a "fossil fuel-fired steam generating unit" and an "electric utility steam generating unit" since Unit 6/Boiler 8 burns fossil fuels at a rate greater than 250 MMBtu/hr and more than one third of Unit 6 net electrical output will be sold to a utility.

The Applicant has acknowledged that the Unit 6/Boiler 8 syngas conversion project, including the plasma gasification syngas production process, will likely meet the test of "reconstruction," as defined in 40 CFR 60, since the costs likely meet 50% of the replacement cost test that would constitute "reconstruction."

B. Conclusion

The NSPS for fossil fuel-fired steam generators and electric utility steam generating units, Title 40 Part 60 Subpart D and Subpart Da, respectively, of the Code of Federal Regulations (the NSPS), are applicable to Unit 6/Boiler 8. This Conditional Approval includes emission limits, monitoring, recordkeeping and reporting requirements in compliance with the NSPS. Compliance with this Conditional Approval means compliance with the NSPS.

VI. BEST AVAILABLE CONTROL TECHNOLOGY

Pursuant to 310 CMR 7.02(3)(j)6., the Applicant is required to evaluate Best Available Control Technology (BACT) as it applies to any air contaminant that will result in a potential emission increase. Boiler 8 conversion to syngas will result in no potential emission increase of any air contaminant. As a new emission source, the proposed emergency flare is subject to the application of BACT for all emissions with a potential to emit of 1 tpy or more. BACT is defined as an emission limitation using the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, and environmental factors.

The first step in a BACT analysis is to determine for the emission source, the most stringent control available for a similar or identical source or source category. The proposed flare must utilize BACT to control NO_x, CO, VOC, SO_2, PM, PM_{10}, and $PM_{2.5}$ emissions. The Department has verified and concurs with the following Comparative BACT Analysis (as referenced in the Applicant's NMCPA).

No precedents for burning plasma gasification syngas during shutdown events in an enclosed flare were identified through the RACT/BACT/LAER Clearinghouse (RBLC) or other background research. The most similar existing sources are enclosed flares at petroleum refineries or landfills firing low-Btu petroleum or landfill gas. In these cases, good (optimized) combustion is the only identified control technology. The Mid-Atlantic Regional Air Management Association (MARAMA) published a model rule for emissions from petroleum refinery flares in October of 2006. BACT emission rates for the emergency syngas flare were based on the emission rates in the MARAMA rule, emission rates of existing petroleum and landfill gas flares in the RBLC, and engineering judgment.

Therefore, based upon the economic analysis portion of the top-down BACT process, currently available data, and the tenets and procedures of the BACT process, the Department has concluded that the use of clean syngas, operational restrictions to 1,000 hours for the first year of operation and 500 hours per year for all subsequent years, and good combustion control are the only technically feasible means to achieve BACT emission rates for the proposed emergency flare.

The BACT combustion controls consist of design and operation of the flare in a manner so as to limit NOx, VOC and CO formation. Combustion control systems seek to maintain the proper conditions to ensure complete combustion through operational design that provides sufficient residence time, excess air, good mixing and staged combustion to completely burn out products of incomplete combustion (VOC and CO).

VII. SOUND

A. Background

The Department regulation concerning sound emissions is contained in 310 CMR 7.10 Noise. This regulation requires that necessary equipment and precautions be used to prevent a condition of air pollution due to sound emissions from the facility. The Department's existing guideline for enforcing the noise regulation is contained in the Department's Policy 90-001; the policy provides broadband and pure tone sound level criteria.

The Somerset Power LLC facility sound impacts were extensively evaluated at the time of the conversion to coal in the 1980's. Sound emissions and control requirements for the coal conversion are contained in the Department's December 11, 1986 Plan Approval (SM82-084-CO, SM83-021-CO, SM-83-022-CO, SM83-094-CO, SM-84-036-CO and SM84-043-M) and remain in effect other than the requirements concerning the design, operation and maintenance of the inactive coal pile. The Department's approval (4B02003), dated February 24, 2003, of the sound barrier wall in lieu of the inactive coal pile remains in effect.

Based upon a records review, the existing facility has not caused a condition of air pollution due to sound emissions since the coal conversion in the 1980's. Offsite sound from major facility sources has been controlled using buildings to enclose stationary equipment, and, recently, by constructing a barrier wall along Riverside Avenue to control sound emissions from the coal handling operations and further reduce overall facility sound impacts toward residences southwest of the facility. The effectiveness of the barrier wall is detailed in a compliance test report letter to MassDEP from Somerset Operations, Inc. on November 25, 2003, and final approval of the sound wall was provided by MassDEP on March 7, 2005.

It is predicted that the sound emissions from the syngas conversion project will result in no perceptible increase in sound [no increase greater than 3 dB(A) will occur] in the adjacent residential areas. Facility buildings will continue to control sound emissions from stationary equipment, and the sound wall will continue to act as a barrier to the receptors southwest of the facility along Riverside Avenue. Several existing sources of sound emissions will be discontinued, including the existing coal pulverizers and ash handling system. Sound emissions from most of the new equipment will be attenuated by enclosure within existing buildings or structures. The proposed ground flare represents a new potential noise source adjacent to the existing building on the North side of the Station. The flare sound emissions were evaluated for potential impacts to the nearest residential receptor (along the north side of Annette Avenue), and was shown to result in no perceptible sound increase [i.e., < 3 dB(A)] at that location. Sound from the emergency ground flare is broadband sound (not tonal) and will be minimized by a concrete sound wall surrounding the flare. The flare design will be specified to meet a sound level at 100 feet from the flare of 61 dB(A) or less, which is predicted to result in no perceptible increase in sound at the nearest residential receptor. The emergency ground flare specification of 61 dBA or less at 100 feet is based on the following:

- existing nighttime sound levels measured at the nearest two residences on May 2007;
- estimated flare sound levels from published empirical equations for flare noise;

- acoustical modeling of estimated flare sound levels to the nearest residential receptors; and
- results of the May 2007 measurements of existing sound, estimated flare sound levels and predicted emergency flare sound at the nearest residential receptors (MassDEP form BWP AQ SFP-3) are presented in Appendix D.

B. General Information

Sound Mitigating Measures

1. All components of the plasma gasification equipment and syngas cleanup train (the main sources of sound) are located within the existing power plant building
2. The Conditional Approval (4B02003) by the Department, dated February 24, 2003, concerning the sound barrier wall will remain in effect. This sound barrier wall mitigates the facility sound impacts from the coal receipt and handling in the South Yard.
3. The Emergency Syngas Flare will be located in the North Yard. A concrete sound wall will surround the flare to reduce sound when the flare is in operation.
4. The new biomass / materials storage and handling facilities which will be located across Riverside Ave, will be largely passive and rotating equipment will be shielded within the enclosure(s). Biomass delivery trucks will deliver to the site 6 days a week between the hours of 7:00 a.m. and 7:00 p.m.

C. Conclusion

Sound impacts due to the Unit 6/Boiler 8 syngas conversion project will result in no perceptible ambient increase in sound impacts at adjacent residential areas. Sound impacts proposed in the application meet the requirements contained in 310 CMR 7.10 <u>Noise</u> and will not cause or contribute to a condition of air pollution.

Somerset Power LLC shall conduct a sound survey within 60 days from the date Unit 6/Boiler 8 is available for commercial operation (as defined by ISO New England, Inc.) with the syngas in continuous operation. A report shall be submitted to the Department, within 30 days after the sound survey, defining actual sound impacts in comparison to impacts proposed in the application approved herein.

VIII. SPECIAL CONDITIONS

1. The Applicant shall submit to the Department, in accordance with the provisions of Regulation 310 CMR 7.02(5)(c), updated completed Department NMCPA application forms, plans, specifications for Boiler 8 modifications, Plasma Gasification Equipment, Syngas Cleanup Train and Emergency Syngas Flare not later than 30 days prior to commencement of construction/installation.
2. Pursuant to Regulation 310 CMR 7.00: Appendix C and the November 7, 1995 US EPA letter to State and Territorial Air Pollution Program Administrators/Association of Local Air Pollution Control Officers (STAPPA/ALAPCO) (now National Association of Clean Air Agencies, NACAA), the modification approved herein will be a "Minor Modification" to Operating Permit 4V95057 since this Conditional Approval (Application No. 4B06046) is a minor NSR action. An Operating Permit Minor Modification application shall be submitted to the Department on or before the

commencement of the alterations/construction that reflects the Amended ECP Final Approval (4B07009), this Conditional Approval (Application No. 4B06046), and any other applicable requirement that the facility is subject to.

3. The Applicant shall submit Standard Operating and Maintenance Procedures (SOMP) for the new equipment to the Department no later than 60 days after commencement of operation of the proposed facility. Thereafter, the Applicant shall submit updated versions of the SOMP to the Department no later than 30 days prior to the occurrence of a significant change. The Department must approve in writing any significant changes to the SOMP prior to the SOMP becoming effective.
4. The Applicant shall submit a revised SOMP to the Department, within 12 months of the date specified in Section XI.4.e. that addresses NOx/CO/VOC minimization/optimization and NH_3 slip minimization.
5. The Applicant shall, within 60 days after the submittal to the Department of the compliance test report, propose a surrogate methodology or parametric monitoring for NH_3 emissions based on compliance test results and operating experience.
6. The Applicant shall maintain a complaint log concerning emissions, odor, dust and noise from the facility. The Applicant shall make available to the general public a telephone number that will receive and record complaints 24 hours per day, 7 days per week. The complaint log shall be maintained for the most recent five (5) year period. The complaint log shall be made available to the Department upon request. The Applicant shall take all reasonable actions to respond to complaints.
7. The Applicant, within 12 months of the date specified in Section XI.4.e., shall propose new CO and VOC emission limits for Unit 6/Boiler 8, and provide supporting justification for the new proposed emission limits taking into consideration the NO_x/VOC/CO optimization/minimization program emission test data, compliance emission test data, CO CEM data and operating experience. The Department will establish final CO and VOC emission limits after review of the Applicant's proposed final emission limits and supporting documentation. The goal of the program is to achieve CO emissions of 20 ppm_{vd} @ 3% O_2 or less.
8. The Applicant shall promptly undertake a reasonable and appropriate study of NH_3 slip from Unit 6/Boiler 8 and upon the completion of the study develop and implement an emission optimization plan that gives due consideration to minimizing ammonia slip.
9. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.48Da Compliance Provisions and within 45 days prior to burning syngas in Unit 6/Boiler 8 submit to the Department the Applicant's plan to meet the requirements therein.
10. Unit 6/Boiler 8 shall cease burning pulverized coal and shutdown for the conversion to syngas on or before September 30, 2010.

IX. MONITORING AND RECORDING REQUIREMENTS

1. All current monitoring and recording requirements remain in effect and are not altered herein.
2. The Applicant shall ensure continuous monitoring and compliance with VOC emission limits utilizing the CO parametric monitoring methodology developed during the initial compliance test.
3. If CO emissions are below the CO emission limit, the VOC emissions shall be considered as meeting the emission limits contained in this Conditional Approval, subject to correlation as contained in Condition IX.4., below.
4. If CO emissions are above the CO emission limit, the VOC emissions shall be considered as occurring at a rate determined by the equation: $VOC_{actual}=VOC_{LIMIT}\ x(CO_{actual}/CO_{limit})$, pending the outcome of the initial compliance testing, after which a VOC/CO correlation curve and/or emission factors for Unit 6/Boiler 8 will be developed and used for VOC compliance determination purposes.
5. Unit 6/Boiler 8 shall meet 40 CFR Part 75 Continuous Emission Monitoring requirements, as applicable.
6. Unit 6/Boiler 8 shall be equipped with an NH_3 CEM within 180 days after the end of any consecutive 12-month period recalculated monthly during which the Boiler 8 SNCR system is utilized for 2,000 hours or more. Once this 2,000 hour SNCR operational trigger is reached in any consecutive period of 12 months, the requirement to maintain the NH_3 CEM will remain in effect even if the use of the SNCR decreases to less than 2,000 hours in subsequent consecutive 12-month periods. If a NH_3 CEM is required on Boiler 8, it shall be certified within 60 days of installation.
7. If the NH_3 CEM is required on Boiler 8, the NH_3 monitor upon certification will be used as direct compliance level monitor. The NH_3 CEM shall comply with the CEM linearity check and Relative Accuracy Test Audit (RATA) frequencies and grace periods specified in 40 CFR 75 in conducting linearities and RATAs. The relative accuracy of the NH_3 CEM systems shall be within the greater of +/- 15% or +/- 0.75 ppm_{vd} @ 3% O_2 or +/- 0.0004 lb/MMBtu or lb/hr = +/- 0.0004 lb/MMBtu x WA_MMBtu/hr, where WA_MMBtu/hr = the weighted average MMBtu/hr determined by the DAHS over the hours during which the RATA was performed. The NH_3 CEM shall obtain valid data for at least 90% of the hours per calendar quarter during which the emission unit is operating.
8. In the event that a given NH_3 CEM RATA does not meet the relative accuracy specified in IX.7., the following shall apply:
    a. Somerset Power LLC shall investigate the possible reasons for a RATA failure and whether repairs or adjustments are necessary for the NH_3 CEM or its sampling location/path. If such NH_3 CEM repairs or adjustments are necessary prior to a successful RATA, or if sampling location/path adjustments are required, then the NH_3 CEM data shall be considered invalid from the time of the failed RATA until a successful RATA occurs.
    b. If no repairs or adjustments to the NH_3 CEM are necessary between the time of a failed RATA and a successful RATA, and no sampling location/path adjustments are needed, then the NH_3 CEM data shall be considered valid during the period between the failed RATA and successful RATA.

9. In the event data from a NH_3 CEM is not available, corrective action shall be implemented as quickly as practical to bring the NH_3 CEM back to service. During the time when the NH_3 CEM is not available, Somerset Power LLC may submit a parametric monitoring methodology to the Department for approval to provide assurance that the NO_x levels, operating loads, and urea injection rates being maintained are consistent with prior urea-compliant operation.

10. At least 60 days prior to commencing construction of the NH_3 CEM systems, the NH_3 CEM monitoring plan shall be submitted to the Department for review and approval. The NH_3 CEM monitoring plan shall include:
    - Source identification
    - Source description
    - Control technology description
    - Applicable regulations
    - Type of monitor
    - A monitoring system flow diagram
    - A description of the data handling system
    - A sample calculation demonstrating compliance with the emission limits using conversion factors from 40 CFR 60 or approved by the Department

11. In the event that an NH_3 CEM is required, the NH_3 CEM system certification protocol shall be submitted to the Department at least 60 days prior to certification testing for the CEM.

12. In the event that an NH_3 CEM is required, the NH_3 CEM system certification report shall be submitted to the Department within 45 days from the completion of testing.

13. The applicant shall comply with 40 CFR 60, Subpart Da, Section 60.49Da Emission Monitoring and within 45 days prior to burning syngas in Unit 6/Boiler 8 submit to the Department the Applicant's plan to meet the requirements therein.

X. RECORD KEEPING REQUIREMENTS

1. A record keeping system for the proposed facility shall be established and maintained on site by the Applicant. All such records shall be maintained up-to-date such that year-to-date information is readily available for Department examination upon request and shall be kept on-site for a minimum of five (5) years. Record keeping shall, at a minimum, include:
    a) Compliance records sufficient to demonstrate that emissions from the facility have not exceeded that allowed by this Conditional Approval. Such records shall include, but are not limited to, fuel usage data, emissions test results, monitoring equipment data and reports.
    b) Maintenance: A record of routine maintenance activities performed on the proposed control equipment and monitoring equipment including, at a minimum, the type or a description of the maintenance performed and the date and time the work was completed.
    c) Malfunctions: A record of all malfunctions on the proposed Unit 6/Boiler 8 control and monitoring equipment including, at a minimum: the date and time the malfunction occurred; a description of the malfunction and the corrective action taken; the date and

time corrective actions were initiated; and, the date and time corrective actions were completed and the proposed equipment was returned to compliance.

2. The Applicant shall maintain on-site for five (5) years all records of output from all continuous monitors for flue gas emissions and fuel consumption, and shall make these records available to the Department upon request.
3. The Applicant shall maintain a log to record upsets or failures associated with the proposed emission control systems.
4. The applicant shall maintain records of the urea consumption per day, per month and on a 12-month rolling period.
5. The applicant shall maintain records of the operating hours of the emergency flare per day, per month and on a 12-month rolling period.
6. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.52Da Recordkeeping Requirements.

XI. REPORTING REQUIREMENTS

1. All notifications and reporting required by this Conditional Approval shall be made to the attention of:

   Department of Environmental Protection
   Bureau of Waste Prevention
   20 Riverside Drive
   Lakeville, Massachusetts 02347
   ATTN: Permit Section
   Telephone: (508) 946-2770
   Fax: (508) 947-6557 or (508) 946-2865

2. Pursuant to 310 CMR 7.00: Appendix A, Somerset Power LLC on an annual basis for a period of 5 years from the date the unit resumes regular operation with the syngas as a fuel, shall submit information demonstrating that the physical or operational change (conversion to syngas) did not result in an emission increase beyond the "representative actual annual emissions" defined in Section IV Emission Offsets and Nonattainment Review. Should there be an increase beyond that defined in Section IV, the Department will consider information provided by Somerset Power LLC that the increase is unrelated to the conversion to syngas, such as, any increased utilization due to the rate of electricity demand growth for the utility system as a whole.
3. Somerset Power LLC shall notify the Department by telephone or fax as soon as possible but no later than three (3) business days after the occurrence of any upset or malfunction to the facility equipment, air pollution control equipment, or monitoring equipment which results in an emission to the ambient air in excess of that approved herein and/or a condition of air pollution.
4. Somerset Power LLC shall notify the Department in writing within 10 days after each activity listed below occurs:
   a) The date construction commences on the syngas conversion equipment.
   b) The date syngas conversion equipment construction is completed.
   c) The date syngas is first burned in Boiler 8 and the flare.
   d) The date Unit 6/Boiler 8 attains the maximum production rate.

e) The date of notification to ISO New England, Inc. that Unit 6/Boiler 8 is released for commercial generation dispatch with the syngas conversion equipment in continuous operation.

5. The applicant shall submit NH_3 CEM Excess Emission Reports for each calendar quarter by the thirtieth (30^{th}) day of April, July, October, and January covering the previous calendar periods of January through March, April through June, July through September, and October through December, respectively, in the event that an NH_3 CEM system is required by Condition IX.6..
6. The applicant shall submit an annual NH_3 CEM Emission Report by January 30^{th} that defines highest hourly average NH_3 emissions (ppm_{vd} corrected to $3\%O_2$) per calendar day and the average calendar day NH_3 emissions (ppm_{vd} corrected to $3\%O_2$), in the event that an NH_3 CEM system is required by Condition IX.6.,
7. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.51Da Reporting Requirements.

XII. TESTING REQUIREMENTS

1. The Applicant shall ensure that the proposed facility (Boiler and flare) is constructed to accommodate the emissions (compliance) testing requirements contained herein. All emissions testing shall be conducted in accordance with the Department's "Guidelines for Source Emissions Testing" and in accordance with the Environmental Protection Agency reference test methods as specified in 40 CFR Part 60, Appendix A, or as otherwise approved by the Department.
2. The applicant shall conduct a NO_x/VOC/CO optimization/minimization emission test program and submit the final test report to the Department at least 30 days prior to the start of emission compliance testing. Special attention shall be given to assure the VOC test method parameters will provide samples that will be within the detection limit of the actual VOC emission levels. Preliminary VOC emission testing shall be conducted prior to the optimization/minimization emission test program to assure results will be within the detection limit during the optimization/minimization test program.
3. The Applicant shall conduct initial emission compliance tests no later than 60 days after achieving the maximum production rate at which Unit 6/Boiler 8 will operate, but not later than 180 days after the initial startup on syngas of Unit 6/Boiler 8. The emission compliance test program shall comply with the Department's "Guidelines for Source Emission Testing."
4. The Applicant must obtain written Department approval of an emissions test protocol. The protocol shall include a detailed description of sampling port locations, sampling equipment, sampling and analytical procedures, and operating conditions for any such emissions testing. It must be submitted to the Department at least 30 days prior to commencement of testing of the facility.
5. The Applicant shall ensure that a final emissions test results report is submitted to the Department within 60 days of completion of the emissions testing program.
6. The Applicant shall conduct emission tests to demonstrate that Unit 6/Boiler 8 is in compliance with the emission limits (lb/hr, lb/MMBtu, ppmvd as applicable, and opacity) for the pollutants listed below:
   a) Nitrogen Oxides (NO_x)

b) Carbon Monoxide (CO)
c) Volatile Organic Compounds (VOC)
d) Particulate Matter (PM)
e) Particulate Matter up to 10 microns in diameter (PM_{10})
f) Sulfur Dioxide (SO_2)
g) Ammonia (NH_3)
h) Opacity
i) Mercury (Hg)

7. The Applicant shall conduct emission tests to demonstrate that the Emergency Syngas Flare is in compliance with the emission limits (lb/MMBtu, lb/hr, and %, as applicable) for the pollutants listed below. Testing for the following pollutants shall be conducted with a steady state heat input of 642 MMBtu/hr (the estimated average heat input over a single shut down event), based on the average of three one-hour runs.:
   a) Nitrogen Oxides (NO_x)
   b) Carbon Monoxide (CO)
   c) Volatile Organic Compounds (VOC)
   d) Opacity
8. In accordance with 310 CMR 7.04(4)(a), the Applicant shall have Unit 6/Boiler 8 inspected and maintained in accordance with the manufacturer's recommendations and tested for efficient operation at least once in each calendar year. The results of said inspection, maintenance and testing and the date upon which it was performed shall be recorded and posted conspicuously on or near the proposed equipment.
9. In accordance with 310 CMR 7.13 the Department may require additional emissions testing of the facility at any time to ascertain compliance with the Department's Regulations or any proviso(s) contained in this Conditional Approval.
10. The Applicant shall comply with 40 CFR 60, Subpart Da, Section 60.50Da Compliance Determination Procedures and Methods.

XIII. GENERAL REQUIREMENTS

1. The Applicant shall properly train all personnel to operate the proposed facility and control equipment in accordance with vendor specifications.
2. All requirements of this Conditional Approval that apply to the Applicant shall apply to all subsequent owners and/or operators of the facility.
3. The Applicant shall maintain the standard operating and maintenance procedures for all air pollution control equipment, including the syngas cleanup train, in a convenient location (e.g., control room/technical library) and make them readily available to all employees.
4. The Applicant shall comply with all provisions of 310 CMR 6.00-8.00 that are applicable to this facility.
5. This Conditional Approval may be suspended, modified, or revoked by the Department if, at any time, the Department determines that the facility is violating any condition or part of the Approval.
6. This Conditional Approval does not negate the responsibility of the Applicant to comply with this or any other applicable federal, state, or local regulations now or in the future.

7. The facility shall be operated in a manner to prevent the occurrence of sound, dust or odor conditions that cause or contribute to a condition of air pollution as defined in Regulations 310 CMR 7.01 and 7.09.
8. Should asbestos remediation/removal be required as a result of this Conditional Approval, such asbestos remediation/removal shall be done in accordance with Regulation 310 CMR 7.15 and 310 CMR 4.00.
9. Any proposed increase in emissions above the limits contained in this Conditional Approval must first be approved in writing by the Department pursuant to 310 CMR 7.02. In addition, any emissions increase may subject the facility to additional regulatory requirements.
10. No person shall cause, suffer, allow, or permit the removal, alteration or shall otherwise render inoperative any air pollution control equipment or equipment used to monitor emissions which has been installed as a requirement of 310 CMR 7.00, other than for reasonable maintenance periods or unexpected and unavoidable failure of the equipment, provided that the Department has been notified of such failure, or in accordance with specific written approval of the Department.
11. The proposed facility shall be constructed and operated in strict accordance with this Conditional Approval. Should there be any inconsistencies between the Applicant's NMCPA (4B06046), and this Conditional Approval, this Conditional Approval shall govern.
12. All provisions contained in existing plan approvals concerning the subject facility issued by the Department to Somerset Power LLC, and/or previous owners, remain in effect other than those specifically altered herein.

XIV. CONSTRUCTION REQUIREMENTS

During the construction phase of the proposed modifications at the facility, the Applicant shall ensure that facility personnel take all reasonable precautions (noted below) to minimize air pollution episodes (dust, odor, noise):

1. Facility personnel shall exercise care in operating any noise generating equipment (including mobile power equipment, power tools, etc.) at all times to minimize noise.
2. Construction vehicles transporting loose aggregate to or from the facility shall be covered and shall use leak tight containers.
3. The construction open storage areas, piles of soil, loose aggregate, etc. shall be covered or watered down as necessary to minimize dust emissions.
4. Any spillage of loose aggregate and dirt deposits on any public roadway, leading to or from the proposed facility shall be removed by the next business day or sooner, if necessary.
5. On site unpaved roadways/excavation areas subject to vehicular traffic shall be watered down as necessary or treated with the application of a dust suppressant to minimize the generation of dust.

XV. MASSACHUSETTS ENVIRONMENTAL POLICY ACT

The Department has determined that the filing of an Environmental Notification Form (ENF) with the Secretary of Environmental Affairs, for air quality control purposes, was not required prior to this action by the Department. Notwithstanding this determination, the Massachusetts Environmental Policy Act (MEPA) and Regulation 301 CMR 11.00, Section 11.04, provide certain "Fail-Safe Provisions" which allow the Secretary to require the filing of an ENF and/or an Environmental Impact Report at a later time.

The Secretary of Environmental Affairs, in response to a Request for Advisory Opinion and Fail-safe Petition from the Conservation Law Foundation (CLF), rendered a decision in a letter to CLF dated January 4, 2008. The Secretary of Environmental Affairs found that the project does not meet the applicability thresholds for MEPA review and that MEPA review is not essential to avoid or minimize damage to the environment and does not warrant fail-safe review provided that the commitments of Somerset Power in its letter of January 4, 2008 are included by the Department as legally enforceable conditions in the Conditional Approval. (see the second paragraph on page 2 and Table 2 of this Conditional Approval)

XVI. LIST OF PERTINENT INFORMATION

Application Title:	Technical Support Document, Non-Major Comprehensive Plan Approval Application – Somerset Unit 6 Re-powering dated December 2006	
Application Prepared by:	ENSR	
Submitted by:	Somerset Power LLC	
Attested to by:	Michael Kravett, P.E. No. 46489	
Date Application Received:	December 22, 2006	
Dates Revisions Received:	March 1, 2007	July 10, 2007
	March 9, 2007	August 3, 2007
	April 20, 2007	August 6, 2007
	June 21, 2007	August 7, 2007
	June 28, 2007	August 9, 2007

Please be advised that this approval does not negate the responsibility of the Applicant to comply with this or any other applicable federal, state, or local regulations now or in the future. Nor does this approval imply compliance with any other applicable federal, state, or local regulation now or in the future.