Waste Heat Recovery Boilers Engineering Services

Request for Proposals (RFP)

ISSUE DATE: Friday, September 2, 2022

QUESTIONS DUE: Friday, September 16, 2022 at 3:00 PM ET

DUE DATE: Friday, October 21, 2022 at 3:00 PM ET

I. INSTRUCTIONS TO CONSULTANTS

A. General Invitation

The BUFFALO SEWER AUTHORITY (hereinafter referred to as "THE AUTHORITY") is public benefit corporation created, in part, to relieve the Niagara River, Buffalo River and Lake Erie from pollution by the sewage and waste of the City. THE AUTHORITY is responsible for the sanitary wastewater and stormwater collection and treatment system within the City of Buffalo.

On December 14th, 2021 THE AUTHORITY was awarded the Green Innovation Grant Program through the Regional Economic Development Councils Round 11 Initiative to fund our Waste Heat Recovery Boiler Rehabilitation Project.

THE AUTHORITY is seeking proposals from qualified professional engineering consulting teams to work with THE AUTHORITY to provide design engineering services, bidding assistance, and construction administration/inspection services for this project.

Sealed submissions must be received by THE AUTHORITY no later than Friday, October 21, 2022 at 3:00 PM ET. LEAD CONSULTANTS shall not submit more than one qualification package. Submissions shall be sealed and clearly labeled on front of package "Bird Island Treatment Facility Boiler and Steam System Improvements" and delivered to:

Roberta L. Gaiek, PE
BUFFALO SEWER AUTHORITY
Administration Building
90 West Ferry Street
Buffalo, NY 14213

Proposals are solicited in accordance with the terms, conditions and instructions as set forth in this Request for Proposals. Submission via telephone, facsimile, e-mail or any other method not specifically provided herein is prohibited. Submissions must be completed in accordance with the requirements of the Request for Proposals. No amendments or changes to submissions will be accepted after the closing date and time. No submissions shall be accepted after the stated deadline. THE AUTHORITY reserves the right to reject any or all submissions.

Any material misrepresentation made by a CONSULTANT may void their submissions and eliminate the CONSULTANT'S submission from further consideration. Any submission that is based upon violation of federal, state or local law, or deemed by THE AUTHORITY, in its sole discretion, to be non-responsive will be eliminated from consideration.

THE AUTHORITY shall not be responsible for any expenses or charges incurred by any CONSULTANTS in preparing a submittal, or in their providing any additional information considered necessary by THE AUTHORITY in the evaluation of their submission.

B. CONSULTANTS Restricted

No submission shall be accepted from or contract awarded to any AUTHORITY employee or official, or any firm in which an AUTHORITY employee or official has a direct or indirect financial interest.

THE AUTHORITY recognizes that many not-for-profit organizations have experts in these fields on staff that occasionally perform fee for service work. THE AUTHORITY is pleased to see this expertise brought to projects. However, if an organization is part of the successful consulting team, the organization will be asked to recuse themselves from serving as stakeholders/advocates in the process to avoid any potential conflicts of interest.

C. Proposed Schedule

Listed below are anticipated target dates and relevant times by which actions related to this Request for Proposals will be completed.

EVENT	***DATE***	***TIME***
RFP Issue	September 2, 2022	12:00 PM
RFP Questions Due	September 16, 2022	3:00 PM
RFP Due Date	October 21, 2022	3:00 PM
Interviews with Consultants	October 30, 2022-November 4, 2022	
Engineer Award	November 9, 2022	
Notice to Proceed	January 18, 2023	
Completion of Design	September 13, 2023	

D. Request for Proposals Review, Additional Information, and Questions

Each CONSULTANT is responsible for carefully examining this Request for Proposals and thoroughly familiarizing themselves with each of THE AUTHORITY's requirements prior to their submission to ensure that their responses are in compliance with this solicitation.

Each CONSULTANT is responsible for conducting its own investigations and any examinations necessary to ascertain conditions and requirements affecting the requirements of this Request for Proposals. Failure to perform such investigations and examinations shall not relieve the CONSULTANT from its obligation to comply, in every detail, with all of the provisions and requirements contained in this Request for Proposals.

Pursuant to State Finance Law §§139-j and 139-k, this "Request for Proposals" includes and imposes certain restrictions on communications about this governmental procurement between THE AUTHORITY and CONSULTANT during the procurement process. A CONSULTANT is restricted from making contact with any AUTHORITY staff, other than the designated contact, about this procurement from the earliest notice of intent to solicit offers or "Requests for Proposals" through final award and approval of Contract by THE AUTHORITY unless it is a contact that is included among certain statutory exceptions set forth in State Finance Law §139-j (3) (a).

Questions regarding the Request for Proposals shall be directed to THE AUTHORITY's designees only. Any impermissible contact with any other AUTHORITY employee regarding the Request for Proposals during this procurement period shall result in the rejection of any such CONSULTANT proposal. CONSULTANTS shall communicate in writing only via email to the email addresses listed in the Request for Proposals. No other communications with THE AUTHORITY's designees regarding the Request for Proposals are permitted during the procurement period.

For purposes of this solicitation, the designated contact shall be:

Roberta L. Gaiek, PE, Treatment Plant Administrator.

All entities interested in responding to this RFP should confirm their receipt of this RFP and the designated contact person(s) for their organization with Ms. Gaiek by email. CONSULTANTS are solely responsible for ensuring that THE AUTHORITY has accurate contact information, including e-mail address(es) for the receipt of such correspondence. THE AUTHORITY does not assume any responsibility for undelivered e-mails or for the receipt of any communication sent to any CONSULTANT.

All questions, requests for clarification or additional information must be sent by email to Ms. Gaiek at rgaiek@buffalosewer.org and **must be received no later than Friday, October 21, 2022 at 3:00 pm EST**. CONSULTANTS shall not communicate with THE AUTHORITY's designee via any other method or outside of the time period set forth herein in regard to this RFP.

No questions will be accepted by phone. No other officers, employees, or representatives of THE AUTHORITY are to be contacted regarding this Request for Proposals. THE AUTHORITY accepts no responsibility for, and the CONSULTANT agrees not to rely upon, any verbal or written statements or representations from any other person, whether or not employed by THE AUTHORITY.

THE AUTHORITY may, in its sole discretion, also elect to provide both the question(s) and the written answer(s) to all known CONSULTANTS via e-mail.

E. Addenda and Modifications

THE AUTHORITY reserves the right, in its sole discretion, to amend this Request for Proposals at any time prior to the deadline for submission. In the event that it becomes necessary to revise or expand upon any part of this Request for Proposals, all addendums, amendments, and interpretations will be made in writing and emailed to all who are known by THE AUTHORITY to have received the Request for Proposals. It is the sole responsibility of the CONSULTANT to ensure that THE AUTHORITY has accurate contact information.

All addendums, amendments, interpretations and/or modifications shall be deemed to have been incorporated as part of this Request for Proposals as though they were originally set forth in this Request for Proposals. No addenda will be issued later than forty-eight (48) hours prior to the date and time for the receipt of submissions, except an addenda withdrawing the Request for Proposals, or addenda for postponement of the due date and/or time. THE AUTHORITY does not assume any responsibility for the receipt of information sent to any CONSULTANTS.

Any information supplied by THE AUTHORITY relative to this Request for Proposals must be considered in preparing submissions. All other contacts that a CONSULTANT may have had before or after receipt of this Request for Proposals with any individuals, employees, subcontractors, consultants or representatives of THE AUTHORITY and any information that may have been read in any news media or seen or heard in any communication facility regarding this Request for Proposals should be disregarded in preparing responses.

F. Submission Format

CONSULTANTS are advised to adhere to the submittal requirements of this Request for Proposals. Failure to comply with the instructions of this Request for Proposals may cause their submission to be rejected. CONSULTANTS must provide information in the appropriate areas throughout this Request for Proposals. Submission in response to this Request for Proposals constitutes acceptance of all requirements outlined in this Request for Proposals.

One (1) original submission must be prepared on 8” X 11” letter size paper, printed double-sided, and bound on the long side. One (1) digital submission to OneDrive containing an Adobe Portable Document Format (PDF) version of all materials must also be provided. Each page of the submission must be numbered in a manner so that it can be uniquely identified. Legibility, clarity and completeness are required.

ITEM	*QUANTITY*	*FORMAT*
Hard Copies	One (4) original	Printed on 8” x 11” letter size paper, double sided and bound on long side
Digital Copy	One (1)	Abode Portable Document Format (PDF) submitted through OneDrive link

The submission must be signed by each individual CONSULTANT or their authorized representative who shall have the legal authority to legally bind the CONSULTANT(s).

II. PROJECT OVERVIEW

A. Introduction

THE AUTHORITY is seeking proposals from qualified professional engineers to provide design engineering services for but not limited to:

1.) Rehabilitation to the existing WHRBs;
- a) Demolition and removal of existing equipment.
- b) Complete retubing of the boilers.
- c) Replacement of insulation and refractory where needed.
- d) Ash management with new compressed air soot blowers.
- e) Inlet and outlet ducts need to be removed and replaced.
- f) Boiler feedwater piping connections.
- g) Adjustments in WHRB feedwater piping.
- h) Hydrostatic tests.
- i) New control panels .
- j) Replacement of the existing steam soot blowers with new air compressed soot blowers.
- k) New control panels (one per rehabilitated WHRB boiler).
- l) Replacement of WHRB ancillary mechanical systems such as blowdown vessels and dampers for the exhaust ducts.
- m) Replacement of WHRB trim valves (feedwater regulator, steam check and regulator, steam pressure and safety).
- n) Miscellaneous WHRB upgrades such as handrails, insulation, and lagging.
- o) ASME certificates will be issued at the end of rehabilitation effort.

2.) Improvements to the steam system:
- a) Replacement/repair of damaged insulation, leaking steam traps and degraded pipes;
- b) General improvements in steam piping and steam traps.
- c) Update record drawings as needed

3.) Auxiliary Boiler #2 Burner Rehabilitation;
- a) New Burner design
- b) Design for Natural Gas and Digester Gas Operation

c) New burner control system
d) Addition of new burner;

4.) Asset Management Database Data Collection;

a) Assist the AUTHORITY with integrating new and existing equipment as well as preventative maintenance requirements into the Authorities Maximo Asset Management Database. The consultant shall work with AUTHORITY personnel by completing existing input templates related to Maximo
b) Additional assistance as needed.

B. Basis of Design Services

The alternative analysis portion of the Engineering Report shall address whether restoration of the existing system is prudent or whether the existing equipment should be replaced on the basis of current condition and long-term maintenance.

C. Construction Design Services

The proposal shall address the CONSULTANT'S approach to providing plans, specifications, and engineer's estimates according to the schedule of:

Updated EFC Compliant Engineering Report (Required)	March 15, 2023
30% Design Plans, Specifications and Engineer's Estimate	April 12, 2023
60% Design Plans, Specifications, and Engineer's Estimate	May 17, 2023
95% Design Plans, Specifications, and Engineer's Estimate	June 14, 2023
Final Construction Documents and Engineer's Estimate	August 16, 2023

The plans, specifications, and engineer's estimate shall address the repair and replacement of Waste Heat Boilers #2 and 3, Auxiliary Boiler #2 burner upgrade, and appurtenances and shall specify the order of operations for this work to minimize impacts upon the operation of the facility and the overall construction time. All documents shall be prepared in accordance with New York State Environmental Facilities Corporation standards.

To achieve these goals, the submission to the AUTHORITY of weekly update memoranda detailing progress to date, any issues encountered which may delay the project, and work planned for the ensuing week shall be required. Additionally, monthly update meetings will be required between THE AUTHORITY and the CONSULTANT.

D. Bidding Services

In addition to design services, the CONSULTANT shall provide the following construction contract bidding services:

1) Prepare copies of plans and specifications for bidders for bidding through a document services provider (THE AUTHORITY has used Avalon Document Services for past projects).
2) Coordinate with the AUTHORITY and the document services provider during preparation of public bid process.
3) Conduct pre-bid meeting.
4) Respond to bidders' questions during bidding period.
5) Prepare tabulation of bids.
6) Conduct pre-award conference with low bidder.
7) Review bids and provide Recommendation on Award.
8) Any other bidding services deemed necessary.

E. Construction Administration

The Typical services which may be required during construction shall include but not be limited to the following:

1) Obtain from the contractor a construction schedule (and updated schedules as the project progresses) which shall indicate their complete operation as it pertains to this project and distribute said schedule to the Authority and any other relevant parties.
2) Provide services of a New York State licensed Professional Engineer and other engineers as needed, who will observe on a twice per week basis the construction to see that it conforms to the requirements of the plans and specifications.
3) Prepare a shop drawing submittal, review and acceptance schedule and distribute said schedule to the contractor(s), Authority, and other relevant parties.
4) Review and approve/disapprove shop drawings submitted by the contractor and manufacturer of equipment and affix to the shop drawings a stamp indicating the results of the review and distribute copies to the Authority, contractor(s) and other relevant parties.
5) Review the contractor's request for substitution of equipment and materials, inform the Authority of the request throughout the review process, obtain Authority consensus for any substitutions, and distribute a written summary of the request and decision to the contractor(s) and Authority.
6) Review the contractor's proposed diffuser system including maintenance requirements, inform the Authority of the request throughout the review process, obtain Authority consensus for approval of the diffuser system, and distribute a written summary of the request and decision to the contractor(s) and Authority.
7) Witness and/or review appropriate tests for materials and equipment as submitted by contractor and distribute results of said tests to the Authority.
8) Assemble all guarantees, warranties and similar items required by the contract documents and forward to the Authority.
9) Prepare an Operations and Maintenance (O&M) Manual in 8 ½" x 11" (with 22"x 34" drawings) paper and electronic formats for review by the Authority.
10) Assist the contractor and resident engineer in preparing bid breakdown for purposes of payment requisitions.
11) Review and make appropriate recommendations to the Authority with respect to contractor claims relating to a design change, differing site conditions and/or additional compensation due to alleged delays.
12) The Consultant shall perform parallel estimates to substantiate costs with respect to change order and/or cost breakdowns furnished by the contractor.
13) Advise, review and recommend, where applicable, any change order(s) to the contract that are in the best interest of the Authority or requested by the contractor.
14) Prepare and process, with the assistance of the Authority, all change orders.
15) Submit a daily e-mail update to the Authority of work completed on that date and work expected the next day.
16) Submit to the Authority a weekly summary of the work completed in the week, work planned for the upcoming week, and calling out any issues that require follow-up.
17) Organize and chair bi-weekly construction progress/coordination meetings with the Authority, Contractor, and other concerned parties.
18) Prepare and distribute minutes of the progress/coordination meetings to concerned parties.
19) Issue supplemental drawings to further explain the intent of the plans and specifications when necessary.
20) Prepare and distribute all field clarifications, memos and bulletins that may be required.
21) Attend project related meetings as requested by the Authority.
22) Make recommendations to the Authority pertaining to special consultants.
23) Cooperate with all affected parties.
24) Review retention money clauses of contracts and make recommendations to the Authority with respect to release of any retained funds.
25) Receive, review and forward to the Authority with recommendations, all relevant documents such as release of

liens, claims, etc.

26) Establish procedures and coordinate arrangements between the Authority and the contractors with respect to the start-up of constructed facilities.
27) Provide services to assist the contractors and resident engineer in checking out the complete facilities for ready-to-serve status and commencement of testing.
28) Maintain an accurate record of all design changes made during construction. Furnish and provide two (2) complete sets of record drawings, prepared on 22” x 34” bonded paper and in pdf format and electronic copies of the modified AutoCAD design file.
29) Conduct a three-dimensional inspection of the completed work and supply to the Authority a three-dimensional model of the completed system.
30) Certify at the completion of the project that the facilities have been built and are operating in accordance with the plans/specifications for the project.
31) Attend and present project details at public outreach events as directed by the Authority.
32) Track and confirm compliance with Clean Water State Revolving Fund requirements throughout course of project including Minority and Women Business Enterprise and women and minority workforce goals.

F. Construction Inspection

1. Provide an on-site resident engineer and assistants (as needed) to coordinate the day-to-day construction.
2. Continuously monitor the approved construction schedules and provide updated information to the Authority.
3. Act as the Authority’s advisor and liaison and coordinate the activities of all contractors in accordance with the construction schedule approved by all parties.
4. Provide continuous coordination with the Authority’s staff as to progress and assure minimal impacts of construction on facility operations.
5. Maintain a shop drawings acceptance schedule on a daily basis.
6. Regulate use of site and building area with respect to storage of materials, temporary offices, storage sheds, parking, traffic control, etc.
7. Monitor the daily performance of the contractor to ensure compliance with the plans, specifications and applicable permits.
8. Inspect material/equipment deliveries to the job site to ensure compliance with the approved shop drawings.
9. Prepare daily inspection reports which describe, in detail, the contractor’s performance for that particular day.
10. Monitor the contractor’s operation to assure proper erosion and sediment control practices are maintained (especially, but not limited to in regard to drying of grit prior to off-site disposal).
11. Review contractor’s estimates and prepare parallel monthly construction pay estimates which indicate the construction completed to date.
12. Coordinate and witness the final testing of the in place improvements as required by the contract specifications.
13. Maintain a detailed daily journal of all on-site activities and visitors.
14. Take progress photos throughout the course of construction and incorporate into inspection reports.
15. Maintain complete and accurate job records of all correspondence, memoranda, supplemental drawings, field clarification memos, change orders, shop drawings, etc.
16. Cooperate with all affected parties.

17. Monitor cleanup activities of all contractors and coordinate such activities with provisions in the respective contract documents.

18. Prepare punch-lists and monitor contractor's activities as required.

G. Start-Up Services

H. Provide services to assist the Authority with understanding the operational features of the completed facilities. The Consultant shall provide and schedule training services of Authority personnel in the maintenance and operation of the facilities. The Consultant will also be responsible for providing all warranties and operations and maintenance documents to the Authority in both hard copy and electronic formats. For planning purposes, it should be assumed that five training sessions will be required for maintenance and operation for each element of the completed facility.

I. Grant/Loan Proposal Services

This project will be funded utilizing a GIGP Energy Efficiency Grant. If federal/loan grant funding becomes available CONSULTANT shall also provide grant/loan proposal services to assist THE AUTHORITY in applying for New York State Environmental Facilities/ New York State Department of Environmental Conservation and other grant/loan funding for this project.

These services shall include:

1) Attending pre-proposal webinars;
2) Drafting proposals and assembling proposal packages.

III. REQUIRED CONTENT AND FORMAT

In order to create a platform for fair and uniform consideration of responses, please provide the following materials in the order listed below. Submissions should be prepared simply and provide a straightforward, concise delineation of the CONSULTANT'S capabilities and description of the offer to meet the requirements of this RFP. THE AUTHORITY will not be responsible for any costs incurred by any CONSULTANT in preparing and submitting a response to this solicitation.

A. Cover Letter

CONSULTANT shall prepare and sign a cover letter confirming their understanding of the RFP including the following provisions for the contract:

1. Project scope of work;
2. Timeframe for completion;
3. BUFFALO SEWER contract requirements;

Submission of the letter shall constitute a representation by the CONSULTANT that it is willing and able to perform the services described in this Request for Proposals and their responsive submission.

B. Approach

CONSULTANT shall provide a narrative description of its approach detailing an understanding of THE AUTHORITY's intent and objectives as well as how the CONSULTANT proposes to achieve those objectives. It must discuss the CONSULTANT's plan for implementing, and effectuating the described services, including any proposed approach to project management, strategies, tools and safeguards for ensuring performance of all required activities as well as any additional relevant factors for THE AUTHORITY'S consideration.

C. Experience

Provide a brief description of at least three (3) similar projects of this type and scope. Include project references and total costs of reference projects. Descriptions for each project should be limited to one page for each location.. Experience will not be considered unless complete reference information is provided. At a minimum, the following information must be included for each reference project:

1. Client name, address, contact person name, telephone, and email address;
2. Project name and location;
3. Description of services provided similar to the services outlined in this Request for Qualifications;
4. Identify services, if any, that were subcontracted, and to what other company(ies);
5. Total dollar value of the contract;
6. Contract term (start and expiration);
7. Actual completion date;
8. CONSULTANT personnel that worked on that project.

The AUTHORITY may solicit relevant information concerning CONSULTANT record of past performance from previous clients, or any other available sources.

D. Professional Team

Present specific expertise and how the CONSULTANT's qualifications would best serve THE AUTHORITY. Include a description of the proposed individuals that will perform the required tasks/scope of work for this project on the STAFFING WORKSHEET included with this RFP including:

1. Name of individual that will be assigned to this project
2. Education background/degrees
3. License or Certifications
4. Area of Expertise
5. Length of time individual has been with proposing company
6. Overall years of experience
7. Description of specific relevant experience
8. Role for Projects Resulting from this RFP
9. Anticipated % of project time working on projects from this RFP
10. Base location (local facility, as applicable)

Include one-page resumes in an appendix for the individuals listed in the STAFFING WORKSHEET, provided as Appendix A.

Please complete the attached EEO plan, provided as Appendix B, for the anticipated project team for the **anticipated project team (**Note: EEO Staffing Plan is required for both project team and firm**)**.

E. Company Profile

CONSULTANT is required to prepare and submit a brief description of the CONSULTANT's firm, company, or corporation, which must include:

1. Name, mailing address, email address, telephone number and fax number of the primary contact person for firm;
2. A brief description of firm, number of years in business, major markets served, company history, relevant operating segments, primary vision and strategy, number of employees, office locations and any Joint Venture Partners;
3. Clearly state whether your main office/parent firm is currently licensed as an individual, partnership, or corporation to practice professional engineering in New York State.
4. State the number of employees in the firm. If a branch office will perform the work, indicate the size of the branch office.
5. Please complete the attached Appendix B: EEO Staffing Plan for the firm (Note: EEO Staffing Plan is required for both project team and firm).
6. List any current or anticipated commitments that may impact the project or use of the identified personnel proposed for this project.
7. Financial statement demonstrating your firm's financial capacity to undertake and complete the project;
8. State any potential conflicts of interest. Include any employment or other relationship your firm has with regulating agencies, local municipalities, or any other entity, which may be perceived as a conflict of interest. Explain why any such conflicts of interest would not impact this project.
9. A copy of any resolution or some other form of THE AUTHORITY, signed by a Chief Executive Officer, Corporate Secretary, or managing partners, which lists the specific officers who are authorized to execute agreements on behalf of the CONSULTANT;

F. Cost Proposal

One (1) original price proposal must be prepared on 8" X 11" letter size paper, printed double-sided, and bound on the long side submitted in a separate sealed envelope. One (1) digital submission to OneDrive containing an Adobe Portable Document Format (PDF). The price proposal shall be as indicated in Appendix C. EVALUATION AND SELECTION PROCESS

The review and selection team will be assigned by the General Manager. The review and selection team will consider, but may not be limited to, the following factors:

CRITERIA	***ESTIMATED WEIGHT***
Demonstrated understanding of project requirements	15%
Technical and creative quality of proposed approach	15%
Proposed schedule	5%
Experience with comparable projects	20%
Professional team organization and expertise	15%

Minorities and Women as percentage of professional team	20%
Company profile	10%

THE AUTHORITY reserves the right, in its sole discretion, to disqualify any CONSULTANT whose conduct and/or submission fails to conform to the requirements of this solicitation. Factors such as, but not limited to, evidence of collusion among respondents, attempts to improperly influence any member of THE AUTHORITY, purposeful provision of false or inaccurate information; default under any type of agreement, and existence of any unresolved litigation or legal dispute may be considered.

Submissions which are incomplete and missing key components necessary to fully evaluate the submission may, at the sole discretion of the committee, be rejected from further consideration due to "non-responsiveness" and rated non-responsive. Submissions providing responses to all sections will be eligible for detailed analysis.

THE AUTHORITY reserves the right, in its sole discretion, to make an award, with or without negotiation, under the solicitation in whole or in part, or no award at all; negotiate with the successful CONSULTANT within the scope of solicitation in the best interests of THE AUTHORITY; subdivide or combine work; accomplish any task or undertaking of any operation or project utilizing its own work force; and utilize any and all ideas submitted.

IV. THE AUTHORITY'S RESERVATION OF RIGHTS

Upon submission in response to this Request for Proposals, each CONSULTANT acknowledges and consents to the following conditions relative to the submission, review and consideration of its submission:

1. All costs incurred by the CONSULTANT in connection with responding to this Request for Proposals and for participating in this procurement process shall be borne solely by the CONSULTANT.
2. THE AUTHORITY reserves the right, in its sole discretion, to reject for any reason any and all responses or components thereof and to eliminate any and all CONSULTANTS responding to this Request for Proposals from further consideration for this procurement.
3. THE AUTHORITY reserves the right, in its sole discretion, to reject any CONSULTANT that submits incomplete responses to this Request for Proposals, or a submission that is not responsive to the requirements of this Request for Proposals.
4. THE AUTHORITY reserves the right, without prior notice, to supplement, amend, or otherwise modify this Request for Proposals, or otherwise request additional information.
5. All submissions in response to this Request for Proposals shall become the property of THE AUTHORITY and will not be returned.
6. All submissions in response to this Request for Proposals shall constitute public records subject to public disclosure.
7. THE AUTHORITY may request that CONSULTANTS personally attend or send representatives to THE AUTHORITY for interviews and a demonstration of CONSULTANT's proposed services.
8. Any and all submissions in response to this Request for Proposals that are not received by THE AUTHORITY by **3:00 PM on Friday, October 21, 2022** shall be rejected and not subject to consideration.

9. Neither THE AUTHORITY, nor its officers, officials nor employees shall be liable for any claims or damages resulting from the solicitation, preparation or delivery of any submission(s) in response to this Request for Proposals.

THE AUTHORITY reserves the unilateral right, in its sole discretion, to make and to accordingly exercise the following rights and options with regard to this Request for Proposals and the procurement process in order to obtain the most advantageous offer for THE AUTHORITY:

1. To waive irregularities and/or minor non-compliance by any CONSULTANT with the requirements of this Request for Proposals;
2. To request clarification and/or further information from one or more CONSULTANTS after the submitted deadline for submissions without becoming obligated to offer the same opportunity to all CONSULTANTS;
3. To enter into negotiations with one or more CONSULTANTS without being obligated to negotiate with, or offer the same opportunity, to all CONSULTANTS;
4. To reject any or all submission or parts of submissions, to accept part or all of a submission or submissions on the basis of considerations and to create a project of lesser or greater scope and/or breadth than described in this Request for Proposals or the CONSULTANT's submission;
5. To determine that any submission received in response to this Request for Proposals complies or fails to comply with the terms set forth herein;
6. To determine whether any perceived or actual conflict of interests exists that would affect or impair the award of any contract arising from this Request for Proposals to any CONSULTANT(s);
7. To waive any technical non-conformance with the terms of this Request for Proposals;
8. To change or alter the schedule for any events called for in this Request for Proposals;
9. To conduct investigations of any or all of the CONSULTANTS, as THE AUTHORITY deems necessary or convenient, to clarify the information provided and to request additional information to support the information included in any submission;
10. To suspend or terminate the procurement process described in this Request for Proposals at any time. If terminated, THE AUTHORITY shall have the unilateral right to determine to commence a new procurement process without any obligation to the CONSULTANT;
11. THE AUTHORITY shall be under no obligation to complete all or any portion of the procurement process described in this Request for Proposals.

CONSULTANTS are advised to submit a complete offer as their submission. Any waiver, clarification or negotiation will not be considered an opportunity for CONSULTANTS to correct errors contained in their submission.

V. CONTRACT REQUIREMENTScs

1. **FORMATION OF AGREEMENT/CONTRACT WITH SUCCESSFUL CONSULTANT**: The Contract to be negotiated as a result of this RFP and subsequent Request for Proposal shall be by and between the CONSULTANT and THE AUTHORITY and shall contain but shall not be limited to provisions included in this RFP.

2. **PROJECT DELIVERABLES:** It is understood and agreed that all drawings, specifications, records, data and maps shall become property of THE AUTHORITY. The CONSULTANT shall deliver such records to THE AUTHORITY as it may request and upon payment of current amounts due under this Agreement. It is understood and agreed that all instruments of professional services developed under said Agreement are the property of the AUTHORITY. THE AUTHORITY reserves the right to modify, expand and adapt said instruments consistent with the intended design objectives. The CONSULTANT shall deliver such records to THE AUTHORITY as it may request and upon payment of current amount due under this Agreement. It is further understood and agreed that existing technical data, pertaining to a specific assignment, shall be made available to the CONSULTANT by THE AUTHORITY.

3. **INDEMNITY OF AUTHORITY:** The CONSULTANT shall and will indemnify and at all times save harmless THE AUTHORITY and the CITY OF BUFFALO (CITY), their officers and employees from all claims, suits, actions, damages, losses and costs of every name and description to which THE AUTHORITY or the CITY may be subjected or put by reason of injury to the person or property of another, or the property of THE AUTHORITY of the CITY may be subjected to put by any reason of injury to the person or property of another, or the property of THE AUTHORITY or the CITY resulting from the negligence or carelessness, active or passive of the CONSULTANT, or the joint negligence, active or passive, of the CONSULTANT and others, or their employees, agents or subcontractors, in the performance of any work under this contract. The provisions of this section shall survive the expiration of termination of this Agreement; shall not be limited by reason of any insurance coverage provided hereunder or the limits of any insurance requirements; and shall be separate and independent of any other requirements of this contract.

   The CONSULTANT shall and will indemnify and at all times save harmless THE AUTHORITY against any and all loss and damage, claims and demands, costs and charges that may arise or accrue by reason of the adoption or use by the CONSULTANT of a patented article, device, or improvement, or by reason of the acceptance, adoption or use by THE AUTHORITY of a patented article, device or improvement furnished or delivered by the CONSULTANT, and the CONSULTANT agrees not to adopt or make use of a patented article, device or improvement unless he shall first obtain the right and privilege so to do and also the right and privilege to THE AUTHORITY to use such patented article, device, or improvement without infringing upon the rights of the patentee and without expenses to THE AUTHORITY.

4. **ASSIGNMENT:** This Agreement contemplates the particular services of the CONSULTANT and the CONSULTANT shall not assign, transfer or otherwise dispose of the contract, or his right, title and interest therein, to any person, firm or corporation, except that moneys due to the CONSULTANT and approved for payment by THE AUTHORITY and the CITY may be assigned by him to any bank or financial institution which is rendering financial assistance to the CONSULTANT on this work.

5. **INSURANCE:** The CONSULTANT agrees to provide and maintain in full force and affect the following insurance. The CONSULTANT shall deliver to THE AUTHORITY Certificates of Insurance, which shall provide thirty (30) days' notice to be given to THE AUTHORITY in event of a cancellation. THE AUTHORITY and the CITY shall be named as additional insureds on the Comprehensive General Liability Insurance and excess liability insurance policy and on the automobile liability insurance policy as evidence thereof appropriate certificates of insurance shall be provided.

a. Comprehensive General Liability Insurance including Blanket Contractual, Broad Form Property Damage, Competed Operations and Independent Contractor's Liability all applicable to Personal Injury, Bodily Injury and Property damage to a combined single limit of $1,000,000 each occurrence subject to $2,000,000 annual aggregate for Completed Operations and Personal Injury other than Bodily Injury.

b. Comprehensive Automobile Liability Insurance including owned, hired and non-owned automobiles, Bodily Injury and Property Damage to a combined single limit of $2,000,000 each occurrence. A combined single limit of $1,000,000 may be acceptable if CONSULTANT provides and maintains excess/umbrella liability insurance coverage in the amount of at least $4,000,000. The certificate of insurance for automobile insurance coverage shall name THE AUTHORITY and the City of Buffalo as additional insured.

c. Excess/Umbrella Liability Insurance coverage in at least the amount of $3,000,000.

d. Workers Compensation and Employers Liability Insurance in compliance with the applicable state and federal laws.

e. Architects and/or Engineers Professional Liability Insurance affording professional liability insurance coverage in at least the amount of $2,000,000 each occurrence/claim, subject to $2,000,000 annual aggregate.

Acceptability of Insurers**:** All of the successful CONSULTANT's insurance policies shall be written by insurance companies admitted in the State of New York and authorized to do business in the State of New York or otherwise acceptable to THE AUTHORITY, City's Comptroller and the Corporation Counsel in their sole respective discretion.

6. **NON-DISCRIMINATION**: The CONSULTANT shall not discriminate against any employee or applicant for employment because of an individual's age, race, creed, color, national origin, sexual orientation, gender identity or expression, military status, sex, disability, predisposing genetic characteristics, familial status, marital status, or domestic violence victim status. Such prohibition against discrimination shall include, but not be limited to, the following: employment, upgrading, demotion or transfer, recruitment or recruitment advertising, layoff or termination, rates of pay or other forms of compensation and selection for training, including apprenticeship.

7. **WORKFORCE DIVERSITY AND INCLUSION:** THE AUTHORITY encourages our contracting partners to adopt business methods and models that foster and result in a diverse workforce. CONSULTANT shall provide a copy of their Equal Employment Opportunity Policy (EEO) and complete the provided Equal Employment Opportunity Staffing Plan. *The CONSULTANT shall use good faith efforts to achieve the utilization of minority group members, women and other disadvantaged workforce members consistent the City of Buffalo Code § 96-13 (F); Article 15A of NYS Executive Law; and federal Equal Employment Opportunity and Disadvantaged Business Enterprise laws, where applicable.*

8. **CONTRACTING WITH MINORITY AND WOMEN BUSINESS ENTERPRISES (M/WBE):** THE AUTHORITY requires the CONSULTANT to take affirmative steps to select certified small business enterprises, including minority and women business enterprise firms as subcontractors. The M/WBE goal for AUTHORITY projects shall be 30% total to include a minimum of 5% MBE participation and 5% WBE participation. CONSULTANT M/WBE must be certified by NYS and the Erie County/City of Buffalo Joint Certification Committee.

   a. THE AUTHORITY and CONSULTANT will take all necessary affirmative steps to assure that minority and women business enterprises are used when possible.
   b. Affirmative steps shall include:
      i. Placing qualified small minority businesses and women business enterprises on solicitation lists;

ii. Assuring that small minority businesses, and women business enterprises are solicited whenever they are potential sources;
iii. Dividing total requirements, when economically feasible, into smaller tasks or quantities to permit maximum participation by small minority business, and women's business enterprises;
iv. Establishing delivery schedules, where the requirement permits, which encourage participation by small and minority business, and women's business enterprises.

The CONSULTANT may be asked to provide an affirmation of the above as well as a MWBE Utilization Plan for each specific project proposal to be undertaken under the term agreement.

9. **FIRST SOURCE:** In support of City of Buffalo First Source hiring policies, the selected Consultant agrees that (i) in the hiring of any employees, subcontractor(s), or person(s) acting on behalf of the subcontractor, preference shall first be given to qualified persons who have resided in the City of Buffalo for at least six (6) consecutive months immediately prior to the commencement of their employment for the performance of work and (ii)the Consultant and any subcontractor(s) will work towards ensuring a minimum residency goal of 30% of workforce to include qualified residents in the City of Buffalo.

10. **PUBLICATIONS:** CONSULTANT shall not make any news/press release, announcements, presentations, publication, or award application pertaining to this Agreement or the Services, or anything contained or referenced herein, without prior written approval from THE AUTHORITY. Any promotion pertaining to the Services or this Agreement may only be made in coordination with THE AUTHORITY. Unless otherwise directed in writing, THE AUTHORITY name and logo shall be prominently featured on all work products and promotional materials, printed and/or electronic. Unless otherwise directed in writing, CONSULTANT'S name and logo shall be subservient to THE AUTHORITY's recognition and labeled as "prepared by" on all work products and promotional materials, printed and/or electronic.

11. **FREEDOM OF INFORMATION LAW:** THE AUTHORITY is subject to the provisions of Article 6 Section 89 of New York State Public Officer's Law, entitled the Freedom of Information Law. All submissions, in their entirety, submitted in response to this Request for Proposals shall constitute a record subject to public disclosure pursuant to the Freedom of Information Law. It is the sole responsibility of each CONSULTANT to this Request for Proposals to identify those portions deemed to constitute a "trade secret" or proprietary information of the commercial enterprise. Any such information shall be clearly marked "CONFIDENTIAL". The phrase trade secret is more extensively defined to include a formula, process, device or compilation of information used in one's business which confers a competitive advantage over those in similar businesses who do not know it or use it. The subject of the trade secret must not be of public knowledge or of a general knowledge in the trade or business. A corresponding letter, on company letterhead, must be provided describing the factors and extent to which the disclosure of the "CONFIDENTIAL" information would cause substantial injury to the competitive position of the commercial enterprise. The entire submission shall not be marked "CONFIDENTIAL". Any portion of the proposal that is not clearly identified as "CONFIDENTIAL" may be disclosed pursuant to the Freedom of Information Law. Further, marking a portion of the submission "CONFIDENTIAL" is no assurance that THE AUTHORITY will not be directed to nonetheless release the information/documentation so marked. THE AUTHORITY DOES NOT ASSUME ANY RESPONSIBILITY WHATSOEVER TO ANY CONSULTANT IN THE DISCLOSURE OF RECORDS PURSUANT TO THE FREEDOM OF INFORMATION LAW, COURT ORDER, OR ANY OTHER METHOD OF DISCLOSURE PROVIDED FOR UNDER THE LAW.

12. **SRF REQUIREMENTS:** CONSULTANTS must comply with the terms and conditions mandated by the New York State Clean Water State Revolving Fund program, administered by the New York State Environmental Facilities Corporation, (See attachment A).THE AUTHORITY may seek funding from the New York State Environmental Facilities Corporation (EFC) for both the design and construction of these structures and the consultant's submission

shall reflect EFC requirements including, but not limited to, those regarding EEO, MWBE, and American Steel, and Federal Disadvantaged Business enterprise Regulations. You are hereby notified that in addition to the MWBE participation goal required by EFC, BUFFALO SEWER has a minimum 5% participation goal for MBEs, a minimum 5% participation goal for WBEs, and a combined M/WBE participation goal of 30%.

13. **GENERAL COMPLIANCE:** The successful CONSULTANT agrees to comply with all applicable Federal, State and local laws and regulations governing the services to be solicited under this Request for Proposals.

APPENDIX A: STAFFING WORKSHEET

Name	Degree	License/ Certifications	Area of Expertise	Length of Time With Proposing Company	Overall Years of Experience	Role for Projects Resulting From RFP	Anticipated % of Project Time Working on Projects From This RFP	Base Location	Hourly Rate
						Total project time:	**100%**		

APPENDIX B: BUFFALO SEWER AUTHORITY EQUAL EMPLOYMENT OPPORTUNITY STAFFING PLAN

☐PRIME ☐ SUB CONSULTANT Name: ____ Project ______________________________________

CONSULTANT Address ____ ____

Email: ____ Phone: ____

This report includes consultant's: ☐ work force to be utilized on this project ☐ total work force

Enter the total number of employees for each classification

Job Category	Total Work Force	Work Force by Gender		White		Black		Hispanic		Asian & Pacific Islander		Native American		Total Minority		Disabled		Veteran		City Resident	
		Male (M)	Female (F)	M	F	M	F	M	F	M	F	M	F	M	F	M	F	M	F	M	F
Board Member																					
Executive/Senior Level Officials & Managers																					
Mid Level Officials and Managers																					
Licensed Professionals																					
Technicians																					
Sales Workers																					
Skilled Craftsmen																					
Operatives Semi-Skilled																					
Laborers and Helpers																					
Service Workers																					
Administrative support/clerical workers																					
TOTALS																					

PREPARED BY (Signature):	Telephone #:	Date
Name and Title (Print or Type):	Email:	

APPENDIX C: COST PROPOSAL

Design Services Deliverable	Not to Exceed Fee
Updated EFC Compliant Engineering Report	
30% Design Plans, Specifications and Engineer's Estimate	
60% Design Plans, Specifications and Engineer's Estimate	
95% Design Plans, Specifications and Engineer's Estimate	
Final Design Plans, Specifications and Engineer's Estimate	
Bid Services	
Total	

CA/CI Services Deliverable	Not to Exceed Fee
Construction Contract Administration	
Resident Inspection	
Start-up Services	
Total	

KATHY HOCHUL
Governor

MAUREEN A. COLEMAN
President & CEO

Mandatory State Revolving Fund Terms and Conditions

for Contracts Funded with the NYS Clean Water State Revolving Fund or Drinking Water State Revolving Fund

Effective November 1, 2021

New York State Environmental Facilities Corporation
625 Broadway, Albany, NY 12207-2997
P: (518) 402-6924 F: (518) 402-7456
www.efc.ny.gov

REQUIRED CONTRACT LANGUAGE

Recipient to Identify Contract Type:

☐ **Construction**

- ☐ **Treatment Works and Drinking Water Projects**
- ☐ **Non-Treatment Works**

☐ **Non-Construction**

Contents

COMMONLY USED TERMS

The following commonly used terms are defined herein as follows:

"Contract" means an agreement between a Recipient and a Contractor.

"Contractor" means all bidders, prime contractors, Service Providers, and consultants as hereinafter defined, unless specifically referred to otherwise.

"Service Provider" means any individual or business enterprise that provides one or more of the following: legal, engineering, financial advisory, technical, or other professional services, supplies, commodities, equipment, materials, or travel.

"Subcontract" means an agreement between a Contractor and a Subcontractor.

"Subcontractor" means any individual or business enterprise that has an agreement, purchase order, or any other contractual arrangement with a Contractor.

"Recipient" means the party, other than EFC, to a grant agreement or a project finance agreement with EFC through which funds for the payment of amounts due thereunder are being paid in whole or in part.

"State" means the State of New York.

"Treatment Works" is defined in Clean Water Act (CWA) Section 212.

"Nonpoint Source Projects" and **"Green Infrastructure Projects"** are defined in CWA Section 319.

"Estuary Management Program Project" is defined in CWA Section 320.

I. SECTION 1 REQUIREMENTS AND PROCEDURES FOR BUSINESS PARTICIPATION OPPORTUNITIES FOR NEW YORK STATE CERTIFIED MINORITY- AND WOMEN-OWNED BUSINESS ENTERPRISES AND EQUAL EMPLOYMENT OPPORTUNITIES FOR MINORITY GROUP MEMBERS AND WOMEN

For purposes of this section:

"Non-Construction" shall mean Contracts for labor, services (including, but not limited to, legal, financial, and other professional services), supplies, equipment, materials, or any combination of the foregoing.

"Contracts Meeting Article 15-A Thresholds" shall mean Contracts or Subcontracts meeting the thresholds under New York State Executive Law Article 15-A as follows:
(a) Non-Construction Contracts greater than $25,000;
(b) Non-Construction Contracts, that are initially under $25,000 but subsequent change orders or contract amendments increase the Contract value to above $25,000;
(c) Construction Contracts greater than $100,000; and,
(d) Construction Contracts that are initially under $100,000 but subsequent change orders or contract amendments increase the Contract value to above $100,000.

The Equal Employment Opportunities requirements of this section apply to all Contracts and Subcontracts, with the exception of:
(1) the requirements under Title VII of the Civil Rights Act of 1964 and 41 CFR Part 60-1 Subpart A which apply only to construction Contracts and Subcontracts;
(2) the Federal Affirmative Action Regulations requirements which apply only to construction Contracts and Subcontracts greater than $10,000.
The Minority- and Women- Owned Business Enterprises ("MWBE") participation requirements of this section apply to the Contracts Meeting Article 15-A Thresholds.

Disregard this section if it does not apply to this Contract or Subcontract.

II. General Provisions

A. Contractors and Subcontractors are required to comply with the following provisions:

1. New York State Executive Law Article 15-A and 5 NYCRR Parts 140-145 ("MWBE Regulations") for all State Contracts as defined therein, with a value (1) in excess of $25,000 for labor, services (including, but not limited to, legal, financial, and other professional services), supplies, equipment, materials, or any combination of the foregoing, or (2) in excess of $100,000 for the acquisition, construction, demolition, replacement, major repair or renovation of real property and improvements thereon.
2. Title VI of the Civil Rights Act of 1964 and 40 CFR Part 7 ("Title VI") for any program or activity receiving federal financial assistance, as those terms are defined therein.
3. Title VII of the Civil Rights Act of 1964 and 41 CFR Part 60-1 Subpart A ("Title VII") for construction Contracts related to any government programs providing federal financial assistance, as those terms are defined therein.
4. 41 CFR Part 60-4 ("Federal Affirmative Action Regulations") for federal or federally assisted construction Contracts in excess of $10,000, as those terms are defined therein.
5. Section 504 of the Rehabilitation Act of 1973 ("Section 504") for any program or activity receiving federal financial assistance, as those terms are defined therein.
6. The Age Discrimination Act of 1975 ("Age Discrimination Act") for any program or activity receiving federal financial assistance, as those terms are defined therein.
7. Section 13 of the Federal Water Pollution Control Act ("Clean Water Act") Amendments of 1972 ("Section 13") for any program or activity receiving federal financial assistance under the Clean Water Act, as those terms are defined therein.

B. Failure to comply with all of the requirements herein may result in a finding by the Recipient that the Contractor is non-responsive, non-responsible, and/or has breached the Contract, leading to the withholding of funds or such other actions, liquidated damages pursuant to subsection III(F) of this section, or enforcement proceedings as allowed by the Contract.

C. If any terms or provisions herein conflict with Executive Law Article 15-A, the MWBE Regulations, Title VI, Title VII, or Federal Affirmative Action Regulations, such law and regulations shall supersede these requirements.

D. Upon request from the Recipient's Minority Business Officer ("MBO") and/or EFC, Contractor will provide complete responses to inquiries and all MWBE and EEO records available within a reasonable time. For purposes of this section, MBO means the duly authorized representative of the SRF Recipient for MWBE and EEO purposes.

III. Equal Employment Opportunities (EEO)

Applicable to all Contracts and Subcontracts unless otherwise noted

A. Each Contractor and Subcontractor performing work on the Contract shall undertake or continue existing EEO programs to ensure that minority group members and women are afforded equal employment opportunities without discrimination because of race, creed, color, national origin, sex, age, disability or marital status. For these purposes, EEO shall apply in the areas of recruitment, employment, job assignment, promotion, upgrading, demotion, transfer, layoff, or termination and rates of pay or other forms of compensation.

B. The Contractor shall comply with the provisions of the Human Rights Law (Executive Law Article 15), Title VI, Title VII, the Federal Affirmative Action Regulations, Section 504, Age Discrimination Act, Section 13, and all other State and Federal statutory and constitutional non-discrimination provisions. The Contractor and Subcontractors shall not discriminate against any employee or applicant for employment because of race, creed (religion), color, sex, national origin, sexual orientation, military status, age, disability, predisposing genetic characteristic, marital status or domestic violence victim status, and shall also follow the requirements of the Human Rights Law with regard to non-discrimination on the basis of prior criminal conviction and prior arrest.

C. Contractors and Subcontractors shall have instituted grievance procedures to assure the prompt and fair resolution of complaints when a violation of Title VI of the Civil Rights Act of 1964 or Title 40 CFR Part 7 is alleged.

D. Pursuant to 40 CFR § 7.95, the Contractor shall display a copy of the EEO notice at the project site in a visible location. The notice shall accommodate individuals with impaired vision or hearing and should be provided in languages other than English where appropriate. The notice must also identify the employee responsible for its EEO compliance. A copy of the EEO notice ("EEO Poster") can be found at:
https://www.dol.gov/ofccp/regs/compliance/posters/pdf/eeopost.pdf .

The Contractor will include the provisions of Subdivisions II(A) and II(C) in every Subcontract in such a manner that the requirements of these subdivisions will be binding upon each Subcontractor as to work in connection with the Contract.

Applicable to all construction Contracts

E. The Contractor and Subcontractor will comply with the requirements of 41 CFR § 60-1.4(b) and (c), and such provisions are hereby incorporated by reference. These provisions require, in part, that the Contractor and Subcontractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, sexual orientation, gender identity, or national origin. The Contractor and Subcontractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment without regard to their race, color, religion, sex, sexual orientation, gender identity, or national origin. Such action shall include, but not be limited to the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship.

Applicable to construction Contracts greater than $10,000

F. The Contractor and Subcontractor will comply with the Affirmative Action Regulations and such provisions are hereby incorporated by reference. These provisions require, in part, that the Contractor and Subcontractor place affirmative action goals on Contracts and Subcontracts, as established by the United States Department of Labor. Affirmative action goals for minorities and women by geographic region can be found here:
https://www.dol.gov/sites/dolgov/files/ofccp/ParticipationGoals.pdf .

G. Required EEO Forms

Pursuant to 41 CFR Section 60-1.7 for federally assisted construction Contracts, Contractor and Subcontractor will annually file an EEO-1 Report with the Joint Reporting Committee for the Office of Federal Contract Compliance Programs (OFCCP) and the Equal Employment Opportunity Commission (EEOC) according to the instructions provided at https://www.eeoc.gov/employers/eeo-1-survey/eeo-1-instruction-booklet , if Contractor or Subcontractor:

1. Is not exempt from compliance pursuant to 41 CFR § 60-1.5;
2. Has 50 or more employees;
3. Is a prime Contractor or first tier Subcontractor; or Subcontractor below the first tier which performs construction work at the site of construction; and
4. Has a Contract, Subcontract, or purchase order amounting to $50,000 or more.

IV. Business Participation Opportunities for MWBEs

Applicable to Contracts Meeting Article 15-A Thresholds

A. Contract Goals

1. For purposes of this Contract, EFC establishes the following goals for New York State certified MWBE participation based on the current availability of qualified MBEs and WBEs.

Program	MWBE Contract Goal*
CWSRF, DWSRF, & Green Innovation Grant Program	20%
NYS Water Infrastructure Improvement Act Grants (also receiving EFC loan)	Clean Water project 20% Drinking Water project 20%
NYS Intermunicipal Grants (also receiving EFC loan)	Clean Water project 20% Drinking Water project 20%

*May be any combination of MBE and/or WBE participation

2. For purposes of providing meaningful participation by MWBEs on the Contract and achieving the MWBE Contract Goals established in Section III-A hereof, the Contractor should reference the directory of New York State Certified MWBEs found at the following internet address: https://ny.newnycontracts.com .
3. The Contractor understands that only sums paid to MWBEs for the performance of a commercially useful function, as that term is defined in 5 NYCRR § 140.1, may be applied towards achievement of applicable MWBE participation goals.
    a. For construction and construction-related services Contracts or Subcontracts, the portion of the Contract or Subcontract with an MWBE serving as a supplier, and so designated in ESD's Directory, that shall be deemed to represent the commercially useful function performed by the MWBE shall be 60% of the total value of the Contract or Subcontract. The portion of a Contract or Subcontract with an MWBE serving as a broker, as denoted by NAICS code 425120, that shall be deemed to represent the commercially useful function performed by the MWBE shall be the monetary value for fees, or the markup percentage, charged by the MWBE.
    b. For non-construction Contracts or Subcontracts, the portion of a Contract or Subcontract with an MWBE serving as a broker that shall be deemed to represent the commercially useful function performed by the MWBE shall be 25% of the total value of the contract
4. Where MWBE Contract Goals have been established herein, pursuant to 5 NYCRR § 142.8, the Contractor must document "good faith efforts" to provide meaningful participation by MWBEs as Subcontractors or suppliers in the performance of the Contract.
5. In accordance with Section 316-a of Article 15-A and 5 NYCRR § 142.13, the Contractor acknowledges that if it is found to have willfully and intentionally failed to comply with the MWBE participation goals set forth in the Contract, such a finding constitutes a breach of Contract and the Contractor shall be liable to the Recipient for liquidated or other appropriate damages, as set forth herein.

B. MWBE Utilization Plan

1. The Contractor represents and warrants that Contractor has submitted an MWBE Utilization Plan to the Recipient prior to the execution of this Contract.
2. The Contractor agrees to use such MWBE Utilization Plan for the performance of MWBEs on the Contract pursuant to the prescribed MWBE goals set forth in Section III-A of this section.

3. The Contractor further agrees that a failure to submit and/or use such MWBE Utilization Plan shall constitute a material breach of the terms of the Contract. Upon the occurrence of such a material breach, the Recipient shall be entitled to any remedy provided herein, including but not limited to, a finding that the Contractor is not responsive.
4. Contractor must report any changes to the Utilization Plan after Contract award and during the term of the Contract to the Recipient's MBO. Contractor shall indicate the changes to the MBO in the next Monthly MWBE Contractor Compliance Report after the changes occurred. At EFC's discretion, an updated MWBE Utilization Plan form and good faith effort documentation may be required to be submitted. When a Utilization Plan is revised due to execution of a change order, the change order should be submitted to the MBO with the Monthly MWBE Contractor Compliance Report or revised Utilization Plan.
5. The Contractor shall submit copies of all fully executed Subcontracts, agreements, and purchase orders that are referred to in the MWBE Utilization Plan to the MBO within 30 days of their execution.

C. Requests for Waiver

1. If the Contractor, after making good faith efforts, is unable to comply with MWBE goals, the Contractor may submit a Request for Waiver to the Recipient documenting good faith efforts by the Contractor to meet such goals. If the documentation included with the waiver request is complete, the Recipient shall forward the request to EFC for evaluation, and EFC will issue a written notice of acceptance or denial within twenty (20) days of receipt.
2. If the Recipient, upon review of the MWBE Utilization Plan and updated Quarterly MWBE Contractor Compliance Reports determines that the Contractor is failing or refusing to comply with the MWBE Contract Goals and no waiver has been issued in regards to such non-compliance, the Recipient may issue a notice of deficiency to the Contractor. The Contractor must respond to the notice of deficiency within seven (7) business days of receipt. Such response may include a request for partial or total waiver of MWBE Contract Goals.

D. Monthly MWBE Contractor Compliance Report ("Monthly MWBE Report")

The Contractor agrees to submit a report to the Recipient by the third business day following the end of each month over the term of this Contract documenting the payments made and the progress towards achievement of the MWBE goals of the Contract. The Monthly MWBE Report must be supplemented with proof of payment by the Contractor to its Subcontractors (e.g., copies of both sides of a cancelled check) and proof that Subcontractors have been paid within 30 days of receipt of payment from the Recipient. The final Monthly MWBE Report must reflect all Utilization Plan revisions and change orders.

E. Liquidated Damages - MWBE Participation

In accordance with Section 316-a of Article 15-A and 5 NYCRR §142.13, if it has been determined by the Recipient or EFC that the Contractor has willfully and intentionally failed to comply with the MWBE participation goals, the Contractor shall be obligated to pay to Recipient liquidated damages or other appropriate damages, as specified herein and as determined by the Recipient or EFC.

Liquidated damages shall be calculated as an amount not to exceed the difference between:

1. All sums identified for payment to MWBEs had the Contractor achieved the approved MWBE participation goals; and,
2. All sums actually paid to MWBEs for work performed or materials supplied under this Contract.

The Recipient and EFC reserve the right to impose a lesser amount of liquidated damages than the amount calculated above based on the circumstances surrounding the Contractor's non-compliance.

In the event a determination has been made by the Recipient or EFC which requires the payment of damages identified herein and such identified sums have not been withheld, Contractor shall pay such damages to the Recipient within sixty (60) days after they are assessed unless prior to the expiration of such sixtieth day, the Contractor has filed a complaint with the Empire State Development Corporation – Division of Minority and Women's Business Development ("ESD") pursuant to Subdivision 8 of Section 313 of the Executive Law in which event the damages shall be payable if the Director of ESD renders a decision in favor of the Recipient.

V. SECTION 2 PARTICIPATION OPPORTUNITIES FOR NEW YORK STATE CERTIFIED SERVICE-DISABLED VETERAN-OWNED BUSINESSES

New York State Executive Law Article 17-B and 9 NYCRR Part 252 provide for more meaningful participation in public procurement by certified Service-Disabled Veteran-Owned Businesses ("SDVOBs"), thereby further integrating such businesses into New York State's economy. EFC recognizes the need to promote the employment of service-disabled veterans and to ensure that certified service-disabled veteran-owned businesses have opportunities for maximum feasible participation in the performance of EFC Contracts.

In recognition of the service and sacrifices made by service-disabled veterans and in recognition of their economic activity in doing business in New York State, Contractors are strongly encouraged and expected to consider SDVOBs in the fulfillment of the requirements of the Contract. Such participation may be as Subcontractors or suppliers, as protégés, or in other partnering or supporting roles.

Contractor is encouraged to make good faith efforts to promote and assist in the participation of SDVOBs on the Contract for the provision of services and materials. The directory of New York State Certified SDVOBs can be viewed at: http://ogs.ny.gov/Core/SDVOBA.asp .

Contractor is encouraged to contact the Office of General Services' Division of Service-Disabled Veteran's Business Development at 518-474-2015 or VeteransDevelopment@ogs.ny.gov to discuss methods of maximizing participation by SDVOBs on the Contract.

VI. SECTION 3 AMERICAN IRON AND STEEL (AIS) REQUIREMENT

The requirements of this section apply to (1) all construction Contracts and Subcontracts for DWSRF projects and CWSRF treatment works projects and (2) all Contracts for the purchase of iron and steel products for a DWSRF project or CWSRF treatment works project. Disregard this section if it does not apply to this Contract or Subcontract.

The Contractor acknowledges to and for the benefit of the Recipient of the Clean Water State Revolving Fund ("CWSRF") or the Drinking Water State Revolving Fund ("DWSRF") financial assistance that the Contractor understands the goods and services under this Agreement are being funded with monies made available by the New York State Environmental Facilities Corporation ("EFC") through the CWSRF or the DWSRF and that such funding is subject to certain statutory restrictions requiring that certain iron and steel products used in the project be produced in the United States ("American Iron and Steel Requirement") including iron and steel products provided by the Contractor pursuant to this Agreement.

The Contractor hereby represents and warrants that:

(a) the Contractor has reviewed and understands the American Iron and Steel Requirement,
(b) all of the iron and steel products covered by the American Iron and Steel Requirement used in the project will be and/or have been produced in the United States in a manner that complies with the American Iron and Steel Requirement, unless a waiver of the requirement is approved, and
(c) the Contractor will provide any further verified information, certification or assurance of compliance with this paragraph, or information necessary to support a waiver of the American Iron and Steel Requirement, as may be requested by the Recipient.

Notwithstanding any other provision of this Agreement, any failure to comply with this paragraph by the Contractor shall permit the Recipient to recover as damages against the Contractor any loss, expense, or cost (including without limitation attorney's fees) incurred by the Recipient resulting from any such failure (including without limitation any impairment or loss of funding, whether in whole or in part, from the EFC or any damages owed to the EFC by the Recipient). While the Contractor has no direct contractual privity with the EFC, as a lender to the Recipient for the funding of this project, the Recipient and the Contractor agree that the EFC is a third-party beneficiary and neither this paragraph, nor any other provision of this Agreement necessary to give this paragraph force or effect, shall be amended or waived without the prior written consent of the EFC.

VII. SECTION 4 DAVIS-BACON (DB) PREVAILING WAGE REQUIREMENTS

The requirements of this section apply to all construction Contracts and Subcontracts greater than $2,000 for either DWSRF projects or CWSRF treatment works projects. Disregard this section if it does not apply to this Contract or Subcontract.

For Contracts in Excess of $2,000:

1. Minimum Wages

(i) All laborers and mechanics employed or working upon the site of the work will be paid unconditionally and not less often than once a week, and without subsequent deduction or rebate on any account (except such payroll deductions as are permitted by regulations issued by the Secretary of Labor under the Copeland Act (29 CFR part 3)), the full amount of wages and bona fide fringe benefits (or cash equivalents thereof) due at time of payment computed at rates not less than those contained in the wage determination of the Secretary of Labor which is attached hereto and made a part hereof, regardless of any contractual relationship which may be alleged to exist between the Contractor and such laborers and mechanics.

Contributions made or costs reasonably anticipated for bona fide fringe benefits under section 1(b)(2) of the Davis–Bacon Act on behalf of laborers or mechanics are considered wages paid to such laborers or mechanics, subject to the provisions of paragraph (1)(iv) of this section; also, regular contributions made or costs incurred for more than a weekly period (but not less often than quarterly) under plans, funds, or programs which cover the particular weekly period, are deemed to be constructively made or incurred during such weekly period. Such laborers and mechanics shall be paid the appropriate wage rate and fringe benefits on the wage determination for the classification of work actually performed, without regard to skill, except as provided in 29 CFR § 5.5(a)(4). Laborers or mechanics performing work in more than one classification may be compensated at the rate specified for each classification for the time actually worked therein provided that the employer's payroll records accurately set forth the time spent in each classification in which work is performed. The wage determination (including any additional classification and wage rates conformed under paragraph (1)(ii) of this section) and the Davis–Bacon poster (WH–1321) shall be posted at all times by the Contractor and its Subcontractors at the site of the work in a prominent and accessible place where it can be easily seen by the workers. The Davis-Bacon poster (WH-1321) can be found at https://www.dol.gov/whd/regs/compliance/posters/davis.htm . Wage determinations may be obtained from the US Department of Labor's website, https://beta.sam.gov/ .

(ii)(A) The contracting officer shall require that any class of laborers or mechanics, including helpers, which is not listed in the wage determination and which is to be employed under the Contract shall be classified in conformance with the wage determination. The contracting officer shall approve a request for an additional classification and wage rate and fringe benefits therefore only when the following criteria have been met:

1. The work to be performed by the classification requested is not performed by a classification in the wage determination;
2. The classification is utilized in the area by the construction industry; and,
3. The proposed wage rate, including any bona fide fringe benefits, bears a reasonable relationship to the wage rates contained in the wage determination.

(B) If the Contractor and the laborers and mechanics to be employed in the classification (if known), or their representatives, and the contracting officer agree on the classification and wage rate (including the amount designated for fringe benefits where appropriate), documentation of the action taken and the request, including the local wage determination shall be sent by the contracting officer to the Administrator of the Wage and Hour Division, Employment Standards Administration, U.S. Department of Labor, Washington, DC 20210 and to the EPA DB Regional Coordinator concurrently. The Administrator, or an authorized representative, will approve, modify, or disapprove every additional classification request within 30 days of receipt and so advise the contracting officer or will notify the contracting officer within the 30–day period that additional time is necessary.

(C) In the event the Contractor, the laborers or mechanics to be employed in the classification or their representatives, and the contracting officer do not agree on the proposed classification and wage rate (including the amount designated for fringe benefits, where appropriate), the contracting officer shall refer the request and the local wage determination, including the views of all interested parties and the recommendation of the contracting officer, to the Administrator for determination. The request shall be sent to the EPA DB Regional Coordinator concurrently. The Administrator, or an authorized representative, will issue a determination within 30 days of receipt of the request and so advise the contracting officer or will notify the contracting officer within the 30–day period that additional time is necessary.

(D) The wage rate (including fringe benefits where appropriate) determined pursuant to paragraphs (1) (ii)(B) or (C) of this section, shall be paid to all workers performing work in the classification under this Contract from the first day on which work is performed in the classification.

(iii) Whenever the minimum wage rate prescribed in the Contract for a class of laborers or mechanics includes a fringe benefit which is not expressed as an hourly rate, the Contractor shall either pay the benefit as stated in the wage determination or shall pay another bona fide fringe benefit or an hourly cash equivalent thereof.

(iv) If the Contractor does not make payments to a trustee or other third person, the Contractor may consider as part of the wages of any laborer or mechanic the amount of any costs reasonably anticipated in providing bona fide fringe benefits under a plan or program *provided* that the Secretary of Labor has found, upon the written request of the Contractor, that the applicable standards of the Davis–Bacon Act have been met. The Secretary of Labor may require the Contractor to set aside in a separate account assets for the meeting of obligations under the plan or program.

2. Withholding. The Recipient shall upon its own action or upon written request of the EPA Award Official or an authorized representative of the Department of Labor withhold or cause to be withheld from the Contractor under this Contract or any other Federal contract with the same prime contractor, or any other federally-assisted contract subject to Davis–Bacon prevailing wage requirements, which is held by the same prime contractor, so much of the accrued payments or advances as may be considered necessary to pay laborers and mechanics, including apprentices, trainees, and helpers, employed by the Contractor or any Subcontractor the full amount of wages required by the Contract. In the event of failure to pay any laborer or mechanic, including any apprentice, trainee, or helper, employed or working on the site of the work, all or part of the wages required by the Contract, the Recipient may, after written notice to the Contractor, sponsor, applicant, or owner, take such action as may be necessary to cause the suspension of any further payment, advance, or guarantee of funds until such violations have ceased.

3. Payrolls and basic records.

(i) Payrolls and basic records relating thereto shall be maintained by the Contractor during the course of the work and preserved for a period of three years thereafter for all laborers and mechanics working at the site of the work. Such records shall contain the name, address, and social security number of each such worker, his or her correct classification, hourly rates of wages paid (including rates of contributions or costs anticipated for bona fide fringe benefits or cash equivalents thereof of the types described in section 1(b)(2)(B) of the Davis–Bacon Act), daily and weekly number of hours worked, deductions made and actual wages paid. Whenever the Secretary of Labor has found under 29 CFR § 5.5(a)(1)(iv) that the wages of any laborer or mechanic include the amount of any costs reasonably anticipated in providing benefits under a plan or program described in section 1(b)(2)(B) of the Davis–Bacon Act, the Contractor shall maintain records which show that the commitment to provide such benefits is enforceable, that the plan or program is financially responsible, and that the plan or program has been communicated in writing to the laborers or mechanics affected, and records which show the costs anticipated or the actual cost incurred in providing such benefits. Contractors employing apprentices or trainees under approved programs shall maintain written evidence of the registration of apprenticeship programs and certification of trainee programs, the registration of the apprentices and trainees, and the ratios and wage rates prescribed in the applicable programs.

(ii)(A) The Contractor shall submit weekly for each week in which any Contract work is performed a copy of all payrolls to the Recipient. Such documentation shall be available on request of EFC or EPA. As to each payroll copy received, the Recipient shall provide written confirmation in a form satisfactory to EFC indicating whether or not the project is in compliance with the requirements of 29 CFR § 5.5(a)(1) based on the most recent payroll copies for the specified week. The payrolls submitted shall set out accurately and completely all of the information required to be maintained under 29 CFR § 5.5(a)(3)(i), except that full social security numbers and home addresses shall not be included on weekly transmittals. Instead the payrolls shall only need to include an individually identifying number for each employee (e.g., the last four digits of the employee's social security number). The required weekly payroll information may be submitted in any form desired. Optional Form WH–347 is available for this purpose from the Wage and Hour Division Web site at https://www.dol.gov/agencies/whd/government-contracts/construction/forms or its successor site. The prime Contractor is responsible for the submission of copies of payrolls by all Subcontractors. Contractors and Subcontractors shall maintain the full social security number and current address of each covered worker, and shall provide them upon request to the Recipient, for transmission to EFC, EPA if requested by EPA, or the Wage and Hour Division of the Department of Labor for purposes of an investigation or audit of compliance with prevailing wage requirements. It is not a violation of this section for a prime Contractor to require a Subcontractor to provide addresses and social security numbers to the prime Contractor for its own records, without weekly submission to the Recipient (or the applicant, sponsor, or owner).

(B) Each payroll submitted shall be accompanied by a "Statement of Compliance," signed by the Contractor or Subcontractor or his or her agent who pays or supervises the payment of the persons employed under the Contract and shall certify the following:

(1) That the payroll for the payroll period contains the information required to be provided under 29 CFR § 5.5(a)(3)(ii), the appropriate information is being maintained under 29 CFR § 5.5 (a)(3)(i), and that such information is correct and complete;

(2) That each laborer or mechanic (including each helper, apprentice, and trainee) employed on the Contract during the payroll period has been paid the full weekly wages earned, without rebate, either directly or indirectly, and that no deductions have been made either directly or indirectly from the full wages earned, other than permissible deductions as set forth in Regulations, 29 CFR part 3;

(3) That each laborer or mechanic has been paid not less than the applicable wage rates and fringe benefits or cash equivalents for the classification of work performed, as specified in the applicable wage determination incorporated into the Contract.

(C) The weekly submission of a properly executed certification set forth on the reverse side of Optional Form WH–347 shall satisfy the requirement for submission of the “Statement of Compliance” required by paragraph (3)(ii)(B) of this section.

(D) The falsification of any of the above certifications may subject the Contractor or Subcontractor to civil or criminal prosecution under section 1001 of title 18 and section 231 of title 31 of the United States Code.

(iii) The Contractor or Subcontractor shall make the records required under paragraph (3)(i) of this section available for inspection, copying, or transcription by authorized representatives of the Recipient, EFC, EPA, or the Department of Labor, and shall permit such representatives to interview employees during working hours on the job. If the Contractor or Subcontractor fails to submit the required records or to make them available, the Recipient, EFC, or EPA may, after written notice to the Contractor, sponsor, applicant, or owner, take such action as may be necessary to cause the suspension of any further payment, advance, or guarantee of funds. Furthermore, failure to submit the required records upon request or to make such records available may be grounds for debarment action pursuant to 29 CFR § 5.12.

4. Apprentices and trainees.

(i) Apprentices. Apprentices will be permitted to work at less than the predetermined rate for the work they performed when they are employed pursuant to and individually registered in a bona fide apprenticeship program registered with the U.S. Department of Labor, Employment and Training Administration, Office of Apprenticeship Training, Employer and Labor Services, or with a State Apprenticeship Agency recognized by the Office, or if a person is employed in his or her first 90 days of probationary employment as an apprentice in such an apprenticeship program, who is not individually registered in the program, but who has been certified by the Office of Apprenticeship Training, Employer and Labor Services or a State Apprenticeship Agency (where appropriate) to be eligible for probationary employment as an apprentice. The allowable ratio of apprentices to journeymen on the job site in any craft classification shall not be greater than the ratio permitted to the Contractor as to the entire work force under the registered program. Any worker listed on a payroll at an apprentice wage rate, who is not registered or otherwise employed as stated above, shall be paid not less than the applicable wage rate on the wage determination for the classification of work actually performed. In addition, any apprentice performing work on the job site in excess of the ratio permitted under the registered program shall be paid not less than the applicable wage rate on the wage determination for the work actually performed. Where a Contractor is performing construction on a project in a locality other than that in which its program is registered, the ratios and wage rates (expressed in percentages of the journeyman’s hourly rate) specified in the Contractor’s or Subcontractor’s registered program shall be observed. Every apprentice must be paid at not less than the rate specified in the registered program for the apprentice’s level of progress, expressed as a percentage of the journeymen hourly rate specified in the applicable wage determination. Apprentices shall be paid fringe benefits in accordance with the provisions of the apprenticeship program. If the apprenticeship program does not specify fringe benefits, apprentices must be paid the full amount of fringe benefits listed on the wage determination for the applicable classification. If the Administrator determines that a different practice prevails for the applicable apprentice classification, fringes shall be paid in accordance with that determination. In the event the Office of Apprenticeship Training, Employer and Labor Services, or a State Apprenticeship Agency recognized by the Office, withdraws approval of an apprenticeship program, the Contractor will no longer be permitted to utilize apprentices at less than the applicable predetermined rate for the work performed until an acceptable program is approved.

(ii) Trainees. Except as provided in 29 CFR § 5.16, trainees will not be permitted to work at less than the predetermined rate for the work performed unless they are employed pursuant to and individually registered in a program which has received prior approval, evidenced by formal certification by the U.S. Department of Labor, Employment and Training Administration. The ratio of trainees to journeymen on the job site shall not be greater than permitted under the plan approved by the Employment and Training Administration. Every trainee must be paid at not less than the rate specified in the approved program for the trainee’s level of progress, expressed as a percentage of the journeyman hourly rate specified in the applicable wage determination. Trainees shall be paid fringe benefits in accordance with the provisions of the trainee program. If the trainee program does not mention fringe benefits, trainees shall be paid the full amount of fringe benefits listed on the wage determination unless the Administrator of the Wage and Hour Division determines that there is an apprenticeship program associated with the corresponding journeyman wage rate on the wage determination which provides for less than full fringe benefits for apprentices. Any employee listed on the payroll at a trainee rate who is not registered and participating in a training plan approved by the Employment and Training Administration shall be paid not less than the applicable wage rate on the wage determination for the classification of work actually performed. In addition, any trainee performing work on the job site in excess of the ratio permitted under the registered program shall be paid not less than the applicable wage rate on the wage determination for the work actually performed. In the event the Employment and Training Administration withdraws approval of a training program, the Contractor will no longer be permitted to utilize trainees at less than the applicable predetermined rate for the work performed until an acceptable program is approved.

(iii) Equal employment opportunity. The utilization of apprentices, trainees and journeymen under this part shall be in conformity with the equal employment opportunity requirements of Executive Order 11246, as amended, and 29 CFR part 30.

5. Compliance with Copeland Act Requirements. The Contractor shall comply with the requirements of 29 CFR part 3, which are incorporated by reference in this Contract.

6. Subcontracts. The Contractor or Subcontractor shall insert in any Subcontracts the clauses contained in 29 CFR § 5.5(a)(1) through (10) and such other clauses as the Recipient may by appropriate instructions require, and also a clause requiring the Subcontractors to include these clauses in any lower tier Subcontracts. The prime Contractor shall be responsible for the compliance by any Subcontractor or lower tier subcontractor with all the Contract clauses in 29 CFR § 5.5.

7. Contract Termination: Debarment. A breach of the contract clauses in 29 CFR § 5.5 may be grounds for termination of the Contract, and for debarment as a Contractor and a Subcontractor as provided in 29 CFR § 5.12.

8. Compliance with Davis–Bacon and Related Act requirements. All rulings and interpretations of the Davis–Bacon and Related Acts contained in 29 CFR parts 1, 3, and 5 are herein incorporated by reference in this Contract.

9. Disputes Concerning Labor Standards. Disputes arising out of the labor standards provisions of this Contract shall not be subject to the general disputes clause of this Contract. Such disputes shall be resolved in accordance with the procedures of the Department of Labor set forth in 29 CFR parts 5, 6, and 7. Disputes within the meaning of this clause include disputes between the Contractor (or any of its Subcontractors) and the Recipient, the U.S. Department of Labor, or the employees or their representatives.

10. Certification of eligibility.

(i) By entering into this Contract, the Contractor certifies that neither it (nor he or she) nor any person or firm who has an interest in the Contractor's firm is a person or firm ineligible to be awarded Government Contracts by virtue of section 3(a) of the Davis-Bacon Act or 29 CFR 5.12(a)(1).

(ii) No part of this Contract shall be subcontracted to any person or firm ineligible for award of a Government contract by virtue of section 3(a) of the Davis-Bacon Act or 29 CFR 5.12(a)(1).

(iii) The penalty for making false statements is prescribed in the U.S. Criminal Code, 18 U.S.C. § 1001.

For Contracts in Excess of $100,000:

1. Overtime requirements. No Contractor or Subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics shall require or permit any such laborer or mechanic in any workweek in which he or she is employed on such work to work in excess of forty hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times the basic rate of pay for all hours worked in excess of forty hours in such workweek.

2. Violation; liability for unpaid wages; liquidated damages. In the event of any violation of the clause set forth in paragraph (1) of this section the Contractor and any Subcontractor responsible therefor shall be liable for the unpaid wages. In addition, such Contractor and Subcontractor shall be liable to the United States (in the case of work done under contract for the District of Columbia or a territory, to such District or to such territory), for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic, including watchmen and guards, employed in violation of the clause set forth in paragraph (1) of this section, in the sum of $25 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of forty hours without payment of the overtime wages required by the clause set forth in paragraph (1) of this section.

3. Withholding for unpaid wages and liquidated damages. The Recipient shall upon its own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any monies payable on account of work performed by the Contractor or Subcontractor under any such Contract or any other Federal contract with the same prime contractor, or any other federally-assisted contract subject to the Contract Work Hours and Safety Standards Act, which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of such Contractor or Subcontractor for unpaid wages and liquidated damages as provided in the clause set forth in paragraph (2) of this section.

4. Subcontracts. The Contractor or Subcontractor shall insert in any Subcontracts the clauses set forth in paragraphs (1) through (4) of this section and also a clause requiring the Subcontractors to include these clauses in any lower tier Subcontracts. The prime Contractor shall be responsible for compliance by any Subcontractor or lower tier subcontractor with the clauses set forth in paragraphs (1) through (4) of this section.

5. In any Contract subject only to the Contract Work Hours and Safety Standards Act and not to any of the other statutes cited in 29 CFR § 5.1, the Contractor or Subcontractor shall maintain payrolls and basic payroll records during the course of the work and shall preserve them for a period of three years from the completion of the Contract for all laborers and mechanics, including guards and watchmen, working on the contract. Such records shall contain the name and address of each such employee, social security number, correct classifications, hourly rates of wages paid, daily and weekly number of hours worked, deductions made, and actual wages paid. Further, the records to be maintained under this paragraph shall be made available by the Contractor or Subcontractor for inspection, copying, or transcription by authorized representatives of the Recipient and the Department of Labor, and the Contractor or Subcontractor will permit such representatives to interview employees during working hours on the job.

VIII.SECTION 5 REQUIREMENTS REGARDING SUSPENSION AND DEBARMENT

The requirements of this section apply to all Contracts and Subcontracts.

Contractor and any Subcontractors shall comply with, Subpart C of 2 CFR Part 180 as implemented and supplemented by 2 CFR Part 1532. The Contractor is not a debarred or suspended party under 2 CFR Part 180 or 2 CFR Part 1532, or 29 CFR § 5.12. Neither the Contractor nor any of its Subcontractors have contracted with, or will contract with, any debarred or suspended party under the foregoing regulations.

The Contractor and any Subcontractor have not been debarred from or deemed ineligible for Government Contracts or federally assisted construction Contracts pursuant to Executive Order 11246.

The Contractor and any Subcontractors have not been deemed ineligible to submit a bid on or be awarded a public contract or subcontract pursuant to Article 8 of the State Labor Law, specifically Labor Law § 220-b. In addition, neither the Contractor nor any Subcontractors have contracted with, or will contract with, any party that has been deemed ineligible to submit a bid on or be awarded a public contract or subcontract under Labor Law § 220-b.

In addition, the Contractor and any Subcontractors have not been deemed ineligible to submit a bid and have not contracted with and will not contract with any party that has been deemed ineligible to submit a bid under Executive Law § 316.

IX. SECTION 6 RESTRICTIONS ON LOBBYING

The requirements of this section apply to all Contracts and Subcontracts greater than $100,000. Disregard this section if it does not apply to this Contract or Subcontract.

The Contractor and any Subcontractor executing a Contract or Subcontract in excess of $100,000 agree to provide to the Recipient an executed Certification Regarding Lobbying pursuant to 40 CFR Part 34 ("Lobbying Certification") in the form attached hereto as Attachment 9, consistent with the prescribed form provided in Appendix A to 40 CFR Part 34.

Buffalo Sewer Authority

ENGINEERING REPORT

Bird Island Wastewater Treatment Plant
Boiler and Steam System Improvements

July 2021

BIRD ISLAND WWTP BOILER AND STEAM SYSTEM IMPROVEMENTS

Engineering Report

Prepared for:

Buffalo Sewer Authority
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Buffalo
New York 14202

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Our Ref.:

30092852

Date:

July 26, 2021

Eric Auerbach, P.E.
Project Manager

Table of Contents

APPENDICES

ACRONYMS AND ABBREVIATIONS

AB	afterburner
ASME	American Society of Mechanical Engineers
BSA	Buffalo Sewer Authority
CAPEX	capital expenditure
GHG	greenhouse gas
H&S	health and safety
NYSDEC	New York State Department of Environmental Conservation
O&M	operation and maintenance
MGD	million gallons per day
MHI	multiple hearth incinerator
mmBTU	metric million British thermal unit
MT	metric ton
PSV	pressure and safety valve
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VFD	variable-frequency drive
WHRB	waste heat recovery boiler
WWTP	wastewater treatment plant

EXECUTIVE SUMMARY

The Buffalo Sewer Authority (BSA) owns and operates the Bird Island Wastewater Treatment Plant (WWTP), which treats average wastewater flows of 180 million gallons per day (MGD). The WWTP currently manages sludge by combusting it in multiple hearth incinerators (MHIs) after it is digested to produce biogas. The plant currently produces steam for heating by burning biogas in auxiliary boilers and uses a combination of biogas and natural gas to burn sludge in the MHIs. The three existing MHIs have waste heat recovery boilers (WHRBs) installed in their exhaust system as part of the original incinerator construction circa 1972 in the Main Equipment Building. These WHRB units have not been operational for more than 20 years and the BSA desires to evaluate the feasibility of rehabilitating the existing WHRBs and put them back into service to produce steam energy for plant heating. As a result, plant auxiliary boilers would only be used as backup systems or possibly during peak heating days in the winter. In either case, auxiliary boiler run-times and maintenance requirements would be significantly reduced. In addition, steam energy would be generated from incinerator waste heat instead of burning gas in boilers which would lead to offsetting the need to burn natural gas for plant operations and reduce the fossil fuel usage at the Bird Island WWTP.

This engineering report presents the basis-of design for the Bird Island WWTP’s Boiler and Steam system and associated work to be performed so that stakeholders, including BSA, Department of Environmental Conservation and Arcadis, have a clear understanding of the design intent.

PROJECT BACKGROUND AND HISTORY

Site Information

The Bird Island WWTP is a 1.4-million square foot campus style facility located along the shores of the Niagara River. The WWTP manages and treats the wastewater produced by the City of Buffalo and surrounding communities. The original treatment plant was constructed with a hydraulic capacity of 570 million gallons per day (MGD) and consisted of bar screens, grit removal equipment, primary settling tanks (clarifiers) and disinfection facilities. Most of these original buildings are still in use today.

The Bird Island WWTP operated in this configuration until the mid-1970s when secondary treatment facilities were added between 1975 and 1979. Under this upgrade, aeration and secondary clarification systems were added along with upgrades to the disinfection system. Upgrades to the facility allowed for improved treatment for up to 360 MGD of flow. Flows in excess of the secondary treatment system capacity are treated through the original primary facilities or a combination of both primary and secondary. Currently the Bird Island WWTP is one of the largest plants in New York State with a designed average flow of 180 MGD and approximately 200 full time employees.

Solids at the plant are thickened and send to mesophilic anaerobic digesters where a portion of the solids is converted to biogas. Digested solids are thickened in centrifuges and then sent to Multiple Hearth Incinerators (MHIs) for combustion. Biogas and natural gas are used to augment the sludge combustion in the MHIs. Biogas is also burned in boilers onsite to create steam for plant heating demands.

Figure 1: Aerial View of Bird Island WWTP

All of the proposed improvements included in the Boiler and Steam System Improvements project will be completed within existing Main Equipment Building. The project is located in the western portion of Erie County on Unity Island, previously known as Bird Island, in the City of Buffalo. The soil within this province generally consists of smoothed Udorthents (0 to 15% slope), Urban land (0 to 3% slope) and Dumps. Based on the Topographic Map by USGS, the site is relative flat, decreasing from north side (approximate elevation of 580 ft) to the south side (approximate elevation of 575 ft). A general location USGS map is included as Appendix A of this report.

Ownership and Service Area

BSA operates and maintains the collection system for the City of Buffalo as shown on Figure 2. The sewer collection system covers 110 square miles including the City of Buffalo and parts of the towns of Alden, Cheektowaga, Elma, Lancaster, Tonawanda, and West Seneca and the Villages of Depew, Lancaster and Sloan, as well as Erie County Sewer District Numbers 1 and 4, approximately 550,000 people. All dry weather sanitary flows are conveyed to the Bird Island WWTP.

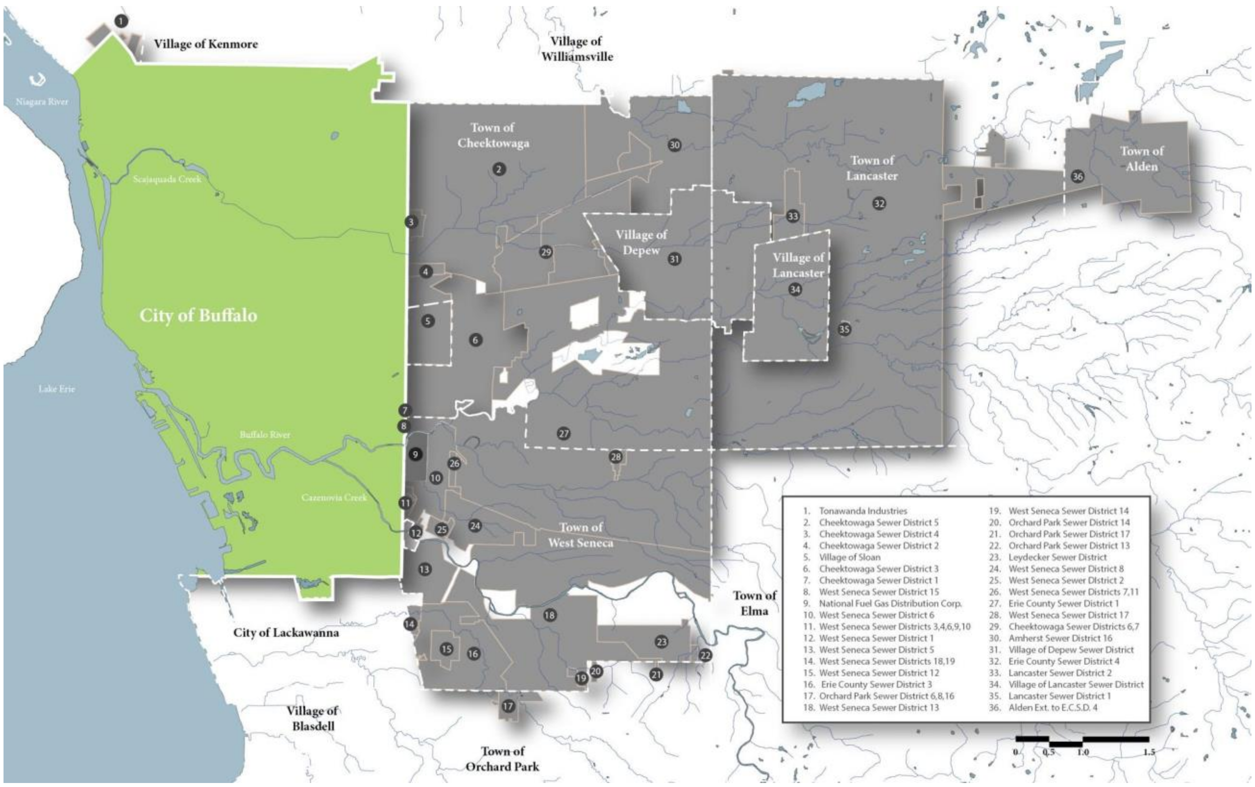


Figure 2: BSA Service Area

Existing Facilities and Present Condition

The focus of this engineering report is on the incineration exhaust, fuel gas, and steam systems of the Bird Island WWTP as shown in Figure 3. Biogas produced in six anaerobic digesters is compressed further by two gas compressors and stored in a digester gas sphere. Biogas stored in the digester gas sphere is shared between the auxiliary boilers and the incinerators.

The WWTP has three incinerators, and each incinerator has a dedicated afterburner (AB) chamber and ducting to a dedicated WHRB. These AB chambers are currently used to achieve additional exhaust detention time and increased temperatures for destruction of pollutants to meet air permit regulations. Combustion in the current incineration system typically produces exhaust gas leaving the AB chambers in the range of 1,200 – 1,400° F.

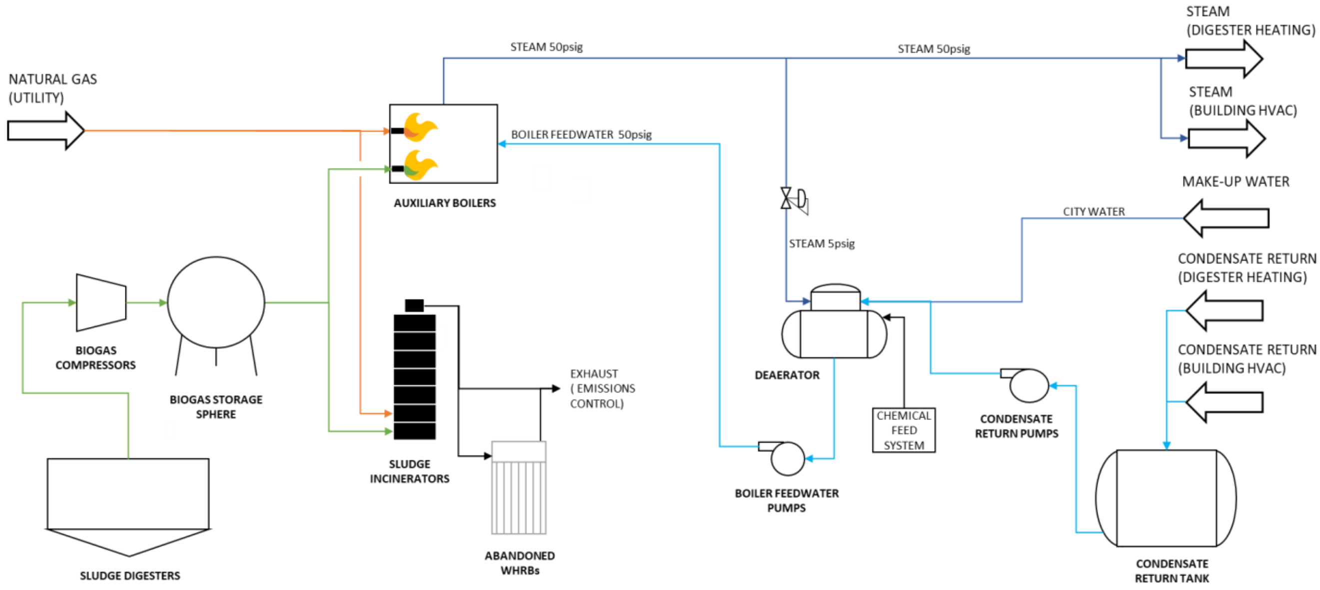


Figure 3: Bird Island WWTP Incineration Exhaust, Fuel Gas, and Steam Process Flow Diagram

The three existing auxiliary boilers can be fueled with biogas, natural gas, or No. 6 fuel oil to produce steam. These units consist of a multiple drum, water tube, water wall, type D steel boiler. Condensate from steam equipment is collected in a receiver tank at the sub-basement level of the Main Equipment Building where it is mixed with make-up water from treated city water. Water from the condensate receiver is then pumped by condensate transfer pumps into a new deaerator where it is then fed to the existing auxiliary boilers.

The plant design steam load is 80,000 pounds per hour (lbs/hr) and each of the three auxiliary boilers has a steam production capacity of 40,000 lbs/hr. These units were originally designed to produce steam at 110 psig but in the recent years have been adjusted to produce steam at 50 psig. Plant staff reported that the largest observed heating load on the coldest winter days is 60,000 lbs/hr. Two auxiliary boilers in operation have capacity to meet full plant design load and the largest actual observed heating load. Average steam loads at the plant are much smaller than the design load or largest observed load. During average winter periods when heat demands are typically highest, the steam demand on average is 15,000 lbs/hr with max month loads approximately 25,000 lbs/hr. In the summer months the steam loads decrease significantly to just digester heating and absorption chillers for building cooling with average steam loads approximately 7,500 lbs/hr. In “shoulder months” where no building heating or cooling is needed the plant steam demands can get as low as 5,000 lbs/hr. Condensate from steam equipment is collected in a receiver tank at the sub-basement level of the Main Equipment Building. Condensate from the receiver is pumped by condensate transfer pumps into a deaerator.

The WHRB units are no longer in service but were previously used to capture heat from incinerator exhaust and generate steam at 110 psig for use in the WWTP’s steam heating system and were designed to received feed water directly from the Condensate Receiver Tank. Each WHRB has a capacity of 28,000 lbs/hr. Based on verbal reports from plant staff, these units were taken out offline soon after installation due operational issues caused by excess ash fouling. Although no current staff were employed at the time the WHRBs were taken offline, the best understanding of the issue as reported by the most senior boiler operator was that saturated steam addition from the soot blowers mixed with the ash in the exhaust stream to form a sticky material that could not be removed by the WHRB vacuum ash removal systems.

Definition of the Problem

The focus of this engineering report is to evaluate the feasibility of a comprehensive Boiler and Steam Systems Improvements project at Bird Island. The project would have the goal of improving the plant's operations, overall energy efficiency, and sustainability indicators while also providing economic benefits. The main components of the solution proposed include:

- Implementation incinerator exhaust waste heat recovery at Bird Island WWTP through rehabilitation of the existing WHRBs in the Main Equipment Building. Since the WHRBs are currently permanently offline, auxiliary boilers have been supplying the plant with steam generated which requires the use of fossil fuels (natural gas) while the heat contained in the exhaust gases is entirely wasted. The estimated annual spending on natural gas at the plant is close to 900,000 $/year, which includes energy used for both MHI combustion and steam generation in boilers.
- General improvements to the integrity of steam systems, including repair or replacement of damaged insulation, degraded pipes, and leaking steam traps. Plant staff has indicated that multiple locations present evidence of significant leaks and have been dripping condensate above mechanical and electrical equipment. Upgrading of these components will translate into energy (steam) savings as well via the reduction of the use of makeup water.
- Repair of burner of Auxiliary Boiler #2. Auxiliary boilers will be kept operational as a backup system for the WHRBs.

Financial Status

The sources of income for the BSA include sewer rents (assessed, metered, and or flat rate) from properties within the City of Buffalo; Outside City Contracts from municipalities that convey wastewater to the BSA's facilities; and Industrial waste charges which include fees for monitoring and treating high strength industrial discharge, and waste haulers who use BSA facilities to dispose of grease, sludge, leachate, and septic waste.

BSA's current rate schedule is included in Appendix D. The most common fees include:

- $12,050,000 in assessment sewer rent for the City of Buffalo, which results in a rate of approximately $1.64 per $1,000 of assessed value.
- $48.30 for 0 to 4,000 CF of water used per quarter, and $11.09 per 1,000 CF thereafter.
- A drainage connection fee of $6.00 per month for residential users and $55.00 per month for commercial users.

BSA's five year capital plan and outstanding debt schedule can be found in Appendix D – BSA Financial Documents. BSA's outstanding debt schedule is also included in Appendix D. BSA has a 20% debt reserve requirement to cover existing debt and any debt that will close in the current fiscal year.

ALTERNATIVES ANALYSIS

This Section includes descriptions of the alternatives that were considered for the Bird Island WWTP Boiler and Steam System Improvements, including identification of the technically feasible alternatives. The project must achieve the following goals:

- Implement heat recovery at the incinerators exhaust in order to reduce or eliminate the use of fossil fuels for MHI sludge combustion and steam production.
- Implement comprehensive steam system improvements to decrease energy usage and to increase the energy efficiency of the WWTP.

In order for an alternative to be considered technically feasible, it must achieve these Project goals. BSA has spent considerable efforts performing a comprehensive analysis of all alternatives. The results of that analysis are summarized below:

- Alternative No. 1 – No action
- Alternative No. 2 – Green infrastructure in combination with gray structure
- Alternative No. 3 – Rehabilitation versus New construction
- Alternative No. 4 – Regional consolidation opportunities.

Alternative No. 1 – No action

This alternative consists of implementing no improvements or changes to the operation of the existing boiler and steam System at the WWTP. The facility would continue to operate as it currently does. This alternative would not achieve the required goals for the Project. This will serve as the comparison baseline for financial viability of other alternatives that achieve the goals for the Project.

Alternative No. 2 – Green infrastructure in combination with gray structure

The boiler and steam systems at the WWTP are located indoors with space constraints. Installing green infrastructure will not serve the purpose of increasing incinerator waste heat recovery or reducing the use of fossil fuel derived natural gas for plant heating. Therefore, this alternative was not considered applicable to this report.

Alternative No. 3 – Rehabilitation versus New construction

New construction of WHRBs was evaluated in the NYSERDA FlexTech Study submitted in February 2013 and provided as Appendix F. This study showed that there would be significant capital cost associated with WHRB along with logistical and constructability challenges such as removing an entire panel wall from the Main Equipment Building to facilitate removing and installing new boiler equipment. This type of investment was not considered practical for the relatively modest cost savings associated with generating steam from incinerator exhaust via WHRB equipment.

The preferred alternative would be to rehabilitate the existing WHRBs. This would save significant capital cost by reutilizing as much as the existing WHRB infrastructure as possible and would also eliminate logistical/constructability issues of large equipment ingress and egress. This rehab approach is estimated to achieve the required goals for the Project. As such, this alternative is considered technically feasible.

Alternative No. 4 – Regional consolidation opportunities

The MHI equipment operated at the Bird Island WWTP is already a regionally consolidated facility. The plant currently receives biosolids cake loads from outlying communities of Kenmore and Tonawanda. With the cake already received regionally, the MHI system is currently nearing the system capacity limit to process biosolids. Therefore, exploring additional regional consolidation was not considered applicable to this report.

Out of the presented alternatives, the only technically feasible alternative is Alternative No. 3 – Rehabilitation of the WHRBs and associated appurtenances. Detailed basis-of-design of Alternative No. 3 will be discussed below.

RECOMMENDED ALTERNATIVE

Detailed Description

The recommended alternative is the rehabilitation of existing WHRB for the purpose of recovering incinerator exhaust waste heat to generate steam to be used at the plant for building and digester heating. Only two WHRBs (No. 2 and 3) will be rehabilitated since this capacity was considered adequate for meeting the plant's steam demands with 100% equipment redundancy. It was assumed the WHRB attached to Incinerator No.1 will remain non-operational.

Ash management will be a key parameter to be accounted for in the WHRBs rehabilitation design. Ash particles collide with boiler tubes causing damage and eventual leakages over time. Another issue is excessive accumulation of ash within the boiler chamber and exhaust ducting, which can lead to fouling of the boiler tubes and a number of other maintenance problems. The existing steam soot blowers use saturated steam as their cleaning medium which was reportedly causing several issues: steam has caused corrosion problems, and the ash would congeal into a wet mass clog portions of the boilers, most notably the vacuum ash removal system. The rehabilitation will include the installation of new compressed air soot blowers. The new blowers will be automatically controlled as opposed to the original manual operation.

In addition to the rehabilitation of the WHRB units themselves, there is also a number of new ancillary equipment required to place these boilers in operation. The isolation (guillotine type) and control dampers (louver type) located in the WHRBs inlet and outlet exhaust ducts are not operable and need to be replaced. The original continuous and intermittent blowdown vessels were disconnected and removed from the original system and need to be replaced.

The WHRBs were originally designed to be fed by the condensate pumps located in the basement. New boiler feedwater piping connection will be implemented to allow the WHRBs to be fed through the same boiler feedwater header that serves the auxiliary boilers. With the connection to the boiler feedwater header, the WHRBs will be supplied with water coming from the new deaeration system that was installed at Bird Island WWTP in 2020. The deaeration system, including a deaerator, chemical feed system and boiler feedwater pumps with VFDs, can operate at all demand scenarios defined for the plant (see steam demand per season in the following subsection).

Similar to the auxiliary boilers, the WHRB were originally designed to operate at 120 psig. In the recent years, the steam system and the auxiliary boilers have been adapted to operate at 50 psig. Operating at these lower pressure levels was considered feasible with the existing pipes and equipment and steam losses were greatly reduced as a result. The rehabilitated WHRB units will need to operate at the same 50 psig levels, and the auxiliary boilers will act as backup if needed. The main adaptation to be made to the WHRBs to adjust the operating pressure will be the set points of steam regulators and steam pressure and safety valves (PSVs).

Figure 4 presents the process flow diagram of the proposed improvements including arrangement of major equipment and piping connections in the condensate/ steam system after the project.

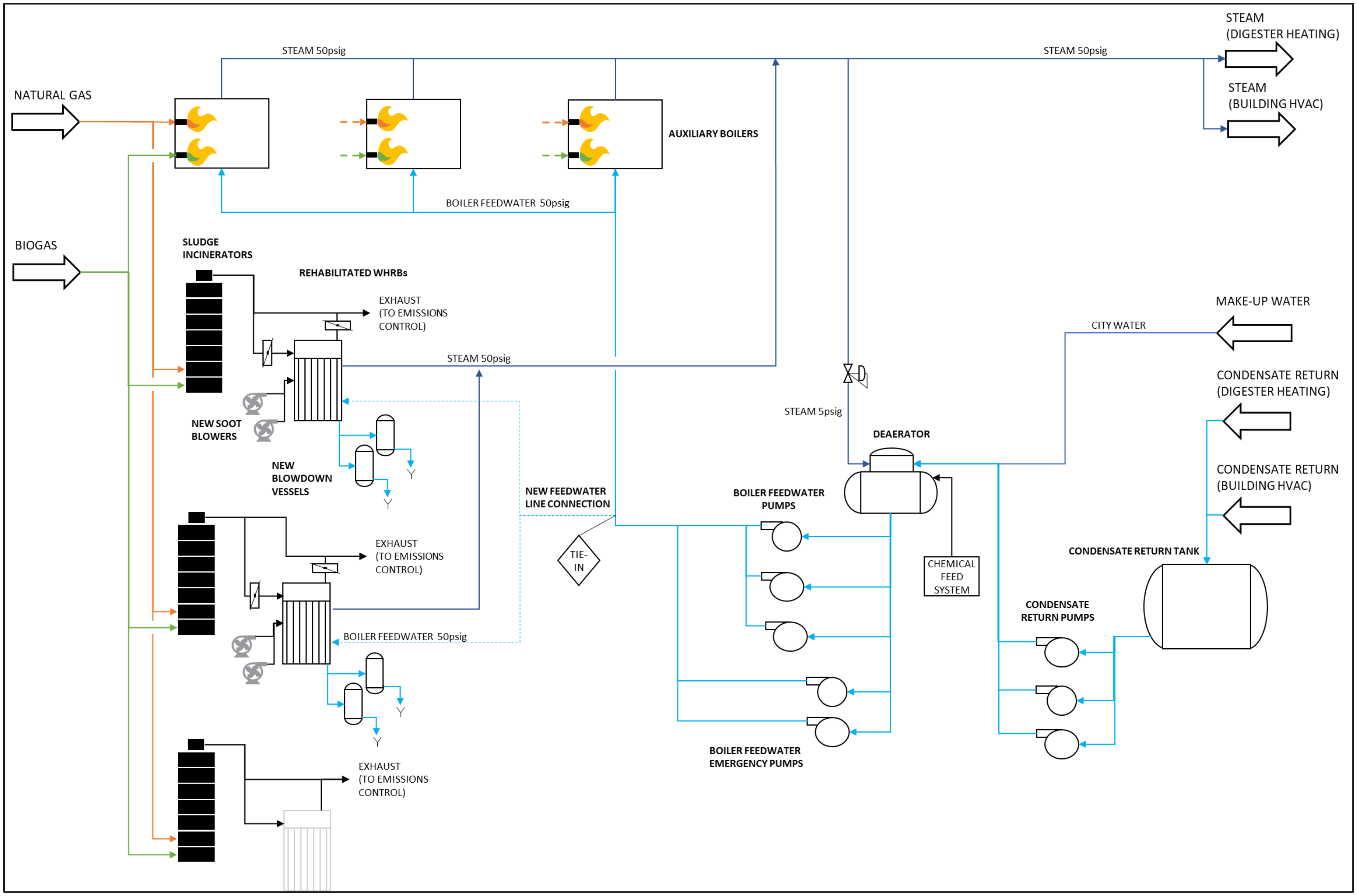


Figure 4: Schematics Showing Future Steam and Condensate System for Bird Island WWTP

Cost Estimate and Projected Savings

The cost estimate for the BSA WWTP Boiler and Steam System Improvements project considered the following components:

- Rehabilitation of two WHRBs. The scope of services includes complete retubing of the boilers, replacement of insulation and refractory where needed and hydrostatic tests. ASME certificates will be issued at the end of rehabilitation effort.
- Replacement of the existing steam soot blowers with new air compressed soot blowers.
- New control panels (one per rehabilitated WHRB boiler).
- Replacement of WHRB ancillary mechanical systems such as blowdown vessels and dampers for the exhaust ducts.
- Replacement of WHRB trim valves (feedwater regulator, steam check and regulator, steam pressure and safety).
- Adjustments in WHRB feedwater piping.
- Miscellaneous WHRB upgrades such as handrails, insulation, and lagging.
- Addition of new burner for one auxiliary boiler.
- Demolition and removal of existing equipment.
- General improvements in steam piping and steam traps.

The largest cost components are the first two bullet points, and their value was based on quotes received by a specialized local boiler servicing contractor who visited the site and evaluated the boilers. However, it is strongly recommended that an official inspection of all WHRB system components with the issuance of an official inspection report by a certified ASME boiler inspector be executed prior to the start of design phase.

The detailed cost estimate spreadsheet is presented in Appendix E. The total construction cost including all permitting and engineering fees is estimated at $ 3,9MM. This cost includes a construction contingency of 30%, considered adequately conservative to balance the detailed and informative quotes received with the lack of an official boiler inspection report.

The economic feasibility of the project will rely on savings from reducing monthly natural gas purchases. Natural gas is used for boiler and incinerator fueling at Bird Island WWTP. The heat recovered by the WHRBs will allow for steam production using incinerator exhaust waste heat and offset the use of natural gas. The biogas currently used in the auxiliary boilers could then be used to offset natural gas used to drive sludge combustion in the MHIs.

Estimated heating demands for the plant were based on data from the NYSERDA FlexTech Study (Appendix F). The following table summarizes the results from the data analysis:

Table 1: Bird Island Heating Demand per Season

Season	Steam demand (mmBTU/hr)	Steam Demand (lbs/hr)	Boiler Fuel input (mmBTU/hr)
Summer	6.83	7,492	8.54
Average	10.67	11,705	13.34
Winter	14.53	15,939	18.16
Max month	22.90	25,121	28.63

Notes:

1. Steam at @ 50 psig, latent heat 911.6 BTU/lb.

2. Assuming 80% efficiency boiler.

The plant utilizes steam for digester and building heating during winter months, and for digester heating and absorption chillers during summer. Each WHRB is rated for 28,000 lbs/hr of steam production nominal capacity, with the two boilers in operation being capable of supplying steam for the plant at maximum demand conditions. In fact, one boiler alone is able to supply energy for the plant at almost all demand conditions. For that reason, one WHRB can be considered a full spare for the system and an annual availability of 100% for the WHRBs was assumed for energy savings calculations:

Table 2: Estimated Savings from Natural Gas Usage Offsetting

Parameter	Unit	Value
Fuel input (average)	mmBTU/hr	13.34
Fuel input (average)	mmBTU/year	116,837
WHRB availability	%	100%
Natural Gas cost	$/mmBTU	5
Energy savings per year	$/year	584,000

Incremental operation and maintenance (O&M) costs for the project are estimated to be very low. Electricity use by the new soot blowers would be approximately 2,000 kWh/year which has a cost considered negligible (less than $1,000/yr). Labor costs are not expected to increase, considering that the operations of the new soot blowers will be automatic. Existing boiler operators currently operating the auxiliary boilers would instead be operating the WHRBs for the majority of the time. Annual boiler inspections are expected to be performed under similar contracting method with the same inspection personnel currently contracted. In fact, the piping and steam traps leaks repairs are expected to reduce housekeeping and maintenance efforts for other equipment as well as reduce the use of makeup water that needs to be chemically treated. An annual sum of $2,000 will be adopted as the incremental O&M costs for the project, corresponding to the additional regular (annual) boiler inspections required by code.

Table 3: Life-Cycle Cost Analysis

Parameter	Unit	Value
CAPEX	$ MM	3.9
Energy savings per year	$/year	584,000
Additional O&M cost per year Annual Boiler Inspections	$/year	2,000
Net savings per year	$/year	582,000
Simple payback period	years	6.7
Useful life of components	years	15

The simple payback of the project is estimated in 6.7 years.

Offsetting the use of natural gas in the boilers is estimated to bring significant greenhouse gas (GHG) emissions reduction in the order of 6,200 MTCO$_2$eq/year.

It is important to note that there will be other energy-related savings besides natural gas offsets such as steam savings due to the improvements in piping insulation and repair of leaks, as well as reduced makeup water and associated chemical treatment. Repair of leaking traps and pipes will also bring benefits in the form of better housekeeping standards, reduced maintenance for equipment affected by the dripping and reduced health and safety risks at the plant. However, these savings were harder to determine and were not quantified at this point.

Project Schedule

The following schedule is proposed for the implementation of this project:

Table 4: Project Schedule

Task	Date
Submit Draft Basis-of-Design Report	September 2021
30% Design Review Workshop/Finalize Report	October 2021
Submit 90% Contract Documents to BSA for review	December 2021
Comments on 90% Contract Documents received from BSA	January 2022
Advertise for Bids	February 2022
Open Bids	March 2022
Recommendation of Award	April 2022
Begin Construction	July 2022
Final Construction Completion	December 2022

APPENDIX A

USGS Location Map

USGS
science for a changing world
U.S. DEPARTMENT OF THE INTERIOR
U.S. GEOLOGICAL SURVEY

The National Map
US Topo

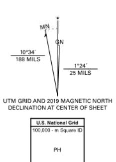
BUFFALO NW QUADRANGLE
NEW YORK - ERIE COUNTY
7.5-MINUTE SERIES

Produced by the United States Geological Survey
North American Datum of 1983 (NAD83)
World Geodetic System of 1984 (WGS84). Projection and
1 000-meter grid:Universal Transverse Mercator, Zone 17T

This map is not a legal document. Boundaries may be generalized for this map scale. Private lands within government reservations may not be shown. Obtain permission before entering private lands.

Imagery........................NAIP, October 2017 - December 2017
Roads........................U.S. Census Bureau, 2016
Names........................GNIS, 1980 - 2019
Hydrography........................National Hydrography Dataset, 1899 - 2019
Contours........................National Elevation Dataset, 1995 - 1999
Boundaries..............Multiple sources; see metadata file 2015

Wetlands................FWS National Wetlands Inventory 2002 - 2010



UTM GRID AND 2019 MAGNETIC NORTH DECLINATION AT CENTER OF SHEET

U.S. National Grid
100,000 - m Square ID
PH
Grid Zone Designation 17T

SCALE 1:24 000

KILOMETERS: 1 0.5 0 1 2
METERS: 1000 500 0 1000 2000
MILES: 1 0.5 0 1
FEET: 1000 0 1000 2000 3000 4000 5000 6000 7000 8000 9000 10000

CONTOUR INTERVAL 10 FEET
NORTH AMERICAN VERTICAL DATUM OF 1988

This map was produced to conform with the
National Geospatial Program US Topo Product Standard, 2011.
A metadata file associated with this product is draft version 0.6.18

QUADRANGLE LOCATION

1	2	3
4		5
	6	7

ADJOINING QUADRANGLES

1 Niagara Falls
2 Tonawanda West
3 Tonawanda East
4 Buffalo NW OE W
5 Buffalo NE
6 Buffalo SE OE W
7 Buffalo SE

ROAD CLASSIFICATION

Expressway
Secondary Hwy
Ramp
Local Connector
Local Road
4WD
Interstate Route
US Route
State Route

BUFFALO NW, NY, ON
2019

NSN. 7643016386500
NGA REF NO. USGSX24K69487

APPENDIX B

Engineering Report Certification

Engineering Report Certification

To Be Provided by the Professional Engineer Preparing the Report

During the preparation of this Engineering Report, I have studied and evaluated the cost and effectiveness of the processes, materials, techniques, and technologies for carrying out the proposed project or activity for which assistance is being sought from the New York State Clean Water State Revolving Fund. In my professional opinion, I have recommended for selection, to the maximum extent practicable, a project or activity that maximizes the potential for efficient water use, reuse, recapture, and conservation, and energy conservation, taking into account the cost of constructing the project or activity, the cost of operating and maintaining the project or activity over the life of the project or activity, and the cost of replacing the project and activity.

Title of Engineering Report: BSA Bird Island WWTP Boiler and Steam System Improvements

Date of Report: July 26, 2021

Professional Engineer's Name: Eric Auerbach, P.E.

Signature: Eric Auerbach

Date: July 26, 2021

APPENDIX C

Smart Growth Assessment Form

Smart Growth Assessment Form

This form should be completed by an authorized representative of the applicant, preferably the project engineer or other design professional.[1]

Section 1 – General Applicant and Project Information

Applicant: Eric Auerbach, P.E. Project No.:

Project Name: BSA Bird Island WWTP Boiler and Steam System Improvements

Is project construction complete? ☐ Yes, date: ☑ No

Please provide a brief project summary in plain language including the location of the area the project serves:

Buffalo Sewer Authority (BSA) owns and operates the Bird Island Wastewater Treatment Plant located on Unity Island in Buffalo, NY. For the Boiler and Steam System Improvements project, two of the three existing waste heat recovery boilers (WHRBs) and their associated appurtenances will be rehabilitated and put back into service to produce steam energy for plant heating. Steam energy would be generated from incinerator waste heat instead of burning gas in auxiliary boilers which would lead to offsetting the need to burn natural gas for plant operations and reduce the fossil fuel usage at the Bird Island WWTP. All of the components of the project will be taken place in the Main Equipment Building of the Bird Island WWTP.

Section 2 – Screening Questions

A. Prior Approvals

1. Has the project been previously approved for Environmental Facilities Corporation (EFC) financial assistance? ☐ Yes ☑ No
2. If yes to A(1), what is the project number(s) for the prior approval(s)? Project No.:
3. If yes to A(1), is the scope of the previously-approved project substantially the same as the current project? ☐ Yes ☐ No

If your responses to A(1) and A(3) are both yes, please proceed to Section 5, Signature.

B. New or Expanded Infrastructure

1. Does the project involve the construction or reconstruction of new or expanded infrastructure? ☐ Yes ☑ No

Examples of new or expanded infrastructure include, but are not limited to:

(i) The addition of new wastewater collection/new water mains or a new wastewater treatment system/water treatment plant where none existed previously;

(ii) An increase of the State Pollutant Discharge Elimination System (SPDES) permitted flow capacity for an existing wastewater treatment system; and OR

[1] If project construction is complete and the project was not previously financed through EFC, an authorized municipal representative may complete and sign this assessment.

(iii) An increase of the permitted water withdrawal or the permitted flow capacity for the water treatment system such that a Department of Environmental Conservation (DEC) water withdrawal permit will need to be obtained or modified, or result in the Department of Health (DOH) approving an increase in the capacity of the water treatment plant.

If your response to B(1) is no, please proceed to Section 5, Signature.

Section 3 –Smart Growth Criteria

Your project must be consistent will all relevant Smart Growth criteria. For each question below please provide a response and explanation.

1. Does the project use, maintain, or improve existing infrastructure?
   ☐ Yes ☐ No

   Explain your response:

2. Is the project located in a (1) municipal center, (2) area adjacent to a municipal center, or (3) area designated as a future municipal center, as such terms are defined herein (please select one response)?

   ☐ Yes, my project is located in a municipal center, which is an area of concentrated and mixed land uses that serves as a center for various activities, including but not limited to: central business districts, main streets, downtown areas, brownfield opportunity areas (see www.dos.ny.gov for more information), downtown areas of local waterfront revitalization program areas (see www.dos.ny.gov for more information), areas of transit-oriented development, environmental justice areas (see *www.dec.ny.gov/public/899.html* for more information), and hardship areas (projects that primarily serve census tracts or block numbering areas with a poverty rate of at least twenty percent according to the latest census data).

   ☐ Yes, my project is located in an area adjacent to a municipal center which has clearly defined borders, is designated for concentrated development in the future in a municipal or regional comprehensive plan, and exhibits strong land use, transportation, infrastructure, and economic connections to an existing municipal center.

   ☐ Yes, my project is located in an area designated as a future municipal center in a municipal or comprehensive plan and is appropriately zoned in a municipal zoning ordinance

   ☐ No, my project is not located in a (1) municipal center, (2) area adjacent to a municipal center, or (3) area designated as a future municipal center.

   Explain your response and reference any applicable plans:

3. Is the project located in a developed area or an area designated for concentrated infill development in a municipally-approved comprehensive land use plan, local waterfront revitalization plan, and/or brownfield opportunity area plan?

   ☐Yes ☐No

   Explain your response and reference any applicable plans:

4. Does the project protect, preserve, and enhance the State's resources, including surface and groundwater, agricultural land, forests, air quality, recreation and open space, scenic areas, and significant historic and archaeological resources?

   ☐Yes ☐No

   Explain your response:

5. Does the project foster mixed land uses and compact development, downtown revitalization, brownfield redevelopment, the enhancement of beauty in public spaces, the diversity and affordability of housing in proximity to places of employment, recreation and commercial development, and the integration of all income and age groups?

   ☐Yes ☐No

   Explain your response:

6. Does the project provide mobility through transportation choices including improved public transportation and reduced automobile dependency?

   ☐Yes ☐No ☐N/A

   Explain your response:

7. Does the project involve coordination between State and local government, intermunicipal planning, or regional planning?

   ☐Yes ☐No

   Explain your response and reference any applicable plans:

8. Does the project involve community-based planning and collaboration?

   ☐Yes ☐No

   Explain your response and reference any applicable plans:

9. Does the project support predictability in building and land use codes?

   ☐Yes ☐No ☐N/A

   Explain your response:

10. Does the project promote sustainability by adopting measures such as green infrastructure techniques, decentralized infrastructure techniques, or energy efficiency measures?

    ☐Yes ☐No

    Explain your response and reference any applicable plans:

11. Does the project mitigate future physical climate risk due to sea-level rise, storm surges, and/or flooding, based on available data predicting the likelihood of future extreme weather events, including hazard risk analysis data, if applicable?

    ☐Yes ☐No

    Explain your response and reference any applicable plans:

Section 4 – Miscellaneous

1. Is the project expressly required by a court or administrative consent order? ☐ Yes ☐ No

   If yes, and you have not previously provided the applicable order to EFC/DOH, please submit it with this form.

Section 5 – Signature

By signing below, you agree that you are authorized to act on behalf of the applicant and that the information contained in this Smart Growth Assessment is true, correct and complete to the best of your knowledge and belief.

Applicant: Eric Auerbach, P.E.	Phone Number: 716-667-6603
Name and Title of Signatory: Senior Project Engineer	
Signature: Eric Auerbach	Date: 7/26/2021

APPENDIX D

BSA Financial Documents

2022-2026 FIVE-YEAR CAPITAL PROGRAM

In accordance with the supplemental Bond Resolution of May 1993, the Buffalo Sewer Authority establishes a Five-Year Capital Program to fund major projects. Personnel from the Engineering Department, the Bird Island Sewage Treatment Plant, the Sewer Maintenance Division and the Administrative Department develop and list capital improvements for inclusion in the Five-Year Capital Plan.

This plan addresses the needs at the Bird Island Sewage Treatment Plant to comply with State and Federal regulations, to rehabilitate equipment, and to complete projects to reduce costs and improve operating efficiencies. This plan also allows the Buffalo Sewer Authority to continue to improve the collection system through rehabilitating combined sewers and constructing additional storm sewers.

Funds for the Capital Program are generated from: bonds, which are paid back over a 20 to 30-year period; lease/purchase proceeds for projects with a shorter life cycle; and a cash reserve fund designated for capital projects. This reserve is sustained by the 20% debt service reserve requirement of the Buffalo Sewer Authority Bond Resolution. For each $1 million used from the capital reserve, sewer system users save approximately $600,000 in interest charges as compared to bond issues. The combination of these funding sources will be used prudently to maximize the Capital Program and minimize costs.

The Sewer Authority’s current debt limit is $250 million. The outstanding bonded debt of the Authority is $41,142,544 as of July 1, 2021.

BUFFALO SEWER AUTHORITY
FIVE YEAR CAPITAL PLAN
2021-2022 TO 2025-2026

ITEM	PROJECT TITLE:	BUDGET 2021-22	2022-23	2023-24	2024-25	2025-26
	TREATMENT PLANT:					
1	SECONDARY SYSTEM PREP	44,000,000				
2	RWW 2 Pump/MOTOR REHAB (INCLUDE DISCHARGE VALVE)	1,200,000				
3	GATE 15 THROUGH 20 INSPECTION & REPAIR	1,000,000				
4	DIGESTER 6 REHAB	2,700,000				
5	PAVING 2 - LANDSCAPE	500,000				
6	PRIMARY TREATMENT REHABILITATION-NFA		60,000,000			
7	REPLACE AHU 7-14/BLOWER BUILDING		1,000,000	1,000,000	1,000,000	1,000,000
8	RWW 3 PUMP/MOTOR REHAB (INCLUDE DISCHARGE VALVE)		1,200,000			
9	FACILITY CONTROLS PHASE 1-RAW WASTEWATER CONTROL		900,000			
10	INTERIORS PHASE 2-PLANT MAINT/AER LOCKER ROOM UPGRADE		750,000			
11	SCRS REHABILITATION		1,000,000	2,000,000	2,000,000	
12	STRUCTURAL PHASE 3-PLANT WIDE GRATING ASSESMENT		200,000			
13	AUX BOILER #2		750,000			
14	INTERIOR/EXTERIOR LIGHTING		1,000,000	1,000,000		
15	ENGINEERING TERM CONTRACTS			1,000,000		
16	FACILITY CONTROLS PHASE 2-OUTLYING STATION CONTROLS			750,000		
17	STRUCTURAL PHASE 3-MEGASTRUCTURE ADDITIONAL STAIRWAYS			1,000,000		
18	DIGESTER #3 CLEANING			500,000		
19	PAVING PHASE 3 - ROADS			2,750,000		
20	IWS WASTE HAULER FACILITIES/FOOD WASTE			250,000	2,000,000	
21	REPLACE GAS COMPRESSORS			2,000,000		
22	PLANT WIDE PIPE EVAL & REPAIR (eg. P&IDs)			500,000	500,000	500,000
23	SCREEN ROOM REHAB			200,000	2,000,000	
24	INTERIORS PHASE 3-BOILER/AERATION CONTROL ROOM UPGRADE			1,000,000		
25	FACILITY CONTROLS PHASE 3-DCS FIBER OPTIC REPLACEMENT				2,000,000	

BUFFALO SEWER AUTHORITY
FIVE YEAR CAPITAL PLAN
2021-2022 TO 2025-2026

ITEM	PROJECT TITLE:	BUDGET 2021-22	2022-23	2023-24	2024-25	2025-26
26	DIGESTER AND INCREASED IMPROVEMENTS FOR SLUDGE ACCEPTANCE				1,200,000	1,800,000
27	TURBO COMPRESSOR UPGRADES				500,000	
28	INTERIORS PHASE 4-ADMINISTRATION BUILDING OFFICE UPGRADE				1,000,000	
29	STRUCTURAL PHASE 4-MEGASTRUCTURE FLOORS/TUNNEL REPAIR				1,000,000	
30	THICKENER REHAB				250,000	2,500,000
31	DIVERSION CHANNEL (CLEAN, PUMPS, GATES etc)				1,500,000	
32	SECONDARY TREATMENT REHABILITATION- NFA					50,000,000
33	FACILITY CONTROLS PHASE 4-OVATION HARDWARE UPGRADE				`	2,000,000
34	ELECTRICAL SUB-METERING AND DISTRIBUTION MODIFICATIONS					750,000
35	INTERIORS PHASE 5-RWW AND PRIMARY CONTROL ROOMS/LOCKER ROOMS					750,000
36	INCINERATOR #1 UPGRADE					9,000,000
37	CENTRIFUGE #4 INSTALLATION					2,750,000
38	DIGAS FLEET VEHICLES AND FILLING STATION					5,000,000
39	COMBINED HEAT AND POWER					2,000,000
40	WASTE HEAT RECOVERY BOILERS					500,000
41	EXTENSION OF NEW FINAL EFFLUENT LINE					350,000
42	PROTECTED WATER SECONDARY SAND FILTER SYSTEM					250,000
43	STOCKROOM CAPACITY ASSESSMENT					200,000
	COLLECTION SYSTEM:					
44	HETREL NORTHWEST IN-LINE STORAGE (NORTH SD)	4,096,000				
45	SOUTH BAILEY IN-LINE STORAGE (SCAJAQUADA SD)	1,904,000				
46	FILLMORE NORTH IN-LINE STORAGE (SOUTH CENTRAL SD)	2,016,000				
47	NIAGARA STREET PHASE 4A: SCAJAQUADA EXPRESSWAY TO HERTEL	2,227,500				
48	GREEN INFRASTRUCTURE PHASE 2	12,000,000	12,000,000			
49	CSO 013 SATELLITE STORAGE, CONVEYANCE, FM AND PS	2,500,000				
50	010, 008/010, 061, 004 UNDERFLOW CAPACITY UPSIZING	610,000				

BUFFALO SEWER AUTHORITY
FIVE YEAR CAPITAL PLAN
2021-2022 TO 2025-2026

ITEM	PROJECT TITLE:	BUDGET 2021-22	2022-23	2023-24	2024-25	2025-26
51	SEWER CLEANING, INSPECTION, AND ANALYSIS - PREVENTATIVE			1,500,000		
52	SEWER CLEANING, INSPECTION, AND ANALYSIS - CORRECTIVE			3,000,000		
53	SEWER REPAIR & REPLACEMENT			3,250,000		
54	NO-DIG SEWER REHABILITATIONS		1,500,000			
55	ENGINEERING TERM CONTRACTS		1,000,000	1,000,000	1,000,000	
56	MISCELLANEOUS SEWER REPAIRS/UNANTICIPATED SEWER REPLACEMENTS		3,000,000			3,000,000
57	ALLEN STREET PHASE 2	600,000				
58	GREEN INFRASTRUCTURE PHASE 3			14,000,000	14,000,000	14,000,000
59	NORTH RELIEF INTERCEPTOR		6,500,000	25,000,000	32,000,000	
60	SCAJAQUADA DISTRICT RTC		3,000,000			
61	NORTH DISTRICT RTC			3,000,000		
62	SOUTH CENTRAL DISTRICT RTC	2,000,000		2,000,000		
		77,353,500	**93,800,000**	**66,700,000**	**61,950,000**	**96,350,000**
	TOTAL	**396,153,500**				

BUFFALO SEWER AUTHORITY
DEBT SERVICE SCHEDULE
2021 - 2022 BUDGET

BOND YEAR ENDING JUNE 30	PRINCIPAL	INTEREST	TOTAL DEBT SERVICE
2022	$ 2,076,649	$ 1,520,338	3,596,987
2023	$ 2,130,298	$ 1,439,324	3,569,622
2024	$ 2,178,948	$ 1,354,903	3,533,851
2025	$ 2,237,597	$ 1,267,328	3,504,925
2026	$ 2,296,231	$ 1,175,765	3,471,996
2027	$ 2,364,895	$ 1,080,361	3,445,256
2028	$ 2,418,544	$ 981,121	3,399,665
2029	$ 2,492,193	$ 878,840	3,371,033
2030	$ 2,560,842	$ 772,543	3,333,385
2031	$ 2,624,491	$ 662,491	3,286,982
2032	$ 4,704,704	$ 549,178	5,253,882
2033	$ 1,595,933	$ 333,389	1,929,322
2034	$ 1,468,565	$ 256,843	1,725,408
2035	$ 924,088	$ 215,523	1,139,611
2036	$ 1,644,618	$ 168,218	1,812,836
2037	$ 556,386	$ 129,915	686,301
2038	$ 565,035	$ 117,727	682,762
2039	$ 568,684	$ 104,930	673,614
2040	$ 582,333	$ 92,933	675,266
2041	$ 590,983	$ 79,841	670,824
2042	$ 599,632	$ 66,534	666,166
2043	$ 603,281	$ 53,012	656,293
2044	$ 1,211,930	$ 39,491	1,251,421
2045	$ 295,579	$ -	295,579
2046	$ 299,228	$ -	299,228
2047	$ 302,877	$ -	302,877
2048	$ 306,526	$ -	306,526
2049	$ 310,175	$ -	310,175
2050	$ 313,825	$ -	313,825
2051	$ 317,474	$ -	317,474
Total	41,142,544	13,340,546	52,337,406

ATTACHMENT A

FINAL SCHEDULE OF SEWER RENTS

AND OTHER CHARGES

FOR 2021 - 2022

TO PROVIDE FUNDS FOR THE FIXED CHARGES AND FOR THE OPERATION AND MAINTENANCE OF THE ENTIRE SEWER SYSTEM IN THE CITY OF BUFFALO AND ALL OF THE BUFFALO SEWER AUTHORITY FACILITIES FOR THE CONVEYANCE, TREATMENT AND DISPOSAL OF SEWAGE AND STORM WATER OPERATED BY THE BUFFALO SEWER AUTHORITY.

I. SEWER RENTS FOR PREMISES SITUATED WITHIN THE LIMITS OF THE CITY OF BUFFALO

(a) $12,050,000 shall be collected from all real property in the City of Buffalo (the "City") by apportioning the said amount upon such property within the City as the same is set down on the last completed annual assessment roll of the City, except that no *ad valorem* sewer rent shall be assessed against real property exempt from real property taxes pursuant to subdivision one of section four hundred, sections four hundred four, four hundred six, four hundred twelve, four hundred eighteen, subdivision one section four hundred twenty, section four hundred forty-six, four hundred fifty-two, four hundred sixty-two and four hundred seventy-seven of the New York Real Property Tax Law.

(b) In the event a person, lot, parcel of land, building or premises, other than a City department, situated within the limits of the City, discharging sewage, water or other liquids into the Buffalo Sewer Authority (the "Authority") sewer system, either directly or indirectly, is a user of water supplied by the Buffalo Water Board or from any other source, and the quantity of water used is measured by a water meter acceptable to the Authority, then in each such case, the quantity of water used, as measured by said meter, shall be used to determine the sewer charge or rental, and the charge for such use shall be as follows:

1. $48.30 for 0 to 4,000 cubic feet of water used per quarter year, if the meter is read quarterly, and any water used in excess thereof shall bear a sewer charge or rental of $11.09 per thousand cubic feet ($.0111 per cubic foot).

2. $16.10 for 0 to 1,333 cubic feet of water used per month, if the meter is read monthly, and any water used in excess thereof shall bear a sewer charge or rental of $11.09 per thousand cubic feet ($.0111 per cubic foot).

II. SEWER RENTS FOR PREMISES SITUATED OUTSIDE THE LIMITS OF THE CITY OF BUFFALO

(a) An annual service charge for the privilege of connecting with the facilities of the Authority shall be due for any premises situated outside the limits of the City for each $1,000 of assessed valuation as determined on the last completed annual assessment, the same rate of $2.71239 per $1,000 of assessed valuation for 2021-2022.

(b) In the event a person, lot, parcel of land, building or premises, other than a City department, situated outside the limits of the City, discharging sewage, water or other liquids into the Authority sewer system, either directly or indirectly, is a user of water supplied by the Buffalo Water Board or from any other source, and the quantity of water used is measured by a water meter acceptable to the Authority, then in each such case, the quantity of water used, as measured by said meter, shall be used to determine the sewer charge or rental, and the charge for such use shall be as follows:

1. $48.30 for 0 to 4,000 cubic feet of water used per quarter year, if the meter is read quarterly, and any water used in excess thereof shall bear a sewer charge or rental of $11.09 per thousand cubic feet ($.0111 per cubic foot).

2. $16.10 for 0 to 1,333 cubic feet of water used per month, if the meter is read monthly, and any water used in excess thereof shall bear a sewer charge or rental of $11.09 per thousand cubic feet ($.0111 per cubic foot).

III. GENERAL PROVISIONS

(a) In the event a person, lot, parcel of land, building or premises discharging sewage, water or other liquids into the Authority sewer system, either directly or indirectly, is a user of water supplied by the Buffalo Water Board, and the quantity of water used is not measured by a water meter acceptable to the Authority, then the sewer charge or rental for all such accounts shall be in the respective amounts (expressed in dollars) set forth in Exhibit A, attached hereto and made a part hereof, as the Authority determines applicable to such person, lot, parcel of land, building or premises.

(b) In addition to all other rentals and charges provided herein, a monthly drainage connection service charge shall be due for any and all persons, lots, parcels of land, building or premises, other than a City department, that discharge sewage, water or other liquids into the Authority sewer system, either directly or indirectly, as follows:

1. A monthly charge of $6.00 shall be due for all lots, parcels, land, buildings or premises where the quantity of water used is not measured by a meter acceptable to the Authority.

2. A monthly charge in the amounts set forth below shall be due for all lots, parcels, land, building or premises where the quantity of water used

is measured by a meter acceptable to the Authority in accordance with the following meter size:

Residential Users		Non-Residential Users	
Meter Size	Charge ($)	Meter Size	Charge ($)
5/8 inch	6.00	5/8 inch	6.00
3/4 inch	6.00	3/4 inch	6.00
1 inch	6.00	1 inch	6.00
1 1/2 inch	6.00	1 1/2 inch	55.00
2 inch	6.00	2 inch	55.00
3 inch	55.00	3 inch	55.00
4 inch or larger	55.00	4 inch or larger	55.00

(c) In the event a person, lot, parcel of land, building or premises discharging sewage, water or other liquids into the Authority sewer system, which directly or indirectly, uses water obtained from a source other than the Buffalo Water Board, and the water so obtained is not measured by a water meter acceptable to the Authority, then, in each such case, the owner, user or other interested party shall, at his own expense, furnish, install, and maintain a water meter or other water or sewage measuring device acceptable to the Authority and the quantity of water used, as measured by said meter, or as otherwise determined, shall be used to determine the sewer charge or rental and there shall be charged an amount determined as set forth in paragraphs II(a), III(a) and III(b) as the case may be.

(d) In the event a person, lot, parcel of land, building or premises discharging sewage, water or other liquids into the Authority sewer system, either directly or indirectly, uses water in excess of 4,000 cubic feet per quarter year and it can be shown to the satisfaction of the Authority, that a portion of the water as measured by the water meter does not and cannot enter the Authority sewer system, then the Authority may determine in such manner as may be found practicable the percentage of metered water entering the Authority sewer system and the quantity of water used to determine the sewer charge or rental shall be that percentage, so determined, of the quantity of water measured by the water meter, or the Authority may require or permit the installation of additional meters or measuring devices in such a manner as to determine the quantity of water or sewage actually entering the Authority sewer system, in which case the quantity of water used to determine the sewer charge or rental shall be the quantity of water actually entering the Authority sewer system and so determined.

(e) In the event a person, lot, parcel of land, building or premises discharges sewage or other wastes into the Authority sewer system which, in the opinion of the Authority, contain unduly high concentrations or any substances which add to the operating costs of the Authority facilities, then the Authority may elect to establish and collect special rates of charge, based on the quantity of these substances, which rate of charge may be established and collected in such manner as the Authority may elect and such charge shall be paid to the Authority, or it may elect to exclude such sewage or other wastes from its facilities.

(f) As a condition of a Buffalo Discharge Elimination System Permit (BPDES), a user may be required to pay an industrial waste surcharge for discharging sewage or waste exhibiting a strength of sewage or waste greater than normal domestic sewage. The Industrial Waste Surcharge Formula reflecting the Treatment Plant unit costs for treatment of Biochemical Oxygen Demand (BOD_5) Total Suspended Solids (TSS) and Total Phosphate (TPO_4) is as follows:

Surcharge = 8.34 QMGY (0.1855 (BOD_5-250) + 0.2079 (TSS-250) + 0.0203 (TPO_4-15.35))

$0.1855 Cost/lb. for treatment of BOD_5
$0.2079 Cost/lb. for treatment of TSS
$0.0203 Cost/lb. for treatment of TPO_4

QMGY shall mean the annual total industrial and sanitary discharge - water retention.
BOD_5 shall mean the average concentration of BOD_5 in sewage or waste discharged to the Authority facilities.
TSS shall mean the average concentration of TSS in sewage or waste discharged to the Authority facilities.
TPO_4 shall mean the average concentration of TPO_4 in sewage or waste discharged to the Authority facilities.

Surchargeable concentrations are as follows:

BOD_5 - Over 250 mg/L; TSS - Over 250 mg/L; TPO_4 - Over 15.35 mg/L

This formula shall be applied in computing the Buffalo Industrial Waste Surcharge subsequent to July 1, 2020 and ending June 30, 2021 for all users that discharge sewage or waste exhibiting a strength of sewage or waste greater than normal domestic sewage. In addition, this formula with the above rates will be used to calculate all monthly, quarterly, semiannual, and annual accounts subsequent to July 1, 2021.

(g) Any person who violates the Sewer Regulations of the Authority or the conditions of the permits issued thereunder shall be subject to fines as specified in said regulations.

(h) Whenever sewage or other wastes result in conditions in the Authority sewer system as to cause blockage or a substantial reduction in the flow, charges for the work necessary to eliminate such blockage or reduction in flow may be made, based upon costs incurred by the Authority for labor, materials, equipment hire, insurances, and other overhead, against the owner of the property or premises that caused the discharge of such sewage or other wastes into the Authority sewer system.

(i) Where sewer facilities have been installed to serve improved and unimproved property and have been paid for in whole or in part by the Authority, a charge shall be made based on a proportionate share of the original cost, determined by the foot frontage of the parcel served, or by the area of such parcels, or by such other method the Authority determines to be equitable, as a condition to a permit for a connection to the Authority's facilities.

(j) An application and inspection fee for sewer connection permits shall be paid as follows at the time said application is filed with the Authority:

Tap Size	Fee ($)
4 inch	100.00
6 inch	200.00
8 inch	300.00
10 inch	500.00
12 inch	800.00
15 inch	1,200.00
18 inch	1,800.00
21 inch or greater	2,500.00

(k) An application fee of $50.00 per 2,500 square feet or part thereof of soil disturbance or impervious area being drained, whichever is greater, shall be paid at time of plans and/or calculations are submitted to the Authority for site stormwater management review.

(l) An application fee of $150.00 plus $25.00 for every 100 linear feet or part thereof of new sanitary sewer pipe proposed shall be paid at the time that plans and/or calculations are submitted to the Authority for any facility proposing to discharge 2,500 gallons per day or more of additional sanitary and/or industrial flow than existing conditions.

(m) All persons owning or operating a pump truck or other transport vehicle and desiring to discharge wastes, directly or indirectly, into the Authority's facilities shall first secure a valid Truckers Discharge Permit after paying an annual permit fee of $120.00. In addition to said permit fee, a separate charge shall be billed based upon the verified quantity or truck capacity, and character of the waste discharged and, if applicable, the point of discharge.

The following surcharge rates are hereby charged for such wastehaulers who are located outside the City:

DISCHARGE LOCATION	TOTAL SUSPENDED SOLIDS	BOD_5	TOTAL PHOSPHATE
Inlet/South Buffalo Pump	$0.1969 /lb	$0.1748 /lb.	$0.0271 /lb.
Mixing Tank	$0.1626 /lb	$0.0998 /lb.	$0.0271 /lb.
Thickener/Digester	$0.1749 /lb	$0.1065 /lb.	$0.0271 /lb.

The above surcharge rates, along with costs incurred by the Authority when handling, testing, conveying, and administering each wastehauler, will be used to determine the cost per gallon of each wastestream. The wastehauler user charges for various wastestreams are as follows:

1. Septage and portable toilet wastes - The rate of $0.04 per gallon discharged will be assigned to all permitted septage and portable toilet wastehaulers.
2. Grease trap wastes - The rate of $0.05 per gallon discharged will be assigned to all permitted grease trap wastehaulers.
3. Sludge wastes - This rate will vary dependent on strength and volume. Sludge rates will be calculated using the parameter costs for the mixing tank location.
4. Miscellaneous Wastes - This rate will vary dependent on strength of waste, volume and discharge location.

These rates will be used for all permits effective July 1, 2021.

(n) In the event a person, lot, parcel of land, building or premises threatens to discharge or discharges sewage or waste into or near the Authority's publicly owned treatment works, either directly or indirectly, which in the opinion of the Authority will or is likely to bypass, upset, harm or endanger the facilities of the Authority, then such person or the owner or operator of such lot, parcel of land, building or premises shall pay to the Authority charges for any and all clean up, removal and remediation costs actually incurred by the Authority, including but not limited to labor, materials, equipment, insurances or laboratory services for the (i) containment or attempted containment of such discharge or threatened discharge, (ii) sampling and analysis of such discharge or threatened discharge, (iii) removal or attempted removal of such discharge or threatened discharge, (iv) taking of reasonable measures to prevent or mitigate damage to property, public health, safety or welfare, or (v) remediation, treatment, storage or disposal of such discharge or threatened discharge and all soils, water or structures affected by such discharge.

(o) All industrial users and wastehaulers shall pay to the Authority a charge for the actual costs of analysis incurred by the Authority for monitoring of any and all discharges of such users.

(p) Any person who is granted a temporary permit to discharge into the facilities of the Authority shall pay a permit fee of $800.00 to the Authority as a condition of the issuance of such permit.

(q) Except as otherwise defined herein, all terms and phrases used or contained in this schedule of sewer rents shall bear the same meaning and definition as set forth in the Authority's Sewer Use Regulations 21 N.Y.C.R.R. Part 10075 and New York Public Authorities Law Section 1175 *et seq*.

(r) Sewer rents and charges as herein provided shall be payable at the office of the Director of the Treasury for the City at Room 117, City Hall, Buffalo, New York 14202, or at such other location or address as may be set forth on the Authority's invoice, and shall become due and payable as follows:

1. So much of the sewer rents and charges as are based upon water use and the drainage connection service charge covering the respective premises, or such other charges as provided herein shall be due and payable, except as otherwise stated in this schedule or in such invoice, on the same day, one month following the month of the invoice billing date, and such invoice may be billed monthly, quarterly or as otherwise determined by the Authority; and

2. So much of the sewer rents and charges as are based upon the assessed valuation of chargeable real estate shall become due and payable from the first day of July 1938, and each year thereafter, and may be paid without interest on or before September 30th next succeeding.

(s) Such sewer rents and charges that remain unpaid after their respective due dates shall be charged interest, and such interest shall continue to be charged until such sewer rents and charges are paid in full, as follows:

1. Sewer rents based upon water use and drainage connection service charges shall be charged interest at the same rate as unpaid City taxes, to wit: four and one-half percent (4.5%) interest shall be added to amounts unpaid from the first through the thirtieth day after the due date, and thereafter one and one-half percent (1.5%) shall be added to all amounts that remain unpaid for each succeeding month;

2. Sewer rents based upon assessed valuation of chargeable real estate that remain unpaid on October 1 of each year shall be charged interest at the rate of two percent (2%), and such sewer rents that remain unpaid shall be charged two percent (2%) for each month thereafter until paid; and

3. All other sewer rents and charges of the Authority shall be charged interest at the rate of one and one-half percent (1.5%) per month if not paid by the due date stated on the invoice issued by the Authority.

(t) All persons and property served by the Authority shall be subject to paying reasonable costs and expenses, including attorney fees incurred in the collection of sewer rents and charges that remain unpaid, as may be determined by the Board of the Authority. In addition to any other remedy or provision hereof, the Authority reserves the right to engage in such collection activities, as it deems appropriate, for all accounts that remain unpaid after the due date. In consideration of such collection activities and to defray the cost thereof with respect to accounts based on water use and drainage connection service, the person or property served by the Authority may pay an additional charge of twenty-one percent (21%) of the amount of each such delinquent account, together with interest as provided herein, that remains unpaid for more than (i) one hundred twenty (120) days from the due date for metered accounts, and (ii) two hundred ten (210) days from the due date for non-metered flat rate accounts. Due date, as used herein, means the date that the Authority's sewer rent and other charges are due and payable pursuant to III (q) (1) and III (q) (2), herein, respectively.

(u) Invoice statements shall be mailed or delivered to the address of the owner or user, as the case may be, as such address appears on the Authority's records. Such mailing or delivery is a matter of convenience. Failure of an owner or user to receive an invoice statement shall not release such owner or user from the obligation to pay such invoice statement, together with any other charges and interest which may accrue on unpaid amounts.

(v) All invoices shall be paid in United States dollars and may be paid by cash, check or credit card at Room 117, City Hall, Buffalo, New York or such other location or address as may be provided on such invoice, by internet, or by telephone as set forth on the invoice. All persons who pay through the City of Buffalo Website or by telephone shall pay any processing fees charged by the City of Buffalo. Multiple payments in the same transaction will be charged the convenience fee only once. The convenience fee will be added automatically to each transaction.

IV. LIEN OF SEWER RENT

From and after the due date thereof, such sewer rents and charges, together with any interest and collection costs shall constitute a lien upon the real property served by the facilities. Such lien shall have the same priority and superiority as the lien of the general tax of the City.

V. EFFECTIVE DATE OF THIS SCHEDULE

This schedule of sewer rents and other charges shall become effective July 1, 2021; provided, however, that the sewer rents and other charges herein set forth, applicable to water use, shall become effective on all billings on and after August 1, 2021, excepting only monthly metered accounts for July 2021, and Section "W" of the quarterly metered accounts for the period May, June, and July 2021, which shall be billed according to the schedule of rents in effect prior to July 1, 2021.

Exhibit A

Stories High:	1	1 ½	2	2 ½	3	4	5
Under 25 ft	21.65	24.38	29.76	35.17	37.84	40.57	45.97
From 25 ft to 30 ft	24.38	29.76	35.17	37.84	40.57	45.97	51.35
From 31 ft to 35 ft	29.76	35.17	37.84	40.57	45.97	51.35	56.74
From 36 ft to 40 ft	35.17	37.84	40.57	45.97	51.35	56.74	59.44
From 41 ft to 45 ft	37.84	40.57	45.97	51.35	56.74	59.44	62.12
From 46 ft to 50 ft	40.57	45.97	51.35	56.74	59.44	62.12	67.56

The Following Rates Apply To More Than One Family Homes or Housekeeping:

1 Family	21.65
2 Families	43.29
3 Families	64.94
4 Families	86.58
5 Families	108.03
6 Families	129.87

Bathtubs & Showers *Bathtubs with attached showers are charged for only bathtubs

1 Bathtub	5.45
2 Bathtubs	10.91
3 Bathtubs	16.36
4 Bathtubs	21.81
5 Bathtubs	27.27
6 Bathtubs	32.72
7 Bathtubs	38.17
8 Bathtubs	43.63
9 Bathtubs	49.08

Toilets:	1 Family	2 Family	3 Family	4 Family	5 Family	6 Family
1 Toilet	10.86					
2 Toilets	19.15	21.73				
3 Toilets	27.43	30.01	32.59			
4 Toilets	35.72	38.30	40.88	43.46		
5 Toilets	44.00	46.58	49.16	51.74	54.32	
6 Toilets	52.29	54.87	57.45	60.03	62.61	65.19
7 Toilets	60.57	63.15	65.73	68.31	70.89	73.47
8 Toilets	68.86	71.44	74.02	76.60	79.18	81.76
9 Toilets	77.14	79.72	82.30	84.88	87.46	90.04
Each Additional Toilet	8.28					

Boarder or Roomer

1	4.13
2	8.26
3	12.38
4	16.51

Office with Water:	21.65	Office without Water:	10.86

Hot Water Heating Billed in November & February:

1	10.84
2	21.67
3	32.51
4	43.35
5	54.18
6	65.02
7	75.86
8	86.69

Car in Garage:	Garage w/out Water	Garage w/Water
1 Car	10.84	21.66
2 Cars	21.67	43.32
3 Cars	32.51	64.98
4 Cars	43.35	86.69
5 Cars	54.18	108.30
6 Cars	65.02	129.96
7 Cars	75.86	151.62
8 Cars	86.69	173.28

APPENDIX E

Boiler and Steam System Improvements Capital Expense Estimate

APPENDIX E
BSA WWTP Boiler and Steam System Improvements Capital Expense Estimate

SCOPE OF WORK	QTY.	UNIT	MATERIAL Unit Rate	MATERIAL Amount	LABOR/EQUIPMENT Unit Rate	LABOR/EQUIPMENT Amount	TOTAL AMOUNT
Division 1 Work - 11% of Subtotal	1	LS					$ 244,000
Division 1 Subtotal							**$ 244,000**
Division 2 - Civil/ Sitework							
Demolition and removal of existing equipment	1	LS	$ 40,000				$ 40,000
Civil Subtotal							**$ 40,000**
Structural Subtotal							**$ -**
Architectural Subtotal							**$ -**
Mechanical							
Retubing of WHB	2	EA	$ 370,000				$ 740,000
Soot blowers (4 units per package)	2	LS	$ 28,319	$ 57,000	$ 8,496	$ 16,991	$ 73,991
Control package for soot blowers	2	EA	$ 13,624	$ 27,000	$ 4,087	$ 8,174	$ 35,174
Dampers (guillotine) - 2 per boiler	4	EA	$ 41,846	$ 167,000	$ 16,739	$ 67,000	$ 234,000
Dampers (control louver) - 2 per boiler	4	EA	$ 41,846	$ 167,000	$ 16,739	$ 67,000	$ 234,000
Expansion Joints - 1 per damper	8	EA	$ 9,600	$ 77,000	$ 3,840	$ 31,000	$ 108,000
Continuous Blowdown Heat Recovery Unit	1	EA	$ 12,381	$ 12,000	$ 3,714	$ 4,000	$ 16,000
Intermittent Blowdown Tank	1	EA	$ 29,354	$ 29,000	$ 8,806	$ 9,000	$ 38,000
Boiler trim valves	1	LS	$ 75,000				$ 75,000
Feedwater piping adjustments	1	LS	$ 75,000				$ 75,000
Handrails/ ladders/ insulation upgrades	1	LS	$ 75,000				$ 75,000
Auxiliary Boiler Burner Replacement	1	LS	$ 50,000				$ 50,000
Steam traps replacement	1	LS	$ 40,000				$ 40,000
General steam piping upgrades	1	LS	$ 20,000				$ 20,000
Mechanical Subtotal							**$ 1,814,000**
Electrical and I&C							
Electrical - % of Mechanical Subtotal	10%						$ 181,000
I&C - % of Mechanical Subtotal	10%						$ 181,000
Electrical and I&C Subtotal							**$ 362,000**
CONSTRUCTION COST - SUB TOTAL							$ 2,460,000
GENERAL CONTINGENCIES				30%			$ 738,000
TAXES+BOND+INSURANCE				5%			$ 123,000
CONTRACTOR OVERHEAD & Profit				15%			$ 369,000
ENGINEERING FEE				9%			$ 221,000
TOTAL CONSTRUCTION COSTS							**$ 3,911,000**

APPENDIX F

NYSERDA FlexTech Study

February 2013

DRAFT FLEXTECH STUDY

Buffalo Sewer Authority
65 Niagara Square
Buffalo, NY 14202

Bird Island WWTP
Incinerator Heat Recovery and Energy Flow Modeling

New York State Energy Research and Development Authority
17 Columbia Circle
Albany, New York 12203-6399

For questions regarding this report or other programs offered by NYSERDA, please contact Mark Decker at 866-697-3732 extension 3494 or by email at md3@nyserda.org.

We hope the findings of this report will assist you in making decisions about energy efficiency improvements in your facility. Thank you for your participation in this program.

List of Tables

List of Figures

Conceptual Design Figures 1-5 appear at the end of Section 3

Appendices

1. Executive Summary

The Buffalo Sewer Authority (BSA) owns and operates the Bird Island Wastewater Treatment Plant (WWTP), which treats average wastewater flows of 180 million gallons per day. BSA is currently upgrading their solids handling facilities in an effort to regionalize by accepting solids from neighboring communities for disposal in their incinerators. BSA recognizes that these solids, as well as influent solids entering the Bird Island WWTP, have a significant energy content that can be harvested as green energy. The purpose of this study is to analyze the energy flows at the Bird Island WWTP and develop a strategy for processing solids that optimizes energy efficiency and financial benefit from energy recovery. Additionally the study will evaluate the feasibility of installing a heat recovery and cogeneration system to utilize the energy available in the incinerator exhaust.

This study consists of the following components:

- Data Analysis and Current Energy Flows
- Feasibility of Incinerator Heat Recovery and Steam Turbine Cogeneration
- Energy Flow Modeling of Bird Island WWTP
- Summary and Recommendations

The major analyses and findings for each of these components are presented in the sections of this report. Detailed calculations and supporting documentation are provided in the report appendices.

Data Analysis and Current Energy Flows

This section examined two years of plant process and utility data from 2010 and 2011 to form a basis for analyzing current energy utilization at the Bird Island WWTP. Some of the items developed under this system include a mass and energy balance of the current solids handling system. Energy utilization data for the entire plant was analyzed to estimate electrical demands, incineration demands, digester heating demands and various building heating demands. The purpose of this section is to develop a set of operating parameters for each process which are used to evaluate energy utilization scenarios in subsequent sections.

Table 1-1 gives some annual average values resulting from the mass balance analysis.

Table 1-1. Results from Mass Balance Analysis

Item	Value		Item	Value	
Digester Feed Solids	66.2	dry tons per day	Incinerator Feed Solids	32.2	dry tons per day
Digester Feed % Volatile Solids	69.7	%	Incinerator Feed % Total Solids	25.3	%
Volatile Solids Reduction (VSR)	50.8	%	Incinerator Feed % Volatile Solids	52.4	%
Biogas Production	478	Mcf/day			

Table 1-2 gives average values resulting from the energy balance analysis. The results are presented as seasonal periods with 'summer' representing the average of the 6-month period from May to October and 'winter' representing the average of the 6-month period from November to April.

Table 1-2. Results from Energy Balance Analysis

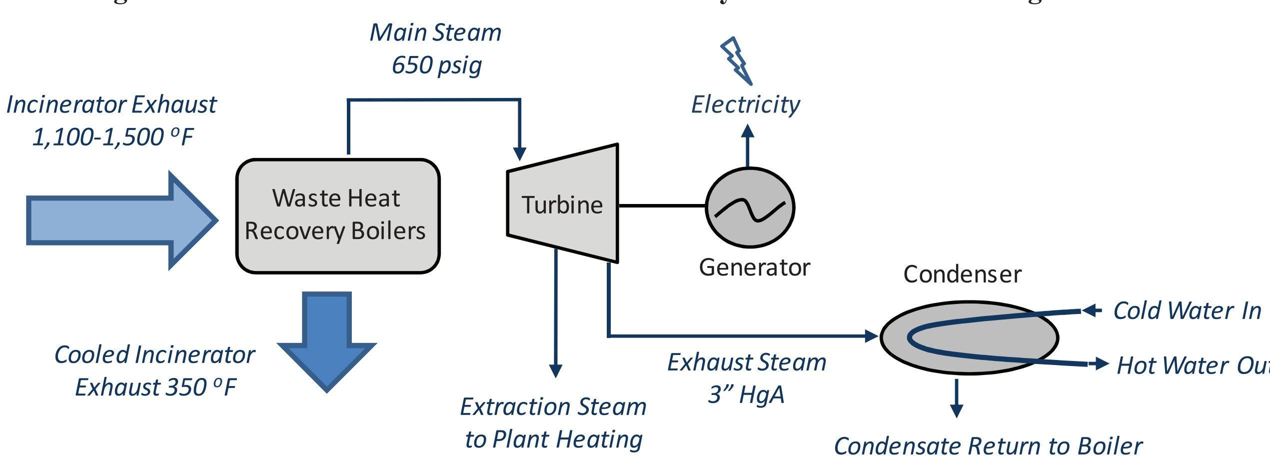
Item	Value	
	Summer	Winter
Total Plant Natural Gas Purchase	14.6 mmBtu/hr	25.0 mmBtu/hr
Natural Gas used for Plant Heating	8.5 mmBtu/hr	18.2 mmBtu/hr
Natural Gas used for Incineration	5.8 mmBtu/hr	7.2 mmBtu/hr
Biogas used for Incineration	12.4 mmBtu/hr	13.2 mmBtu/hr
Incinerator energy used per wet ton	3.5 mmBtu/wt	3.5 mmBtu/wt
Total Plant Electric Purchase	7.0 MW	7.5 MW

During the two years examined (2010 and 2011), Bird Island has consumed on average 64,000 megawatt-hours (MWh) per year of electricity at a delivered cost of approximately \$5.5 million annually with a typical plant demand ranging between 6 and 9 MW. An average of 175,000 thousand cubic feet (Mcf) per year of natural gas is consumed at a delivered cost of approximately \$1.4 million annually. The natural gas energy consumption rate ranges seasonally from 10 to 40 mmBtu/hr.

Feasibility of Incinerator Heat Recovery and Steam Turbine Generation

A significant amount of energy can be harvested from incinerator exhaust gases at the Bird Island WWTP. As the plant regionalizes and expands its incineration program, the amount of energy to be recovered will expand as well. The proposed system aims to harness exhaust energy and is composed of a waste heat recovery boiler (WHRB) system driven by incinerator exhaust followed by an extraction steam turbine generator which converts steam into electricity while also providing steam for process heating. A simplified schematic of the proposed system is given in Figure 1-1.

Figure 1-1. Schematic of Incinerator Heat Recovery and Steam Turbine Cogeneration



This section describes the components of the proposed system, develops operating parameters, determines conceptual level costs, and estimates the performance of the system. The result of this section is an economic and feasibility analysis of the proposed system to determine whether incinerator heat recovery and steam turbine cogeneration is a viable opportunity for BSA.

The analysis of the proposed incinerator heat recovery and steam turbine cogeneration system showed that the proposed infrastructure improvements could be feasibly constructed and operated at the Bird Island WWTP without any major constraints. The estimated system would produce an average of approximately 1.75 MW of electricity annually while also providing steam heating for the entire plant throughout the year. The system was also found to be economically viable with a simple payback period of 8.2 years. The economic analysis for the proposed system is summarized in Table 1-3 below.

Table 1-3. Summary of Economic Analysis for the Proposed System

Item	Value
Net Electrical Savings	$1,237,000 / year
Additional O&M cost	$56,000 / year
Additional Natural Gas Cost	$293,000 / year
Net Annual Savings	$888,000 / year
Capital Cost	$7,290,000
Simple Payback Period	8.2 years

Potential funding opportunities administered by The New York State Energy Research and Development Authority (NYSERDA) were investigated for the proposed system. The potential incentive that could be procured was estimated to be approximately $1 million which would drive the estimated payback period down by approximately 1 year.

Energy Flow Modeling of Bird Island WWTP

Energy flows through a WWTP in a variety of forms which include the heating value of solids, chemical energy in biogas and natural gas, hot exhaust gases, steam, hot water, and electricity. There are complex decisions to be made on not only how much energy to route to plant processes, but also what form that energy should take. In this section, an ‘Energy Flow Model’ tool was developed for the Bird Island WWTP. This is an interactive tool that tracks and quantifies the amount of energy flowing through the plant. The user of the Energy Flow Model has an option to adjust operational variables that change how energy is routed throughout the plant. By modifying variables, the user can create a set of scenarios that can be compared against one-another easily and quantitatively. The outputs of the model are annual cost savings, green house gas (GHG) reductions and energy efficiency.

In this section the Energy Flow Model developed for the Bird Island WWTP is described. A set of scenarios was developed with input from BSA staff and analyzed using the tool. Some examples of decisions that can be addressed using this tool include:

Is it better to send undigested solids to incinerators or digesters?

Is it beneficial to augment the Steam Turbine with energy from natural gas?

What would be the energy benefit from accepting additional import sludge?

The detailed descriptions of the modeled scenarios and results are presented in this section. Analysis of the model results was used to recommend an optimized overall strategy for utilizing energy at the plant. Some of the major recommendations are listed below:

- The initial expected Import sludge loading condition is 10.9 dtpd. With the proposed system implemented, the annual cost savings was estimated to be $290K-$360K per year which includes payments for capital cost. The GHG reduction was estimated to be between 6,400 and 8,800 MT eCO_2 per year which is equivalent to removing 1,250 to 1,700 cars from the road.

- Sending PS or WAS generated at the plant to incineration does not appear to be economically favorable. There did not appear to be a significant energy difference between sending Import sludge to digesters or directly to incineration. This solids handling decision could be made based on ease of operations.

- Under the current energy prices of $0.085/kWh for electricity and $5/mmBtu for natural gas, it would not be economically favorable to purchase additional natural gas to maximize electrical production. BSA could remain flexible in its operations by ramping up electrical production if electricity prices rise, if natural gas prices fall or during peak periods for electric rates.

- 26 dtpd of additional Import sludge could be accepted directly to incinerators while only keeping one incinerator in service. The energy based cost savings in this instance would improve to $380K-$500K per year depending on the heat value of import sludge.

- Electrical production from the proposed system could be increased by beneficially utilizing hot water exiting the condenser. The most feasible and economically favorable option for utilizing condenser water appears to be heating digesters.

Summary and Recommendations

This section summarizes the main conclusions and performance estimations resulting from the previous sections. Recommended next steps are provided to optimize energy utilization practices for BSA at the Bird Island WWTP.

The proposed incinerator heat recovery and steam turbine cogeneration system is recommended for implementation at Bird Island WWTP. BSA should look to accept additional import sludge from outlying communities to increase the revenue potential of this energy recovery system. BSA should remain flexible in its solids handling strategy by deciding where to route import sludge based on ease of operations. BSA should also remain flexible in relation to electrical generation by ramping up production if electricity prices rise, if natural gas prices fall or during peak periods for electric rates. The model will be submitted to BSA to be used in evaluating any future decisions that may arise regarding solids handling and/or energy utilization.

2. Data Analysis and Current Energy Flows

The most recent two years of available process and utility data was examined for the Bird Island WWTP. This two year or 24 month period started with February 2010 and ended in January 2012. The process data was used to develop a solids handling mass balance analysis. The mass balance was used to characterize the solids entering the digesters, estimate digester performance and characterize the solids feed to the incinerators. The utility data was used to develop a plant energy balance analysis. The energy balance was used to estimate the amount of energy used for incineration, amount of energy used for digester heating, and the amount of energy used for building heat. The amount of electricity consumed at the Bird Island WWTP was also examined in the energy balance.

The results and critical values obtained from the mass and energy balances are presented below. The values obtained from the data were used for subsequent analyses including:

- Developing a baseline condition for economic analysis
- Sizing equipment for the Incinerator Heat Recovery System
- Developing parameters for the Energy Flow Modeling Tool

2.1. Mass Balance

The mass balance analysis started by characterizing the primary sludge (PS) and waste activated sludge (WAS) prior to thickening. Other areas of solids handling that were characterized included thickened sludge to digesters, digested sludge to centrifuges and solids feed to incinerators. Digester gas production data was also analyzed in order to estimate current digester performance.

The data sources and assumptions used in the mass balance are given in Table 2-1.

Table 2-1. Mass Balance Data Sources and Assumptions

Process Flow	Data Source/Assumptions
Primary Sludge	Calculated as [Thickened Sludge – WAS], assumed %Volatile Solids (%VS) = 75%
WAS	Flow, %Total Solids (%TS) and %VS from provided data
Thickened Sludge to Digester	Flow, %TS and %VS from provided data
Digested Sludge	Flow, %TS from centrifuge feed data, %VS from digested sludge data
Incinerator (INC) Feed	Wet tons per day (wtpd), %TS and %VS from provided data
Recycle from Centrifuge	Calculated as [Digested Sludge – INC Feed], assumed %VS = Digested
Import Sludge	Dry tons per day (dtpd) and %VS from provided data
Digester Gas Production	Volumetric gas flow from provided data

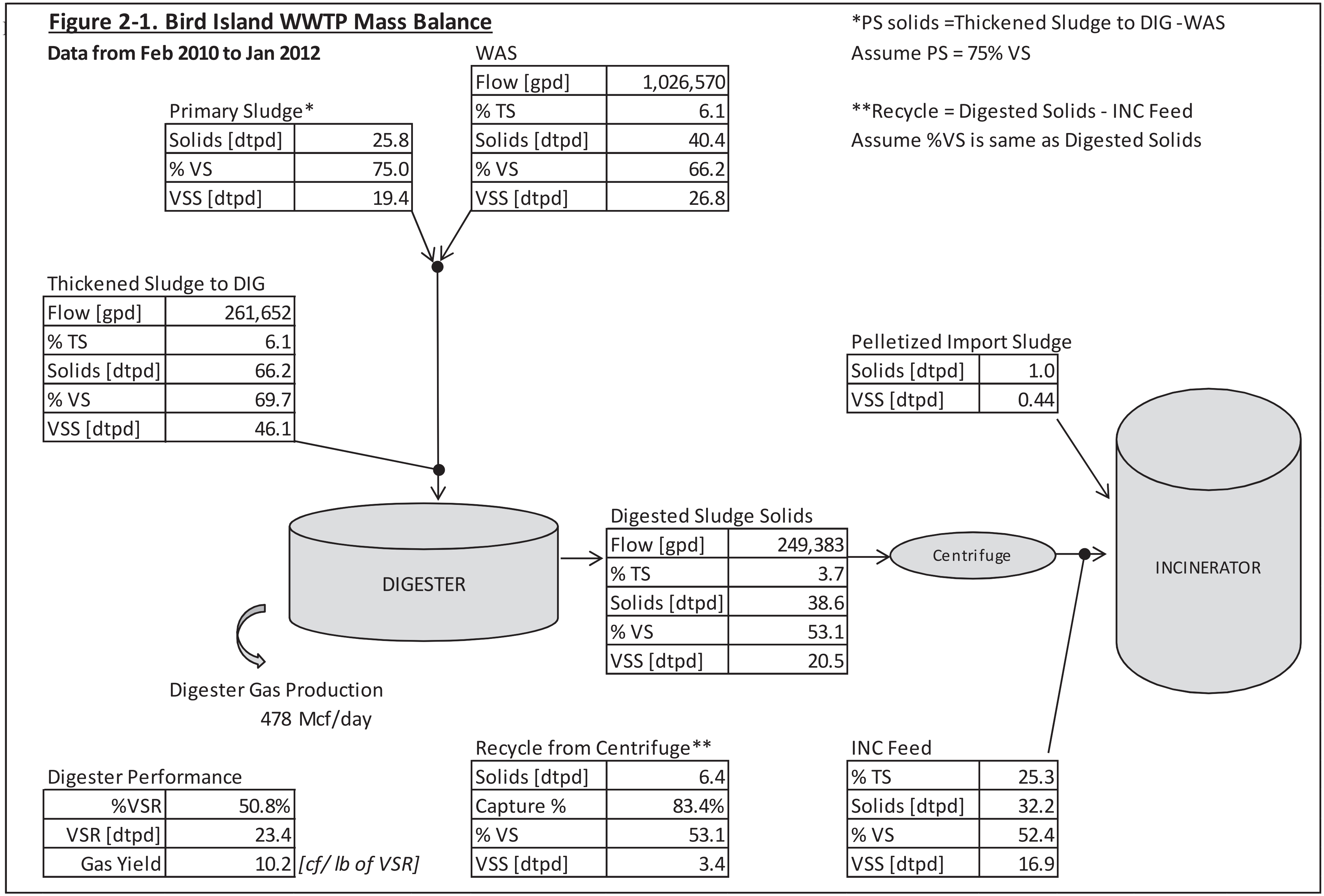
The results from the mass balance analysis are shown on Figure 2-1.

Figure 2-1. Bird Island WWTP Mass Balance

Data from Feb 2010 to Jan 2012

*PS solids =Thickened Sludge to DIG -WAS
Assume PS = 75% VS

**Recycle = Digested Solids - INC Feed
Assume %VS is same as Digested Solids



Primary Sludge*

Solids [dtpd]	25.8
% VS	75.0
VSS [dtpd]	19.4

WAS

Flow [gpd]	1,026,570
% TS	6.1
Solids [dtpd]	40.4
% VS	66.2
VSS [dtpd]	26.8

Thickened Sludge to DIG

Flow [gpd]	261,652
% TS	6.1
Solids [dtpd]	66.2
% VS	69.7
VSS [dtpd]	46.1

Pelletized Import Sludge

Solids [dtpd]	1.0
VSS [dtpd]	0.44

Digested Sludge Solids

Flow [gpd]	249,383
% TS	3.7
Solids [dtpd]	38.6
% VS	53.1
VSS [dtpd]	20.5

Digester Gas Production
478 Mcf/day

Digester Performance

%VSR	50.8%	
VSR [dtpd]	23.4	
Gas Yield	10.2	*[cf/ lb of VSR]*

Recycle from Centrifuge**

Solids [dtpd]	6.4
Capture %	83.4%
% VS	53.1
VSS [dtpd]	3.4

INC Feed

% TS	25.3
Solids [dtpd]	32.2
% VS	52.4
VSS [dtpd]	16.9

The mass balance results from Figure 2-1 are summarized below:

- On average there is significantly more WAS (40.4 dtpd) sent to the digesters than PS (25.8 dtpd).
- The volatile solids reduction (VSR) in the digesters was 50.8% and falls near the typical range of 40-50% for single stage, mesophillic digesters.
- The gas yield in the digesters was 10.2 cf/lb VSR which is lower than the typical range of 12-18 cf/lb VSR.
- The data shows significantly more solids in the centrifuge feed (38.6 dtpd) then in the incinerator feed (32.2 dtpd). This would indicate an 84% solids capture rate in the centrifuges. The difference between the reported feed loads is likely a result of inaccuracies in data measurement. A more typical solids capture rate of 90% will be assumed for centrifuges in subsequent analyses.
- The amount of import sludge fed to the incinerators during the period examined (2010 and 2011) was small at only 1 dtpd on average. This amount has already increased as of this writing, with BSA now receiving Amherst sludge on a daily basis. The estimated amount of Amherst sludge received for subsequent analyses was 10.9 dtpd.

In general, the solids data appears to be balanced within the accuracy limits dictated by grab sampling and methods used to measure %TS and %VS. The data shows that digesters are functioning in an acceptable manner that is in agreement with typically observed performance parameters.

2.2. Energy Balance

An accurate estimation of the energy consumed at the Bird Island WWTP is an important component of determining the size and performance of a proposed incinerator heat recovery and steam turbine cogeneration system. Components of the energy balance included electricity purchased, natural gas purchased, digester gas production, incinerator energy demands, building heating demands, and digester heating demands.

The data sources and assumptions used in the mass balance are presented in Table 2-1.

Table 2-2. Mass Balance Data Sources and Assumptions

Process Flow	Data Source/Assumptions
Electricity	Monthly data from National Grid bills
Natural Gas Purchased	Monthly data from National Fuel bills
Natural Gas to INC	Sub-metered gas flow data provided, converted at 1,000 Btu/cf
Natural Gas to Heating	Sub-metered gas flow data provided, converted at 1,000 Btu/cf
Digester Gas to INC	Assumed all digester gas produced to INC, converted at 640 Btu/cf
Digester Heating Demand	Estimated by heating calculation based on sludge flows and temperature
Building Heating Demands	Calculated as [Natural Gas to Heating – Digester Heating Demand]

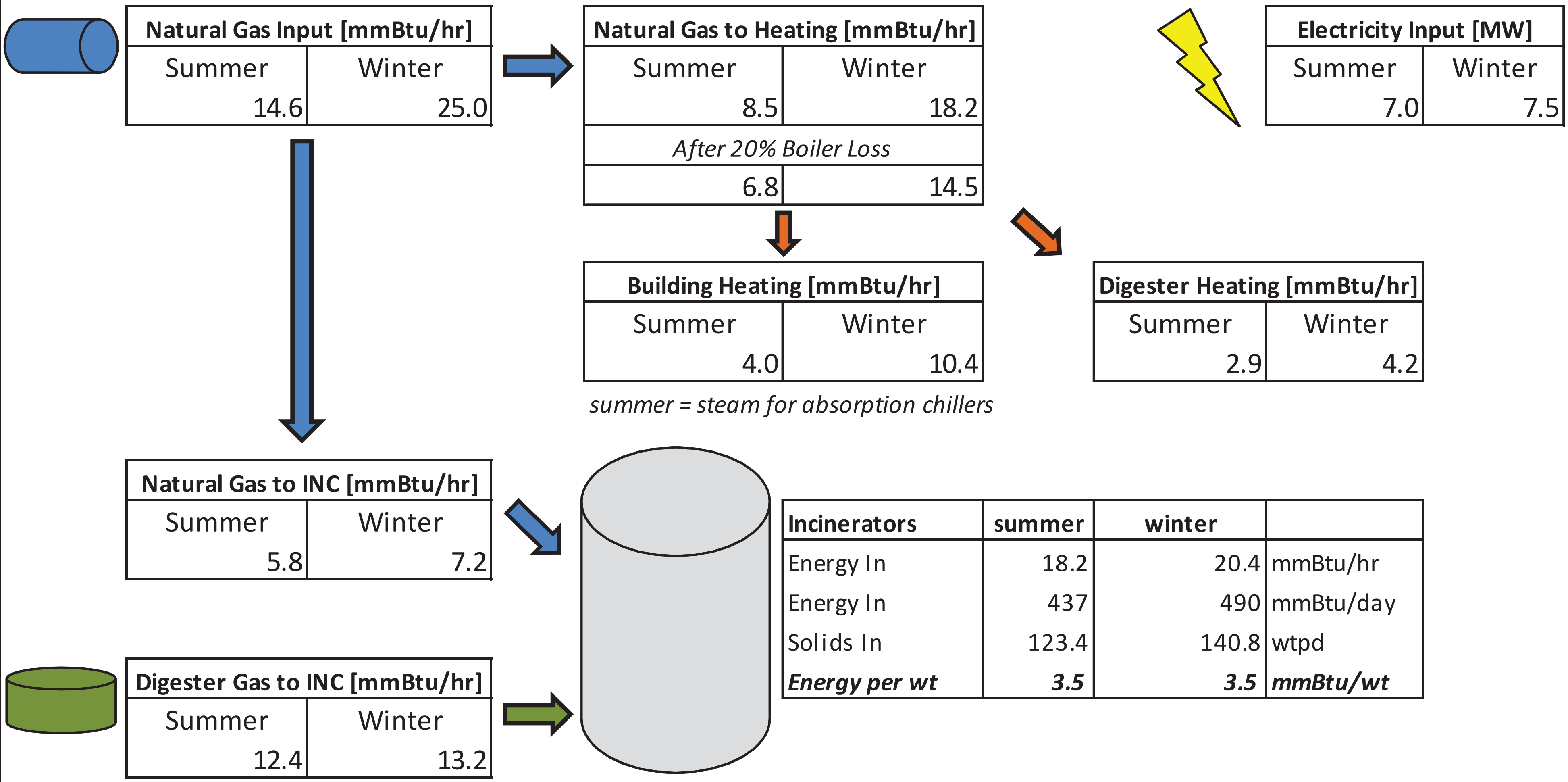
There were a number of important assumptions and calculations used to analyze the energy balance data for the plant. These items are described in more detail below:

- **Seasonal Data** – heating demands have significant seasonal variation as more heating is required in colder winter months. To capture this variation, data was divided into a 6-month ‘summer’ period (May to Oct) and a 6-month ‘winter’ period (Nov to Apr).
- **Natural Gas Meters** – the plant has natural gas sub meters measuring gas to incinerators and auxiliary heating boilers. Sub-metered data matches utility bill data with less than 1% difference. For this reason the sub-metered natural gas data is considered accurate.
- **Digester Gas to Incinerators** – the only digester gas metering available was metering on total production. Since no sub-metering was available it is assumed that all digester gas produced is consumed in the incinerators. Plant staff confirmed that this is the typical mode of operation for a great majority of the time. This assumption is also conservative as digester gas that is actually flared is being counted as incinerator energy demand.
- **Gas Heating Value** – the volumetric flow of natural gas was converted to energy using the standard conversion of 1,000 Btu/cf. The volumetric flow of digester gas was converted to energy using gas heating value supplied by BSA testing which was 640 Btu/cf.
- **Boiler Efficiency** – when determining the heat demands at the plant, it was assumed that the existing auxiliary boilers are 80% efficient since no recent boiler firing tests were available. This assumption is conservative as boiler efficiency is likely lower than 80% meaning that plant heating demands are likely being over-estimated.
- **Digester Heat Demands** – the plant has sub-metered steam flow data to digester heating. However, plant staff has indicated that this data is likely not accurate. Therefore, rather than using actual plant data, a heat load calculation based on sludge flows and temperatures was performed to estimate digester heating. Details of this calculation are provided in Appendix A. Following completion of the calculation, BSA staff indicated that these estimates appeared to be accurate.
- **Building Heat Demands** – the building heat demands at the plant were estimated by starting with the total natural gas for heating and subtracting the estimated digester heat demand. Heat demands for individual plant buildings were also estimated, more details of the individual building loads are discussed in Section 3 of this report. It should be noted that the term ‘building heating’ includes steam that is sent to absorption chillers to provide building cooling in the summer.
- **Data for Natural Gas to Incinerators** – the data showed that there was an abnormally large amount of natural gas sent to the incinerators in Jan, Feb and Mar of 2011. Discussions with plant staff revealed that there was a process upset during this time period resulting in excess natural gas being used because digester gas was not available for incineration. These 3 months of data were considered outliers and were removed from the averages of natural gas to incineration to provide a more accurate estimate of typical operations.

The results from the energy balance analysis shown graphically on Figure 2-2.

Figure 2-2. Bird Island WWTP Energy Balance

Data from Feb 2010 to Jan 2012* - (Natural Gas to INC outliers removed for Jan, Feb, Mar 2011)



Incinerators	**summer**	**winter**	
Energy In	18.2	20.4	mmBtu/hr
Energy In	437	490	mmBtu/day
Solids In	123.4	140.8	wtpd
Energy per wt	***3.5***	***3.5***	***mmBtu/wt***

The values presented in Figure 2-2 will be used in subsequent analyses to establish a baseline energy consumption condition at the plant. These values will also be used to develop parameters for the Energy Flow Model. One important parameter to be determined is the amount of energy sent to the incinerator for every wet ton of solids incinerated. The results from the energy balance show that approximately 3.5 mmBtu/hr of gas is used for every wet ton of solids incinerated. This performance parameter is dependent on many variables including %TS and %VS of feed solids, energy value of volatile solids, incinerator exhaust temperature, excess air used and ambient temperature. Calibration of the incinerator portion of the Energy Flow Model is discussed in more detail in Section 4 of this report.

The data from Figure 2-2 shows that the Bird Island WWTP has a relatively constant rate of electricity consumption with an average consumption rate of 7.0 MW in the summer and 7.5 MW in the winter. Over the two year period examined, the maximum month consumption rate was 9.4 MW and the minimum month consumption rate was 6.4 MW.

2.3. Utility Prices

The price of energy will be a major factor in determining the economic viability of a potential incinerator heat recovery and steam turbine cogeneration system. The prices of electricity and natural gas are known to be volatile, but predicting future energy prices was considered outside the scope of this project. As directed by BSA, the economic analysis was conducted based on the current delivered cost for both electricity and natural gas at the time (Feb 2012). These prices are given in Table 2-3.

Table 2-3. Mass Balance Data Sources and Assumptions

Item	Current Delivered Cost
Electricity	$0.085 per kWh
Natural Gas	$5 per mmBtu ($0.50 per therm)

The prices given in Table 2-3 will be used for all economic analyses conducted in this study. It should be noted that when using the Energy Flow Model, energy prices are an input variable that are set by the user. This gives the user the ability to compare different energy scenarios at various energy prices.

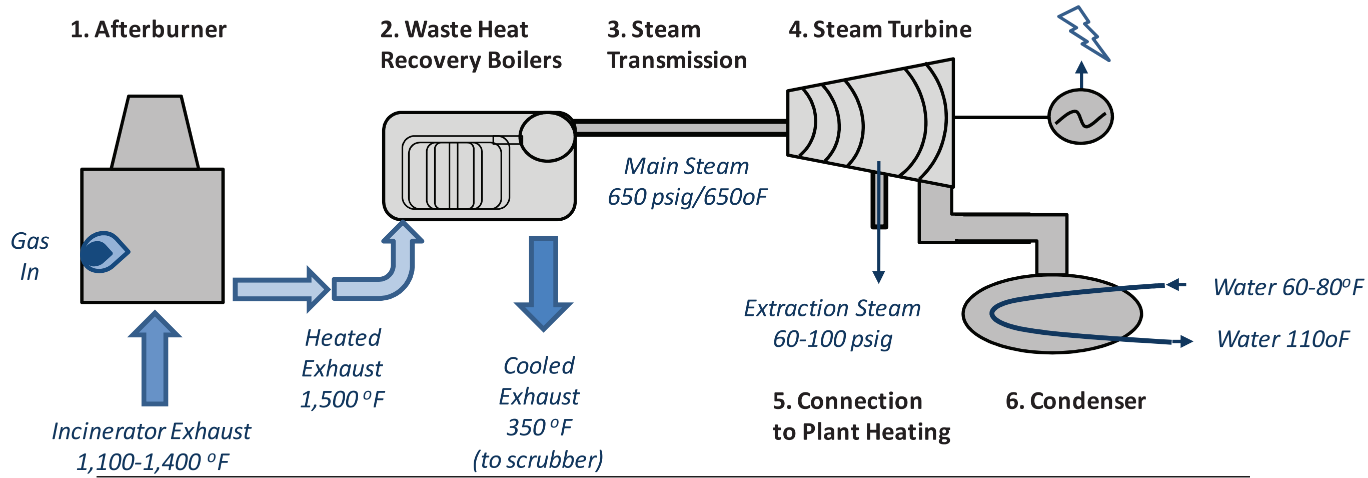
3. Feasibility of Incinerator Heat Recovery and Steam Turbine Cogeneration

The method of final solids disposal at the Bird Island WWTP is through multiple hearth incineration. From the data in Section 2, an average of 32.2 dry tons per day of solids is disposed in the incinerators. This combustion reaction generates tens of thousands of pounds per hour of exhaust gas leaving the incinerator at temperatures from 1,200-1,400^{o} F. This represents a large amount of energy that can be harvested for beneficial utilization at the plant. Currently this energy is wasted through quenching water of the incinerator wet scrubber system which is necessary to meet air permit limits. In the 1970's the plant installed waste heat recovery boilers (WHRBs) to generate steam to be used exclusively in the plant heating system which operates at approximately 110 psig. Our understanding is that the existing WHRBs are no longer in service and that all steam for plant heating is currently generated in auxiliary boilers that are typically fired off natural gas.

The system proposed in this study would capture the heat contained in the incinerator exhaust with new WHRBs that generate high pressure, superheated steam (650 psig/650^{o}F). This steam is then transmitted to a steam turbine driven generator to produce electricity. A portion of steam can be extracted from a middle turbine stage to provide heating at a pressure matching the plant's steam system. The remaining steam is exhausted to a condenser at pressures below atmospheric conditions. The vacuum in the condenser is maintained by a cooling water flow which will be provided by the plant's existing Final Effluent (FE) water system.

The proposed system is presented in this section. The system description is organized into six different components as shown in Figure 3-1 below. The description of each component will include sizing considerations, inputs and outputs, operating points, cost estimates and any other pertinent information.

Figure 3-1. Components of Incinerator Heat Recovery and Steam Turbine Cogeneration



The plant has three incinerators, and each incinerator has a dedicated afterburner chamber and ducting to a dedicated WHRB. The proposed system would install two new WHRBs dedicated to Incinerator No.2 and Incinerator No.3. These boilers would discharge steam into a common header that connects to a single steam turbine generator and condenser located in the Blower Building. Conceptual drawings of the proposed system are provided in Figures 1-5 at the end of this Section.

After the incinerator upgrade project is complete, the intended incinerator operations is to run only one incinerator the majority of the time with a maximum solids feed rate of 60 dtpd with the other incinerators acting as standby. The operation of the proposed system would have only one WHRB boiler generating steam, while the other serves as backup. New burners installed in the afterburner chambers would give BSA the option of generating additional steam by increasing exhaust gas flow and temperature. Providing heat via the afterburners would also allow BSA to continue to make steam in the WHRBs even when the incinerator must be taken out of service.

An economic analysis of the entire proposed system is provided following the description of each of the six system components listed in Figure 3-1. This analysis will estimate the total capital cost, operating cost and net electrical savings to determine the economic viability of the system via simple payback period analysis.

3.1. Afterburners

As hot exhaust gas exits the incinerator hearths, it enters existing afterburner (AB) chambers dedicated to individual incinerators. These AB chambers are currently used to achieve additional exhaust detention time and increased temperatures for destruction of pollutants to meet air permit regulations.

Under the proposed system, the AB chambers would serve a similar purpose of elevating the temperature of the incinerator exhaust gases. Under current operations, high exhaust temperatures are undesirable because this heat energy is simply wasted. With a heat recovery system in place, higher temperatures in the exhaust provide more opportunity for energy capture. An optimal exhaust temperature for generating steam in the proposed WHRBs is 1,500^{o} F which would be a targeted operation point. Note that combustion in the current incineration system typically produces exhaust gas leaving the AB chambers in the range of 1,200-1,400^{o} F.

3.1.1. Incinerator Exhaust

The amount of exhaust produced during incinerator combustion is a key value for sizing the proposed heat recovery system. Because gas volumes vary greatly with temperature, exhaust gas production is typically expressed as a mass flow rate (lbs/hr). The mass flow of incinerator exhaust is determined by a stoichiometric combustion calculation which is summarized below.

<u>Incinerator Combustion Calculation (mass flows)</u>

Sludge + Water in Sludge + Gaseous Fuel + Combustion Air = Exhaust

A detailed discussion of the incinerator combustion reaction for Bird Island WWTP is provided in Appendix B. Listed below are the input assumptions and resulting exhaust mass flow for the combustion reactions.

Input Assumptions

- Sludge In = 46.1 dtpd (32.2 from mass balance plus 10.9 of additional import sludge)
- Water in with sludge = sludge is 25.3 % TS (from mass balance)
- Gas Fuel In = 1,350 lbs/hr digester gas, 838 lbs/hr natural gas (based on incinerator energy balance for 1,500^o F exhaust, discussed in Section 4)
- Combustion Air = 40% excess above stoichiometric requirements

Incinerator Exhaust from Combustion

- Incinerator Exhaust = 70,500 lbs/hr @ 1,500^o F
- Approximate composition = 59.5% N_2, 24% H_2O, 13% CO_2, 3.5% O_2

3.1.2. Incinerator ID Fan

One item for consideration is the capacity of the incinerator induced draft (ID) fan that pulls air and exhaust through the incinerator. New ID fans are being installed as part of the incinerator upgrade contract currently being constructed at the plant. Heating the exhaust up to 1,500^o F for heat recovery requires more gas fuel which produces more exhaust than was likely intended in the ID fan design. A check was made to ensure the new ID fans have adequate capacity for 1,500^o F exhaust. Based on the Incinerator Upgrade Basis of Design Report, the ID fan design conditions are as follows:

- Routine Operation = 62,800 lbs/hr of mass flow
- Peak Operation = 81,500 lbs/hr of mass flow
- Upset Conditions Operations = 89,600 lbs/hr of mass flow

Our understanding is that the ID fans were sized to handle the upset condition shown above. Based on this design it is anticipated that the new ID fans will have adequate capacity for the estimated exhaust flows at 1,500^o F. At this point, no change in the ID fans including operations or electrical usage is anticipated. The ID fan capacity will would be confirmed during the detail design phase. Further discussion of this item is provided in Appendix B.

3.1.3. Burner Replacement

According to plant staff, the existing burners in both the incinerator hearths and the AB chambers are at the end of their service life. Burners in the incinerator hearths are being replaced under the incinerator upgrade contract currently being constructed at the plant. Our understanding is that the AB chamber burners are not being replaced under that contract. Therefore, the design of the proposed system would include replacement of the AB chamber burners for Incinerators No. 2 and 3. Each AB chamber has six burners so a total of 12 new burners would be required. The new burners would match the burners currently being installed in the incinerator hearths. They would be dual fuel capable and each rated at 2.37 mmBtu/hr giving each AB chamber the capability of adding 14.2 mmBtu/hr of additional heat.

The capital cost estimate for installing the 12 new AB burners includes the new burners, installation and integration of burner controls into the plant SCADA system. New local control panels for each burner were not included in this estimate. Existing combustion air blowers to the AB chambers are in good condition, so it was assumed that these blowers would not need to be replaced. Details of this cost estimate are provided in Appendix B.

Capital Cost

- New AB Chamber Burners = $162,000

3.2. Waste Heat Recovery Boilers (WHRBs)

The waste heat recovery boilers (WHRBs) component of the proposed system is where the incinerator exhaust heat energy is captured by converting water into steam. As stated previously, Bird Island WWTP currently has WHRBs that have no remaining service life. The proposed system design would demolish the existing WHRBs and replace them with new high pressure, superheated steam units. Utilizing the existing space and ductwork to the existing WHRBs will save on construction costs and allow for minimal process disruption. Preliminary equipment layouts suggest that there is adequate footprint to accommodate the new WHRBs. BSA has indicated there are plans for in-kind replacement of the existing WHRBs. The new proposed WHRBs will eliminate the need for this capital project. Therefore, a capital cost credit equal to the cost of replacing the WHRBs in-kind was applied to the capital cost estimate of the proposed system.

3.2.1. Existing WHRBs

Bird Island WWTP currently has WHRBs dedicated to each of its three incinerators. These units are no longer in service but were previously used to capture heat from incinerator exhaust and generate steam at approximately 110 psig for use in the plant's steam heating system. These units were installed in 1972 and were taken out of service due to performance reduction caused by excessive ash fouling. BSA is considering a capital improvement project to demolish these boilers and replace them in-kind. The estimated capital cost for replacing one WHRB unit in-kind was provided by Rentech Boilers. The need for this capital improvement project would be eliminated with the addition of two new high pressure WHRBs.

Capital Cost

- Credit for In-Kind Replacement of WHRBs = $1,250,000 per unit

3.2.2. New WHRBs

The proposed system would demolish two of the existing WHRBs and replace them with new, high pressure WHRBs that generate superheated steam at 650 psig and 650^{o} F. These new WHRBs would utilize the existing boiler inlet and outlet ducts that penetrate the floor at the boiler level (2nd floor) of the Megastructure. Figure 2 at the end of this section gives a conceptual level drawing of the proposed new WHRBs.

The intended typical operation of the proposed system is to have one incinerator in service, feeding exhaust to one WHRB to produce steam. As described in Section 3.1, the new WHRBs were sized based on 70,500 lbs/hr of exhaust entering one boiler at 1500^o F. It was assumed that the new WHRBs would extract heat and reduce the incinerator exhaust to a temperature of 365^o F. This conservative estimate is well above the temperature at which acid gases will start to precipitate in the boiler and cause corrosion. Since the actual chemical composition of exhaust gas varies significantly from facility to facility, an analysis of the acid gases contained in the incinerator exhaust is recommended for future design phases to more accurately set the outlet exhaust temperatures from the WHRBs. It should also be noted that with the proposed heat recovery system, the incinerator exhaust entering the new venturi scrubber system will be significantly cooler (365^o F) than originally intended in the new scrubber design (1,000^o F). One significant operational change resulting from this project would be a reduction in the required amount of cooling water to be sent to the quencher portion of the scrubbers which is discussed in Section 3.6.

Rentech Boilers provided a recommended boiler unit, performance estimation and capital cost quotation for this application. Details of this selection are provided in Appendix C. The recommended WHRB unit would produce approximately 22,000 lbs/hr of steam at 650 psig and 650^o F based on the given input assumptions. The boilers were sized to produce a maximum of 30,000 lbs/hr of steam so that they can accommodate future increases in incinerator loading up to the incinerator capacity of 60 dtpd.

<u>New High Pressure WHRB Performance Parameters</u>

- Output steam conditions = 650 psig/650^{o}F (superheated)
- Typical steam output from incinerator exhaust = 22,000 lbs/hr
- Maximum steam production of one unit = 30,000 lbs/hr

<u>Capital Cost</u>

- New high pressure WHRBs = $1,600,000 per unit

In addition, based on concerns identified by plant staff and on past historical maintenance issues, ash mitigation measures were included into the proposed WHRB quotation in an effort to minimize the fouling effects experienced in the previous WHRBs. These ash mitigation measures include:

<u>Ash Mitigation in New WHRBs</u>

- Higher exhaust gas velocities to reduce ash buildup
- Bare tubed superheater and economizer to avoid plugging
- Hoppers designed for optimal ash removal
- Man way access for boiler cleaning

A cost estimate to demolish the existing WHRBs and install two new WHRBs was provided by Nicholson and Hall, a contractor involved in the current incinerator upgrade project at the plant. The installation of the proposed new WHRBs would require removal of a portion of the Megastructure's north wall and restoration after construction. The estimated installation cost was $1,800,000 for the entire construction process. Details are provided in Appendix C. An installation cost of $1,600,000 was estimated for in-kind WHRB replacement since in-kind WHRB replacement would not require labor to assemble superheaters and other ancillary equipment.

<u>Installation Cost</u>

- Installation of two new WHRB units = $1,800,000
- Credit for in-kind WHRB installation = $1,600,000

The incremental cost of installing two new WHRBs was based on the information in Sections 3.2.1 and 3.2.2 and is summarized below

<u>Incremental Cost of new WHRBs</u>

- Cost of new WHRBs = $5,000,000 (equipment and installation for 2 units)
- Cost of in-kind WHRBs = $4,100,000 (equipment and installation for 2 units)
- Incremental Cost = $900,000

Maintenance of the new WHRBs would be similar to the maintenance required for in-kind WHRB replacements and also similar to the maintenance required for auxiliary boilers that are currently used for plant heating. The proposed system would utilize extraction steam from the steam turbine for the majority of plant heating. As a result, plant auxiliary boilers would only be used as backup systems or possibly during peak heating days in the winter. In either case, auxiliary boiler run-times and maintenance requirements would be significantly reduced. For these reasons there was no additional O&M cost assumed for new WHRB maintenance.

3.2.3. Boiler Feedwater Pumps

To generate steam at 650 psig, the new WHRBs must receive feedwater at 650 psig. This will require new, multi-stage boiler feedwater pumps. A preliminary selection of the required pumps was performed with details of the selected pumps provided in Appendix C. Each multistage pump will deliver 75 gpm of water at 650 psig and will have a variable frequency drive. It was assumed that the three pumps would be installed with one pump serving each new WHRB plus an additional swing pump. The power draw of the new feedwater pumps was estimated assuming that only one pump would typically be in operation. This power draw was compared to the power draw of the current feedwater pumps to provide an estimate of the additional parasitic electrical load of the new feedwater pumps. Details of the power draw estimations are provided in Appendix C.

<u>Capital Cost</u>

- Three new boiler feedwater pumps = $126,000 (three pumps plus installation)

Boiler Feedwater Pump Operation

- Current Feedwater Pumping Power = 8.0 HP
- New Feedwater Pumping Power = 42.6 HP
- Estimated Additional Feedwater Pumping Power = 34.6 HP (rounded to 35 HP)
- Parasitic Electricity Load = 228,700 kWh/year (35 HP of pumping operating 24/7)

3.2.4. Boiler Water Treatment

At the proposed operating temperatures and pressures for the new WHRBs, even very small buildups of solids or scale within the boiler tubes can cause severe corrosion. The plant currently softens incoming city water via an ion exchange system to reduce hardness in the current boiler feedwater. The proposed system would add a reverse osmosis (RO) system to provide exceptionally clean feedwater to the new WHRBs on the order of 1 ppm of total dissolved solids. The current ion exchange system and the proposed RO system would operate on the make-up water stream to the boiler. An optional item would be a secondary ion-exchange “polisher” that operates on the entire feedwater stream that could protect against condensate return water contaminated with solids. However, discussions with a system manufacturer (Nalco) suggests at the secondary polisher was considered unnecessary and was therefore not included in the system economics.

Selections and cost estimates on the proposed boiler water treatment improvements were provided by Nalco. Details of the selected system are provided in Appendix C. The RO system was sized conservatively for both boilers in operation producing a total of 60,000 lbs/hr of steam and a make-up water rate of 20%. This yielded an RO system capacity of approximately 20 gpm and which includes a discharge brackish water holding tank. Operation and maintenance of the RO system is typically performed under a comprehensive contract with the system manufacturer. The cost for this type of contract was quoted as $6,000 per year. The typical power draw of the RO system was estimated to be 5 HP with only one boiler in operation.

Capital Cost

- Reverse osmosis (RO) system for make-up water = $79,000
- RO installation = $25,000 (lump sum for pre-packaged system)

Boiler Water Treatment Operation

- Comprehensive O&M contract = $6,000 per year.
- Estimated RO System Pumping Power = 5 HP
- Parasitic Electricity Load = 32,700 kWh/year (5 HP of pumping operating 24/7)

3.3. Steam Transmission

This component of the system includes piping that will transmit the 650 psig superheated steam from the new WHRBs to the proposed steam turbine generator. Based on a preliminary review of the facility, the pipe will originate at the boiler level (second floor) of the Megastructure, drop down to the basement level and head north through the tunnel connecting to the Blower Building which is the proposed location of the steam turbine generator. This pipe has an approximate length of 370 feet and is shown conceptually on Figures 2, 3 and 4 at the end of this section.

The pipe selection was based on the ASTM A53 B standard for carbon steel pipe. The selected pipe was 6 inch diameter, schedule 80 carbon steel with welded joints which has a working pressure of 1,200 psig. At a design steam flow rate of 30,000 lbs/hr the 6 inch pipeline would have an approximate steam velocity 145 feet per second (fps) and minimal pressure losses. Typical velocities for high pressure, superheated steam are in the range of 100-300 fps. Details of the cost estimate are provided in Appendix D.

<u>Capital Cost</u>

- Schedule 80 carbon steel steam transmission pipeline = $180,000 installed

3.4. Steam Turbine

The steam turbine is the ‘prime mover’ component of the proposed heat recovery and cogeneration system. ‘Prime mover’ is a power generation term that refers to the equipment that converts heat, gas or steam energy into mechanical energy and then into electricity. As discussed with plant staff, the proposed steam turbine would be located in the Blower Building in the bay currently occupied by Aeration Blower No. 2. BSA staff has indicated that this blower requires a motor rebuild and its capacity is no longer needed due to an aeration upgrade project recently completed at the plant. Aeration Blower No. 2 would be demolished to make room for the proposed steam turbine generator. This location for the steam turbine is ideal for several reasons listed below:

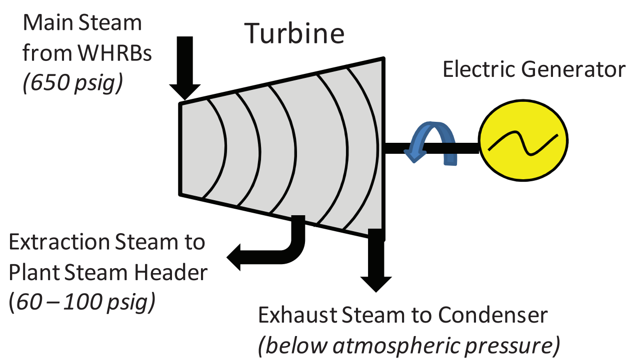
- Very close in proximity to the main plant switchgear
- Existing pad and floor penetrations can be utilized
- Basement level provides an ideal space for the turbine condenser
- Basement level is adjacent to tunnel and pipe galleries connecting the Blower Building to the Megastructure.

The factors listed above will provide significant savings on installation costs and allow for a steam turbine and condenser configuration that has minimal operating complications. Conceptual drawings of the proposed steam turbine and condenser configuration are provided in Figures 4 and 5 at the end of this section.

3.4.1. Steam Turbine Generator

The steam turbine generator would receive input steam or ‘main steam’ that is generated by the WHRBs at 650 psig and 650^{o} F. This high pressure steam is passed through a series of turbine stages wherein the steam pressure is converted to momentum to spin the turbine blades. An extraction port and valve would be located in one of the middle turbine stages to provide ‘extraction steam.’ Extraction steam can be removed at varying flow rates as needed by throttling the extraction valve. Extraction steam is only available at a single pressure that is determined by the location of the extraction point. Extraction steam can then be used to supply the plant heating system. The 'exhaust steam' that is not extracted passes through the remaining turbine stages and then is discharged to the condenser. The condenser uses a cooling water flow to create a vacuum and drives exhaust steam pressures to well below atmospheric conditions. Figure 3-2 below gives a general schematic of the turbine steam flows.

Figure 3-2. Schematic of Steam Turbine Flows



For the operation of the turbine, as more steam flows through each turbine blade, more electricity is generated. The flow of main steam will be determined by the amount of incinerator exhaust heat that is generated. The flow of extraction steam will vary with plant heating demands. The pressure of extraction steam will be set by the minimum pressure needed to inject steam into the plant steam header. Currently the plant header operates at approximately 110 psig but this pressure could potentially be decreased as discussed in Section 3.5. The pressure of exhaust steam is determined by the available flow and temperature of cooling water to the condenser which will be provided by the plant final effluent (FE) system. Since FE water is abundant and has a low temperature, the exhaust steam can be reduced to a very low pressure of 3 inches of mercury absolute (3" HgA) to generate as much electricity as possible.

Dresser-Rand provided a steam turbine generator performance estimation and capital cost quotation for this application. Details of this information are provided in Appendix E. The quoted system included a multistage extraction turbine with a multi-valve governor arrangement, electric generator and condenser along with ancillary equipment. The steam turbine was sized to receive a maximum main steam load of 30,000 lbs/hr at 650 psig and 650^{o}F. The electrical output of the turbine is dependent on the amount and pressure of extraction steam. This extraction load will vary seasonally with plant heat demands and is estimated and discussed in Section 3.5. Assumed parameters for estimating turbine output are listed below.

<u>Steam Turbine Performance Parameters</u>

- Main Steam = 30,000 lbs/hr at 650 psig/650^{o} F
- Extraction Steam = 7,500 lbs/hr in summer, 16,300 lbs/hr in winter, both at 80 psig
- Exhaust Steam = Pressure at 3" HgA
- Estimated Turbine Output = 1.74 MW average (2.01 MW summer, 1.46 MW winter)

Capital Cost

- Steam Turbine Generator and Condenser = $2,250,000
- Installation of Steam Turbine and Condenser = $325,000

3.4.2. Connection to Plant Electric System

As discussed with plant staff, the output of the steam turbine generator will be connected to the 13.8KV Main Primary Distribution Switchgear located in the Electrical Room adjacent to the turbine location in the Blower Building. An existing spare cubicle (No. 32) and 1200A circuit breaker will be completely refurbished for the output connection from the turbine generator to the main switchgear. The installation will also include synchronization hardware and software components to allow the turbine generator to be connected to either of the two existing incoming primary lines. The plant main electrical system currently operates with a Main-Tie-Main configuration with the tie breaker between the two primary systems open. During normal operations, the generator would synchronize and connect to the “B” side of the switchgear. If the “A” side system needs to be disconnected and the tie breaker closed, the generator would continue operating without any additional synchronization required. Additional control equipment for the turbine, as well as the turbine generator main control panel will be located adjacent to the turbine. The estimated capital cost for the required electrical modifications is provided in Appendix E.

Capital Cost

- Electrical Modifications = $109,000

3.4.3. Steam Turbine Operation and Maintenance

Steam turbines are known for having low operation and maintenance requirements. Steam turbine operations require a low level of operator attention and would not require dedicated operators. One reason why steam turbines have low maintenance is that the high temperatures and contaminants resulting from combustion are confined to the boiler portion of the system so they do not affect the turbine equipment. The main cost item for steam turbine maintenance is an accrual for the rotor overhaul which would be required in intervals of 5 to 10 years. Predictive monitoring of data such as turbine temperatures and vibrations are employed to determine when an overhaul is necessary.

There are a wide range of maintenance contracts available from turbine manufacturers that provide varying amounts of coverage and services for both preventative and corrective maintenance. An annual steam turbine maintenance cost was estimated to include labor and parts for preventative maintenance, corrective maintenance on an as-needed basis and accrual for overhauls every 5 years. The specific parameters of the desired maintenance contract would be developed during the detailed design and start-up phases.

Steam Turbine Operation and Maintenance

- Annual Maintenance = $50,000 per year

3.5. Connection to Plant Heating

The steam turbine system provides heating to the plant by injecting extraction steam into the existing steam header. The extraction port in the turbine would be designed to provide steam that matches the operating pressure of the steam heating system. This medium pressure steam would be transmitted in a new pipeline that drops down from the turbine bay, through the existing floor penetration and connects through the tunnel in the basement level to the Megastructure. Conceptual drawings of this pipeline are provided in Figures 2, 3, 4 and 5 at the end of this Section.

3.5.1. Existing Steam Heating Pressure

The existing plant heating system is currently operated at approximately 110 psig. It is recommended that BSA conduct testing to explore potential steam pressure reductions in their existing system. Reducing the system pressure will help reduce steam demands, reduce energy losses in the system and will enhance the electrical efficiency of the proposed steam turbine. A US DOE manual of best practices for steam pressure reduction is included in Appendix F for reference.

A typical method for steam pressure reduction testing is to enact incremental and gradual pressure reductions throughout the winter heating season. This gradual lowering would identify the lowest pressure for operations before issues occur. It is estimated that the Bird Island WWTP could lower its system pressure to 80 psig while keeping its existing steam heating intact. Another recommended option to investigate would include switching the southernmost plant buildings (Raw Wastewater Pump Station, Screen and Grit Chamber, Administration Building) to a new hot water boiler heating system. By removing the furthest outlying steam loads, the system pressure could be reduced to an estimated 60 psig. This recommended option is developed further in Section 3.5.2.

3.5.2. Extraction Steam Demands

The proposed heat recovery system would satisfy all steam heating demands at the plant with extraction steam from the steam turbine. Determining the required mass flow and pressure of the extraction steam is a key component for estimating the performance of the steam turbine. As extraction steam pressure and/or mass flows are reduced, the electrical output of the steam turbine is increased. This section discusses how extraction steam demands were evaluated for several potential plant heating scenarios.

Current heating energy demands at the plant were analyzed in Section 2 with results of the plant energy balance presented in Figure 2-2. Some values from this energy balance analysis are provided in Table 3-1.

Table 3-1. Values from Plant Energy Balance

	Summer [mmBtu/hr]	Winter [mmBtu/hr]	Source/Comment
Total Natural Gas Purchased	14.6	25.0	Data from utility bills
Natural Gas into Heating Boilers	8.5	18.2	Data from natural gas sub-metering
Heat Energy out of Boilers	6.8	14.5	Assumed boilers are 80% efficient
Heat Energy into Digesters	2.9	4.2	Heating load calculation
Heat Energy into Buildings	4.0*	10.4	Assumed equal to: [Heat Energy out of Boilers] - [Heat Energy into Digesters]

* Steam into absorption chillers for cooling

It should be noted that there are some slight rounding errors included in the Table 3-1 values. It should also be noted that the assumption of 80% boiler efficiency provides a conservative estimate for plant heating demands as the existing auxiliary boilers are likely operating at a lower efficiency.

As described in Section 3.5.1, a potential option for consideration is to reduce the steam system pressure at the plant. Another potential option for consideration is to transition some of the building heating loads to a new, high efficiency, condensing hot water boiler system. This would reduce both the steam pressure and mass flow required for heating. The required extraction steam loads for the following three options were evaluated:

Option 1 – Current Conditions: The steam system pressure remains unchanged at 110 psig and all areas currently heated by steam are left intact. It should be noted that most building heating applications reduce steam pressure to 50 psig before use in heating.

Option 2 – Reduce Steam System Pressure: The steam system is reduced to 80 psig utilizing the methods recommended in Section 3.5.1. All areas currently heated by steam are left intact.

Option 3 – Convert to Hot Water and Reduce Pressure: In this option, the furthest outlying buildings (Raw Wastewater Pump Station, Screen and Grit Chamber, Administration Building) would be removed from the steam system. Heating for these buildings would be converted to a new hot water condensing boiler system that would replace the steam to hot water converters in the basement of the Administration Building. With the furthest steam demands eliminated it is estimated that the steam system pressure could be reduced down to 60 psig.

Evaluation of these options required an estimate of the winter heating load for each individual building at the plant. A full scale ASHRAE analysis of building envelopes for each individual plant building was outside the scope of this study. Instead, conceptual level heating loads were developed by estimating the percentage of the total winter heating load for each building. The percentages of total winter heating load were derived from discussions with BSA staff, building floor area and building usage. The conceptual level heating loads estimated for each building are shown in Table 3-2.

Table 3-2. Conceptual Level Winter Building Heating Loads

Building/Area	Percentage	Value [mmBtu/hr]
Total Winter Building Heating	100%	10.38*
Raw Waste Water Pump Station (#2)	5.5%	0.57
Screen and Grit Chamber (#3)	4.5%	0.46
Administration Building (#4)	7%	0.74
Grit Removal (#5)	4%	0.42
Megastructure (#9)	40%	4.15
Maintenance Building (#13)	4%	0.41
Chemical Handling (multiple buildings)	35%	3.63

* From Energy Balance Analysis

The conceptual level heating load estimation showed that the vast majority of building heating goes to the Megastructure (40%) and the group of buildings heated by the Chemical Handling steam to hot water converters (35%). The remaining buildings each used between 4% and 7% of the winter building heating energy.

The extraction steam demand was calculated for Options 1, 2 and 3 described above with the following equation:

$$\text{Steam Demand [lbs/hr]} = \frac{\text{Heat Demand [mmBtu/hr]}}{\text{Latent Heat of Steam [Btu/lb] [mmBtu/}10^6\text{ Btu]}}$$

Latent Heat of Steam varies with steam pressure as shown in Table 3-3 below.

Table 3-3. Latent Heat of Steam at Various Pressures

	110 psig	80 psig	60 psig	50 psig	15 psig
Latent Heat of Steam [Btu/lb]	875.9	892.2	904.9	912.1	945.8

Tables 3-4, 3-5 and 3-6 give the estimated extraction steam loads for Options 1, 2 and 3 described above.

Table 3-4. Option 1 – Current Conditions

Building/Area	Heat Demand [mmBtu/hr]		Steam Pressure [psig]	Steam Demand [lbs/hr]	
	Winter	Summer		Winter	Summer
Raw Waste Water Pump Station (#2)	0.57	0	50	600	0
Screen and Grit Chamber (#3)	0.46	0	50	500	0
Administration Building (#4)	0.74	0	50	800	0
Grit Removal (#5)	0.42	0	50	500	0
Megastructure (#9)	4.15	0	50	4,500	0
Maintenance Building (#13)	0.41	0	50	400	0
Chemical Handling (multiple buildings)	3.63	0	50	4,000	0
Digesters	4.15	2.88	50	4,500	3,200
Absorption Chillers	0	3.95	15	0	4,300
Total Demand	**14.53**	**6.83**		**15,800**	**7,500**
Total Supplied by Aux Boiler			**110**	**16,600**	**7,800**

Table 3-5. Option 2 – Reduce System Pressure

Building/Area	Heat Demand [mmBtu/hr] Winter	Summer	Steam Pressure [psig]	Steam Demand [lbs/hr] Winter	Summer
Raw Waste Water Pump Station (#2)	0.57	0	50	600	0
Screen and Grit Chamber (#3)	0.46	0	50	500	0
Administration Building (#4)	0.74	0	50	800	0
Grit Removal (#5)	0.42	0	50	500	0
Megastructure (#9)	4.15	0	50	4,500	0
Maintenance Building (#13)	0.41	0	50	400	0
Chemical Handling (multiple buildings)	3.63	0	50	4,000	0
Digesters	4.15	2.88	50	4,500	3,200
Absorption Chillers	0	3.95	15	0	4,300
Total Demand	**14.53**	**6.83**		**15,800**	**7,500**
Total Supplied by Extraction Steam			**80**	**16,300**	**7,700**

When comparing Option 1 and Option 2, the results show that there is a slight reduction in steam demands for Option 2. This is due to the fact the lower pressure steam in Option 2 has a larger latent heat content. Option 2 is recommended since there would be minimal cost involved with reducing the system steam pressure.

Table 3-6. Option 3 – Convert to Hot Water and Reduce Pressure

Building/Area	Heat Demand [mmBtu/hr] Winter	Summer	Steam Pressure [psig]	Steam Demand [lbs/hr] Winter	Summer
Raw Waste Water Pump Station (#2)	removed	0	50	0	0
Screen and Grit Chamber (#3)	removed	0	50	0	0
Administration Building (#4)	removed	0	50	0	0
Grit Removal (#5)	0.42	0	50	500	0
Megastructure (#9)	4.15	0	50	4,500	0
Maintenance Building (#13)	0.41	0	50	400	0
Chemical Handling (multiple buildings)	3.63	0	50	4,000	0
Digesters	4.15	2.88	50	4,500	3,200
Absorption Chillers	0	3.95	15	0	4,300
Total Demand	**12.76**	**6.83**		**13,900**	**7,500**
Total Supplied by Extraction Steam			**60**	**14,100**	**7,500**

When comparing Option 2 and Option 3, the results show a significant reduction in extraction steam for Option 3. This is mostly due to the removal of steam loads for the Raw Wastewater Pump Station, Screen and Grit Chamber, and the Administration Building under Option 3. The heating loads would be converted to hot water boilers that do not require steam. There are a variety of tradeoffs that must be evaluated to compare Options 2 and 3 as Option 3 provides greater energy efficiency but also has cost associated with new hot water boilers. These options will be compared in more detail in the Energy Flow Modeling analysis in Section 4. A capital cost estimate was made for installing new hot water boilers, tie-ins to the existing how water systems in the Screen and Grit chamber and the Administration Building and conversion of the Raw Wastewater Pump Station to a hot water heating system. Details of this cost estimate are provided in Appendix F.

Capital Cost

- New Hot Water Condensing Boiler System and Tie-ins = $340,000

New Hot Water Boiler Operation and Maintenance

- Annual Maintenance Estimate = $6,000 per year
- Boiler Efficiency = 90%

A payback period analysis was performed for Options 2 and 3 using methods presented in section 3.7. The results of this analysis showed that Option 2 had a payback period of 8.2 years while Option 3 had a payback period of 8.7 years. Details are provided in Appendix F. For this reason, Option 2 was selected for developing the economic analysis for the proposed system. It should be noted that Option 3 allows the system to produce more electricity and will increase in financial viability if electricity prices rise (or if grant funding is procured on a per kWh generated basis). Option 3 would also make financial sense when the heating infrastructure in the Administration Building is in need of replacement.

3.5.3. Extraction Steam Connection to Existing Plant Header

The extraction steam would be transmitted in a pipeline back to the Megastructure for injection into the plant's steam header. This pipeline would be a 10 inch diameter pipe and be constructed of schedule 80 carbon steel. Automatic control valves would be provided on this pipeline so that the steam header could be isolated to operate on extraction steam, steam from auxiliary boilers, or a combination of both steam sources. Details of the cost estimate are provided in Appendix F.

Capital Cost

- Schedule 80 carbon steel steam transmission pipeline = $159,000 installed

3.6. Condenser

The final component of the proposed system is the steam turbine condenser which would be located in the basement level of the Blower Building directly below the steam turbine bay. The condenser is a large shell and tube heat exchanger that receives the exhaust steam from the turbine and uses a cooling water flow to convert the steam into liquid condensate for return to the boilers. The cooling water source for the condenser would be the final effluent (FE) water currently produced at the plant. The filtered and chlorinated FE water is an ideal cooling water source that has a main header run directly adjacent to the proposed condenser location in the basement of the Blower Building. A conceptual drawing of the condenser is shown in Figure 4 at the end of this Section.

3.6.1. Condenser Cooling Water Supply

The final turbine exhaust steam pressure is determined by the heat exchange from the steam to the cooling water in the condenser. Having an abundant supply of cooling water at a relatively low temperature will reduce the exhaust steam pressure to a minimum and maximize the electrical output from the turbine.

The amount of cooling water needed to maintain a 3" HgA exhaust steam pressure was calculated as shown below with details provided in Appendix G. It should be noted that the required amount of cooling water will vary seasonally as there would be less exhaust steam to be condensed and lower FE water temperatures available in the winter.

<u>Condenser Cooling Water Calculation</u>

Exhaust Steam Mass Flow * h_{fg} Steam = Cooling Water Mass Flow * Cp * delta T

<u>Input Assumptions</u>

- Exhaust Steam Flows = 22,500 lbs/hr in summer; 13,700 lbs/hr in winter
- Exhaust Steam Pressure = 3" HgA (condensing temperature ~ 110^{o}F)
- FE Water Temperature = 80^{o}F in summer; 60^{o}F in winter

<u>Condenser Cooling Water Required</u>

- Average Cooling Water Flow = 1850 gpm in summer; 600 gpm in winter
- Maximum Cooling Water Flow = 2200 gpm (summer, extraction only for digester heat)

The existing FE water system originates in the Final Effluent Screening Building at the far north end of the plant. The current FE water system is supplied by three pumps each rated at 2,940 gpm at a design head of 156 ft. Typical operation has two pumps in service and one as stand-by. The FE water is distributed throughout the plant through a main 18" FE header and a second Chiller header. The amount of FE currently used at the plant was estimated and compared to the additional FE water needed for the condenser. A system curve for the FE Header was also developed and evaluated for additional flow to the condenser. This information is summarized in Table 3-7 with details of the estimation provided in Appendix G.

Table 3-7. FE Water Flows and FE

Item	FE Header Usage [gpm]	Chiller Header Usage [gpm]	Total FE Water [gpm]	Total Head in FE Header [ft]
Current Usage	2,258	1,270	3,528	121.6
FE Pump Capacity[1]			5,880	156 (design)
Excess Pump Capacity			2,352	
New Winter Usage[2]	2,858	1,270	4,128	125.0
New Summer Usage[2]	4,108	1,270	5,378	134.4
New Maximum Usage[2]	4,458	1,270	5,728	137.6

1 – design capacity with two pumps running and one on standby
2 – includes additional water to condenser through FE Header

The analysis from Table 3-7 shows that there is adequate existing pumping capacity to transmit the additional FE water to the condenser. Also the total head through the FE header at maximum usage (135.8 ft) is below the design head of the system (156). Additional pumps were not considered necessary and were not included as part of the proposed system.

As shown in Figure 4, the 18” FE Header pipe runs directly outside the basement level of the Blower Building where the proposed condenser would be located. A branch pipe from the existing 18” FE header to the condenser would be constructed. A flow control valve connected to the plant DCS would be included in the condenser water feed pipe to allow for control of the FE water to the condenser. Heated water exiting the condenser would be routed to the drain for the absorption chillers. A tee branch and blind flange was included in the condenser water drain line to provide a connection for potential beneficial use of the heated water in the future. The estimated capital cost for required FE water modifications is provided in Appendix G. It should be noted that the cost of the condenser itself was included in the quoted cost of the steam turbine generator.

<u>Capital Cost</u>

- FE water system modifications = $50,000

There would be additional parasitic pumping loads required to pump the additional FE water to the condenser. This additional pumping load is calculated below with details provided in Appendix G.

<u>FE Water Pump Operation</u>

- Current FE Header Pumping Power = 92.5 HP
- New FE Header Pumping Power = 120.4 HP summer; 186.1 HP winter
- Average Additional Pumping Power = 60.8 HP (rounded to 65 HP)
- Parasitic Electricity Load = 424,800 kWh/year (65 HP of pumping operating 24/7)

3.7. Economic Evaluation

An economic evaluation was conducted on the proposed incinerator heat recovery and cogeneration system described in the sections above. A simple payback period was calculated for this system based on the method shown below.

<u>Simple Payback Period</u>

Payback Period = Capital Cost/Annual Cost Savings

where

Annual Cost Savings = Net Electrical Savings – Additional O&M Cost – Change in NG Cost

The estimated capital cost for the proposed system was approximately $7.3 million which is summarized in Table 3-8 below.

Table 3-8. Total Capital Cost for Incinerator Heat Recovery and Steam Turbine Cogeneration

	Units	Unit Cost	Equipment Cost	Installation Cost	Total Cost
New WHRB	2	$1,600,000	$3,200,000	$1,800,000	$5,000,000
In-Kind WHRB Replacement Credit	2	$1,250,000	$2,500,000	$1,600,000	($4,100,000)
Incremental WHRB Cost					$900,000
New Boiler Feedwater Pumps	3	$28,000	$84,000	$42,000	$126,000
Turbine and Condenser	1	$2,250,000	$2,250,000	$325,000	$2,575,000
Boiler Water Treatment	1	$79,000	$79,000	$25,000	$104,000
New Burners in AB Chambers					$162,000
Steam Piping from Boiler to Turbine					$180,000
Electrical Modifications					$109,000
Connection of Extraction Steam					$159,000
FE Water System Modifications					$50,000
Net Subtotal					$4,365,000
Miscellaneous Additions	15%				$655,000
General Conditions	12%				$524,000
Contractor Overhead and Profit	15%				$655,000
Engineering	25%				$1,091,000
Total Capital Cost					**$7,290,000**

From Section 3.4.1, the average electrical generation from the steam turbine is 1.74 MW based on the assumed conditions described throughout Section 3. The proposed system also included the addition of parasitic electrical loads from new boiler feedwater pumps, boiler water RO treatment and additional FE water pumping. The net electrical cost savings are summarized in Table 3-9.

Table 3-9. Net Electrical Savings

Item	Value		Notes
Turbine Generated Electricity	1.74	MW	annual average
Turbine Generated Electricity	15,242,400	kWh/yr	
Feedwater Pump Parasitic	228,724	kWh/yr	35 HP operating 24/7
RO System Parasitic	32,675	kWh/yr	5 HP operating 24/7
FE Water Line Parasitic	424,772	kWh/yr	65 HP operating 24/7
Net Output	14,556,229	kWh/yr	
Net Electrical Savings	**$1,237,000**	**per year**	@ $0.085/kWh

There would be additional O&M costs incurred for various components of the proposed system. As described in Section 3.2.3, the O&M for the new WHRBs would be equivalent to the O&M currently required for existing auxiliary boilers so no additional O&M cost was assumed. There would be additional O&M cost for the maintenance of the steam turbine which would mostly be accrual for overhauls every 5 to 10 years. There would also be additional O&M cost for increasing the level of boiler feedwater treatment. The additional O&M is summarized in Table 3-10 below.

Table 3-10. Additional O&M Costs

Item	Cost	
Turbine Maintenance	$50,000	per year
Boiler Water Treatment	$6,000	per year
Total Additional O&M	**$56,000**	**per year**

To operate the proposed system under the assumptions developed in Section 3, there would be a change in natural gas utilization as compared to the 'baseline' condition in which there is no heat recovery or cogeneration installed. The baseline natural gas consumption differs from the 2010 and 2011 process data presented in Figure 2-2 because the baseline includes the delivery of 10.9 dtpd of import sludge to plant incinerators (this load did not exist in the 2010 and 2011 process data). With the implementation of the proposed system, additional natural gas would be needed for incineration to heat exhaust to 1,500^{o} F. It was also assumed that additional natural gas would be added in the AB chambers to produce the maximum amount of steam (30,000 lbs/hr) in the WHRB. It should be noted that there would also be some natural gas savings because no natural gas fuel is needed for the auxiliary boilers since plant heating would come from turbine extraction steam. The estimated changes in natural gas utilization and the associated costs are summarized in Table 3-11.

Table 3-11. Change in Natural Gas Utilization

	Natural Gas Use					
Item	**To Aux Boilers**	**To INC**	**To AB Chamber**	**Total**	**Units**	**Notes**
Current Process Data	13.4	6.5	0.0	19.9	mmBtu/hr	
Baseline	13.4	9.7	0.0	23.1	mmBtu/hr	additional 10.9 dtpd to INC
Heat Recovery/Cogen	0	19.5	10.3	29.8	mmBtu/hr	
Net Change in Natural Gas				6.7	mmBtu/hr	[Heat Recovery/Cogen – Baseline]
Annual Change in Natural Gas				58,692	mmBtu/yr	additional consumption
Change in Natural Gas Cost				**$293,000**	**per year**	@ $5/mmBtu

The amount of natural gas consumed under the baseline scenario and under the implementation of heat recovery and cogeneration was determined by running the Energy Flow Model tool. More detailed discussion of the Energy Flow Model is provided in Section 4. A simple payback period for the proposed heat recovery and cogeneration system was calculated as follows and was based on the values from Tables 3-8 through 3-11

Annual Cost Savings = $1,237,000 - $56,000 - $293,000 = $888,000 per year

Simple Payback Period = $7,290,000 / $888,000 per year = 8.2 years

This payback period of approximately 8 years indicates that the implementation of the proposed system would be economically desirable as it falls below the 10 year threshold established by BSA for desirable projects. The useful lifespan of the proposed equipment is typically 20-30 years which would provide continued savings beyond the payback period. It should also be noted that this payback period does not include any funding benefits from state energy programs such as The New York State Energy Research and Development Authority (NYSERDA). Procuring funding under such a program would make this project even more economically desirable. A discussion of the potential NYSERDA funding opportunities is provided in the next Section.

3.7.1. Potential NYSERDA Funding

NYSERDA administers the Renewable Portfolio Standard (RPS) program, a policy that seeks to increase the proportion of renewable electricity used by retail customers. Energy generated from anaerobic digester gas (ADG) is considered renewable. At this time, it appears that two programs, exclusive of each other, may be available for this project. The programs are:

- Customer-Sited Tier: for small scaled generators
- Main Tier: for large scaled generators that sell power to the wholesale grid, or in some cases generate power for onsite use

This section examines the potential funding that could be procured by BSA under these two programs.

Since NYSERDA funding is tied to the amount of electricity generated directly from ADG, an additional electric generation option for BSA was evaluated. Under this option, BSA would install a second CHP system in addition to the steam turbine. This second CHP system would receive all the ADG at the plant with the purpose of maximizing electricity directly generated from ADG. The second CHP option selected was a reciprocating engine system that was estimated to generate 1.20 MW of electricity when receiving all the ADG available at the plant. Under this option, all supplemental fuel used for incineration combustion would be purchased natural gas. Incinerator exhaust heat would still be recovered by the proposed WHRB and steam turbine system described in previous sections. Power generation from the steam turbine would still occur but at a lower rate of approximately 1.06 MW. Under this dual CHP option, it was assumed that hot water recovered from the engines would be used to heat plant digesters.

This dual CHP option was evaluated alongside the option to implement only the steam turbine CHP system. The dual CHP system would increase overall electrical generation and increase the potential to receive NYSERDA funding as more electricity would be directly generated from ADG. The dual CHP system would also require more capital and operation cost.

Customer-Sited Tier Anaerobic Digester Gas to Electricity Program **(PON 2276) –** this program supports the installation and operation of anaerobic digester gas (ADG)-to-electricity systems in New York State. PON 2276 is currently open until December 2015. Incentives are available as a one-time incentive based on the installed capacity of the power generating equipment and an additional production-based incentive provided for a period of 3 years. This program is applicable to systems that use ADG as their only fuel source. In the case of the proposed steam turbine CHP system, however, ADG will only contribute to a portion of the fuel, together with sludge and natural gas, to the power generation from the steam turbine. Therefore the incentive will be prorated based on the fraction of the total fuel source attributable to ADG.

The full Capacity Incentive is $1,000 per kilowatt (kW); however, the Total Capacity Incentive shall not exceed the lesser of $850,000 or 50% of the Total Eligible Capital Expenses. The full Performance Incentive is $0.10/kWh generated at 75% capacity over 3 years. There is a cap of $1 million per facility.

Based on the proposed steam turbine CHP system operating as described in the previous sections, with an average electrical generation of 1.74 MW, the ADG portion contributing to steam turbine fuel for renewable energy generation, calculated as the percentage of heat input from ADG compared to the total heat input of sludge, natural gas, and ADG, is approximately 25%. The incentives would be prorated by this portion. The maximum incentive would be the cap of $1 million over three years.

With the dual CHP option using engine generators in addition to the steam turbine, the incentive would not be prorated, but the incentive would still be the capped at $1 million over 3 years. This scenario would also have additional capital cost and cost for operation and maintenance of the engine and associated gas pre-treatment systems. Air permitting issues would also have to be considered.

Main Tier Program - this is a periodic competitive procurement. Prospective participants submit an application, which is evaluated based on the generation type and fuel source eligibility requirements, the bid price and the economic benefit of the project. RFP 2554, the Eighth Main Tier solicitation, is currently open for facilities that plan to enter commercial operation after January 1, 2003 and on or before May 1, 2014. The program is typically reopened by NYSERDA every year.

The first step for participating in the program is to submit an application, which is evaluated based on eligibility and the qualification criteria. Once qualified, participants submit proposals with a bid price per megawatt-hour (MWh) of RPS Attributes associated with electricity generated by the facility, and the expected economic benefits to New York created by this project. The scoring system assigns 70% to the bid price and 30% to the economic benefits.

Contract awards will be for a fixed contract duration of ten (10) years. In the past, awarded contracts included wind, hydroelectric, landfill gas-to-electricity and anaerobic digester projects. The weighted average price awarded for the Seventh Main Tier solicitation (December 2011) was $28.70 per RPS attribute (MWh) or $0.0287 per kWh.

Incinerated or directly combusted sludge is ineligible for this program. The sludge needs to be converted to a liquid or gaseous fuel, such as ADG. As in the case of Customer-Sited Tier program, the incentives for the Main Tier program would be prorated to the ADG portion of the fuel generating electricity. Assuming a successful bid price of

$0.025/kWh, and an ADG portion of approximately 25%, the maximum incentive from this program would be approximately $1 million over ten years.

Under the dual CHP option using engine generators in addition to the steam turbine, the full incentive would be significantly higher at approximately $2.6 million over 10 years. The incentive is higher because more electricity is being generated and there would be no prorating necessary because all electricity would be generated from ADG. The additional capital, O&M and air permitting costs would also be included in this option.

3.7.2. Economics with Potential NYSERDA Funding

The economic performance of various potential energy recovery scenarios were analyzed for simple payback period. A detailed breakdown of the analyses performed is provided in Appendix H.

These scenarios included steam turbine CHP scenarios with different extraction steam conditions as described as Option 2 and Option 3 in Section 3.5. A new steam turbine CHP option was also included to send all incoming solids (including 10.9 dtpd of import) to the digesters with the purpose of increasing the Main Tier incentive. Two dual CHP scenarios that included engine generators in addition to the steam turbine were also evaluated. One dual CHP scenario assumed no siloxane (SiO) cleaning system would be required for the engines while the other dual CHP scenario assumed SiO cleaning would be required.

<u>Scenarios Evaluated for Potential NYSERDA Funding</u>

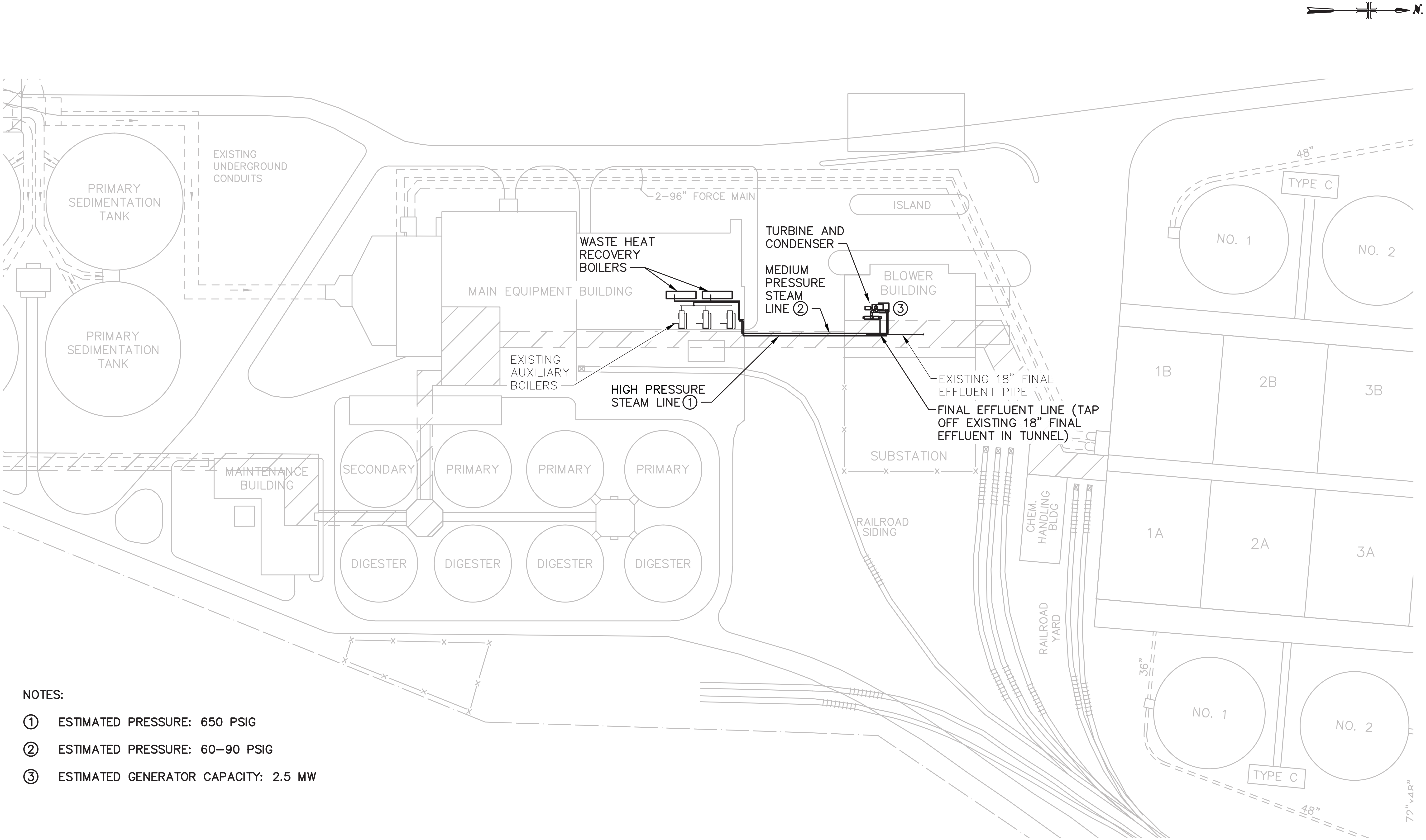
- Steam Turbine CHP – Extraction at Option 2 from Section 3.5
- Steam Turbine CHP – Extraction at Option 3 from Section 3.5
- Steam Turbine CHP – Sending all solids to digesters to maximize Main Tier Incentive
- Dual CHP - Engines require SiO cleaning
- Dual CHP - Engines do not require SiO cleaning

The results are summarized in Table 3-12 below.

Table 3-12. Economic Scenarios with NYSERDA funding

Scenario	Payback without incentive (yrs)	ADG-to-Electric Incentive ($)	Payback with ADG-to-Electric Incentive (yrs)	Main Tier Incentive ($)	Payback with Main Tier Incentive (yrs)
Steam Turbine - Option 2	8.2	$1 million	7.1	$924,000	7.2
Steam Turbine - Option 3	8.6	$1 million	7.6	$941,000	7.6
Steam Turbine - All Solids to Digesters	8.1	$1 million	7.0	$1.1 million	6.9
Dual CHP with SiO cleaning	14.6	$1 million	13.7	$2.6 million	12.5
Dual CHP without SiO cleaning	13.4	$1 million	12.6	$2.6 million	11.5

The results from Table 3-12 show that the dual CHP scenarios that include additional engine generators are not cost competitive with scenarios that only include a steam turbine. It appears the maximum NYSERDA incentive that could be procured under the proposed steam turbine CHP system is approximately $1 million. This would drive the estimated payback period down by approximately 1 year. This incentive will improve the financial viability of the proposed incinerator heat recovery and steam turbine cogeneration system and make it more attractive for implementation. A more detailed analysis of the best operating practices for the proposed system is provided in Section 4 which covers Energy Flow Modeling.



NOTES:

① ESTIMATED PRESSURE: 650 PSIG

② ESTIMATED PRESSURE: 60–90 PSIG

③ ESTIMATED GENERATOR CAPACITY: 2.5 MW

MALCOLM PIRNIE | ARCADIS

The Water Division of ARCADIS

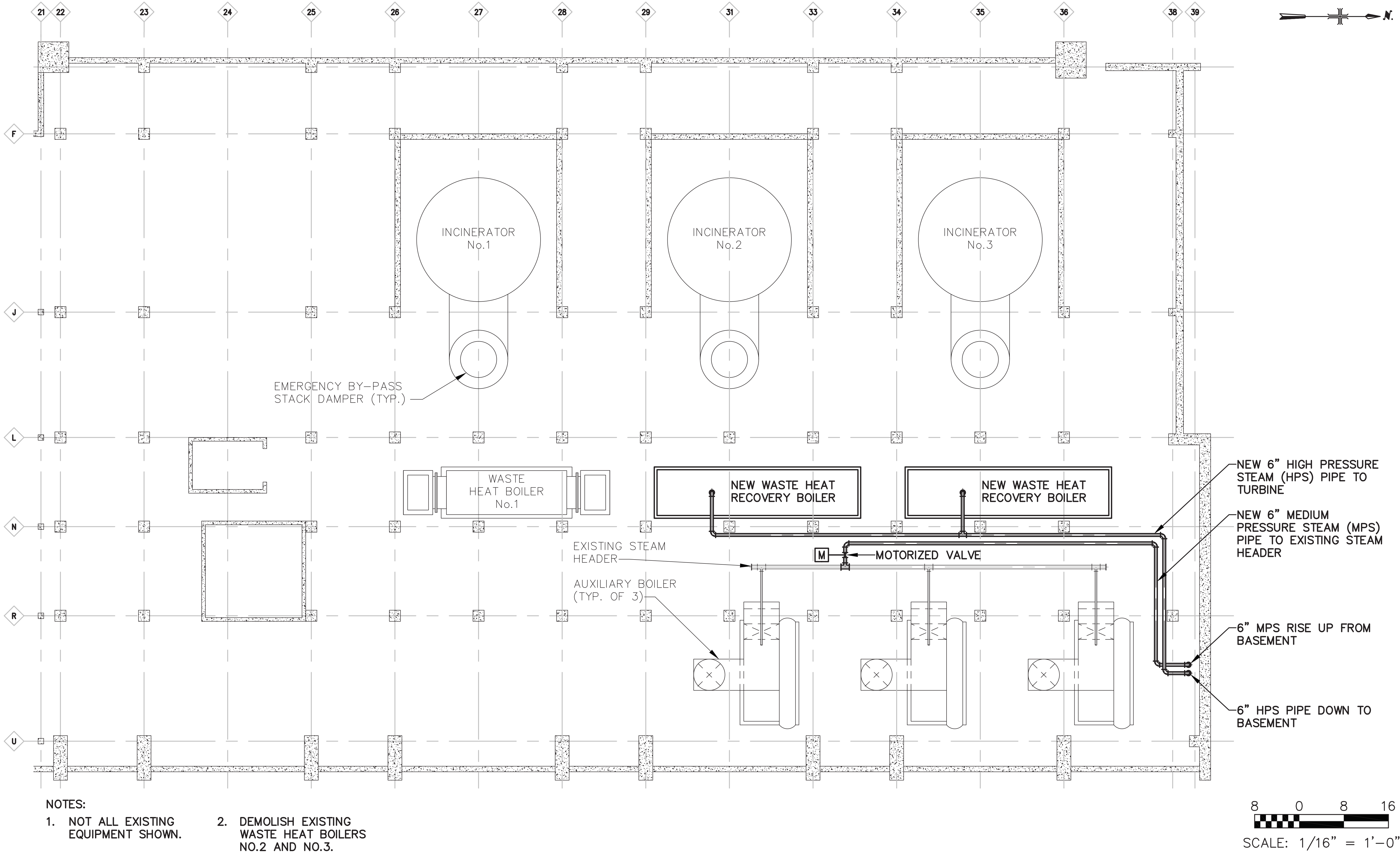
BUFFALO SEWER AUTHORITY
BUFFALO, NEW YORK

WASTEWATER TREATMENT PLANT

INCINERATOR WASTE HEAT RECOVERY
SITE PLAN
NOT TO SCALE

ARCADIS U.S., INC.

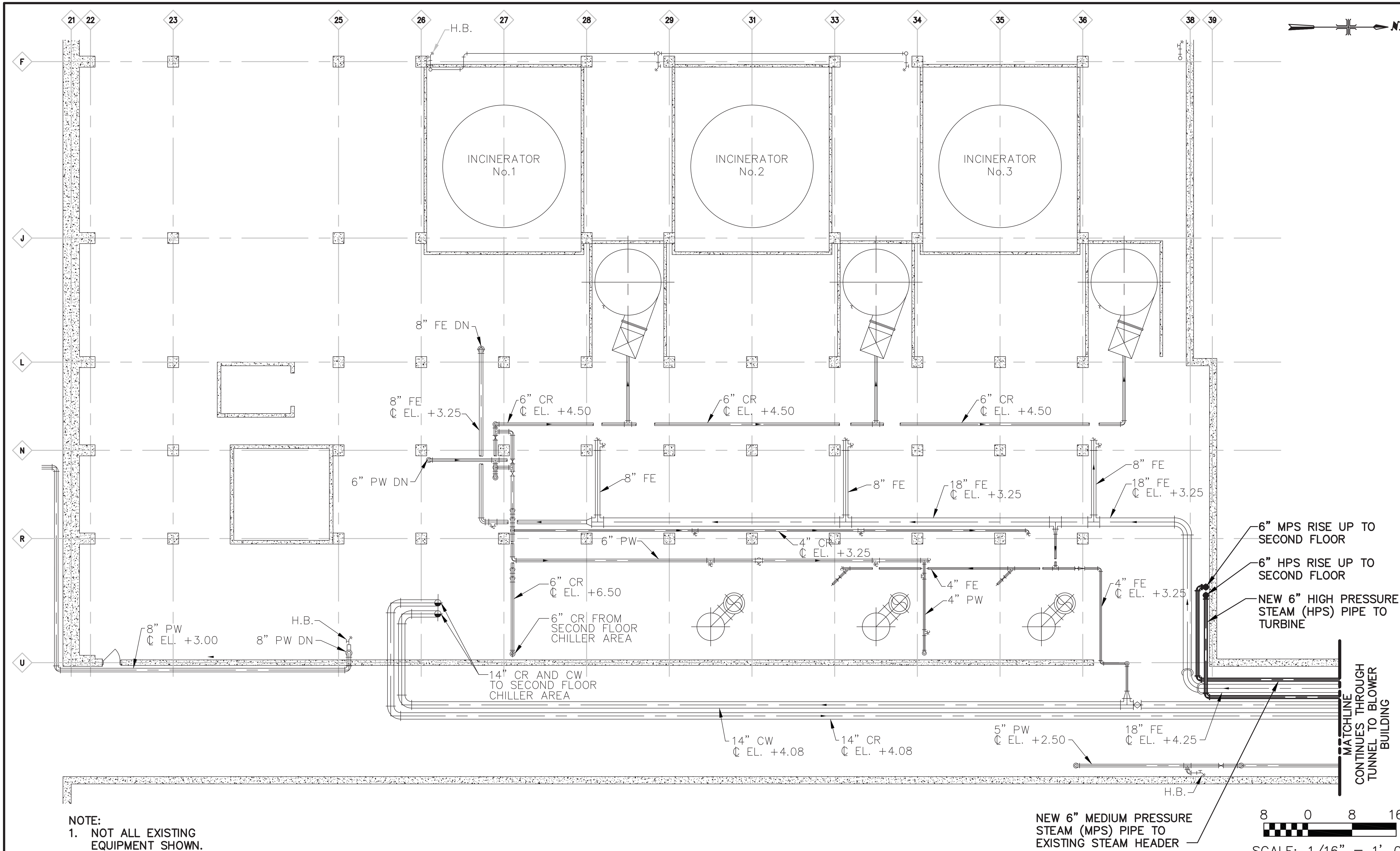
FIGURE 1



NOTES:

1. NOT ALL EXISTING EQUIPMENT SHOWN.
2. DEMOLISH EXISTING WASTE HEAT BOILERS NO.2 AND NO.3.

MALCOLM PIRNIE ARCADIS The Water Division of ARCADIS	BUFFALO SEWER AUTHORITY BUFFALO, NEW YORK **WASTEWATER TREATMENT PLANT**	MAIN EQUIPMENT BUILDING PROPOSED WASTE HEAT BOILERS AND STEAM PIPING SECOND FLOOR PLAN SCALE: 1/16"=1'-0"	ARCADIS U.S., INC. FIGURE 2



NOTE:
1. NOT ALL EXISTING EQUIPMENT SHOWN.

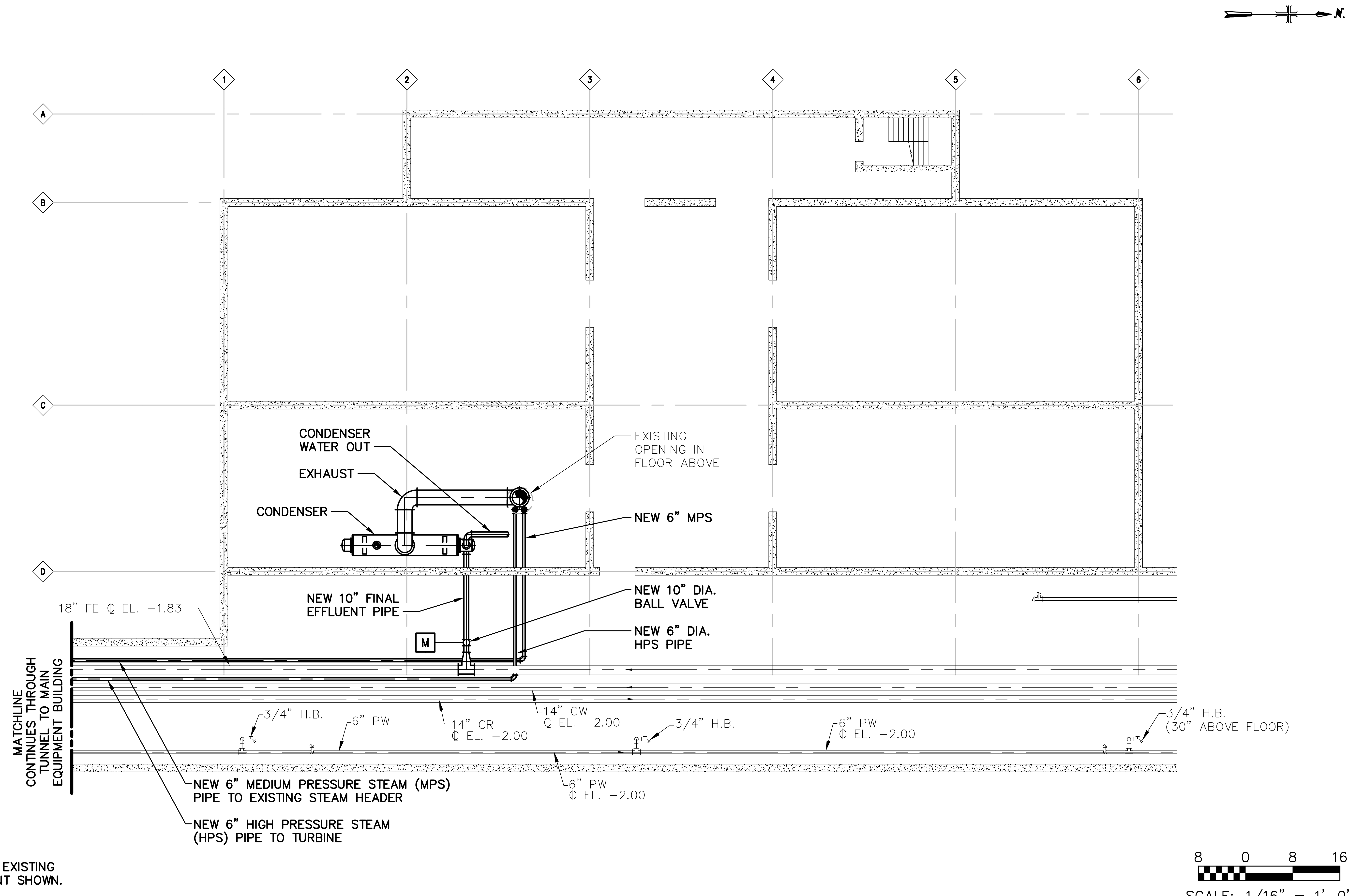
MALCOLM PIRNIE | ARCADIS
The Water Division of ARCADIS

BUFFALO SEWER AUTHORITY
BUFFALO, NEW YORK
WASTEWATER TREATMENT PLANT

MAIN EQUIPMENT BUILDING
PROPOSED STEAM PIPING
BASEMENT FLOOR PLAN
SCALE: 1/16"=1'-0"

ARCADIS U.S., INC.

FIGURE 3



NOTES:

1. NOT ALL EXISTING EQUIPMENT SHOWN.

MALCOLM PIRNIE | ARCADIS

The Water Division of ARCADIS

BUFFALO SEWER AUTHORITY
BUFFALO, NEW YORK

WASTEWATER TREATMENT PLANT

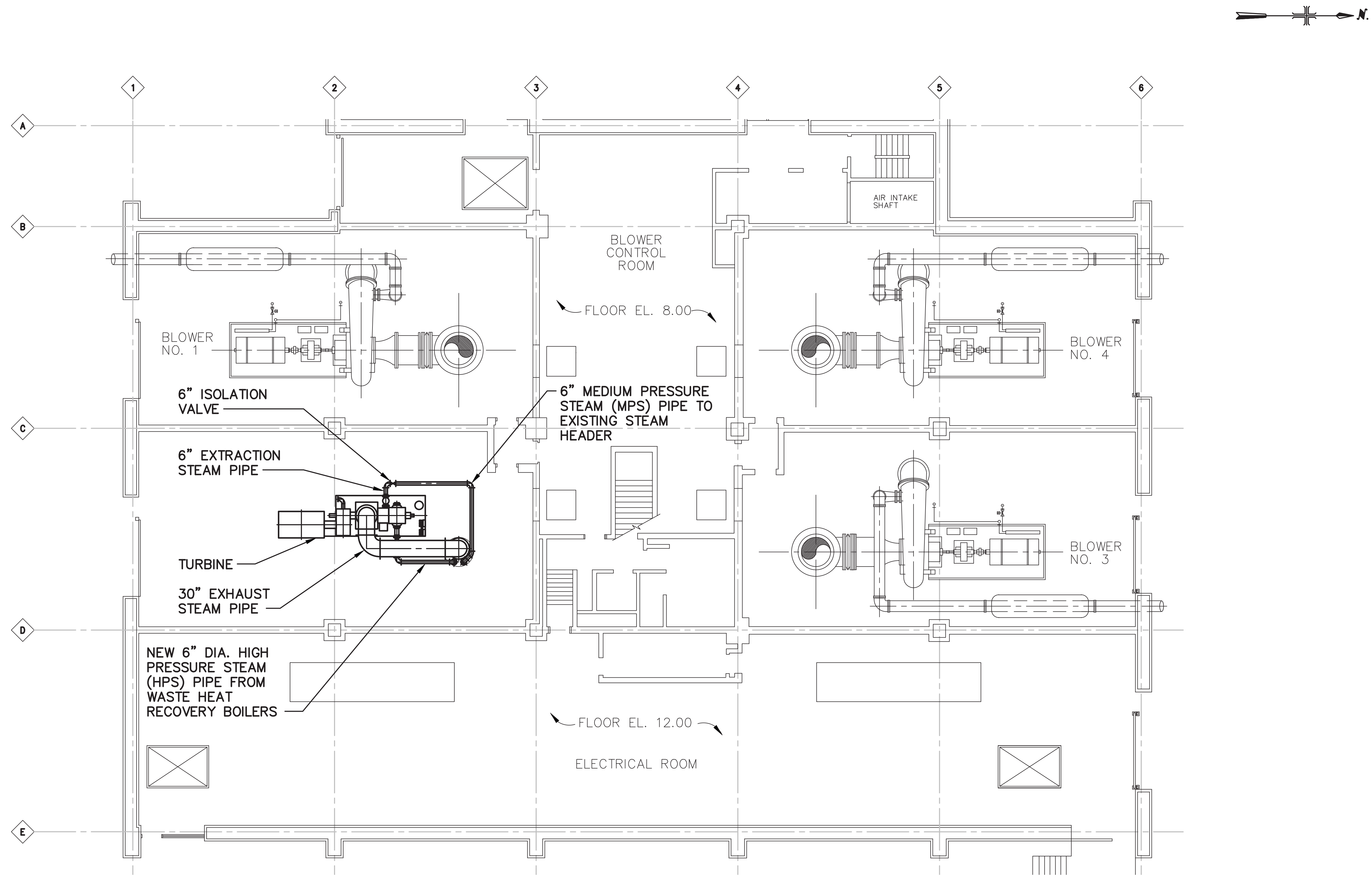
BLOWER BUILDING

PROPOSED STEAM PIPIG, CONDENSER, AND FINAL EFFLUENT PIPING BASEMENT FLOOR PLAN

SCALE: 1/16"=1'-0"

ARCADIS U.S., INC.

FIGURE 4



NOTE:

1. NOT ALL EXISTING EQUIPMENT SHOWN.
2. BLOWER NO.2 (NOT SHOWN) TO BE DEMOLISHED.

8 0 8 16

SCALE: 1/16" = 1'-0"

MALCOLM PIRNIE / ARCADIS — The Water Division of ARCADIS	BUFFALO SEWER AUTHORITY BUFFALO, NEW YORK **WASTEWATER TREATMENT PLANT**	BLOWER BUILDING PROPOSED TURBINE AND STEAM PIPING FIRST FLOOR PLAN SCALE: 1/16"=1'-0"	ARCADIS U.S., INC. FIGURE 5

4. Energy Flow Modeling

The Bird Island WWTP employs an array of processes that use energy in various forms. As energy flows from one process to another, the quantity and type of energy is affected. This type of relationship is illustrated by considering the distribution of sludge to either digesters or incinerators. Digesters convert some energy in the sludge to biogas which can be used for energy. Digesters also reduce the amount mass to incinerate leading to less fuel consumption. Digesters also require heating and produce solids for incineration which are more inert and require more fuel per unit mass. Sending undigested sludge directly to incineration will increase the energy content of the incinerator feed and lead to less fuel consumption. Sending sludge directly to incinerators also requires a larger load to dewatering centrifuges and requires more water to be vaporized during incineration. These types of interdependencies give rise to a complex network when plant energy use is examined as a whole. The addition of a cogeneration system powered by incinerator exhaust would add an additional layer of complexity to energy use at the plant. With this complexity comes the opportunity to optimize the plant energy usage across all processes.

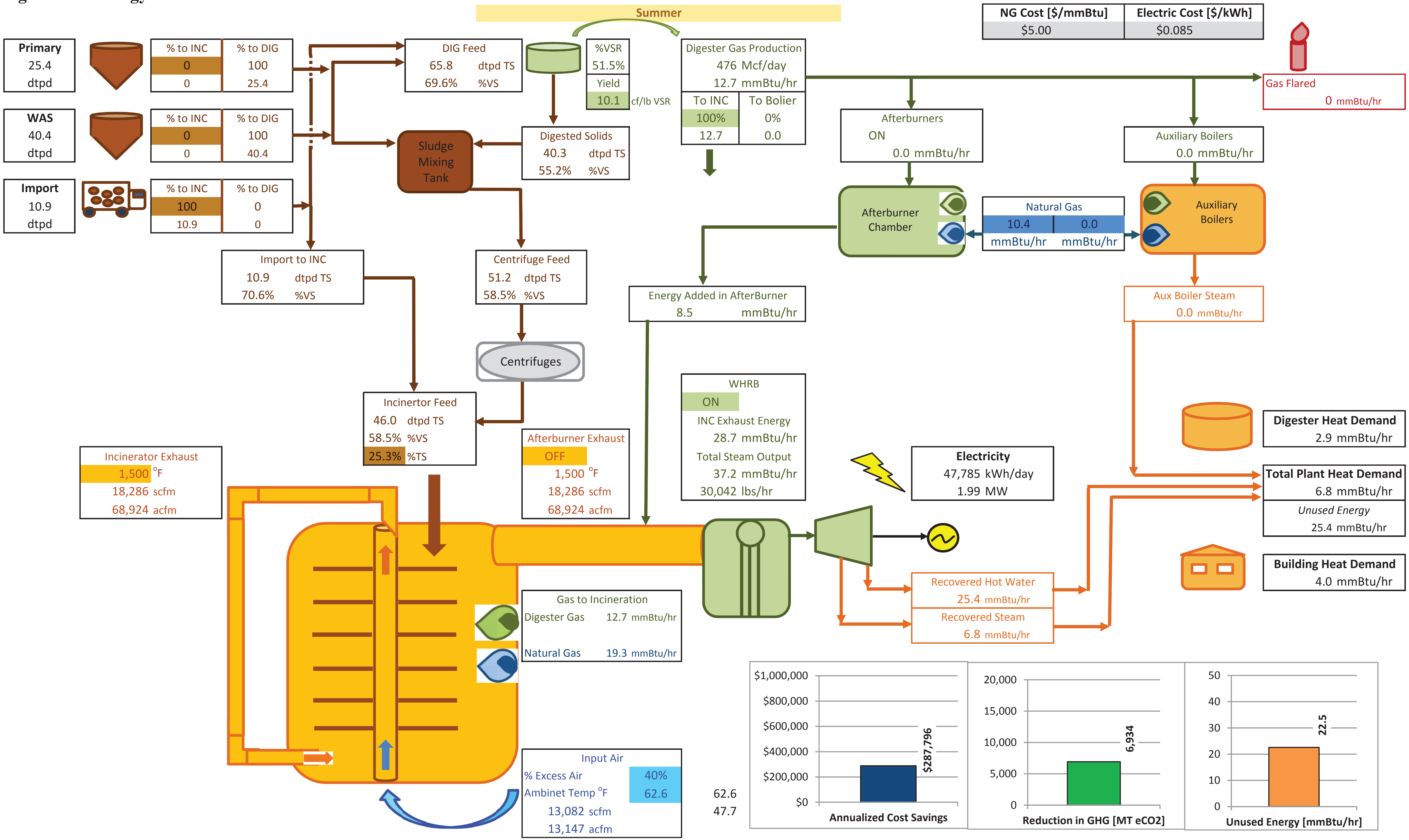
An Energy Flow Model was developed for Bird Island WWTP as a tool for optimizing energy utilization. This tool is a spreadsheet based model that tracks the flow of energy through the various solids treatment processes at the plant. The model allows the user to adjust a set of input variables that affect energy use, for example the water content of dewatered sludge or ambient air temperature. The model also allows the user to decide how to route energy to the different plant processes. Each specific set of user inputs creates a 'scenario' for which the model gives outputs on economic performance, green house gas (GHG) reduction and energy efficiency. The intent of the model is for the user to create a group of scenarios by adjusting inputs. The scenarios can then be compared against each other easily and quantitatively to make decisions on how to best utilize energy at the plant.

This section provides a description of the Energy Flow Model and also presents the evaluation results for a set of model scenarios aimed at identifying the most beneficial operational modes for utilizing energy at the plant.

4.1. Description and Model Outputs

The Energy Flow Model encompasses the solids handling system at the plant starting with thickened WAS, thickened PS and import sludge. Amounts and characteristics of each solids stream can be adjusted as user inputs. Different mixes of solids can then be routed to the digesters or to incineration. Biogas produced from digestion and natural gas purchased from the pipeline can be routed as desired by the user to meet various energy needs at the plant. The proposed system consisting of WHRBs and an extraction steam turbine generator is also modeled to determine the amount of steam and electricity that can be generated based on the operational input variables set by the user. A screen shot of the Energy Flow Model network is given in Figure 4-1.

Figure 4-1. Energy Flow Model Network



The outputs from the Energy Flow Model are the annualized cost savings of the scenario, the GHG emission reduction provided by the scenario and the amount of unused energy for the scenario.

The output parameter of 'Annualized Cost Savings' was selected as the best description of the economic performance of each scenario. This is a different method of economic analysis than 'Life Cycle Cost' that is typically seen in engineering evaluations. The main difference between the two is that Life Cycle Cost takes reoccurring annual costs and translates them into one sum in today's dollars to be combined with capital costs. Annualized cost instead translates capital costs into reoccurring annual payments in today's dollars to be combined with all other reoccurring annual costs and revenues.

Annualized cost savings included annualized capital cost, O&M costs, cost for purchasing natural gas and net cost savings (or avoided cost) from electrical generation. Capital costs associated with each scenario were translated into an annualized capital cost assuming a 20 year bond period at a 5% annual interest rate.

GHG reduction for each scenario included avoided emissions from net electrical generation along with emissions from consuming natural gas. To help provide a more intuitive understanding of model results, reductions were presented as positive numbers meaning scenarios with larger GHG reductions are performing better environmentally.

Unused energy is the measure of the heat energy being captured by the steam turbine that is not being used beneficially. This unused energy takes the form of heated condenser water being wasted to the drain. Flared biogas is also included as unused energy. Unused energy is presented as an annual average heat rate in mmBtu/hr and can be used to determine how well each scenario is utilizing the available energy.

4.2. Calibrations and Assumptions

The Energy Flow Model was calibrated with the two years of process data analyzed and presented in Section 2 of this report. The three main model processes to be calibrated included the digesters, the incinerators and the cogeneration system (WHRBs and steam turbine). This section describes how the modeled inputs and outputs matched the available process data and what assumptions were made for process parameters.

4.2.1. Seasonal Variation

As noted in Section 2, the energy requirements at the Bird Island WWTP will vary significantly with the season. To capture this variation, the model is divided into two periods (summer and winter) with separate inputs. The 'summer' period represents a 6-month average from May to October and the 'winter' period represents a 6-month average from November to April. Items such as building heating loads, digester heating loads and ambient air temperature used for combustion are varied in the model from summer to winter. From climate data, Buffalo, NY has an average summer temperature of 62.6^{o} F, an average winter temperature of 32.8^{o}F and a total annual average temperature of 47.7^{o} F with average relative humidity at 76%.

4.2.2. Digesters

The solids input to the digesters were set to match the process data values presented in Figure 2-1. These values are summarized in Table 4-1 below.

Table 4-1. Digester Calibration Inputs

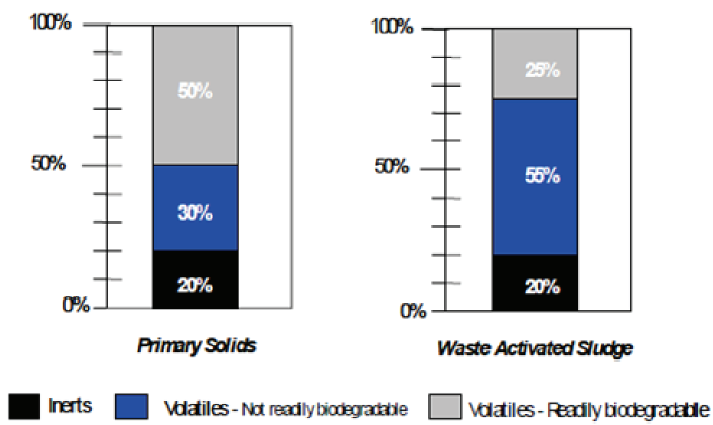
Solids Stream	Process Data		Model Values	
	dtpd	%VS	dtpd	%VS
Primary Sludge	25.4	--	25.4	75.0%
WAS	40.4	66.2%	40.4	66.0%
Digester Feed	66.2	69.7%	65.8	69.6%

Solids entering the digesters were modeled as consisting of three components:

- Readily degradable volatiles
- Not readily degradable volatiles
- Inerts

The modeled digesters transform readily degradable volatiles into biogas while passing the other two components on as digested solids. An example of these three components in PS and WAS is given in Figure 4-2.

Figure 4-2. Example of Components in Digester Solids



The %VS values presented in Table 4-1 were used to determine the percentage of inerts in each of the solids streams. To calibrate the model, the percentage of readily degradable and non-readily degradable volatiles was adjusted in each solids stream until the modeled digester output matched the data for digested solids. The results of this calibration are presented in Table 4-2.

Table 4-2. Digester Calibration Outputs

Solids Stream	Process Data		Model Values	
	dtpd	%VS	dtpd	%VS
Digester Effluent	38.6	53.1%	40.3	55.2%

The modeled performance of the digesters had a volatile solids reduction (VSR) of 51.5%. This is close to the data derived value of 50.8%. The amount of biogas generated in the digesters is a function of both VSR and Gas Yield. Gas Yield in the model is set as a user input variable. The modeled Gas Yield was adjusted to 10.1 cf/lb VSR so that the modeled gas production was 476 Mcf/day. The gas production from process data was 478 Mcf/day.

4.2.3. Incinerators

The incinerator portion of the model performs combustion calculations on the incoming feed, natural gas fuel and digester gas fuel as presented in Section 3.1 and detailed in Appendix B. The modeled incinerator also performs an energy balance on the combustion reaction determining how much energy is required to drive the reaction, how much energy is released from volatiles, how much energy is coming in through digester gas fuel (this is set as a user input) and how much natural gas fuel is needed to bring the combustion reaction into energy balance.

There are a large number of input variables for the incineration process that must be derived from process data or assumed. A list of the required input variables for the incinerator calibration is presented below along with the values used and the source of those values.

<u>Input Variables for Incinerator Calibration</u>

- Solids into incinerator – 32.2 dtpd – data value from Fig 2-1
- Water content of solids into incinerator – 25.3% total solids – data value from Fig 2-1
- Volatile solids into incinerator – 52.4% volatile solids – data value from Fig 2-1
- Chemical makeup of solids – 53.5% C, 8% H, 32.2% O, 4.7% N, 1.6% S – assumption
- **Heat value of volatiles – 9,000 Btu/lb – adjusted/determined from calibration**
- Excess combustion air – 40% – assumption
- Ambient air temp – 47.7^{o} F – yearly average from Buffalo, NY weather data
- Temp of incinerator feed – 60.6^{o} F – from data for sludge temperature
- Exhaust temp leaving afterburners – 1300^{o} F – approximate average from INC data
- Ash temp – 850^{o} F – assumption
- Digester gas to incineration – 476 Mcf/day – assumed all digester gas to incinerators
- Digester gas heat value – 640 Btu/cf – from sampling data provided

The variable 'heat value of volatiles' is highlighted above because it is the key value for determining incinerator energy balance. This value tends to be site specific to plant solids and is known to be difficult to predict empirically. It is strongly recommended that BSA begin a sampling regime to determine the heat value of volatiles for various plant solids streams. A sampling plan was developed in conjunction with BSA staff and is provided in Appendix I. Obtaining heat value of volatiles from actual sampling analysis will significantly enhance the accuracy of Energy Flow Model results.

The standard range from literature for the heat value of volatiles is 9,000-10,000 Btu/lb. The incinerator portion of the model was calibrated by adjusting the heat value of volatiles until the required natural gas input matched the average value from Figure 2-2. This calibration yielded a volatile heat value that was slightly lower than 9,000 Btu/lb and outside the typical range for solids of this type. The volatile heat value was set at 9,000 Btu/lb to calibrate the model. The results of this calibration are given in Table 4-3 below.

Table 4-3. Incinerator Calibration Gas Fuel Requirements

	Process Data		Model Values	
Gas Fuel	**Mcf/day**	**mmBtu/hr**	**Mcf/day**	**mmBtu/hr**
Digester Gas to Incinerator	478	12.8	476	12.7
Natural Gas to Incinerator	156	6.5	153	6.4

The modeled performance of the incinerators had a gas fuel energy input of 3.6 mmBtu/wet ton. This is close to the data derived value of 3.5 mmBtu/wet ton.

The incinerator portion of the model also provides the mass flow and chemical composition of the exhaust gas from the incinerator. The temperature of the exhaust gas flow is a user input that will affect the amount of gas fuel required by the incinerator and afterburners. The mass flow, composition and temperature of the exhaust are the key variables that determine how much energy can be recovered for beneficial utilization.

4.2.4. WHRBs and Steam Turbine

The new proposed WHRBs and steam turbine were modeled but could not be calibrated against existing process data because these processes do not yet exist. Instead these modeled components were compared to the performance specifications provided by the WHRB and steam turbine manufacturers.

The WHRB output steam production is based on the mass flow, composition and temperature of the incinerator exhaust. The change in enthalpy of this gas flow is equal to the energy required to boil water at 650 psig and superheat it to 650^{o} F. The performance specifications from the WHRB manufacturer is given on page 10 of Appendix C. The input conditions given to the manufacturer were 70,500 lbs/hr of exhaust at 1500^{o} F as calculated in Section 3.1.1. The comparison of the modeled WHRBs to these specifications is given in Table 4-4 below.

Table 4-4. WHRB Performance Calibration

Item	Performance Specification	Model Value
Exhaust Mass Flow	70,416 lbs/hr	70,504 lbs/hr
Exhaust Temperature	1500^{o} F	1500^{o} F
Steam Generation @ 650 psig/650^{o}F	22,300 lbs/hr	21,800 lbs/hr

The steam turbine generates electricity based on the change in enthalpy of main steam as it moves from high pressure to low pressure. Electrical generation will be determined by main steam mass flow, temperature and pressure as well as extraction mass flow, extraction pressure and exhaust pressure. The performance specifications from the steam turbine manufacturer are given on page 3 of Appendix E. The steam turbine was analyzed assuming that additional energy would be added to the system so that the WHRBs would be producing steam at maximum capacity which is 30,000 lbs/hr. The turbine was analyzed under two different extraction conditions which are described as Option 2 and Option 3 in

Section 3.5. The exhaust pressure of the turbine was given as 3" HgA. The comparison of the modeled steam turbine to these specifications under various extraction conditions is given in Table 4-5 below.

Table 4-5. Steam Performance Calibration

Item	Performance Spec	Model Value
Main Steam to Turbine	30,000 lbs/hr	30,019 lbs/hr
Electric Generation under Option 2 Extraction	1.74 MW	1.75 MW
Electric Generation under Option 3 Extraction	1.84 MW	1.82 MW

4.3. Energy Flow Model Scenario Analysis

The calibrated Energy Flow Model was used to evaluate an array of scenarios for the Bird Island WWTP. These scenarios encompassed some of the future decisions and operational options that would potentially be available to BSA with the implementation of an incinerator heat recovery and steam turbine cogeneration system. There were 19 separate scenarios developed which were grouped into four different evaluations described below:

- **Operational Mode Evaluation**: (Scenarios 1-8) – evaluated operational decisions on how to rout solids between digesters and incinerators. Also examined additional energy addition to maximize WHRB output and to maximize electric generation.
- **Additional Import Evaluation**: (Scenarios 9-14) – evaluated the value of accepting additional import sludge up to the capacity of a single incinerator.
- **Hot Water Recovery Evaluation**: (Scenarios 15-19) – evaluated various options for beneficially utilizing hot water from the condenser to boost system electrical efficiency.
- **Energy Price Sensitivity**: (Scenarios 1-4) – re-examined Scenarios 1-4 under varying prices of electricity and natural gas to evaluate the potential economic effects resulting from changes to energy prices.

These evaluations along with the baseline scenario are described in the sections below.

4.3.1. Baseline Scenario

The baseline scenario served as a comparison point for all other scenarios to determine the net benefit as compared to the baseline. The baseline assumed that 10.9 dtpd of import sludge would be delivered to the plant for treatment along with the PS and WAS produced onsite as described in Section 2.1. The baseline assumed that the additional import sludge would be sent directly to incineration without digestion. The baseline also assumed that the existing heat recovery system at Bird Island WWTP was not in operation and therefore any incinerator exhaust heat would be wasted. The energy balance for the baseline scenario is given in Table 4-6 below.

Table 4-6. Baseline Energy Balance

Scenario	Natural Gas Use [mmBtu/hr]				Digester Gas Use to INC [mmBtu/hr]	Unused Energy [mmBtu/hr]	Electric Generation [MW]
	To Aux Boilers	To INC	To AB Chamber	Total			
Baseline Scenario	13.4	9.7	0.0	23.1	12.7	20.6	0

Under the baseline scenario it was assumed that all digester gas generated was used for fuel in the incinerators. Natural gas was used to heat the plant via auxiliary boilers and also used as supplemental fuel for incineration. These natural gas usage levels were used as baseline benchmarks to compare against all other scenarios evaluated. In the baseline, exhaust exits the afterburners at 1300^{o} F which was derived from plant process data. There is also an unused energy value of 20.6 mmBtu/hr which represents the heat in the incinerator exhaust wasted to the scrubber system. There is no electrical generation in the baseline scenario.

4.3.2. Operational Mode Evaluation

This evaluation was comprised of 8 different scenarios aimed at determining the most optimal operational modes for routing solids and energy through the plant. These scenarios included 10.9 dtpd of import sludge as part of the plant's solids handling regime. Incinerator exhaust was heated to 1,500^{o} F and delivered to the proposed heat recovery and steam turbine cogeneration system described in Section 3. These scenarios examined whether to send various solids to either digesters or directly to incinerators. These scenarios also examined the benefits of using additional natural gas to maximize the output of the WHRB and maximize electrical production. The scenarios in this evaluation are described below.

Scenario 1 – Import to INC, Maximize WHRB – in this scenario, all import is sent directly to incineration while all PS and WAS generated at the plant is sent to digesters. Additional natural gas is added via the afterburners so that the WHRB reaches its maximum steam output capacity of 30,000 lbs/hr.

Scenario 2 – Import to DIG, Maximize WHRB – in this scenario, all import is sent to the digesters along with all PS and WAS generated at the plant. Additional natural gas is added via the afterburners so that the WHRB reaches its maximum steam output capacity of 30,000 lbs/hr.

Scenario 3 – Import to INC, Only Exhaust to WHRB – in this scenario, all import is sent directly to incineration while all PS and WAS generated at the plant is sent to digesters. No additional natural gas is added via the afterburners so the WHRB produces steam only from the heat contained in the incinerator exhaust.

Scenario 4 – Import to DIG, Only Exhaust to WHRB – in this scenario, all import is sent to the digesters along with all PS and WAS generated at the plant. No additional natural gas is added via the afterburners so the WHRB produces steam only from the heat contained in the incinerator exhaust.

Scenario 5 – PS and Import to INC, Maximize WHRB – in this scenario, all import is sent directly to incineration along with 100% of the PS and generated at the plant. WAS is sent to digesters. Additional natural gas is added via the afterburners so that the WHRB reaches its maximum steam output capacity of 30,000 lbs/hr.

Scenario 6 – WAS and Import to DIG, Maximize WHRB in this scenario, all import is sent directly to incineration along with 100% of the WAS and generated at the plant. PS is sent to digesters. Additional natural gas is added via the afterburners so that the WHRB reaches its maximum steam output capacity of 30,000 lbs/hr.

Scenario 7 – Import to INC, Only Exhaust to WHRB – in this scenario, all import is sent directly to incineration along with 100% of the PS and generated at the plant. WAS is sent to digesters. No additional natural gas is added via the afterburners so the WHRB produces steam only from the heat contained in the incinerator exhaust.

Scenario 8 – Import to DIG, Only Exhaust to WHRB – in this scenario, all import is sent directly to incineration along with 100% of the WAS and generated at the plant. PS is sent to digesters. No additional natural gas is added via the afterburners so the WHRB produces steam only from the heat contained in the incinerator exhaust.

The Energy Flow Model results for Scenarios 1-8 are given in Table 4-7 and Figure 4-3.

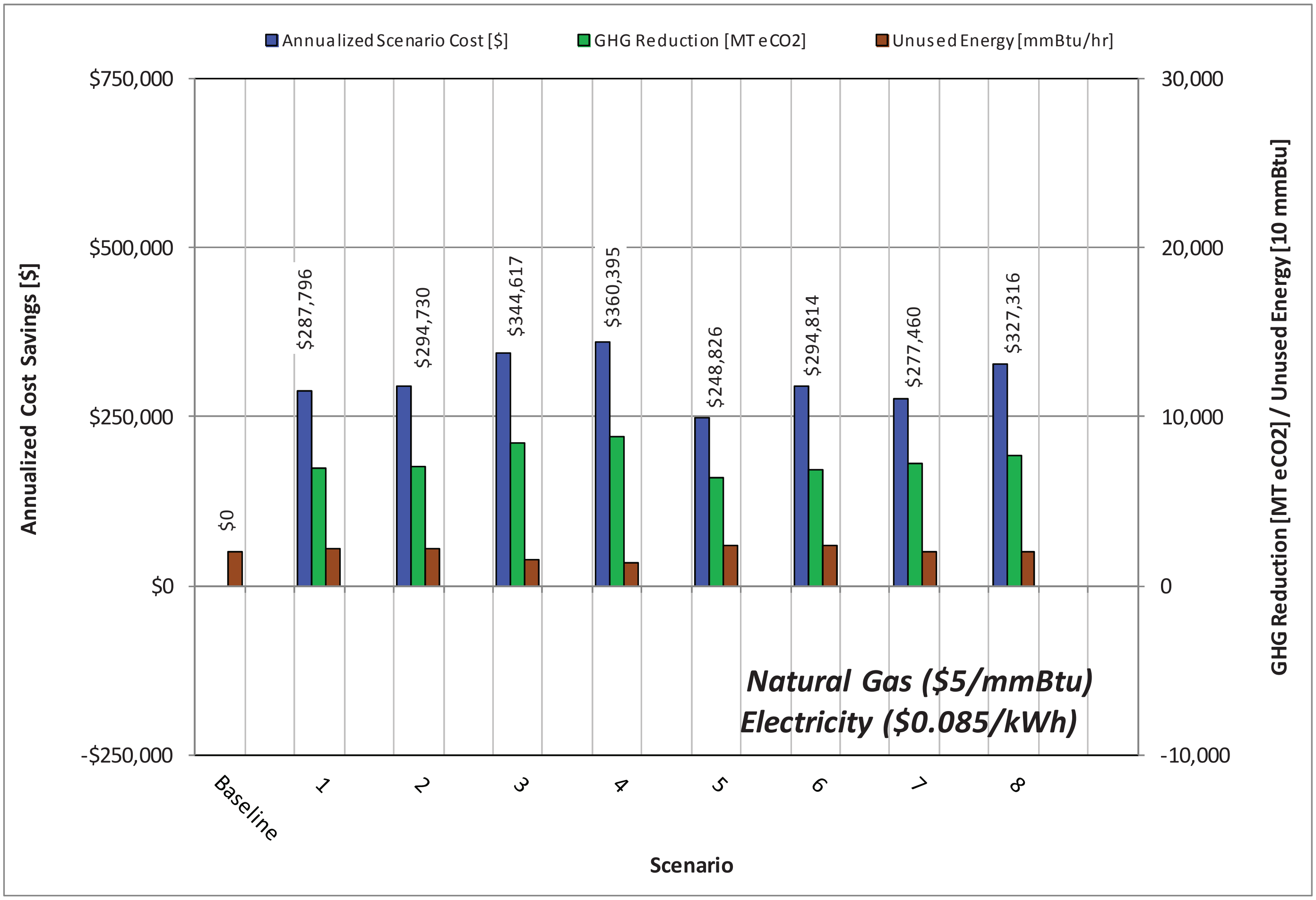
Table 4-7. Model Results for Scenarios 1-8

Scenario	Description	Annualized Cost Savings [$]	GHG Reduction [MT eCO2]	Unused Energy [mmBtu/hr]	Avg MW
Baseline	No WHRB or Steam Turbine	$0	0	20.6	0.00
1	Import to INC, Max steam from WHRB	$287,796	6,934	22.5	1.75
2	Import to DIG, Max steam from WHRB	$294,730	7,055	22.0	1.71
3	Import to INC, Exhaust only to WHRB	$344,617	8,473	15.6	1.21
4	Import to DIG, Exhaust only to WHRB	$360,395	8,834	14.0	1.09
5	All PS to INC, Max steam from WHRB	$248,826	6,438	23.6	1.82
6	All WAS to INC, Max steam from WHRB	$294,814	6,834	24.2	1.87
7	All PS to INC, Exhaust only to WHRB	$277,460	7,215	20.0	1.55
8	All WAS to INC, Exhaust only to WHRB	$327,316	7,715	20.2	1.56

The results show that there is a significant annual cost savings for all scenarios in this evaluation in the range of $250K - $360K per year. GHG reductions ranged from 6,400 – 8,800 metric tons of equivalent CO_2 [MT eCO_2] which equates to approximately removing 1,250 to 1,700 cars from the road. These economic and environmental benefits over the baseline are derived mainly from the electricity generated by the steam turbine.

In comparing the scenarios, it appeared that sending PS or WAS directly to incinerators was not an optimal operational mode as these scenarios (Scenarios 5-8) were generally out performed by scenarios that digested the majority of solids (Scenarios 1-4). The model accounts for the additional electricity usage that would be required to pass undigested plant solids through dewatering centrifuges. This may be a reason why sending plant solids directly to incineration would appear to be undesirable.

Figure 4-3. Model Results for Scenarios 1-8



The results also showed that the scenarios that used only exhaust heat in the WHRB (Scenarios 3, 4, 7, 8) outperformed scenarios in which additional natural gas was used to maximized WHRBs (Scenarios 1, 2, 5, 6). This result indicates that at current energy prices, the cost of additional natural gas is greater than the value of additional electricity generated in the turbine. It should be noted that this evaluation does not encompass items such as peak period electric rates or demand charges which could enhance the viability of additional electric generation.

When comparing scenarios that send import sludge to incinerators versus digesters (Scenario 1 vs. 2, or Scenario 3 vs. 4) there does not appear to be a significantly large difference in either economics or GHG reductions. This finding suggests that the plant staff could remain flexible in the routing of import solids to either digesters or incinerators and make decisions that are based on ease of operations.

From this evaluation, the most optimal scenarios appear to be Scenarios 3 and 4. These scenarios digest all PS and WAS generated at the plant and allow flexibility on where to best route import sludge delivered to the plant. It should be noted that these two scenarios also have the lowest electrical generation of the group with electrical production only slightly over 1 MW. Analyses presented in Section 4.3.5 show under what price conditions does this lower generation remain favorable.

In examining the unused energy values from Table 4-7, it appears that unused energy is increased over the baseline in scenarios that maximize WHRB steam production (Scenarios 1, 2, 5, 6). The most optimal scenarios (Scenarios 3 and 4) reduced the unused energy in the system from approximately 20 mmBtu/hr down to 15 mmBtu/hr.

4.3.3. Additional Import Evaluation

This evaluation examined the energy benefits that could be gained by BSA from accepting additional import sludge from outlying communities. The previous scenarios (Scenarios 1-8) assumed that Bird Island WWTP would receive 10.9 dtpd of import sludge. The 6 scenarios in this evaluation (Scenarios 9-14) examine how the system would perform if additional sludge was accepted up to the point that a single incinerator reaches its capacity of 60 dtpd. It should be noted that all import sludge to this point was assumed to have similar characteristics to PS and WAS generated at the plant which includes an assumed heat value of 9,000 Btu/lb volatiles. This heat value is on the lower end of the typical range. Additionally, cake sampling results were received for Amherst import sludge that showed a heating value that was significantly higher at approximately 11,000 Btu/lb volatiles. These sampling results are given in Appendix J. This evaluation examined system performance at varying ranges of heat values for import sludge. The scenarios in this evaluation are described below.

Scenario 9 – 26 dtpd Import to INC, Maximize WHRB – in this scenario, 26 dtpd of import is sent directly to incineration. This maximizes incinerator feed to 59.6 dtpd. Import sludge is assumed to be 9,000 Btu/lb volatiles. Additional natural gas is added via the afterburners so the WHRB reaches its maximum steam output capacity of 30,000 lbs/hr.

Scenario 10 – 26 dtpd Import to INC, Only Exhaust to WHRB – in this scenario, 26 dtpd of import is sent directly to incineration. This maximizes incinerator feed to 59.6 dtpd. Import sludge is assumed to be 9,000 Btu/lb volatiles. No additional natural gas is added via the afterburners so the WHRB produces steam only from the heat contained in the incinerator exhaust.

Scenario 11 – Scenario 10: 9,500 Btu/lb volatiles – this scenario has the same sludge loading conditions as Scenario 10 with only exhaust heat going to the WHRBs. In this scenario Import sludge is assumed to be 9,500 Btu/lb volatiles.

Scenario 12 – Scenario 10: 10,000 Btu/lb volatiles – this scenario has the same sludge loading conditions as Scenario 10 with only exhaust heat going to the WHRBs. In this scenario Import sludge is assumed to be 10,000 Btu/lb volatiles.

Scenario 13 – Scenario 10: 10,500 Btu/lb volatiles – this scenario has the same sludge loading conditions as Scenario 10 with only exhaust heat going to the WHRBs. In this scenario Import sludge is assumed to be 10,500 Btu/lb volatiles.

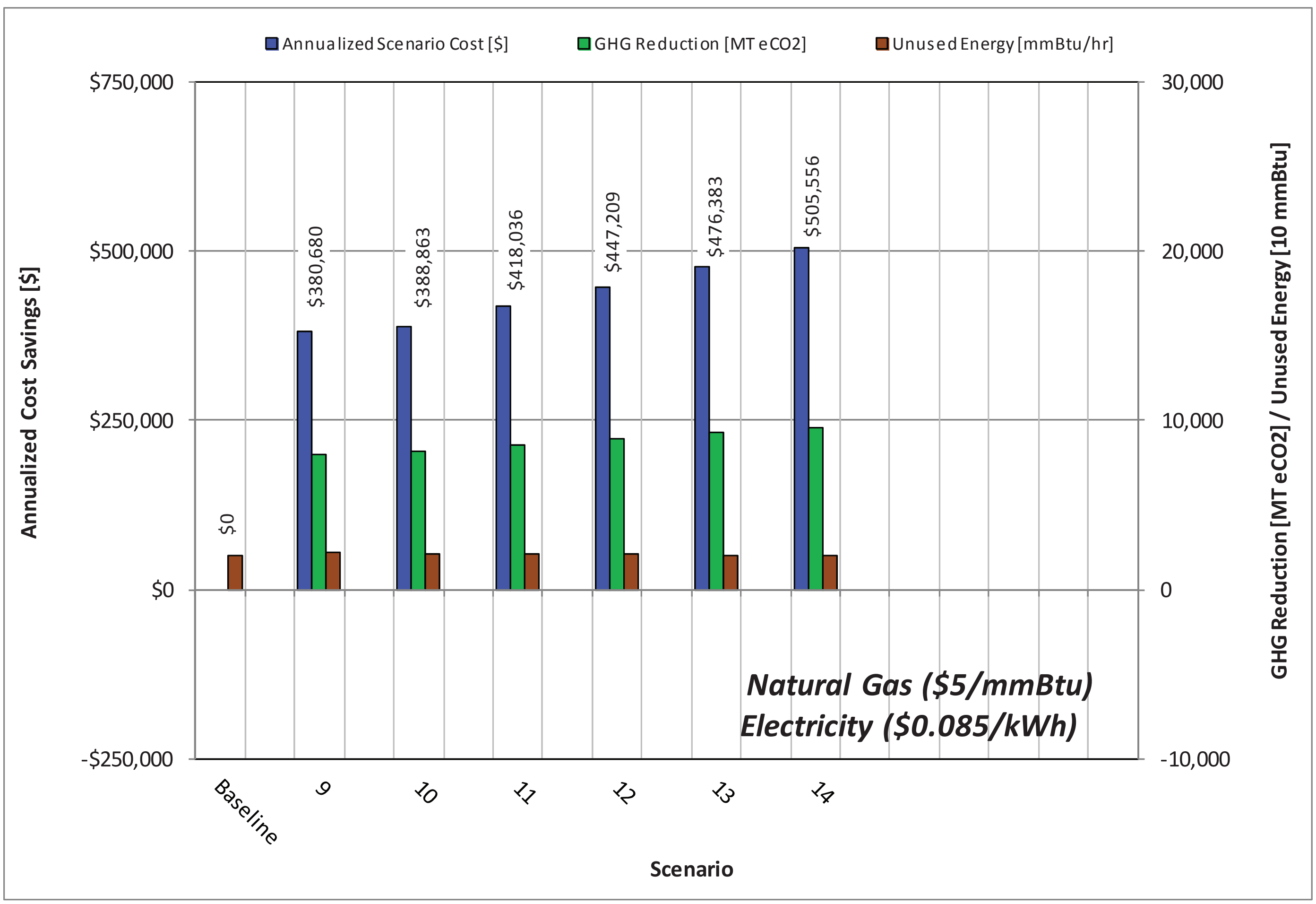
Scenario 14 – Scenario 10: 11,000 Btu/lb volatiles – this scenario has the same sludge loading conditions as Scenario 10 with only exhaust heat going to the WHRBs. In this scenario Import sludge is assumed to be 11,000 Btu/lb volatiles.

The Energy Flow Model results for Scenarios 9-14 are given in Table 4-8 and Figure 4-4.

Table 4-8. Model Results for Scenarios 9-14

Scenario	Description	Annualized Cost Savings [$]	GHG Reduction [MT eCO2]	Unused Energy [mmBtu/hr]	Avg MW
Baseline	No WHRB or Steam Turbine	$0	0	20.6	0.00
9	26 dtpd Import to INC , Max WHRBs	$380,680	7,982	22.5	1.74
10	26 dtpd Import to INC , Exhaust to WHRBs	$388,863	8,206	21.5	1.66
11	Scenario 10: 9,500 Btu/lb volatile	$418,036	8,560	21.1	1.64
12	Scenario 10: 10,000 Btu/lb volatile	$447,209	8,914	20.8	1.61
13	Scenario 10: 10,500 Btu/lb volatile	$476,383	9,268	20.5	1.59
14	Scenario 10: 11,00 Btu/lb volatile	$505,556	9,622	20.1	1.56

Figure 4-4. Model Results for Scenarios 9-14



When comparing Scenarios 9 and 10 from the results above, it appears that these two operating conditions are relatively equivalent. What this tells us is that when an incinerator is being loaded to capacity at approximately 60 dtpd, the exhaust heat generated will nearly maximize WHRB steam production at 30,000 lbs/hr (given exhaust is heated to 1,500^o F). Scenarios 9 and 10 provide cost savings of approximately $380K per year which is favorable compared to the most optimal scenarios from the previous evaluation (Scenarios 3 and 4) which had approximate cost savings of $360K per year. It should be noted that the modeled economics incorporated only the energy benefits of each scenario so any revenue associated with additional tipping fees for receiving sludge were not considered. GHG reductions for all these scenarios fell in the range of 8,000-9,600 MT eCO_2 per year which equates to approximately removing 1,550 to 1,900 cars from the road.

Scenarios 9 and 10 also represent a 'worst case scenario' for import sludge heating values which were assumed at relatively low value of 9,000 Btu/lb volatile. Since import sampling results presented in Appendix J showed heating values as high as 11,000 Btu/lb volatile, Scenarios 11, 12, 13 and 14 were run at increasing levels of import sludge heating values. As expected, as sludge heating value increases, economic performance also increases as less and less natural gas is needed for incineration. Scenario 14 represents what can be considered the 'best case scenario' for sludge heating value and has a cost savings of approximately $500K per year. If BSA was to accept 26 dtpd of import sludge directly to incinerators, the benefits would likely fall between Scenario 10 and Scenario 14.

This evaluation shows that accepting additional import sludge from outlying communities would provide several benefits. The additional sludge adds energy to the system which improves economic performance by approximately $100-$150K per year. The additional sludge also drives the most optimal electrical production levels higher in the range of 1.5 to 1.75 MW which could provide additional savings via demand and peak period charges. Finally, although not considered in this evaluation, accepting additional import solids will also result in additional economic benefits through the collection of tipping fees.

4.3.4. Hot Water Recovery Evaluation

The scenarios evaluated to this point have had a maximum electrical generation potential of 1.75 MW. In these previous scenarios, the steam generated in the WHRB has already been maximized. The 5 scenarios in this evaluation (Scenarios 15-19) examine ways to further increase electrical production by beneficially utilizing hot water (HW) leaving the condenser thereby reducing the demand for extraction steam.

Scenario 15 explores Option 3 presented in Section 3.5.2 which would eliminate steam heating in the Raw Wastewater Pump Station, Screen and Grit Chamber and Admin Building by replacing the existing steam to HW converters in the Admin Building basement with new high efficiency HW condensing boilers. Scenarios 16-19 propose concepts for recovering and utilizing HW exiting the condenser. Unlike all other model runs, capital costs were not developed for implementing these concepts. The purpose of these scenarios is to estimate the energy value of the proposed ideas. Decisions on implementation would have to weigh the energy value gained versus the capital cost and any operational complexities.

The utilization of condenser water for heating would require that water to be of a certain temperature. The desired temperature can be achieved by throttling the supply of FE water to the condenser. While reducing the supply of water to the condenser will raise the temperature, it will also raise the exhaust steam pressure and thereby lower electrical efficiency of the turbine. For this reason, using the lowest possible temperature for the specific heating application would be desired. Table 4-9 below gives a range of exhaust pressures and the corresponding temperature of condenser water. Table 4-9 also gives some assumed temperatures required for specific heating applications.

Table 4-9. Exhaust Pressure and Condenser Water Temperature

Exhaust Pressure	Condenser Water Temperature	Applications of Condenser Water
3" HgA	103^{o} F	Waste to Drain
6" HgA	129^{o} F	Digester Heating, Chillers
12" HgA	157^{o} F	Building Heating

The scenarios in this evaluation are described below.

Scenario 1 – Import to INC, Maximize WHRB – this scenario is repeated as a comparison point for enhancing electrical production. With WHRBs maximized the electrical generation potential of the system is 1.75 MW. All other scenarios in this evaluation will start with Scenario 1 conditions.

Scenario 15 – New HW Boilers in Admin Building – As described above, this scenario lessens the extraction steam demand by switching a portion of the plant heating load to high efficiency HW boilers to be installed in the Admin Building basement.

Scenario 16 – Heat Digesters with Condenser HW – in this scenario, HW leaving the condenser would be used for heating the digesters. The exhaust pressure is set to 6” HgA in both the summer and winter to achieve water temperatures for this application.

Scenario 17 – Run Chillers off Condenser HW – in this scenario, HW leaving the condenser would be used to drive new HW absorption chillers for building cooling in the summer. The exhaust pressure is set to 6” HgA in the summer achieve water temperatures for this application. Exhaust pressure remains at 3” HgA in the winter.

Scenario 18 – Heat Chemical Handling with Condenser HW – in this scenario, HW leaving the condenser would be used to heat the group of buildings currently heated by the steam to HW converters in the Chemical Handling area. The exhaust pressure is set to 12” HgA in the winter achieve water temperatures for this application. Exhaust pressure remains at 3” HgA in the summer.

Scenario 19 – Heat Buildings and Digesters with Condenser HW – in this scenario, HW leaving the condenser would be used to replace all major steam heating and cooling loads throughout the plant. The exhaust pressure is set to 12” HgA in the winter and 6” HgA in the summer to achieve water temperatures for this application.

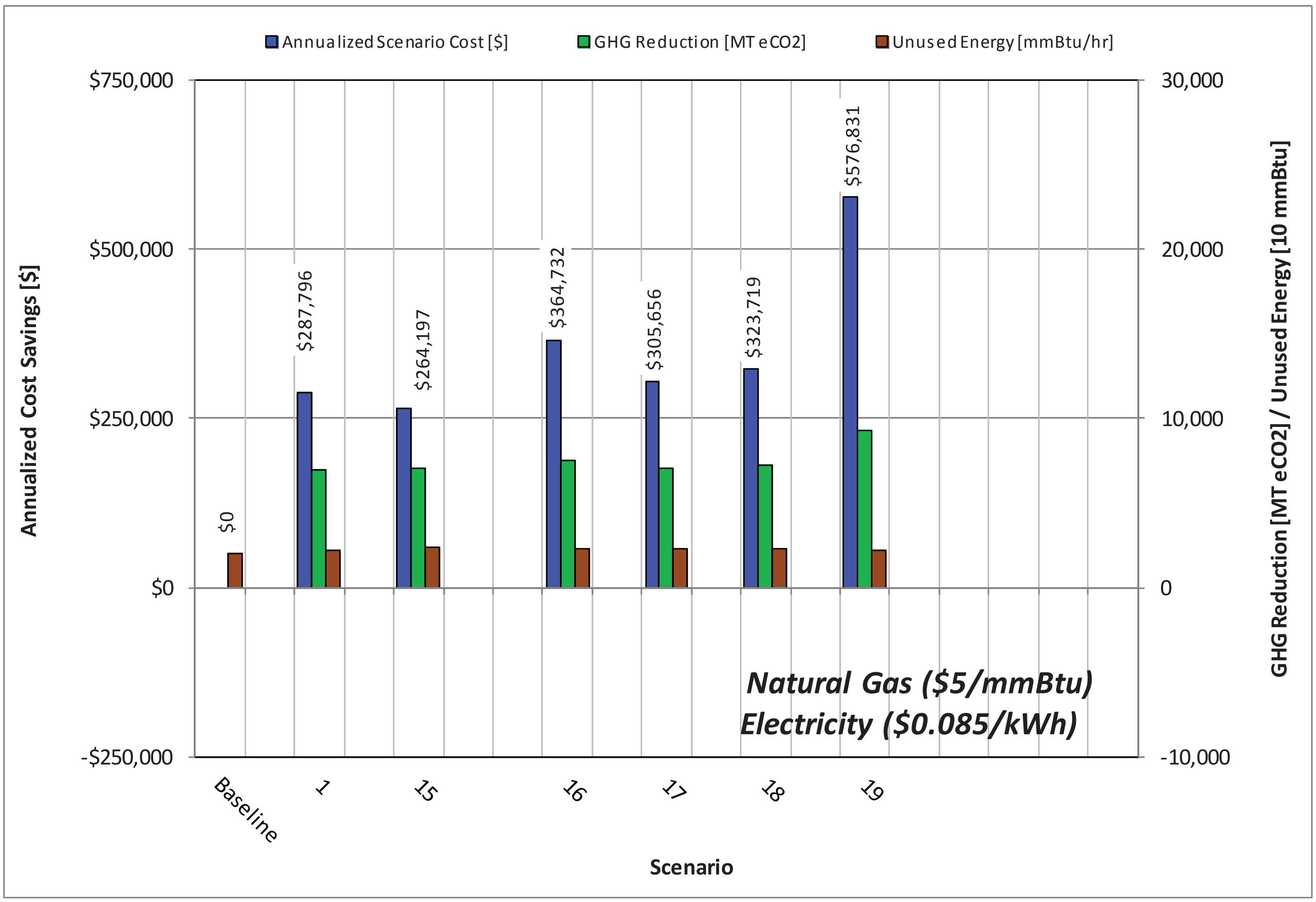
The model results for Scenarios 15-19 are given in Table 4-10 and Figure 4-5.

Table 4-10. Model Results for Scenarios 15-19

Scenario	Description	Annualized Cost Savings [$]	GHG Reduction [MT eCO2]	Unused Energy [mmBtu/hr]	Avg MW
Baseline	No WHRB or Steam Turbine	$0	0	20.6	0.00
1	Import to INC, Max WHRBs	$287,796	6,934	22.5	1.75
15	HW Boilers in Admin Building	$264,197	7,061	23.9	1.84
16*	Heat Digesters with Condenser HW	$364,732	7,567	23.0	1.85
17*	Run Chillers off Condenser HW	$305,656	7,081	22.9	1.77
18*	Heat Chem Handling with Condenser HW	$323,719	7,229	23.3	1.79
19*	Heat Buildings and Digesters with HW	$576,831	9,311	22.4	2.14

** - Capital cost of implementation is not incorporated into model results*

Figure 4-5. Model Results for Scenarios 15-19



In comparing Scenario 1 to Scenario 15, it appears that the additional electrical generation resulting from implementing new high efficiency HW boilers in the Admin Building does not justify the cost of implementation. It may be possible to justify this system improvement in the future when the current steam to HW converters or other important heating infrastructure is in need of replacement. It should be noted that Scenario 16 assumed that by eliminating the furthest outlying heating applications, the plant's steam system could be reduced to 60 psig. This would make the plant heating system more efficient and also require the steam turbine to be designed with a 60 psig extraction port. This improvement may still be desirable if BSA would like to maximize electrical generation and/or has any problems with the current steam heating in this area.

From Scenario 16, there was a significant energy cost savings resulting from heating the digesters with condenser water of approximately $75,000 per year. There would likely have to be alterations made to the digester heating system to deliver the water to the digesters, to use heating water at only 130^{o} F and to run treated FE water through heat exchangers. This type of system could be considered in the future when major components of the digester heating system are in need of replacement.

From Scenario 17, running absorption chillers in the summer off hot water does not seem to provide a significant economic return. This is because the exhaust pressure for the entire system must be raised in summer to only use a small amount of condenser water for the cooling load. Replacement of existing steam chillers with HW chillers would also be costly.

Scenario 18 would involve sending condenser water to the heating station at the Chemical Handling area. This would be conceptually feasible as the existing steam to HW converters are in close proximity to the condenser and are accessible via tunnel. There would be a variety of technical considerations, however, for this change including using 157^{o} F water in the HW heating systems (current system uses ~200^{o} F) and using treated FE water in the heating distribution network.

Scenario 19 shows that switching the entire plant to HW heating would approximately double the economic benefits from Scenario 1 providing an additional $290K per year in cost savings. This would involve an extensive overhaul of the entire plant heating system which could only be achieved through long term planning and multi-phased capital improvements.

Of all the scenarios examined in this evaluation, heating digesters with condenser water appears to show the best promise in terms of feasibility and significant economic returns. This improvement could be considered when major replacements in the digester heating system are required.

4.3.5. Energy Price Sensitivity

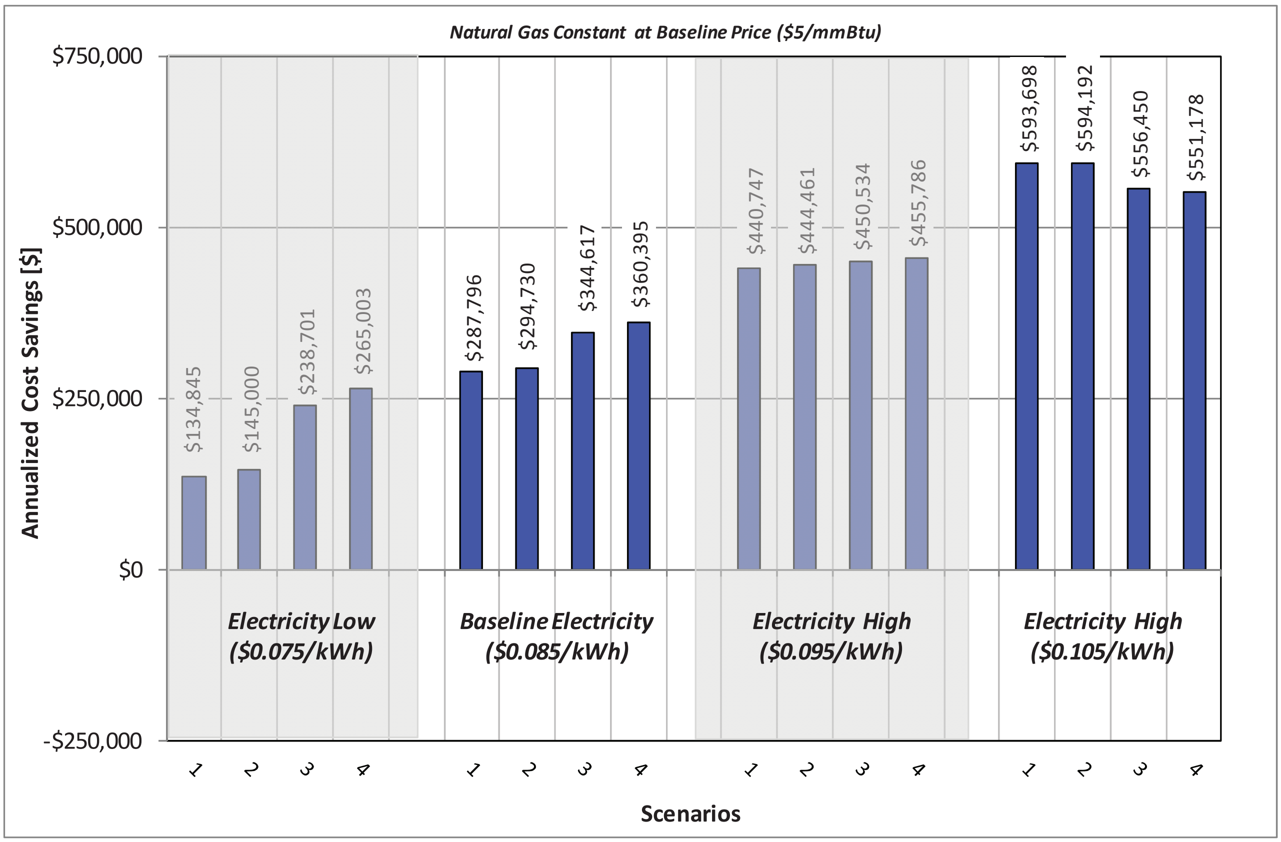
Fluctuations in future energy prices will have a significant impact on the economics of a heat recovery and steam turbine cogeneration system. Predicting future energy prices is outside the scope of this study. However, an evaluation was performed to examine how some of the previously identified scenarios could perform economically under a range of future energy prices. This evaluation started with Scenarios 1-4 from Section 4.3.2 and examined how they would perform economically when energy prices were lowered and raised. Recall that Scenarios 1 and 2 involved purchasing additional natural gas to maximize electric production while Scenarios 3 and 4 relied on only incinerator exhaust heat to generate steam for the turbine. The evaluations are described below.

Sensitivity to Electric Price – Scenarios 1-4 were examined with natural gas price held constant at the baseline value of $5/mmBtu. Electric price was varied at $0.075, $0.085, $0.095 and $0.105 per kWh.

Sensitivity to Natural Gas Price – Scenarios 1-4 were examined with electric price held constant at the baseline value of $0.085/kWh. Natural gas price was varied at $4, $5, $6 and $7 per mmBtu.

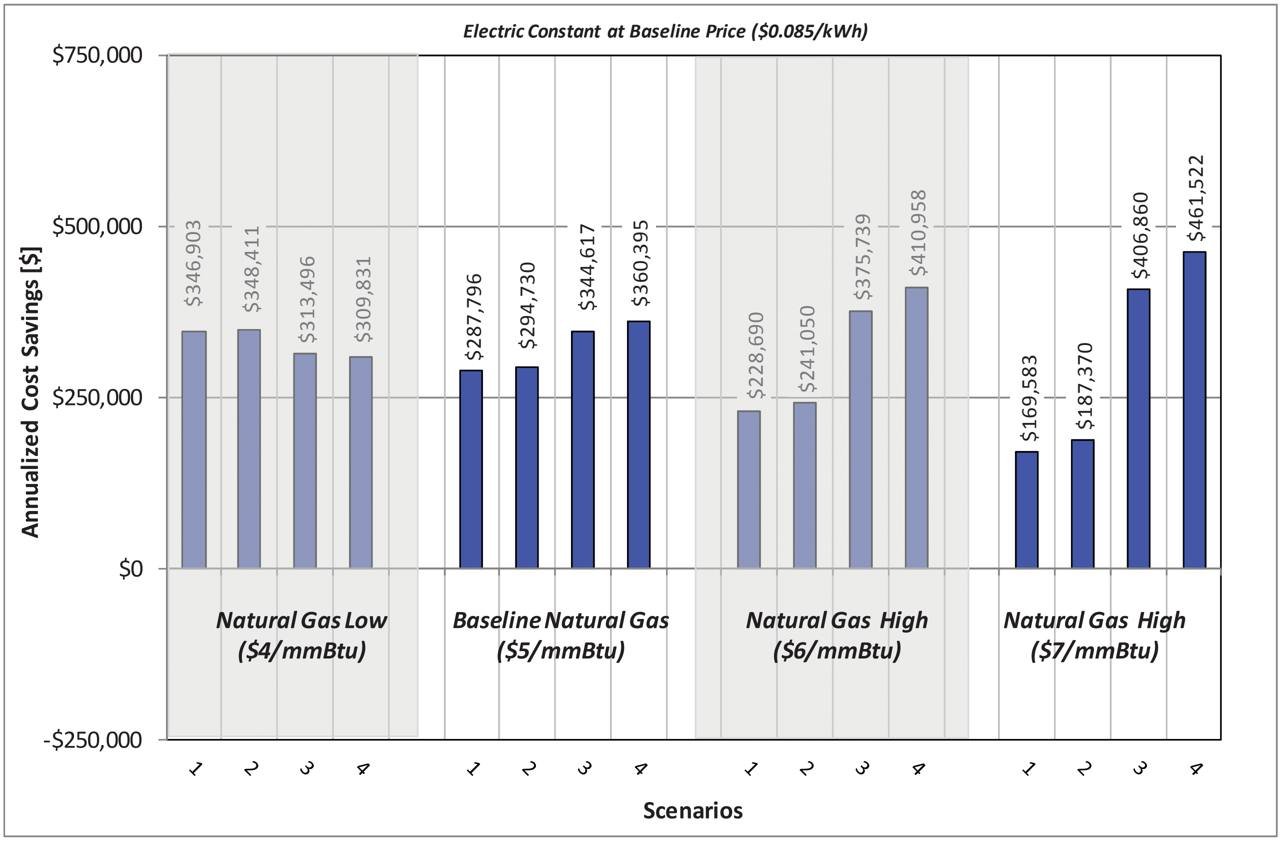
The results of these sensitivity analyses are shown in Figures 4-6 and 4-7 below.

Figure 4-6. Sensitivity to Electric Price



The trends from Figure 4-6 results are expected as higher electric prices tend to favor the scenarios that maximize electrical production (Scenarios 1 and 2). It is interesting to note the price value at which a change in operation is warranted. At the current price of $0.085/kWh, generation with only incinerator exhaust (Scenarios 3 and 4) is favorable. With a 1 cent increase to $0.095/kWh all scenarios appear to be equivalent, and with a 2 cent increase to $0.105/kWh the maximizing electric production (Scenarios 1 and 2) is favorable. BSA could potentially switch operating modes depending on the price of electricity including ramping up generation during peak periods and ramping down generation during non-peak periods. Demand charges should also be considered in this type of decision.

Figure 4-7. Sensitivity to Natural Gas Prices



The trends from Figure 4-7 results are also expected as lower natural gas prices tend to favor the scenarios that maximize electrical production (Scenarios 1 and 2). At the current price of $5/mmBtu or higher, generation with only incinerator exhaust (Scenarios 3 and 4) is favorable. With a $1 decrease to $4/mmBtu, maximizing electric production (Scenarios 1 and 2) is favorable. Similar to the electricity analysis, BSA could potentially switch operating modes by ramping generation up and down depending on the price of natural gas.

4.4. Conclusions

The evaluations presented in this section show how the Energy Flow Model tool can be used to guide decisions on energy utilization throughout the plant. Some general conclusions from these initial evaluations are summarized below.

- Understanding the composition of the solids to be routed through the plant will greatly enhance the accuracy of model results. Regular sampling and analysis should be conducted on PS, WAS, and various Import Sludge for items such as water content, volatile solids content, chemical composition and heat value. A proposed sampling plan that the BSA can follow to initiate this data collection is provided in Appendix I.

- The proposed incinerator heat recovery and steam turbine cogeneration system would provide cost savings in the range of $290K - $360K per year. GHG reductions ranged from 7,000 – 8,800 MT eCO_2 which equates to approximately removing 1,350 to 1,700 cars from the road.

- Under current energy prices, the most optimal operation for the proposed system would be to only generate steam with incinerator exhaust heated to 1,500^o F. Adding additional natural gas to maximize electric generation would not be favorable unless demand charges and/or peak period rates were considered.

- Sending PS or WAS generated at the plant to incineration does not appear to be economically favorable. Sending Import sludge to either digesters or incinerators appears to be energetically equivalent and should be routed based on ease of operations.

- Accepting additional import sludge would be beneficial to BSA based only on the economics of energy gains. BSA could accept up to 26 dtpd of import directly to incineration while keeping only 1 incinerator in service. The cost savings in this instance would rise to $380K-$500K per year depending on the heat value of import sludge.

- Adding a new HW boiler system in the Admin Building basement (Option 3 from Section 3.5.2) would make the plant more energy efficient and increase electrical generation, but would not increase the overall economic performance due to the required capital investment.

- Electrical production from the proposed system could be increased by beneficially utilizing hot water exiting the condenser. The most feasible and economically favorable option for utilizing condenser water appears to be heating digesters.

- The most economically favorable operational modes for the proposed system will depend on energy prices. BSA could ramp electrical generation up when favorable by purchasing additional natural gas and maximizing steam production in the WHRB.

5. Conclusions and Recommendations

The proposed incinerator heat recovery and steam turbine cogeneration system as described in Section 3 is recommended for implementation at Bird Island WWTP. The proposed system is economically viable with an estimated simple payback period of 8.2 years which could be reduced by approximately 1 additional year with NYSERDA incentives. From a feasibility perspective, the proposed system would integrate well into the current plant processes. New WHRBs would utilize existing space and ductwork of the current WHRBs. The steam turbine generator and condenser would be conveniently located in the Blower Building adjacent to the main plant switchgear and with tunnel access to the Megastructure. Also the existing Final Effluent (FE) water system is an ideal condenser water source that has enough existing capacity to service the turbine needs.

The economics developed in Section 3 for the proposed system is summarized below.

Table 5-1. Estimated Capital Cost for Proposed System

Item	Units	Unit Cost	Equipment Cost	Installation Cost	Total Cost
New WHRB	2	$1,600,000	$3,200,000	$1,800,000	$5,000,000
In-Kind WHRB Replacement Credit	2	$1,250,000	$2,500,000	$1,600,000	($4,100,000)
Incremental WHRB Cost	LS				$900,000
New Boiler Feedwater Pumps	3	$28,000	$84,000	$42,000	$126,000
Turbine and Condenser	1	$2,250,000	$2,250,000	$325,000	$2,575,000
Boiler Water Treatment	1	$79,000	$79,000	$25,000	$104,000
New Burners in AB Chambers	LS				$162,000
Steam Piping from Boiler to Turbine	LS				$180,000
Electrical Modifications	LS				$109,000
Connection of Extraction Steam	LS				$159,000
FE Water System Modifications	LS				$50,000
Net Subtotal					$4,365,000
Miscellaneous Additions	15%				$655,000
General Conditions	12%				$524,000
Contractor Overhead and Profit	15%				$655,000
Engineering	25%				$1,091,000
Net Total Capital Cost					**$7,290,000**

Table 5-2. Estimated Payback Period for Proposed System

Item	Value	Units	Comment
Electric Generation	1.74	MW	
Electric Generation	15,242,400	kWh/yr	
Parasitic Electric Load	424,772	kWh/yr	Boiler Feedwater Pumps, FE Pumps, RO System
Net Generation	14,556,229	kWh/yr	
Electric Savings	$1,237,000	per year	@ $0.085/kWh
Maintenance Cost	$56,000	per year	Boiler Water Treatment, Turbine O&M including overhauls
Additional Natural Gas	58,692	mmBtu/yr	30% increase over baseline (from 23.1 to 29.8 mmBtu/hr)
Natural Gas Cost	$293,000	per year	@ $5/mmBtu
Net Cost Savings	$888,000	per year	
Capital Cost	$7,290,000		
Simple Payback Period	**8.2**	**years**	

From an O&M standpoint, existing BSA boiler staff could operate and maintain the new WHRBs. Operation and monitoring of the steam turbine generator would require a minimal level of attention which could be assumed by existing plant staff. Major turbine maintenance procedures and inspections would be performed under a contract with the turbine manufacturer. Implementing the proposed system would also help to simplify incinerator operations. With a heat recovery system installed on incinerator exhaust, energy used for incinerator combustion will no longer be wasted. Incinerator operators can focus on maintaining a consistent combustion reaction without as much concern for excess fuel use or elevated exhaust temperatures.

Some additional recommendations regarding the implementation of the proposed system are given below.

Pressure Reduction of Plant Steam Heating Pressure – it is recommended that BSA attempt to lower its steam heating pressure. This could be accomplished by gradually lowering the system pressure over the course of a winter heating season. The current pressure levels are in the range of 100-110 psig. It is estimated that the pressure could be reduced to 80 psig. Guidelines and instructions for reducing system pressure is provided in Appendix F.

Procurement Contracts for New WHRBs and Steam Turbines – the major equipment for the proposed system would involve long manufacturing lead times with the lead time for the steam turbine generator estimated at 48 weeks. It is recommended that BSA consider executing separate procurement contracts for major equipment ahead of the system installation contract to mitigate coordination issues stemming from long lead times. Procurement contracts will save cost by eliminating certain contractor markups but will also incur more engineering cost for document preparation.

Section 4 presented the Energy Flow Modeling tool developed for Bird Island WWTP and also demonstrated ways in which the model could be used to analyze plant energy utilization scenarios. The model will be submitted to BSA to be used in evaluating any future decisions that may arise regarding solids handling and/or energy utilization. The model can be adjusted and refined in the future based on the aspects that BSA finds most useful.

The model evaluations presented in Section 4 yielded some interesting results and conclusions which are briefly summarized below.

- The initial expected Import sludge loading condition is 10.9 dtpd. With the proposed system implemented, the annual cost savings was estimated to be \$290K - \$360K per year which includes payments for capital cost. The GHG reductions ranged from 7,000 – 8,800 MT eCO_2 which equates to approximately removing 1,350 to 1,700 cars from the road.

- Sending PS or WAS generated at the plant to incineration does not appear to be economically favorable. There did not appear to be a significant energy difference between sending Import sludge to digesters or directly to incineration. This solids handling decision could be made based on ease of operations.

- Under the current energy prices of \$0.085/kWh for electricity and \$5/mmBtu for natural gas, it would not be economically favorable to purchase additional natural gas to maximize electrical production. BSA could remain flexible in its operations by ramping up electrical production if electricity prices rise, if natural gas prices fall or during peak periods for electric rates.

- 26 dtpd of additional Import sludge could be accepted directly to incinerators while only keeping one incinerator in service. The energy based cost savings in this instance would improve to \$380K-\$500K per year depending on the heat value of import sludge.

- Electrical production from the proposed system could be increased by beneficially utilizing hot water exiting the condenser. The most feasible and economically favorable option for utilizing condenser water appears to be heating digesters.

A summary table and figure showing all model results along with some additional recommendations regarding the Energy Flow Modeling are given below.

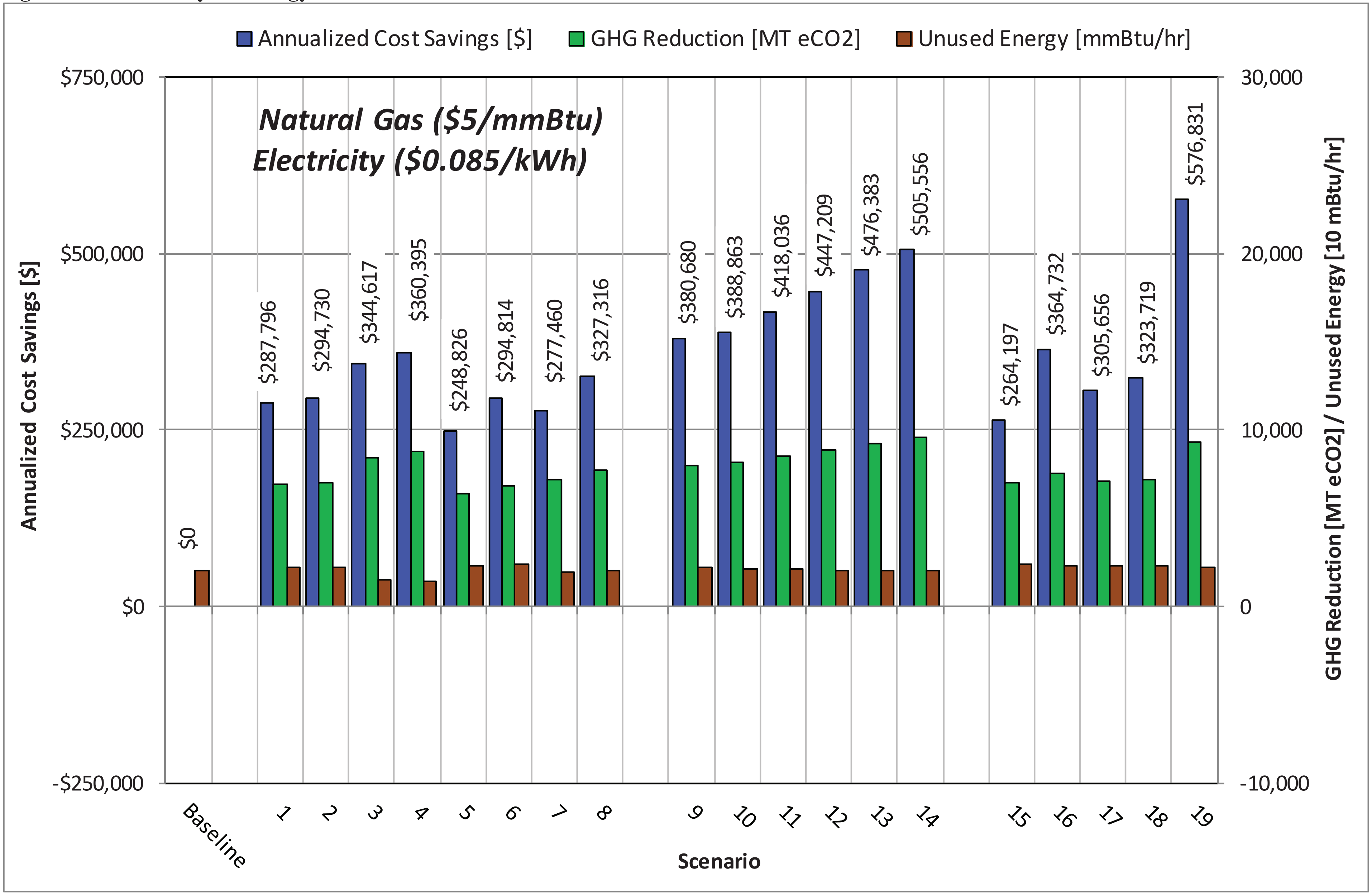
Sampling and Analysis of Solids – Understanding the composition of the solids to be routed through the plant will greatly enhance the accuracy of model results. Regular sampling and analysis should be conducted on PS, WAS, and various Import Sludge for items such as water content, volatile solids content, chemical composition and heat value. A sampling plan is provided in Appendix I.

Table 5-3. Summary of Energy Flow Model Results

Scenario	Description	Annualized Cost Savings [$]	GHG Reduction [MT eCO2]	Unused Energy [mmBtu/hr]	Avg MW
Baseline	No WHRB or Steam Turbine	$0	0	20.6	0.00
1	Import to INC, Max steam from WHRB	$287,796	6,934	22.5	1.75
2	Import to DIG, Max steam from WHRB	$294,730	7,055	22.0	1.71
3	Import to INC, Exhaust only to WHRB	$344,617	8,473	15.6	1.21
4	Import to DIG, Exhaust only to WHRB	$360,395	8,834	14.0	1.09
5	All PS to INC, Max steam from WHRB	$248,826	6,438	23.6	1.82
6	All WAS to INC, Max steam from WHRB	$294,814	6,834	24.2	1.87
7	All PS to INC, Exhaust only to WHRB	$277,460	7,215	20.0	1.55
8	All WAS to INC, Exhaust only to WHRB	$327,316	7,715	20.2	1.56
9	26 dtpd Import to INC , Max WHRBs	$380,680	7,982	22.5	1.74
10	26 dtpd Import to INC , Exhaust to WHRBs	$388,863	8,206	21.5	1.66
11	Scenario 10: 9,500 Btu/lb volatile	$418,036	8,560	21.1	1.64
12	Scenario 10: 10,000 Btu/lb volatile	$447,209	8,914	20.8	1.61
13	Scenario 10: 10,500 Btu/lb volatile	$476,383	9,268	20.5	1.59
14	Scenario 10: 11,00 Btu/lb volatile	$505,556	9,622	20.1	1.56
15	HW Boilers in Admin Building	$264,197	7,061	23.9	1.84
16*	Heat Digesters with Condenser HW	$364,732	7,567	23.0	1.85
17*	Run Chillers off Condenser HW	$305,656	7,081	22.9	1.77
18*	Heat Chem Handling with Condenser HW	$323,719	7,229	23.3	1.79
19*	Heat Buildings and Digesters with HW	$576,831	9,311	22.4	2.14

** - Capital cost of implementation is not incorporated into model results*

Figure 5-1. Summary of Energy Flow Model Results



Appendix A

Digester Heating Load Calculations

Digester Influent

Specific Heat	1.00	Btu/lb-^{o}F	(water)
Density of sludge	62.40	lbs/ft^{3}	(water at 60^{o}F)
Influent Sludge Thickness	6.1	%	
Desnisty of Sludge	64.93		

Heat Loss Coeffcients (U)

Buried Walls in Dry Soil	0.11	Btu-ft thick/hr/ft^{2}/^{o}F
Floating Cover	0.33	Btu/hr/ft^{2}/^{o}F

Digester Dimensions

Inner Diameter	90	ft
Side Water Depth	38	ft
Top area	6,362	ft^{2}
Bottom area	6,362	ft^{2}
Total Wall area	10,625	ft^{2}
% of Digester buried	100%	
Wall Thickness	2.0	ft
Bottom Thickness	1.5	ft
Volume per DIG	285,100	ft^{3}

Unit Digester Heating Loss

Through Floating Cover	2,099	Btu/hr/^{o}F
Through Buried Walls	584	Btu/hr/^{o}F
Through Bottom	467	Btu/hr/^{o}F

***Steam Condensing Energy** (h_{fg})*

At steam pressure 80 psig	892	Btu/lb

Date	Sludge Temp oC	Sludge Temp (oF)	Ambinet Temp (oF)	Soil Temp (oF)	Process Temp (oF)	Thickened Sludge GPD	Thickened Sludge cf/hr	Bulk Sludge Heating mmBtu/hr	Cover+Wall+ Floor Loss mmBtu/hr	Total Digester Heating mmBtu/hr	Steam Demand @80 psi lbs/hr
Feb-10	8.8	47.9	23.2	55	95	295,307	1,645	5.03	0.25	5.28	5,923
Mar-10	9.3	48.8	24.6	55	95	273,039	1,521	4.56	0.25	4.81	5,394
Apr-10	12.0	53.6	38.1	55	95	259,423	1,445	3.88	0.22	4.10	4,600
May-10	15.1	59.1	51.1	55	95	261,434	1,456	3.39	0.19	3.58	4,019
Jun-10	19.9	67.8	60.2	55	95	256,106	1,427	2.52	0.17	2.69	3,016
Jul-10	23.4	74.2	67.0	55	95	230,500	1,284	1.74	0.16	1.90	2,126
Aug-10	24.3	75.8	73.5	55	95	225,594	1,257	1.57	0.14	1.71	1,920
Sep-10	23.2	73.8	71.7	55	95	247,848	1,381	1.90	0.15	2.05	2,301
Oct-10	19.7	67.5	62.6	55	95	262,664	1,463	2.61	0.17	2.78	3,113
Nov-10	16.4	61.5	50.9	55	95	277,013	1,543	3.35	0.19	3.55	3,976
Dec-10	12.2	53.9	41.5	55	95	260,767	1,453	3.87	0.21	4.08	4,578
Jan-11	9.5	49.1	26.2	55	95	278,528	1,552	4.62	0.24	4.86	5,454
Feb-11	8.4	47.0	21.3	55	95	302,933	1,687	5.25	0.25	5.51	6,176
Mar-11	8.3	47.0	24.6	55	95	305,313	1,701	5.30	0.25	5.55	6,222
Apr-11	9.6	49.3	31.9	55	95	274,984	1,532	4.55	0.23	4.78	5,358
May-11	13.0	55.3	45.7	55	95	263,808	1,470	3.78	0.20	3.99	4,470
Jun-11	18.1	64.6	58.7	55	95	281,651	1,569	3.09	0.18	3.27	3,664
Jul-11	22.8	73.0	66.8	55	95	289,992	1,615	2.31	0.16	2.47	2,766
Aug-11	23.9	75.0	75.2	55	95	253,012	1,409	1.83	0.14	1.97	2,213
Sep-11	22.7	72.9	71.3	55	95	238,328	1,328	1.91	0.15	2.06	2,307
Oct-11	19.8	67.6	65.5	55	95	215,511	1,200	2.14	0.16	2.30	2,576
Nov-11	16.8	62.3	52.2	55	95	252,721	1,408	2.99	0.19	3.18	3,563
Dec-11	13.3	56.0	46.5	55	95	251,830	1,403	3.55	0.20	3.76	4,210
Jan-12	10.7	51.3	35.5	55	95	221,343	1,233	3.50	0.22	3.72	4,171
All Winter	13.0	55.3	39.9	55	95	270,511	1,507	3.94	0.22	**4.15**	4,653
All Summer	19.0	66.2	59.3	55	95	256,890	1,431	2.71	0.17	**2.88**	3,230
Total	16.1	61.0	50.0	55	95	263,405	1,467	3.29	0.19	3.50	3,911

Equations

Bulk Sludge Heating = sludge flow * sludge density * (95oF - Ambient Temp)
Wall Losses = Uwall/(Wall Area * Wall Thickness) * (95oF - 55oF)
Floor Losses = Uwall/(Floor Area * Floor Thickness) * (95oF - 55oF)
Cover Losses = Ucover * Cover Area * (95oF - Ambient Temp)

Appendix B

Incineration Combustion Calculation

Incinerator ID Fan Capacity

AB Burner Cost Estimate

Calculation of INC exhaust

Approximate Stoichiometric Combustion Equations

Sludge

$C_{10}H_{17}O_4N + 12.25\ O_2 + (12.25*3.76)\ N_2 \rightarrow 10\ CO_2 + 8.5\ H_2O + 0.5\ N_2 + 46\ N_2$

Natural Gas

$CH_4 + 2\ O_2 + (2*3.76)\ N_2 \rightarrow CO_2 + 2\ H_2O + 7.5\ N_2$

Digester Gas

$2CH_4 + CO_2 + 4\ O_2 + (4*3.76)\ N_2 \rightarrow 3CO_2 + 4\ H_2O + 15\ N_2$

Sludge In

*Ultimate analysis**	Mass Fraction	*Incinerator Feed*		
C	53.5	Sludge DT	46.0	dtpd
H	8.05	Sludge In Dry	3,836	dry pounds per hour
O	32.2	Sludge WT	182.0	wtpd
N	4.65	Sludge in Wet	15,163	wet pounds per hour
S	1.6	% Solids	25.3%	of wet feed
Total	100	% Volatile	58.5%	of solids
		Volatile Solids In	2,244	pounds per hour

*Ultimate analysis assumed from typical values, sludge sampling is recommended to improve accuracy

Gas Fuel In

(*From Energy Balance on Incinerator*)

Natural Gas = 819 lbs/hr;
Digester Gas = 1,350 lbs/hr

Results from Combustion Reactions

(Detailed combustion reactions shown on next pages)

	CO2	O2	N2	H2O	SO2	
Exhaust from Sludge Combustion	3,988	729	14,514	1,721	72	[lbs/hr]
Exhaust from Water In with Sludge	0	0	0	11,327	0	[lbs/hr]
Exhaust from NG Fuel	2,296	815	13,425	1,888	0	[lbs/hr]
Exhaust from DG Fuel	2,820	848	13,986	2,075	0	[lbs/hr]
Total Exhaust Flow Rate					70,504	[lbs/hr]

Combustion Reaction for Dry Sludge (per pound of dry volatile solids)

	Mass Fraction	MW	lb. Moles	as	lb. Moles O required	
C*	0.485	12.01	0.0404	C	0.0808	*Assumes 5% carbon unburned
H	0.0805	1.008	0.0399	H_2	0.0399	
O	0.322	16	0.0201	O_2	-0.0201	
N	0.0465	14.008	0.0017	N_2	0.0000	
S	0.016	32.07	0.0005	S	0.0010	
				Total	0.1016	lb. Moles O required

Theoretical Air Required	lb. Moles	MW	#/# dry volatile		
lb. Moles O_2	0.0508	32	1.6251		N to O ratio =
lb. Moles N_2	0.1910	28	5.3493		3.7619
lb. Moles Theoretical Air	0.2418	28.84	6.9744		
Excess Air Used		MW	#/# dry volatile		
lb. Moles O_2	0.0102	32	0.3250		
lb. Moles N_2	0.0382	28	1.0699		
lb. Moles Excess Air	0.0484	28.84	1.3949		
Total Air Used	lb. Moles	MW	#/# dry volatile		
lb. Moles O_2	0.0609	32	1.9501		
lb. Moles N_2	0.2293	28	6.4192		SCF Air / # Volatile
lb. MolesTotal Air	0.2902	28.84	8.3693		109.99
					1 mole of any gas occupies 379 FT^3 at 60 ^oF and 30" Hg.

Theoretical Products of Combustion (POC)

	MW	lb. Moles	#/# dry volatile		
CO_2	44.010	0.0404	1.7773		
H_2O	18.016	0.0399	0.7194		
SO_2	64.070	0.0005	0.0320		
N_2	28.016	0.1927	5.3989		
Dry POC		0.2336	7.2081		Dry POC MW
					30.86

Exhaust Gases	lb. Moles	#/# dry volatile	SCF / # Volatile	
Dry POC	0.2336	7.2081	88.53	
Excess Air	0.0484	1.3955	18.33	
Water Vapor	0.0399	0.7194	15.13	SCF Exhaust / # Volatile
Total	0.3219	9.3230	121.99	121.99
Dry Total	0.2820	8.6036	106.86	1 mole of any gas occupies 379 FT^3 at 60 ^oF and 30" Hg.

Volatile Sludge Feed Rate	2,244	lbs/hr	***Exhaust Out***	**20,917**	**lbs/hr**
Total Air In	18,778	lbs/hr	*Exhaust Out*	4,562	scfm
Total Mass In	21,021	lbs/hr			
Total Air In	4,113	scfm			

Lbs water vaporized from Sludge = 15,163 wet lbs/hr – 3,836 dry lbs/hr = **11,327 lbs/hr**
Water Vapor In with Combustion Air (assumes 50oF and 75% RH) **= 310 lbs/hr**

Combustion of Natural Gas as INC Fuel (per pound of NG)

					Assumed	
Assumed Composition	%	MW	lb. Moles	as	Moisture Free	
N_2	1.3	28.016	0.0005	N_2		
CH_4	80.5	16.042	0.0502	CH_4		
C_2H_6	18.2	30.068	0.0061	C_2H_6		
Total	100		0.0567	lb. Moles Natural Gas		
Required O_2 for Combustion	lb. Moles	O_2 moles needed	lb. Moles O_2			
CH_4	0.0502	2	0.1004	lb. Moles O_2		
C_2H_6	0.0061	3.5	0.0212	lb. Moles O_2		
Total			0.1215			
					MW	# / # Natural Gas
Theoretical Air	Theoretical O_2		0.1215	lb. Moles O_2	32	3.8895
	Theoretical N_2		0.4572	lb. Moles N_2	28	12.8029
	Theoretical Air		0.5788	lb. Moles Air	28.85	16.6982
Excess Air					MW	# / # Natural Gas
	Excess O_2		0.0304	lb. Moles O_2	32	0.9724
	Excess N_2		0.1143	lb. Moles N_2	28	3.2007
	Excess Air		0.1447	lb. Moles Air	28.85	4.1746
Total Air					MW	# / # Natural Gas
	Total O_2		0.1519	lb. Moles O_2	32	4.86
	Total N_2		0.5716	lb. Moles N_2	28	16.00
	Total Air		0.7235	lb. Moles Air	28.85	20.87
Products of Combustion (POC)						
	MW	lb. Moles	# / # Natural Gas	Btu / # Natural Gas		
CO_2	44.01	0.0623	2.7412	1042.2		
H_2O from CH_4	18.016	0.1004	1.8081	1311.4		
H_2O from C_2H_6	18.016	0.0182	0.3271	237.3		
N_2	28.016	0.5720	16.0258	6102.4		
O_2	32	0.0304	0.9724	343.5	Total Btu/# Natural Gas	
					11,109	
Dry POC		0.6647	19.7394			
Exhaust Gases	lb. Moles	# / # Natural Gas	SCF / # Natural Gas			
Dry POC	0.6647	19.7394	251.92			
Water Vapor	0.1185	2.1353	44.92		SCF Exhaust / # NG	
Total	0.7832	21.8747	296.84		296.84	
				1 mole of any gas occupies 379 FT^3 at 60 °F and 30" Hg.		
NG Feed Rate	838	lbs/hr	***Exhaust Out***	**18,325**	**lbs/hr**	
Total Air In	17,485	lbs/hr	*Exhaust Out*	4,144	scfm	
Total Mass In	18,323	lbs/hr				
Total Air In	3,828	scfm				

Combustion of Digester Gas as INC Fuel (per pound of DG)

					Assumed	
Assumed Dry Composition	%	MW	lb. Moles	as	Saturated	# / # Digester Gas
N_2	1.0	28.016	0.0004	N_2		0.0100
CH_4	63.0	16.042	0.0393	CH_4		0.6300
CO_2	36.0	44.01	0.0082	CO_2		0.3600
Total	100		0.0478	lb. Moles Digester Gas		
Required O_2 for Combustion	lb. Moles	O_2 Req.				
CH_4	0.0393	2	0.0785	lb. Moles O_2		
CO_2	0.0082	0	0.0000	lb. Moles O_2		
					MW	# / # Digester Gas
Theoretical Air	Theoretical O_2		0.0785	lb. Moles O_2	32	2.5134
	Theoretical N_2		0.2955	lb. Moles N_2	28	8.2733
	Theoretical Air		0.3740	lb. Moles Air	28.85	10.7904
Excess Air					MW	# / # Digester Gas
	Excess O_2		0.0196	lb. Moles O_2	32	0.6284
	Excess N_2		0.0739	lb. Moles N_2	28	2.0683
	Excess Air		0.0935	lb. Moles Air	28.85	2.6976
Total Air					MW	# / # Digester Gas
	Total O_2		0.0982	lb. Moles O_2	32	3.1418
	Total N_2		0.3693	lb. Moles N_2	28	10.3416
	Total Air		0.4675	lb. Moles Air	28.85	13.4880
Products of Combustion (POC)						
	MW	lb. Moles	# /# Digester Gas	Btu / # Digester Gas		
CO_2	44.01	0.0475	2.0884	794.0		
H_2O from CH_4	18.016	0.0785	1.4150	1026.3		
N_2	28.016	0.3697	10.3575	3944.0		
O_2	32	0.0196	0.6284	222.0		
Dry POC		0.4368	13.0742			
		lb. Moles	# /# Digester Gas			
Saturated Water Content in Digester Gas		0.0025	0.0450			
Exhaust Gases	lb. Moles	# / # Digester Gas	SCFM / # Digester Gas			
Dry POC	0.4368	13.07	165.54			
Water Vapor	0.0810	1.46	30.71		SCF exhaust / # DG	
Total	0.52	14.53	196.26		196.26	
				1 mole of any gas occupies 379 FT^3 at 60 ^oF and 30" Hg.		

DG Feed Rate	1,350	lbs/hr	***Exhaust Out***	**19,626**	**lbs/hr**
Total Air In	18,213	lbs/hr	*Exhaust Out*	4,417	scfm
Water Vapor In	61	lbs/hr			
Total Mass In	19,624	lbs/hr			
Total Air In	3,988	scfm			

Auerbach, Eric

Subject: FW: Incinerator ID fan check

From: Wester, Ben C.
Sent: Wednesday, October 10, 2012 9:24 AM
To: Auerbach, Eric
Subject: RE: Incinerator ID fan check

Eric,
I am assuming the gas flow has gone through a wet scrubber, therefore the water vapor coming into the scrubber is not going to be seen by the ID fan only a saturated mixture. At 120 degrees the amount of water per pound of dry air under saturated conditions is 0.08128 # H2O per # dry air.
---- weight of saturated gas is (20,917 +19,626 + 18,268) pounds per hour assumed dry which it more than likely has moisture as a product of combustion but will be conservative and assume everything is dry. Therefore dry gas weight is assumed as 58,811 with water in the gas stream being 4,780 pounds (the other water would condense in the scrubber) for a total of 63,591 pounds of saturated mixture per hour.

The volume of saturated mixture at 120 degrees F is 16.515 cubic feet per pound of sat. mixture gas or 16.515 x 58,811 #/hour = 971,264 cubic feet per hour of gas flow. This would equal 16,188 cubic feet per minute at atmospheric pressure. Assuming it is drawing the air in at a negative pressure (suction) say 30 inches of water, the air density would be less (volume more per same mass) at the fan inlet (P1V1 = P2V2) or (407 inches of water + 0) V1 = (407 inches of water -30) V2 calculates to V2 being 8 percent more volume or 1.0796 x 16,188 cfm =17,476 cfm @ 120 degrees with a static pressure of -30 inches of water. Correcting for altitude (620 feet above sea level) it would increase the volume by another 2.5% resulting in 17,472 cfm x 1.025 = 17,909 cfm.

If your numbers are close and the above assumptions are correct then the fan at peak operation conditions should have the capacity. My three questions are –do your numbers include “leakage of air into the incinerator –i.e. 80 to 100% more air than stoichiometric)? and has the fan horsepower been checked to make sure all conditions are satisfied (i.e. what if the scrubber cools the gases closer to 100 degrees and the air density is closer to 0.07?), does this fan operate on a VFD which might compensate for the cooler flows since the volume would also be less with the cooler flow.

You can call to discuss, but outside of checking to make sure our typical operating range does not drastically change, I would say the ID fans should be able to handle the flows.
Ben

From: Auerbach, Eric
Sent: Tuesday, October 09, 2012 4:23 PM
To: Wester, Ben C.
Subject: Incinerator ID fan check

Hi Ben,

Here are the numbers I’d like you to give a quick check on.

From my combustion calculations, here is what will be flowing through the incinerator:
Combustion products of dry sludge = 4,562 scfm and 20,917 lbs/hr
Vaporized water with sludge = 3,971 scfm and 11,327 lbs/hr
Combustion products of digester gas = 4,417 scfm and 19,626 lbs/hr
<u>Combustion products of natural gas = 4,132 scfm and 18,268 lbs/hr</u>
Total Exhaust Flow = 17,082 scfm and 70,447 lbs/hr or 19,053 acfm @ 120oF

This exhaust flow is probably a little higher than they initially designed because we are adding in more natural gas to enhance the steam flow to the turbine

Here is the design sizing on the ID fan being installed:
Routine Operation: 16,200 acfm @ 120oF and density of 0.0646 lbs/cf
Peak Operation: 21,150 acfm @ 120oF and density of 0.0642 lbs/cf
Upset Operation: 23,470 acfm @ 120oF and density of 0.0636 lbs/cf

It looks like the current ID fan will work but I wanted to get your opinion. Please let me know if there is additional info you would need to evaluate.

Thanks

Eric

Eric Auerbach, P.E.

Malcolm Pirnie | The Water Division of Arcadis

Please note new address and office numbers
2800 W Higgins Rd, Suite 1000 | Hoffman Estates, IL 60169
eric.auerbach@arcadis-us.com
Hoffman Estates Office: (847) 805-1050
Downtown Office: (312) 575-3719
Cell: (716) 228-7538

BUFFALO SEWER AUTHORITY
CONCEPTUAL ESTIMATE OF PROBABLE PROJECT COST

Afterburner Burner Replacement
November 28, 2012

Division	Description	Quantity	Unit	Material		Labor		Total
				Unit Cost	Total	Unit Cost	Total	Cost
1	**GENERAL REQUIREMENTS**							
2	**SITE WORK**							
3	**CONCRETE**							
5	**METALS**							
11	**EQUIPMENT**							
	Burners (6 per AB Chamber, 12 total)	12	EA	$ 4,000	$ 48,000	$ 1,600	$ 19,200	$ 67,200
	Refractory Replacement (10 sq ft per burner)	120	SQ FT	$ 100	$ 12,000	$ 100	$ 12,000	$ 24,000
13	**SPECIAL CONSTRUCTION**							
15	**MECHANICAL**							
16	**ELECTRICAL**							
	Power and Control Wiring Replacements	12	EA	$ 2,000	$ 24,000	$ 3,000	$ 36,000	$ 60,000
	SCADA Integration	1	LS	$ 3,000	$ 3,000	$ 7,000	$ 7,000	$ 10,000
		Subtotal Project:			**$ 87,000**		**$ 74,200**	**$ 162,000**

Appendix C

WHRB Performance and Quotation

Boiler Installation

Boiler Feedwater Pumps

Boiler Water Treatment System

5025 E. Business 20
Abilene, Texas 79601
Phone 325-672-3400
Fax 325-672-9996

To: Malcolm Pirnie
1515 E. Woodfield Rd., Suite 360
Schaumburg, IL 60173

November 26, 2012

ATTN: Mr. Eric Auerbach

SUBJ: Waste Heat Boiler Quote

RENTECH Proposal No.: WHB-HFB-3546-MC-12 Rev. 1

Based upon your recent inquiry we are pleased to furnish:

> ONE (1) WATERTUBE BOILER WITH HOPPERS, SUPERHEATER, INTEGRAL STEAM DRUM, SOOTBLOWERS, ASH HOPPERS, ECONOMIZER TRANSTION, ECONOMIZER AND TRIM:

to be designed and built in accordance with the requirements of Section l of the ASME Boiler and Pressure Vessel Code and described in the following pages:

Page No.

Thank you for your interest in doing business with **RENTECH BOILER SYSTEMS, INC.** We look forward to providing you prompt response to all of your questions, attention to all details and top quality boilers. Please don't hesitate to contact me if you have any questions.

Sincerely,

Mike Carter

Mike Carter
Proposal Manager

TECHNICAL DISCUSSION

in order to meet your process and mechanical requirements, we are recommending a WATERTUBE TYPE BOILER WITH INTEGRAL SUPERHEATER, HOPPERS, ECONOMIZER, TRIM, and SOOTBLOWERS. Please refer to the data sheets for performance at the given conditions.

The proposed boiler has been carefully designed for your specific application with regards to:

- Placement of hoppers to maximize cleanout capabilities.
- Placement of sootblowers to maximize cleaning ability.
- Placement of superheater
- Steam Drum Sizing.
- Steam Drum Internals.
- Steam Outlet Location.

Additional descriptive information appears on the pages that follow.

DESCRIPTION

EVAPORATOR SECTION

The first boiler section is a screen section and it will have 10 bare tubes per row. The convection section will have 20 bare tubes per row and 47 rows deep. The superheater will be located between the screen and the convection sections. Please see the mechanical data sheet for further details. The tubes are 2" OD x .135" Minimum Wall Thickness, SA-178A ERW tubes. The screen section utilizes a 8.0" transverse spacing to minimize any potential bridging due to solids accumulation at the boiler inlet. In the main evaporator section the transverse spacing is 4.0". Both the screen section and main evaporator section tubes are placed on a 4.0" longitudinal pitch. They will be attached to the drums via rolling and flaring. Each tube hole will be serrated with 1 groove and will be carefully cleaned and polished just prior to tube installation. To further assure a good tube joint, the ends of each tube will also be polished just prior to installation. The gas inlet and outlet connections are channel iron frames, each with one (1) alignment hole in each corner.

SUPERHEATER

Immediately following the screen or 1st cleaning cavity is a two-stage superheater. The unit has horizontal tubes with vertical headers. Both sections are in counter flow configuration. The first superheater section utilizes 12 tubes/row on a 6.75" transverse pitch with a 5" longitudinal pitch. This section of the superheater is 8 rows deep and utilizes 1.5"OD x .150" Minimum Wall Thickness tubes. Tube material is SA-213 T11 seamless chromoly material. The second section has 12 tubes/row on a 6.75" transverse pitch with a 5" longitudinal pitch. This second section also is 8 rows deep and utilizes 1.5"OD x .150" Minimum Wall Thickness tubes. Tube material is SA-213 T11 seamless chromolly material. Steam temperature control is provided by utilizing an interstage de-superheater between the two sections of the superheater. Spray water must be demineralized.

STEAM DRUM

The steam drum will be 42" I.D.. Each head of the drum will have a **12" x 16" manway** to provide access for inspection. The drum is provided with primary "Belly-Pan" type separators and a secondary "Chevron" to provide 1 PPM maximum carryover, provided that the boiler water is maintained within ABMA specified limits. We have located the steam outlet at the center of the steam production, as measured from the front to rear of the boiler, to assure that half of the steam flows to the outlet from each end. This provides for low steam velocities along the drum length and minimizes the potential for re-entrainment of water due to high surface velocities. All other drum internal pipings are also furnished as needed to make the unit operational.

MUD DRUM

There is one 36" I.D. mud drum. The mud drum comes complete with bottom blowdown connections to allow for proper intermittent blowdown of the solids that do accumulate on the bottom of the drum. Also, each head has a **12" x 16" manway** to provide the proper access to the drum. The lower mud drums are cradled in a base assembly made of I-Beams and channel iron. The base assembly will have openings in the bottom to accommodate four refractory lined hoppers.

CASING

The boiler casing will be constructed with .25" thick carbon steel and lined with a dual layer of refractory for a total of 7" [4" of AP Green KS4 + 3" of Kastolite 16].

ECONOMIZER

A "Horizontal" gas flow economizer was selected for the boiler. The gases will exit the boiler vertically down and enter the economizer and then go to the existing ductwork. The casing will be made of .25" thick carbon steel and will be externally insulated with 3" mineral fiber block insulation and protected with an aluminum pebble grain lagging. The economizer tubes are 2.0" OD x 0.135"MW and are made with SA-178A material.

ECONOMIZER INLET TRANSITION

We will be providing the transition between the evaporator and the inlet to the economizer. It will be insulated with 3" of mineral fiber insulation and protected with pebble grain aluminum lagging. Two (2) manways [18” x 18”] will be provided for cleaning and inspection access for the economizer. Expansion joint between the boiler and the transition is provided.

PIPING

Piping will be provided up through the ASME code valves. Sootblower piping from the steam drum to each individual sootblower will be provided with associated steam traps to assure dry steam at the entrance to the sootblower. Shop fabricated feedwater control valve station with block and bypass valve is provided for installation in Buyers piping. Supports for the piping are not included at this time.

BOILER TRIM AND SOOTBLOWERS

The boiler trim offered with this proposal will be crated for shipment and will be installed by others in the field. We have included all retractable and rotary sootblowers for the boiler. One retractable sootblower will be installed after the screen section and before the superheater. Two rotatry sootblowers will be provided after the second superheater section. Two each rotary sootblowers will be installed after rows 19, and 38 of the evaporator section. The rotary sootblowers will have a 7” center to center of the tubes. Two rotary sootblowers will be provided for the economizer.

TUBE SHIELDS

Sacrificial stainless steel tube shields will be provided on the first row of tubes in the screen section and at the retractable sootblower lanes.

INSULATION, LAGGING AND PAINTING

The steam drum and mud drums, excluding the drum heads, will be insulated with 2” of mineral fiber insulation and protected with a 12 ga. carbon steel lagging and .040” corrugated aluminum respectfully. All exposed surfaces and piping will be cleaned in accordance with SSPC-SP6 procedure and primed with 3 mils of inorganic zinc-rich primer and top coat.

LADDERS AND PLATFORMS

By others.

HOPPERS

The Evaporator hoppers (3) will be refractory lined the same as the boiler casing and will have a nominal 12" x 12" plate flange on the outlet side. The hoppers will require seal welding to the bottom of the boiler. One economizer outlet hopper will also be provided. They will not be refractory lined but will be insulated and lagged with corrugated aluminum.

Equipment Scope of Supply For Boiler #1

Each Waste Heat Boiler furnished by Rentech will be equipped as follows:

Description	By Rentech	By Others	Option	Not Applicable
Screen				
Upper Drum	X			
Lower Drum	X			
Superheater				
Superheater - First Stage	X			
Superheater - Second Stage	X			
Inner stage De-superheater	X			
Piping from boiler to superheater	X			
Evaporator				
Upper Drum	X			
Lower Drum	X			
Refractory	X			
Internal Insulation				X
External Insulation	X			
Painting, 1 primer & 1 finish coat - SSPC-SP6	X			
Downcomers - External				
Downcomers - Internal	X			
Economizer				
Rectangular economizer - Horizontal Flow	X			
Internal Casing - Carbon Steel	X			
External Insulation	X			
Outer Casing - Corrugated Aluminum	X			
Access Door 18" X 24"				X
Economizer Structural Support		X		
Economizer Sootblower	X			
Sootblowers				
Sootblower head fixed - Manual	X			

Description	By Rentech	By Others	Option	Not Applicable
Sootblower head retractable - Manual	X			
Sootblower lance	X			
Steam piping - Boiler to Sootblower	X			
Controls				
Integrated NEMA 4 Enclosure Sootblower	X			
Allen Bradley Control Logix PLC	X			
PanelView Plus 1000 local HMI display				X
Ethernet switch				X
24 VDC power supply				X
Interposing relays				X
Panel indication lights & switches				X
Audible horn				X
Emergency pushbutton				X
Terminal blocks, fuses, circuit breakers & wiring				X
Vortex Cooler for integrated enclosure				X
Ductwork				
Inlet ductwork		X		
SCR Inlet Duct				X
SCR Outlet Duct				X
Economizer Inlet Duct	X			
Economizer Outlet Duct				X
Expansion Joint	X			
Main Stack				
Main Stack Carbon Steel		X		
Stack Platforms - Full		X		
Stack Platforms - Partial		X		
Stack Ladder		X		
Rain Hood		X		
EPA Ports		X		
Access Door		X		
Personnel protection screen		X		
Corrosion Allowance		X		
FAA Lights		X		
Stack Damper - Butterfly Type with actuator		X		
Deareator				
Tray type deareator head - 0.005 CC/L		X		
Storage Tank with 10 min holding capacity		X		
Feedwater Pumps -2 X 100%		X		
DA Controls -Integrated in HRSG CCS		X		
DA Structural Support		X		
DA Platforms & Ladders		X		
Piping from DA to HRSG		X		
PRV from DA to HRSG		X		
Support Steel & Platforms & Ladders				
Steam Drum - Front End		X		
Steam Drum - Rear End		X		
Steam Drum - Side		X		
Sootblowers		X		

Description	By Rentech	By Others	Option	Not Applicable
Economizer		X		
Support steel to raise boiler above grade		X		
Ash hoppers				
Boiler Hoppers	X			
Economizer Hoppers	X			
Air rotary Valves		X		
Ash Removal System		X		
Miscellaneous Equipment				
Blowdown Tank		X		
Chemical Feed System		X		
Continuous Emission Monitoring System - CEMS		X		
Service & Training		X		
Vent Valve Silencers		X		
Safety Relief Valve Silencers		X		
Freight				
Standard Crating & Packaging	X			
Desiccant Bags	X			
Nitrogen Blank				X
Spreader Bar				X
Equipment is offered EX-WORKS Abilene, TX, USA	X			

PROCESS SUMMARY SHEET
220F FEEDWATER

	SCREEN	FINISHING SUPERHEATER	PRIMARY SUPERHEATER	EVAPORATOR	ECONOMIZER
GAS SIDE					
Flow Rate, lb/hr	70,416	70,416	70,416	70,416	70,416
Inlet Temperature,°F	1,500	1,375	1,289	1,210	577
Outlet Temperature,°F	1,375	1,289	1,210	577	365
Specific Heat, Btu/lb °F	0.348	0.343	0.339	0.323	0.303
Fouling Factor, ft^2 °F Btu	0.01	0.01	0.01	0.01	0.01
Heat Loss, %	2	2	2	2	2
Heat Exchange, mmbtu/hr	2.98	2.04	1.84	14.11	4.56
Pressure Drop, in. W.C.	0.1	.02	.02	1.2	0.7
Velocity ft/sec.	30.0	35.5	33.8	38.7	24.1
Gas Oper. Pressure, in W.C.	ATM	ATM	ATM	ATM	ATM
Gas Design Pressure, in W.C.	+/- 15	+/- 15	+/- 15	+/- 15	+/- 15
STEAM SIDE					
Design Pressure, psig	760	760	760	760	860
Operating Pressure, psig	690*	650	660	690*	700
Inlet Temperature, °F	417	526	502	417	220
Outlet Temperature, °F	517	650	608	502	417
Blowdown, %	5	-	-	5	-
Fouling Factor, ft^2 °F Btu	0.001	0.001	0.001	0.001	0.001
Pressure Drop, psig	-	10	8	-	10
Flow Rate, lb/hr	Incl in Evap	22,300	21,025	21,025	22,131
Heating Surface ft^2	275	207	207	4,750	3,619

Flue Gas Analysis Normal Case -% Vol.: CO_2=7.62: H_2O=34.5: N_2 =55.09: O_2=2.75; SO_2= 0.04

* Operating pressure allows 14 psig drop through the non-return steam valve, desuperheater and piping.
Difference in flow between the superheater is 1,275 lb/hr of spray water at 220F
All steam flow rates are predicted. The unit will start to foul immediately and the steam production will actually be more than the predicted number until the gas side fouling reaches the level listed above. After reaching that level the steam production will decrease as the unit continues to foul. Variations in flue gas flow, inlet gas temperature, flue gas analysis, and continuous blowdown will affect steam production, flue gas outlet temperature, and gas side pressure drop.

PROCESS SUMMARY SHEET
290F FEEDWATER

	SCREEN	FINISHING SUPERHEATER	PRIMARY SUPERHEATER	EVAPORATOR	ECONOMIZER
GAS SIDE					
Flow Rate, lb/hr	70,416	70,416	70,416	70,416	70,416
Inlet Temperature,°F	1,500	1,375	1,289	1,210	578
Outlet Temperature,°F	1,375	1,289	1,210	578	405
Specific Heat, Btu/lb °F	0.348	0.343	0.339	0.323	0.304
Fouling Factor, ft^2 °F Btu	0.01	0.01	0.01	0.01	0.01
Heat Loss, %	2	2	2	2	2
Heat Exchange, mmbtu/hr	2.98	2.04	1.84	14.11	3.76
Pressure Drop, in. W.C.	0.1	.02	.02	1.2	0.7
Velocity ft/sec.	30.0	35.5	33.8	38.7	24.1
Gas Oper. Pressure, in W.C.	ATM	ATM	ATM	ATM	ATM
Gas Design Pressure, in W.C.	+/- 15	+/- 15	+/- 15	+/- 15	+/- 15
STEAM SIDE					
Design Pressure, psig	760	760	760	760	860
Operating Pressure, psig	690*	650	660	690*	700
Inlet Temperature, °F	444	529	502	444	220
Outlet Temperature, °F	517	650	604	502	444
Blowdown, %	5	-	-	5	-
Fouling Factor, ft^2 °F Btu	0.001	0.001	0.001	0.001	0.001
Pressure Drop, psig	-	10	8	-	10
Flow Rate, lb/hr	Incl in Evap	23,100	21,830	21,830	22,979
Heating Surface ft^2	275	207	207	4,750	3,619

Flue Gas Analysis Normal Case -% Vol.: CO_2=8.13: H_2O=38.32: N_2 =51.55: O_2=2.0;

* Operating pressure allows 14 psig drop through the non-return steam valve, desuperheater and piping.
Difference in flow between the superheater is 1,270 lb/hr of spray water at 290F
All steam flow rates are predicted. The unit will start to foul immediately and the steam production will actually be more than the predicted number until the gas side fouling reaches the level listed above. After reaching that level the steam production will decrease as the unit continues to foul. Variations in flue gas flow, inlet gas temperature, flue gas analysis, and continuous blowdown will affect steam production, flue gas outlet temperature, and gas side pressure drop.

MECHANICAL DATA SHEET

ITEM	Screen	Finishing Superheater	Primary Superheater	Evaporator	Economizer
Tubes					
O.D., (in.)	2	1.5	1.5	2	2
Minimum thickness, in.	.135	.150	.150	.135	.135
Effective length, ft.	8.75	5.5	5.5	9.65	12
Tubes / Row	10	12	12	20	24
Transverse Spacing, in.	7	6.75	6.75	3.5	3
Number of Rows	6	8	8	47	24
Longitudinal Spacing, in.	4	5	5	4	3
Material	SA-178A	SA213-T11	SA213-T11	SA-178A	SA-178A
Fins	BARE			BARE	BARE
Height, in.					
Thickness, in.					
Fins Per Inch					
Solid/Serrated					
Material					
Steam Drum					
Diameter, in.	42	6” IPS	6” IPS		4” IPS
Thickness, in.	PER CODE	Sch. 80	Sch. 80		Sch. 40
Length, ft.	31’ 0”	7	7		5.5’
Material	SA-516-70	SA335P11	SA106B		SA106B
Steam Outlet, in.	4				
Feedwater Inlet, in.	2				2
Manways	2 – 12” x 16				-
Mud Drum					
Diameter, in.	1 – 36” I.D.	6” IPS	6” IPS		4” IPS
Thickness, in.	PER CODE	Sch. 80	Sch. 80		Sch. 40
Length, ft.	31’ 0”	7	7		5.5’
Material	SA-516-70	SA335P11	SA106B		SA106B
Manways	2 – 12” x 16				

Superheater utilizes 12 streams
Economizer utilizes 4 fluid streams

COMMERCIAL INFORMATION

A. **BUDGET** SELLING PRICE FOR SYSTEM DESCRIBED IN THIS PROPOSAL:

Total Net Price F.O.B. Trucks Abilene, Texas:............................**$1,600,000.00 Each unit**

B. TERMS OF PAYMENT

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

15% Upon submittal of General Arrangement Drawings(s)
30% Upon receipt of tubes
15% Upon receipt of drum cylinders
30% Upon stabbing first tube
10% Upon readiness to ship
Payment Terms: Net 30 days
Warranty – 12 months from acceptance, not to exceed 18 months from shipment.

C. SHIPMENT

The following preliminary schedule is provided for your consideration:

- Submittal of General Arrangement drawing with loadings and anchor bolt locations, P & ID, Code Calculations: 6-8 weeks after receipt of an order
- Return of approved drawings: 1-2 weeks ARD.
- Shipment: 24-26 weeks after drawing approval with release to purchase major materials at time of order placement

Any significant changes, performance change, and other major changes will change the price and shipment schedule.

If RENTECH is delayed or disrupted in its performance under the Contract as the result of actions or omissions of the Buyer or persons acting on behalf of the Buyer, RENTECH shall be entitled to an extension of time as its exclusive remedy.

D. STARTUP

Startup, if required will be available the going rate at time of start-up.

GENERAL NOTES

1. Materials will not necessarily be domestic. Flanges will not be of China origin.

2. Installation of equipment and shipped loose items is to be done in the field by others.

3. Interconnecting piping and wiring between terminals of major components is to be furnished and installed in the field by others.

4. Unit is bid utilizing FCAW weld process.

ATTACHMENT I

TYPICAL TRIM LIST

TYPICAL Boiler Trim

Safety Relief Valves

1	Boiler		Drip pan elbows
1	Superheater		Vent stacks
	Economizer		Silencer(s)
	Gags		Silencer supports
X	Spring covers		

Water Columns

1	**Qty.**			**Level Switches**				
X	Probe Type		Float Type	Column 1		Column 2		
	Valves			X	HI-HI		HI-HI	
X	Process block			X	HI		HI	
X	Drain			X	LO		LO	
	Vent			X	LO-LO		LO-LO	

Aux. LWCO

	Qty.		Valves
	Probe type		Process block
	Float type		Drain
			Vent

Water Level Gage Glass

	Glass 1	Glass 2
Prismatic		
Flat glass	X	X
Bi-Color		
Illuminator	X	X
Direct vision hood	X	X
Remote viewing hood with mirrors		
Fiber optic remote		
Valves		
Water gage	X	X
Drain	X	X
Vent		

Remote Level Indicator

Probe Type	
Number of remote indicators	
Number of lights per indicator	
Valves	
Process block	
Drain	
Vent	

Controllers / Analyzers

	Drum level controller		Conductivity analyzer (steam)
	Desuperheater controller		Conductivity analyzer (water)
	Desuperheater		PH analyzer (water)
	O2 Analyzer		

Flow Elements

Service	Orifice Plate	Flow Nozzle	Venturi	Piezometer
Steam	1	0	0	0
Water	1	0	0	0
Combustion air	0	0	0	0
Flue gas	0	0	0	0

Boiler Trim

Sootblowers – Qty.

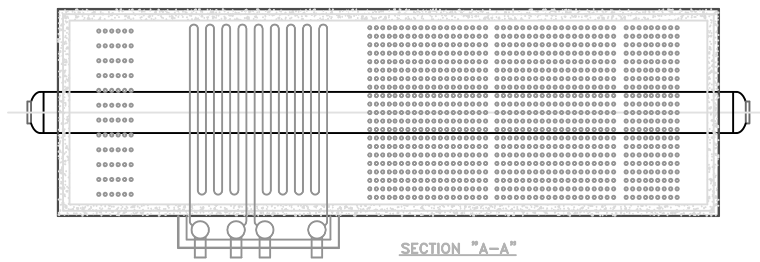
Service	Retractable	Manual Rotary	Electric Rotary	Others	Controls
Boiler / Superheater	1	0	0	X	Motor starters
Boiler	0	0	6	X	Piping
Economizer	0	0	2		

Description	PI	PT	TI	TT	TC/TW	PS	LT	FT
Flue Gas								
Fresh air inlet								
FGR								
Air preheater outlet								
Mix – Fan inlet								
Fan discharge								
Burner windbox								
Furnace								
Convection section								
SH inlet								
SH intermediate								
SH outlet								
Boiler outlet								
Economizer inlet								
Economizer outlet								
Water								
Upstream control valve station								
Downstream control valve station								
Upstream economizer					1			
Downstream economizer					1			
Steam								
Boiler outlet								
SH Interstage				1	1			
SH outlet	1			1	1			
Steam drum	1							
Continuous blowdown								
Steam Drum Metal					4			
SH Tubes								

PI = Pressure Indicator
PT = Pressure Transmitter
TI = Temperature Indicator
TT = Temperature Transmitter
TC/TW = Thermocouple/Thermowell
PS = Pressure Switch
LT =Level Transmitter
FT = Flow Transmitter

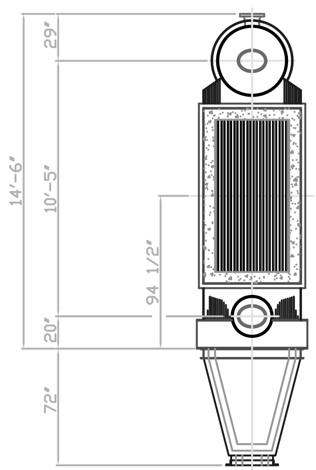
Boiler Trim

Valves	Qty.	Manual	Actuated
Feedwater			
Stop	1		
Check	1		
Level control	1		
Control valve block	2		
Control valve by-pass	1		
Control valve drain	4		
Economizer block	0		
Economizer by-pass	0		
Steam non-return	1		
Steam stop	1		
Free blow drain	1		
Continuous blowdown control	1		
Continuous blowdown block	1		
Intermittent blowdown	4		
Boiler vent	1		
Chemical feed block	1		
Chemical feed check	1		
Superheater start-up	1		
Start-up block	0		
Superheater vent	4		
Superheater drain	4		
Economizer vent	1		
Economizer drain	1		
Sootblower steam block	1		
Desuperheater spray water			
Control valve	1		
Control valve block	2		
Control valve by-pass	1		
Control valve drain	4		
Power operated block	0		
Stop valve	1		
Check valve	1		
Boiler drain	0		
Steam sample	0		
Water sample	0		
Sootblower steam pressure reducing valve			

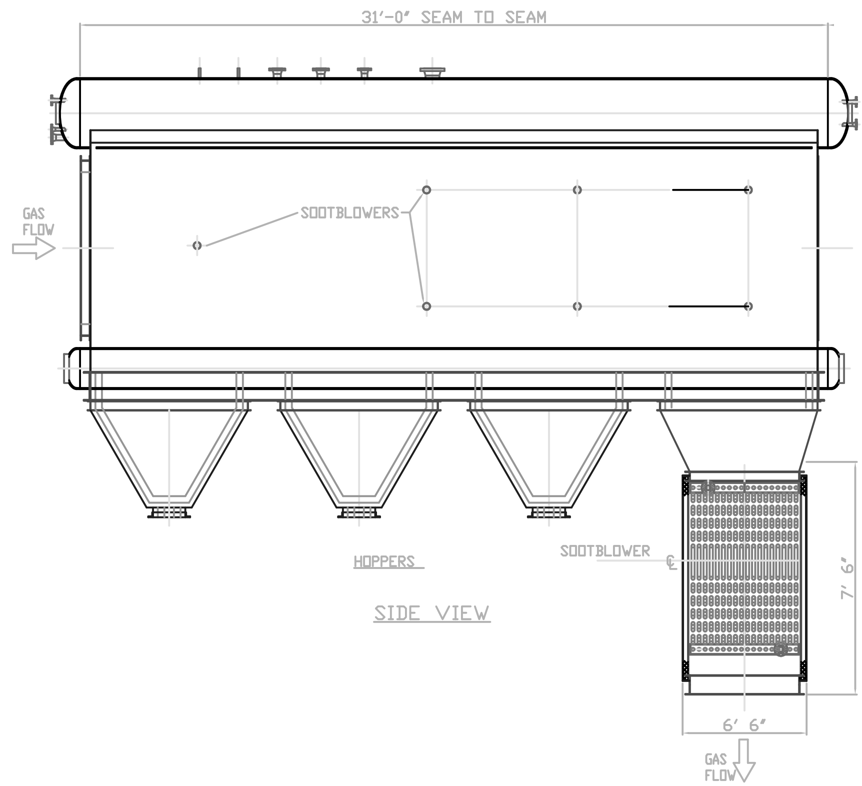


SECTION "A-A"

SECTIONAL PLAN VIEW



INLET END VIEW



SIDE VIEW

RENTECH BOILER
SYSTEMS, INC.
ABILENE, TEXAS

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DESCRIPTION: WATERTUBE BOILER

CUSTOMER:

SCALE:	N.T.S.	DRAWN BY:	MAK	DRAWING NUMBER	REV.
DATE:	9-11-97	APPR. BY:	.	HFB-3546-MC	1

From: Mike Carter [mailto:mcarter@rentechboilers.com]
Sent: Monday, April 02, 2012 9:55 AM
To: Auerbach, Eric
Cc: 'Lopata Technical Service Corp.'
Subject: RE: REQUEST FOR BUDGETARY QUOTES ON WASTE HEAT BOILERS ... REQUESTED DUE DATE: APRIL 6, 2012 (SOONER, IF POSSIBLE)

In order to make 28,000 lbs/hr of 125 psig steam, we would require to cool approximately 148,000 lb/hr of flue gas from 1,200 to 600F. This system would include the boiler, sootblowers, ash hoppers and trim. Budget cost for this unit would be $1,250,000.00.

I hope this information helps in the decision process. We would be more than pleased to give a firm proposal when this projects gets closer. If you have any questions, please feel free to contact me.

Regards,
Mike Carter
Rentech Boiler Systems, Inc.
PH# 325-794-5606
Fax# 325-672-9996

From: Lopata Technical Service Corp. [mailto:lopatatechservice@ameritech.net]
Sent: Thursday, March 22, 2012 10:13 AM
To: Mike Carter
Cc: Auerbach, Eric
Subject: REQUEST FOR BUDGETARY QUOTES ON WASTE HEAT BOILERS ... REQUESTED DUE DATE: APRIL 6, 2012 (SOONER, IF POSSIBLE)

Hi, Mike ---

We have been working on a project / study project for the Buffalo , NY Waste Water Treatment Plant being done by:

Mr. Eric Auerbach
Project Engineer
Malcolm Pirnie

(847) 517-4094
E-Mail: Eric.Auerbach@Arcadis-US.com

This is only a study at this point in time. Eric needs budget quotes on two waste heat boilers ... for this project (for different purposes). The first budgetary quote is for a waste heat boiler that might get purchased if the project goes ahead. The second is just a "number" which would be the cost of replacing one of their existing waste heat boilers at the plant "in kind". The new project study is to generate steam and electricity ... the existing waste heat boilers only generate steam.

Boiler Number 1: This boiler will generate high pressure (750 PSIG), high temperature (750F) steam to be let down through a steam turbine. It will recover heat from the flue gas of an existing sludge incinerator and it will "over fire" the available heat ... or supplement the flue gas flow with additional heated air coming into the waste heat boiler with digester gas. RENTECH needs to quote on the burner / ductwork assembly to fire the digester gas (probably a register burner firing into the boiler or duct just in front of the boiler) as well as the complete waste heat boiler ... normal scope of supply. The digester gas will contain siloxanes so all the tubes in the waste heat boiler must be bare. They don't have any acid gas analysis on the flue gas ... so don't take the flue gas below 350F just to avoid corrosion problems. I think that the Waste Heat Boiler should include hoppers and soot blowers ...in this budgetary proposal.

Boiler Number 2: This boiler will not be bought. They need to know the cost of replacement of one of the existing waste heat boilers since part of their financial analysis will be to take a credit for not replacing that boiler. The current Waste Heat Boiler is a water tube waste heat boiler that produces 28,000 pounds per hour of 125 PSIG saturated steam by taking ??? pounds per hour of flue gas from the incinerator (same flue gas analysis as above) and reducing the temperature of the flue gas from 1200F to 600F. I am not sure why the difference in inlet temperature ... but ... can you give them an approximate cost of a replacement waste heat boiler for this one ... no supplemental firing, but it does include soot blowers and normal boiler controls.

If you have any questions on this one ... please either call me or e-mail me. Thanks in advance for doing your best to meet this budgetary quote request. Regards,

Jim Lopata
Lopata Technical Service Corporation
Suite 1702
1130 North Dearborn Street
Chicago , IL 60610

(312) 280-1574
FAX (312) 951-0484
E-Mail: LopataTechService@ameritech.net

Chicago Area Manufacturers' Representative for:

Air Emissions Control Equipment and Technologies
Boilers (Waste Heat and Gas / Oil Fired)
Solid Waste Incinerators

Adirondack Combustion Technologies, Inc.
4488 Duanesburg Road
P.O. Box 278
Duanesburg, New York 12056
Ph: (518) 357-4488 Fax: (518) 357-2698

December 11, 1212

Malcolm Pirnie
2800 W. Higgins Road – Suite 1000
Hoffman Estates, SC 60169
ATT: Mr. Eric Auerbach

Dear Mr. Auerbach,

The following is written in regard to the City of Buffalo Waste Water Treatment Plant in Buffalo, New York.

Based on that meeting, I offer the following:

Q1. You asked if this project is feasible and similar to what is going on in the other contract being completed by Nicholson and Hall.

A1. Nicholson and Hall is refurbishing the sludge dryers which are connected to the waste heat boilers. It would seem reasonable to either rebuild or replace the existing HRSG's.

Q2. What is the best way to integrate the controls?

A2. If the project is approved to move forward, then a meeting should be held with the existing control vendor. There appears to be enough base control system to handle the extra I/O.

Q3. Would it make sense/save money to use a change order rather than a complete bid?

A3. Because the contractor has been working in the plant and is completing a project that works hand in hand with the new HRSG Project, and since the contractor's main business is large industrial boilers, it appears a reasonable course to proceed on.

Q4. Please provide a cost estimate.
A4. The cost to open the building, remove both old generators, install the new generators with all connections and close the building back up is estimated at <u>$1,767,000.00.</u>

5. Additionally, at the meeting held with Joe Paszkiewicz of Nicholson and Hall, the following observations were made:

a. Soot blowers should not be steam because of the amount of particular in the gas stream. Compressed air should be used for soot blowing.
b. A finned super heater will tend to plug. A bare tube superheater should be considered.
c. Same for the economizer
d. Air compressor for compressed air could be provided by contractor.
e. The location of the economizer should be relocated further downstream. There is sufficient room for a filter or baghouse, which will enhance heat recover and assure the economizer doesn't plug up.
f. The afterburners should be replaced, not rebuilt. The age and condition of the equipment does not lead itself to rebuilding, reconditioning.

Respectfully submitted,

William H. Park
Sales Representative
Adirondack Combustion Technologies, Inc. (Agent for Rentech Boiler Company)

Cc: file
Joe Paszkiewicz – Nicholson and Hall

December 7, 2012

Arcadis
2800 W. Higgins Road
Suite 1000
Hoffman Estates, IL 60169

Attention: Eric Auerbach

RE: Removal of Existing Heat Recovery Boiler/ Installation of New Boiler
QUOTE #12-263

Dear Eric:

Thank you for considering Nicholson & Hall Corporation for the aforementioned project. We are pleased to provide for your review a budgetary price to perform the following scope of work:

- Mobilize men and equipment onsite at the Buffalo Sewer Authority.
- Removal of building side wall to access boiler room elevation.
- Removal of existing waste heat boiler, boiler platforms, inlet duct, outlet duct and hoppers.
- Fabricate new hoppers, inlet duct transition sections and outlet duct.
- Install new boiler, hoppers, inlet duct and outlet ducts.
- Install soot blowers and associated piping.
- Reinstall building side walls.
- Demobilize from site.

BUDGETARY PRICE: $850,000.00
(EIGHT HUNDRED FIFTY THOUSAND DOLLARS)

Note:

Projected duration of project is 12-14 weeks.

Proposal is based upon working straight time hours Monday through Friday.

Customer shall supply the following facilities and utilities in suitable quantities, within one hundred (100) feet of the work site, at no charge to the Contractor: A) Water; B) Electricity; C) Compressed Air; D) Feed Pumps for Hydrostatic Test; E) Wash Up and Toilet Facilities.

This Proposal is based upon the premise that all operations hereunder exclude the use, handling and/or exposure to asbestos, lead or other hazardous materials unless specifically stated otherwise in this proposal.

Completion dates are estimated and there shall be no penalty for the delay in performance of completing the work scope due to events that are beyond our control, such as acts of God, fire, floods or labor disputes.

Contractor shall not be responsible for any consequential or liquidated damages.

Invoices payable upon receipt. Customer agrees to pay Nicholson & Hall Corp. 1.5% per month (18% per annually) service charge for the entire outstanding of any and all invoices, adjustment fees, service charges or collection fees past due. This service charge is in addition to and not in lieu of any other remedies Nicholson & Hall Corporation may have.

Sales and use tax on rentals, consumables and small tools are included in our proposal. Sales and use tax on labor and materials is not included as we presume a tax-exempt certificate will be provided. If a certificate is not provided, sales and use taxes on labor and materials would have to be added to the amount bid.

This proposal is contingent upon the parties developing and agreeing to mutually acceptable contractual language addressing the availability of qualified manpower.

In the event of any dispute involving this proposal or any resulting contract, the parties agree to timely mediate such dispute before a mutually acceptable mediator. In the event mediation is unsuccessful, then the dispute shall be resolved by timely arbitration administered by the American Arbitration Association in accordance with its Construction Industry Arbitration Rules.

Any action or proceeding arising out of this agreement shall have as its venue a court located in Erie County, New York.

We thank you for this opportunity to bid this project and look forward to performing this work for Arcadis.

Regards,

NICHOLSON & HALL CORPORATION

Joseph Paszkiewicz
Manager – Non Utility Division

JP/km
Attachment

-----Original Message-----
From: Hawbaker, Olivia
Sent: Friday, December 14, 2012 2:01 PM
To: Auerbach, Eric
Subject: FW: Boiler Feed Pump

Info from Goulds is below and attached for the boiler feed pump. Cost estimate is $28k.

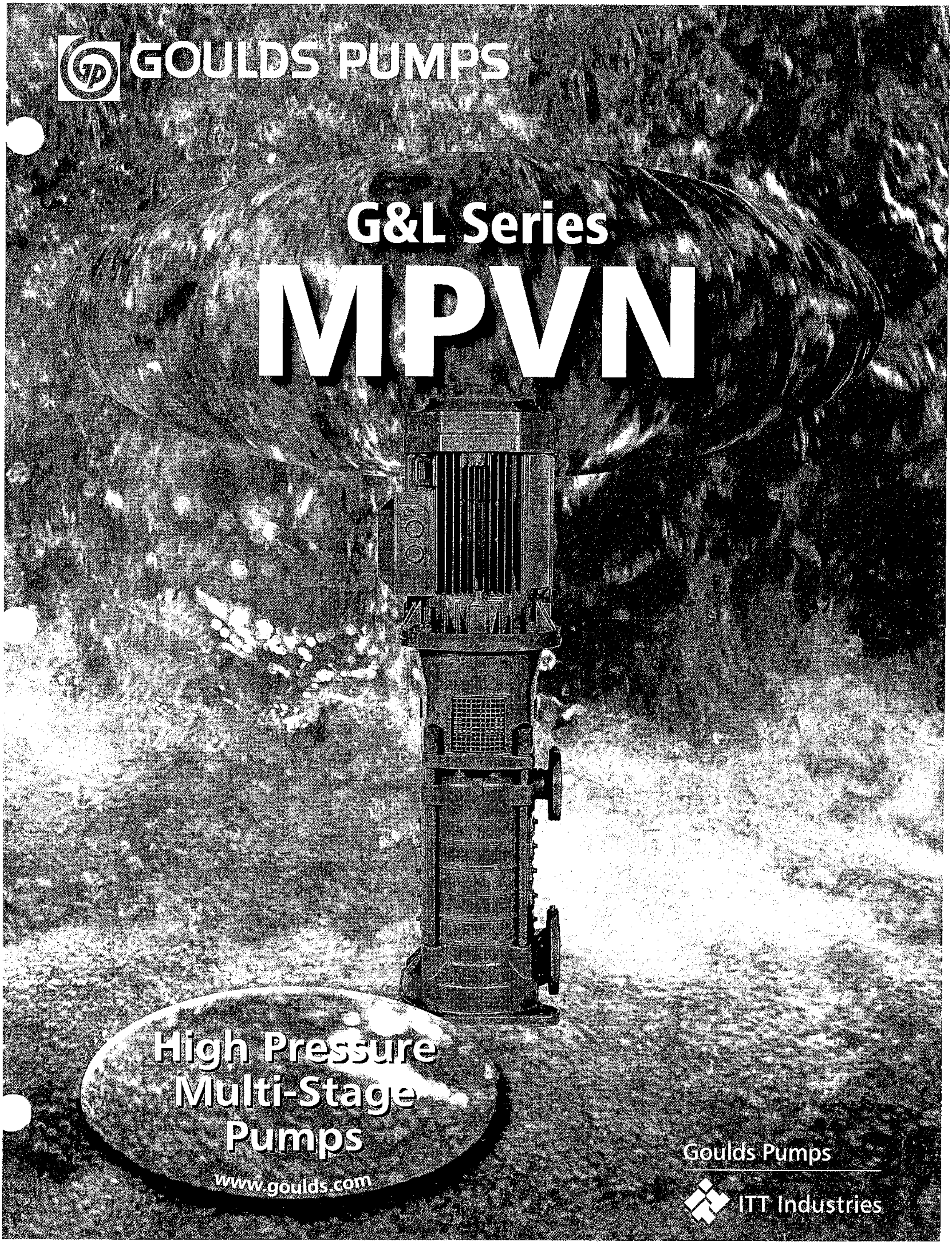
-----Original Message-----
From: Doug Hayes [mailto:dhayes@fluidkinetics.net]
Sent: Friday, December 14, 2012 2:20 PM
To: Hawbaker, Olivia
Subject: Boiler Feed PUmp

Olivia: Attached is info on Goulds MVPM 100 HP PUMP SST Fitted 75 GPM at 1502' TDH (650 PSI) Budget Price $ 28,000.00 If you have any questions please let me know. Doug Douglas J Hayes President

Fluid Kinetics, Inc
251 Thorn Avenue
PO Box 655
Orchard Park, NY 14127
716-662-7900
716-662-7982 Fax

dhayes@fluidkinetics.net

info@fluidkinetics.net 20121214 152900;



GOULDS PUMPS

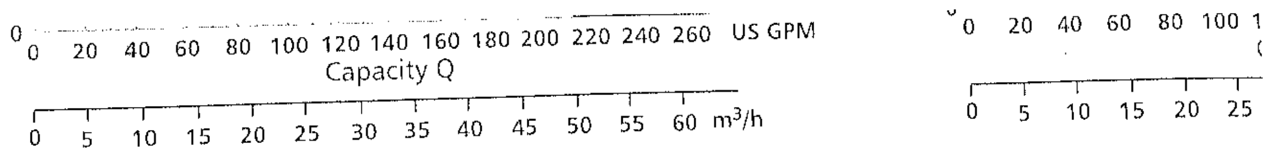
G&L Series
MPVN

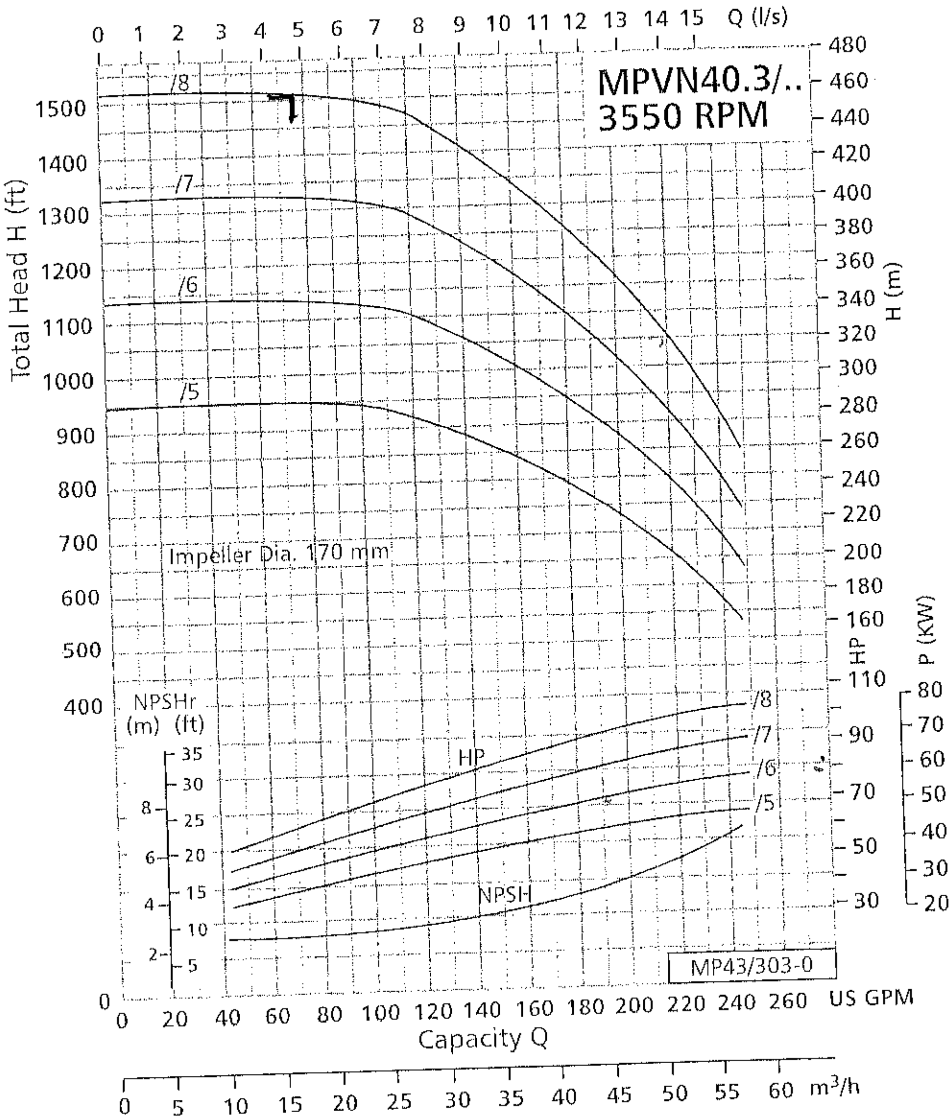
High Pressure Multi-Stage Pumps

www.goulds.com

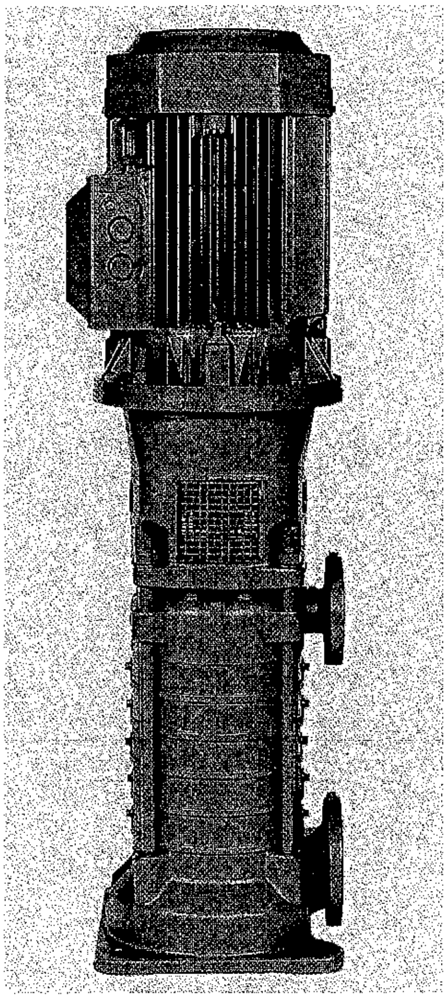
Goulds Pumps

ITT Industries





GOULDS PUMPS



The MPVN is manufactured for Goulds Pumps by ITT Vogel Pumpen at their plant near Vienna, Austria.

Performance Range:

Capacities	up to 1500 GPM (340 m^3/h)
Head	up to 1640 feet (500 m)
Maximum speed	up to 3600 RPM

Multistage pumps for capacities up to 8800 GPM (2,000 m^3/h), available – Series P

Sizes:

From 1½" to 5" discharge.

Maximum Temperature:

280° F (140° C)

Maximum Casing Pressure:

800 psig (55 bar)

Handled Liquids:

Pure as well as slightly contaminated media such as:
Cold and Hot Water
Condensate
Oil Suspensions
Acids as well as their watery solutions

Applications:

Water Supply
Booster Systems
Irrigation
Fire Fighting
Snow Making
Cooling Circuits
Boiler Feed
Condensate
District Heating
Reverse Osmosis and Ultra Filtration
Spray Water Systems
Cleaning Systems

Modular System:

VOGEL Vertical Multistage pumps utilize a modular design concept which maximizes component interchangeability. As such, multiple design configurations can be engineered to meet customer requirements without compromise to repair part inventories. The entire performance range is covered by 4 mechanical sizes that hold 8 different hydraulics.

Hydraulics:

Closed radial type impellers designed for casing wear rings on both sides. Axial thrust is minimized by balance holes for minimum bearing loads and maximum bearing lifetime. Diffusers separated from stage casings, easily exchangeable. Balanced radial forces, minimum shaft deflection, minimum vibrations.

HEAVY DUTY DESIGN FOR LONG-TERM OPERATION IN INDUSTRIAL APPLICATIONS.

MPV 2 03 B 3 A D 1 A

Flange Orientation:
A = Left Suction, Left Discharge (OO)
B = Left Suction, Rear Discharge (OR)
C = Left Suction, Front Discharge (OL)
D = Left Suction, Right Discharge (OG)

Seal Materials: For Optional Mechanical Seal modify catalog order no. with Seal Code listed below.

Seal Code	Rotary	Stationary	Elastomers
1	Carbide	Sil-Carbide	EPR
2			Viton

Motor Frames:
D = 254TD/256TD
E = 284TSD/286TSD
F = 284TD/286TD
G = 324TSD/326TSD
H = 324TD/326TD
J = 364TSD/365TSD
K = 364TD/365TD
L = 404TSD/405TSD
M = 404TD/405TD
N = 444TSD/445TSD
O = 444TD/445TD
P = 447TSD/449TSD
R = 447TD/449TD
S = 5009SD

Pump Material:
A = All Iron
B = Bronze Fitted
C = Stainless Fitted
D = All Stainless

Seal Type:
2 = SA – Unbalanced
3 = SB – Balanced

ANSI Discharge Flange Class:
A = 150
B = 300
C = 600

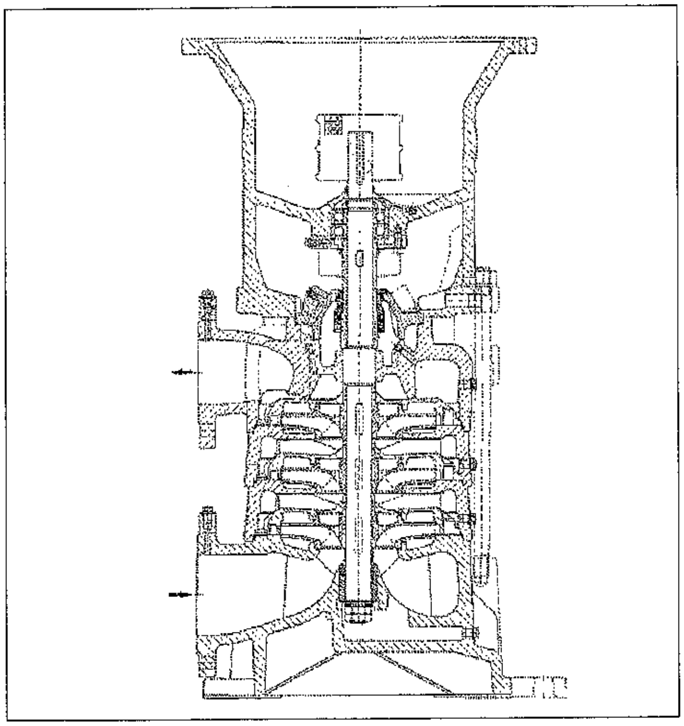
Number of Stages

Pump Size:
1 = 40.1
2 = 40.2
3 = 40.3
4 = 65.1
5 = 65.2
6 = 100.1
7 = 100.2
8 = 125.1
9 = 125.2

Pump Model

Complete Pump Consists of: Waterend, Coupling and Motor.

MPVN Sectional Assembly



Type MPVN:

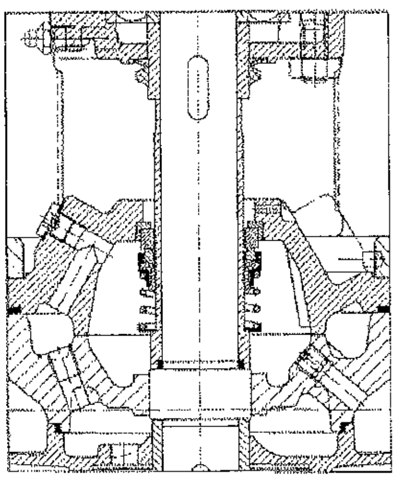
- Vertical configuration with separate thrust bearing, grease lubrication with grease nipples.
- Standard motor according to NEMA MG1-4.07, D flange mounting.
- Flexible coupling between pump and motor.
- Medium lubricated sleeve bearing in suction casing.
- Maintenance friendly design. Shaft sealing maintainable without pump disassembly.

Shaft Seal Options:

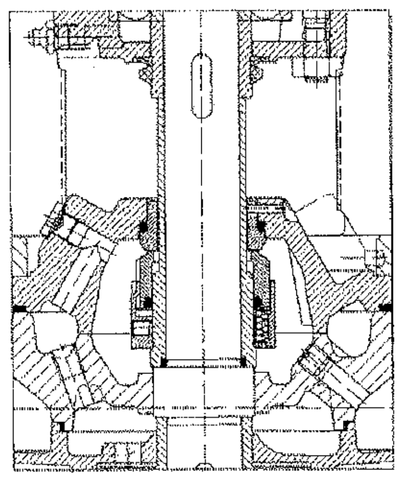
Mechanical Seal:

Seal chamber dimensions-comply with ISO 3096. Mechanical seals of all brands that comply with this standard and EN 12756, version "K" can be used without modification of the standard parts.

The taper bore type seal chamber is self venting and guarantees optimum lubrication and cooling of the seal faces.



Single mechanical seal, design U
unbalanced up to a maximum of 250 PSI (16 bar)



Single mechanical seal, design B
balanced up to a maximum of 800 PSI (55 bar)

Table of Materials

Pos.	Index of Part	Material-code			
		111	211	311	532
		Cast Iron	Bronze Fitted	Stainless Fitted	All Stainless
1	Impeller	0.6025	2.1050.01	1.4408	1.4408
2, 2/E	Diffuser	0.6025	0.6025	0.6025	1.4408
3	Suction casing	0.6025	0.6025	0.6025	1.4408
4	Discharge casing	0.6025 (Class 600 –0.7040)	0.6025 (Class 600 –0.7040)	0.6025 (Class 600 –0.7040)	1.4408
9	Wear ring	1)	1)	1)	1.4408
8, 12	Bearing cover	0.6025	0.6025	0.6025	0.6025
18	Seal cover	0.6025	0.6025	0.6025	1.4408
21	Bearing bush	G-CuSn16	G-CuSn16	G-CuSn16	G-CuSn16
23, 2444	Shaft and shaft sleeves	1.4021	1.4021	1.4021	1.4462
60	Intermediate bearing housing, stage casing	0.6025	0.6025	0.6025	1.4408

1) Upon request of 1.4410 possilble

Elastomers (O-Ring) of EPDM for hot water up to 284°F (140°C) (Pay attention to operation limits and chemical resistance), optional Viton elastomers available.

Casted Material Standards	DIN Designation	DIN	ASTM	UNS
Cast Iron	EN GJL-250 (GG 25)	0.6025	A48 Class 30 (general castings) A278 Class 30 (press. castings)	F12401
Ductile Iron	EN-GJS-400-18-LT	0.7043	A395 Grade 60-40-18	F32800
	EN-GJS-400-15 (GGG 40)	0.7040	A536 Grade 60-40-10②	–
Carbon Steel	GP 240 GH (GS-C25)	1.0619	A216 – WCB	J03002
Stainless Steel	1.4408	1.4408	A351 / A743 / A744 CF-8M③	J92900
	1.4410	1.4410	A789 / A790 Typ 2507①	S32750
Duplex SS	1.4517	1.4517	A351 CD4-MCu	
Bronze	G – CuSn 10 / CC480K	2.1050.01	B427④	C90700
Wrought Material Standards				
Stainless Steel	1.4021	1.4021	A276 Typ 420	S42000
Duplex SS	1.4462	1.4462	A276 Typ 2205	S31803
Fastener Materials (Bolts)				
Carbon Steel	DIN 267 Class 8.8	1.7225	A193 B7	J41400
Stainless Steel	A2	A2	A193 B8	S30400
Stainless Steel	A4	A2	A193 Grade B8M	S31600

① only used for casing wear rings
② less elongation
③ A351/A743 for general applications
A744 for several services
④ also available B148/B584

Comparison of Various Standards

EN (DIN)		ISO	BSI (UK)	AISI	ASTM	UNS
0,6025	EN-GJL-250 (GG 25)	185/Gr. 250		1452 Gr. 220	A 278 Class 30	
0.7040	EN-GJS-400-15 (GGG 40)	1083/400-12			A 536 Gr. 60-40-18	
2.1050.01	G-CuSn10				B584 C 90700	
1.0421	X20Cr13	683-13-4	970 420 S 37	420	A 276 Type 420	
1.4408	G-X6CrNiMo 18-10		3100-316 C 16	CF8M	A (351) 744 Gr. CF8M	
1.4410	X2CrNiMoN25-7-4				A182/A479/2276	S32750
1.4462	X2CrNiMoN22-5-3		1503 318 S13		A240	S31803 S32205

Mechanical Seal Materials

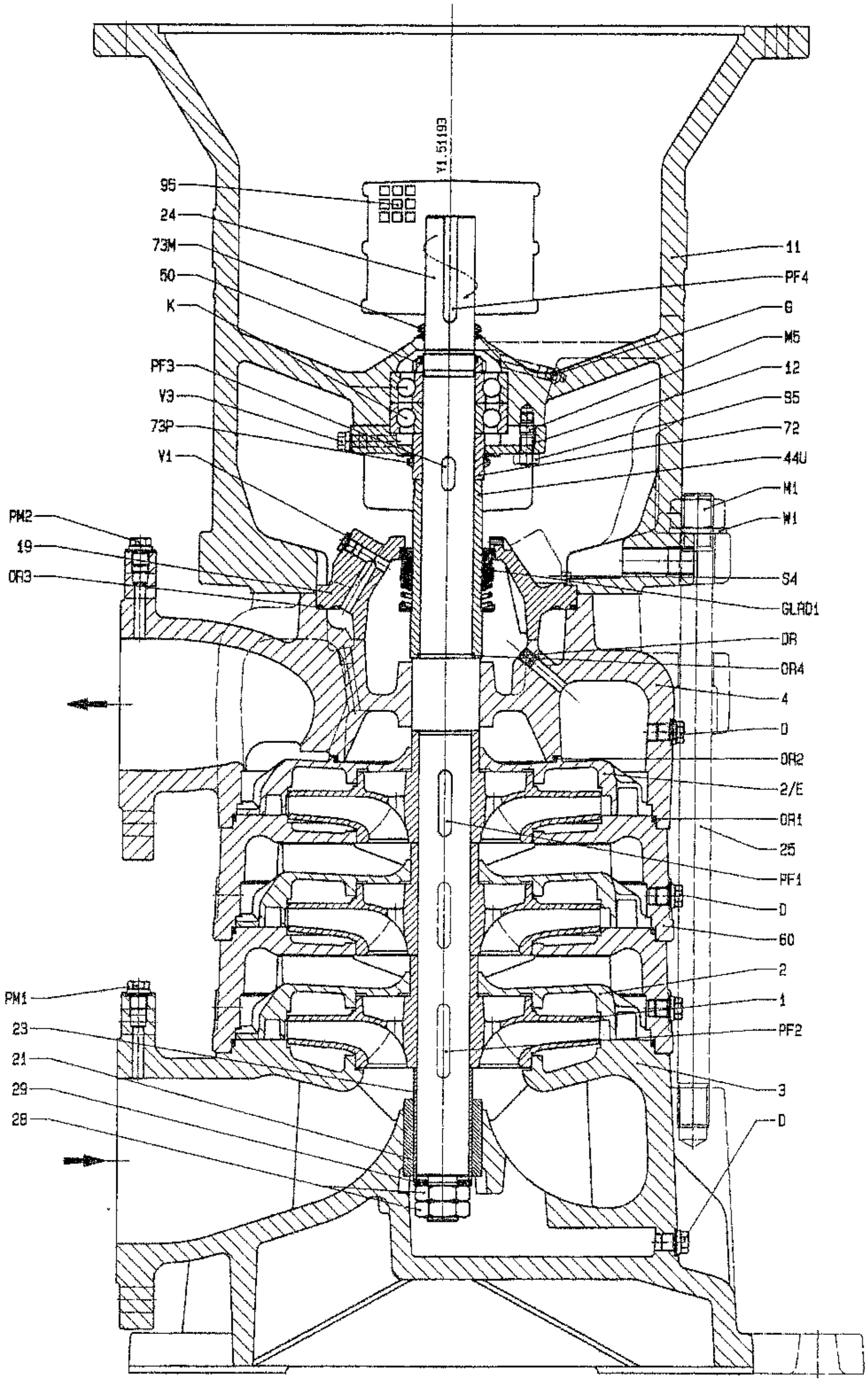
DIN Code	Mechanical Seal	Stationary Ring	Elastics	Metal Parts
BQ 1 EGG	Carbon①	SIC②	EPDM	316TC
BQ 1 VGG	Carbon①	SIC②	Viton	316TC
Q1 Q1 VGG	SIC②	SIC②	Viton	316TC

① Carbon resin impregnated
② Pure silicon carbide (without free silicone)

Shaft Seal:
Mechanical Seal Code . . .SA (Unbalanced)

Size: MPVN100.1, MPVN100.2, MPVN125.1, MPVN125.2

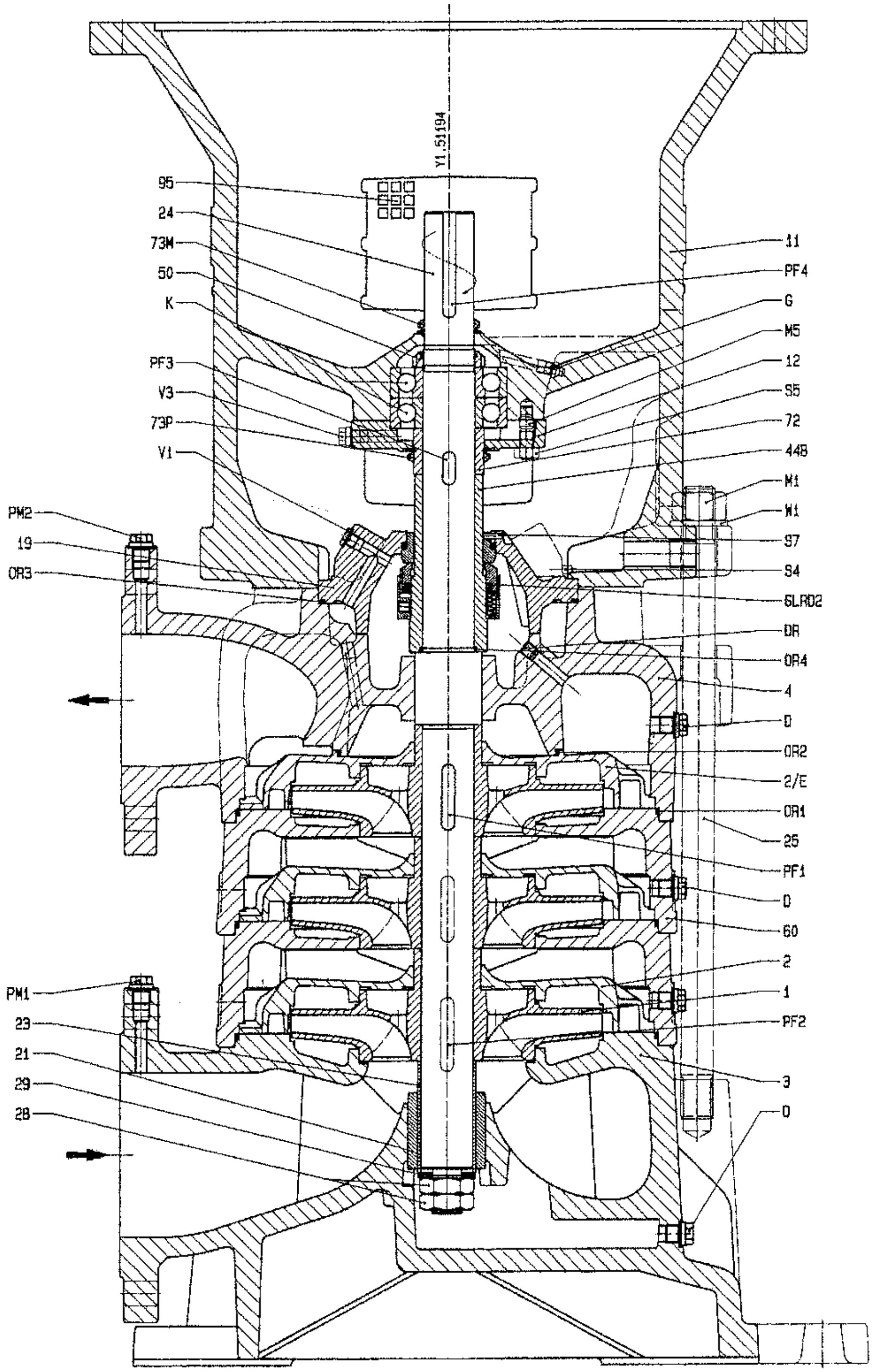
Part Number	Description
1	Impeller
2	Diffuser
2E	Diffuser, last stage
3	Suction casing
4	Discharge casing
8	Bearing pedestal
12	Bearing cover
18	Seal cover
21	Bearing bushing
23	Bearing sleeve
24	Shaft
25	Tie bolt
28	Impeller nut
29	Washer
44U	Shaft wearing sleeve
50	Bearing nut
60	Stage casing
69	Gland
72	Spacer sleeve
73M	Thrower
73P	Thrower
95	Shaft guard
D	Drain plug
DR	Throttling element
G	Grease nipple
GLRD1	Mechanical seal
K	Radial ball bearing
M1	Nut
M5	Nut
OR1	O-ring
OR2	O-ring
OR3	O-ring
OR4	O-ring
PM1	Pressure gauge
PM2	Pressure gauge
PF1	Key
PF2	Key
PF3	Key
PF4	Key
S4	Pin
S5	Stud
V1	Plug, threaded
V3	Plug, threaded
W1	Washer



Shaft Seal:
Mechanical Seal Code . . .SB, SD (Balanced)

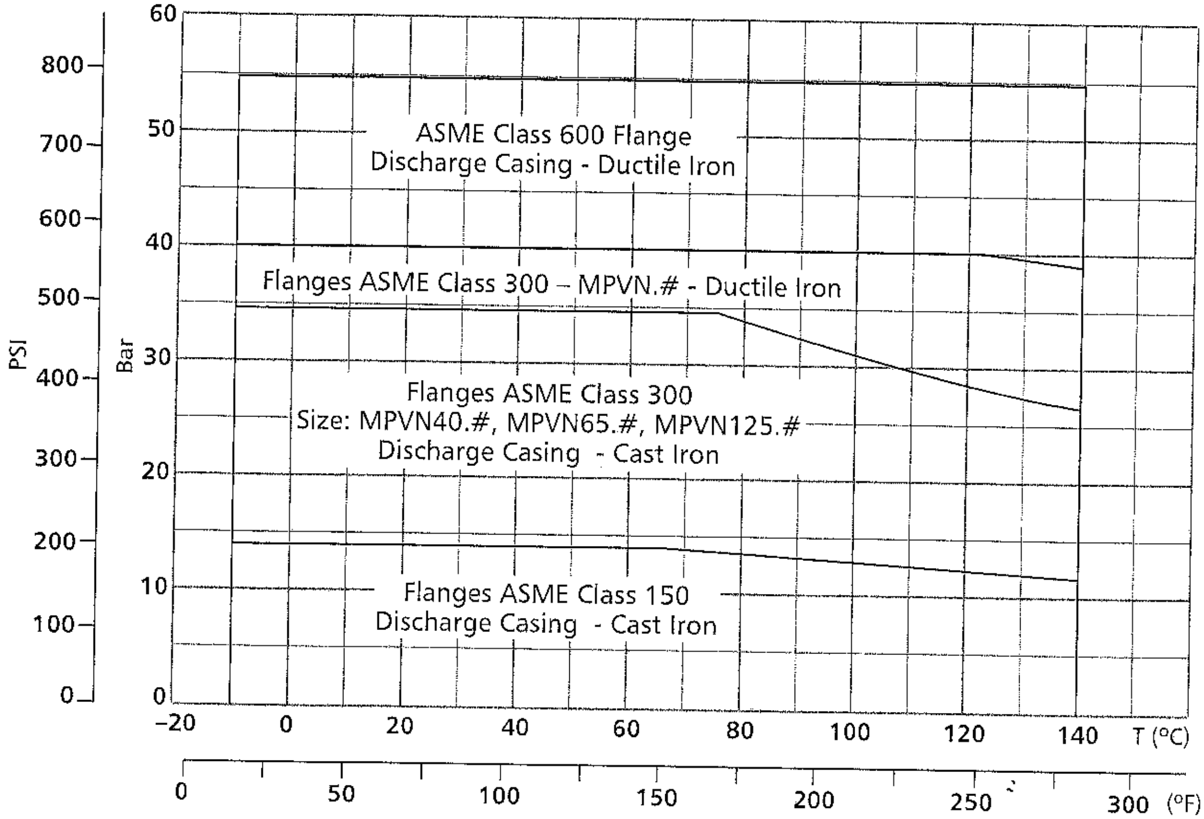
Size: MPVN100.1, MPVN100.2, MPVN125.1, MPVN125.2

Part Number	Description
1	Impeller
2	Diffuser
2E	Diffuser, last stage
3	Suction casing
4	Discharge casing
8	Bearing pedestal
12	Bearing cover
18	Seal cover
21	Bearing bushing
23	Bearing sleeve
24	Shaft
25	Tie bolt
28	Impeller nut
29	Washer
44B	Shaft wearing sleeve
50	Bearing nut
60	Stage casing
69	Gland
72	Spacer sleeve
73M	Thrower
73P	Thrower
95	Shaft guard
D	Drain plug
DR	Throttling element
G	Grease nipple
GLRD1	Mechanical seal
K	Radial ball bearing
M1	Nut
M5	Nut
OR1	O-ring
OR2	O-ring
OR3	O-ring
OR4	O-ring
PM1	Pressure gauge
PM2	Pressure gauge
PF1	Key
PF2	Key
PF3	Key
PF4	Key
S4	Pin
S5	Stud
S7	Pin
V1	Plug, threaded
V3	Plug, threaded
W1	Washer

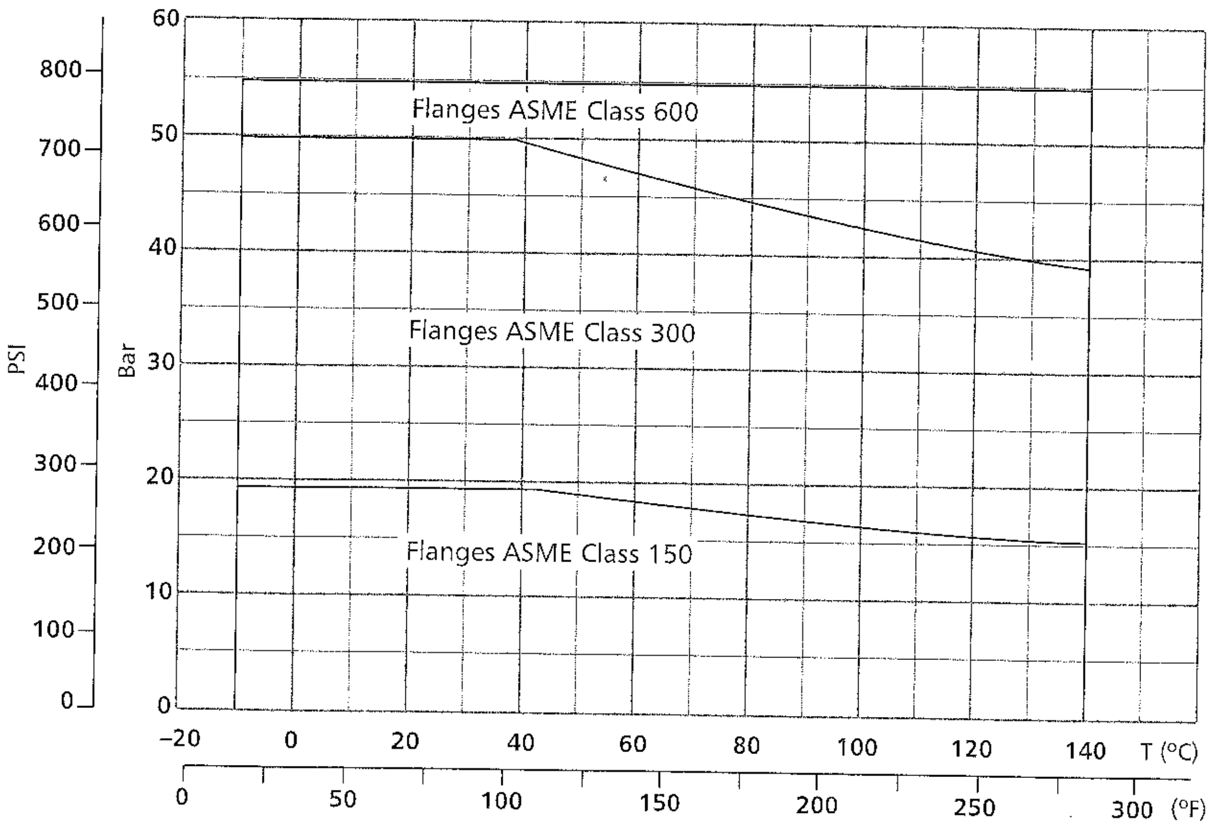


Pressure and Temperature Limits

Maximum Allowed Operating Pressure (Casing and Flanges): Material Code 111 (Cast Iron), 211 (Bronze Fitted), 311 (SS Fitted)



Maximum Allowed Operating Pressure (Casing and Flanges): Material Code 532 (All Stainless)



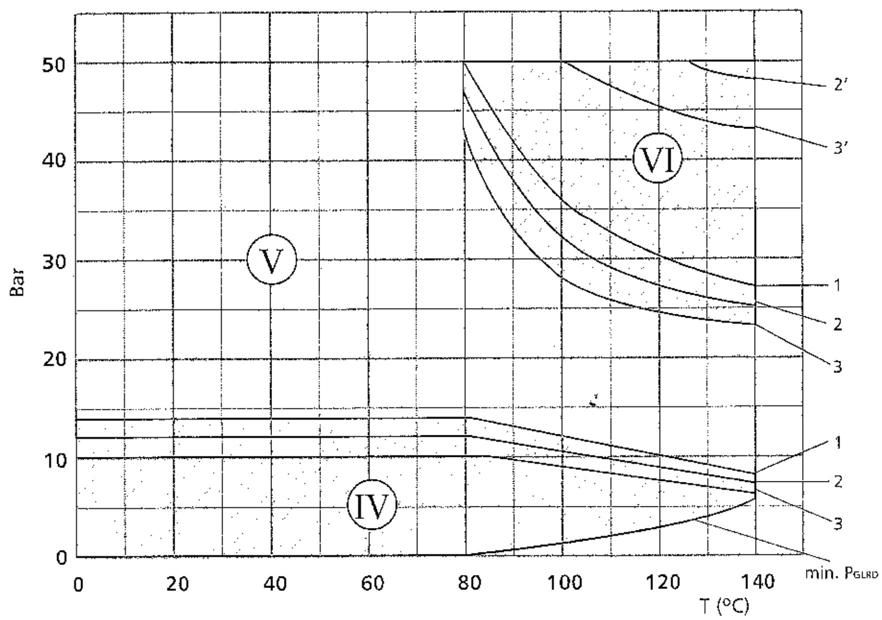
Maximum Allowed Operating Pressure = incoming pressure at suction flange and pump head at 0 flow.

Selection Charts for Shaft Sealing with Mechanical Seal, API-Plan 1 (11)

P_z = Incoming pressure at suction flange
P_p = Pump head at Q = 0 m³/h
i = Number of stages

	MP40	MP65	MP100	MP125
1450	1	1	1	2
1750	1	1	2	2
2200	1	2	2	2
2950	2	2	3	3
3550	2	3	3	3
rpm				

$P_{GRLD} = P_z + P_P / i \times (i-1)$



min. P_{GRLD} . . .minimum pressure at the mechanical seal

2'. 3' . . .Max. allowed pressure on the mechanical seal

Sealing Code of Mechanical Seal:

Discharge Side	Code
IV	SA
V	SB
VI	SD*

* upon request

General:
Area IV: Mechanical seal acc. DIN 24960, U-shape with L1k, Material: carbon – SiC - EP
Area V: Mechanical seal acc. DIN 24960, B-shape with L1K, Material: carbon – SiC - EP
Area VI: Mechanical seal acc. DIN 24960, B-shape with L1k, Material: carbon – tungstencarbide - EP

Selection charts are only valid for clean water resp. demineralized boiler feed water. For SiO2 (silicic acid) contents > 4 mg/l resp. SiO2 containing water treatment liquids, please ask manufacturer.

Clean liquids, solids < 10 mg/l

Minimum pressure at suction flange at temperatures > 176°F (80°C) needs to be available.

Pump Energy Use (For Boiler Feedwater Pumps)

Pump HP =	(head in feet)*(flow rate in gpm)* (S.G.) / 3956	Hydraulic Horsepower Equation
BHP=	whp/pump efficiency	from Civil Engineering Reference Manual, Table 4.2
Pump efficiency =	75%	
S.G. water =	1	

Current Boiler Feedwater Pumping Power

head	475	ft	Pressure Head 125 psi =	288	ft head
flow rate	50	gpm	Pressure Head 650 psi =	1,499	ft head
Pump BHP	8.0	HP	Additional Head =	1,211	ft head

New Boiler Feedwater Pumping Power

head	1,686	ft
flow rate	75	gpm
Pump BHP	42.6	HP

Additional New BHP

Additional HP	34.6	HP	(New - Current)

Auerbach, Eric

From: Auerbach, Eric
Sent: Monday, December 03, 2012 4:17 PM
To: 'Lawrence Frauen'
Subject: RE: Follow up to Bird Island Site Visit

Hi Larry,

Thanks for all the information, it is very helpful. Please see below for the summary of my understanding of your proposed equipment and how I plan to enter it into my economic analysis.

Capital Cost
RO System = $66.5K, Brackish water Discharger Tank = $11.9K (assumed largest), Total = $79K

Installation Cost
You gave me an estimate of ~ $6,600 for Nalco install services, I bumped that up to $25k to cover everything including contractor installation labor

Operating Cost
I am using the annual maintenance contract cost of ~$6k per year.

DI Polisher
Not including this in the economics since it is not recommended. If BSA decides they want it for extra protection it will cost them roughly $10k per year which will be dependent on the actual number of exchanges needed.

Please let me know if this sounds reasonable for a conceptual level study.

Thanks

Eric

From: Lawrence Frauen [mailto:lfrauen@nalco.com]
Sent: Wednesday, November 28, 2012 4:03 PM
To: Auerbach, Eric
Subject: RE: Follow up to Bird Island Site Visit

Eric,

Attached is the quote for an RO system and DI for the Buffalo Sewer Authority.
Keep in mind I do not believe the DI polishers or the associated fees for rental and change outs are needed for the 600 PSI boiler.
The quote includes a multimedia filter which is required due to the SDI of Buffalo city water and a storage tank.

Let me know what additional questions you have.

Thanks ….

Larry Frauen
Nalco Company
lfrauen@nalco.com

716-998-7582

From: Auerbach, Eric [mailto:Eric.Auerbach@arcadis-us.com]
Sent: Monday, November 19, 2012 3:02 PM
To: Lawrence Frauen
Subject: RE: Follow up to Bird Island Site Visit

Hi Larry,

At this point we would want the cost of including the mixed bed polisher. I will note in the report that it is not deemed absolutely necessary at 650 psi. We will have a discussion with the client on whether they would like to include it based on cost and additional protection the system provides.

Thanks

Eric

From: Lawrence Frauen [mailto:lfrauen@nalco.com]
Sent: Monday, November 19, 2012 1:36 PM
To: Auerbach, Eric
Subject: RE: Follow up to Bird Island Site Visit

Eric,

Sorry for the delay. Nalco has implemented a new system to process the design of [retreatment equipment I was not aware of.
I have sent the forms in and should be hearing some results this week.

In the interim; I requested the mixed bed polishers on the quote as that is what you requested and got in the past. However, at 600 psig this is not high pressure and does not require ultrapure water. The RO is sufficient at this pressure do you really want the mixed bed or is it up to Nalco to make the recommendations.

Thanks …. Larry

From: Auerbach, Eric
Sent: Friday, September 14, 2012 10:34 AM
To: 'l_frauen@nalco.com'
Subject: Follow up to Bird Island Site Visit

Hi Larry,

Thanks for coming out to the plant yesterday. Hopefully you found it informative. I promised you a calculation on the boiler make-up water to size your equipment:

60,000 lbs per hour max flow for both boilers
Condensate return is currently at 180oF which is about 8.1 lbs/gal
So total return flow should be about 125 gpm
Currently the boiler makeup water is about 20% of total flow so it would be about 25 gpm
I'm not sure what sizes your RO system come in but something small in the 20-50 gpm range is probably right. Keep in mind that we will typically only be running one boiler at a time so the system should be able to handle a turndown to smaller flows in the 10 gpm range.

In terms of items we would be looking for:

- General description of the proposed equipment to treat water for a 650 psig boiler
- Budgetary Cost for the proposed equipment
- Important O&M items to consider for the proposed equipment and estimated cost if possible

One other item to consider. Yesterday I mentioned we might need to look into a chemical exchanger for the entire boiler water flow. The reason for this is that we will be extracting steam from the turbine and injecting it into the general plant heating distribution system. So that means this steam will be returning via the plant's general condensate return system. It might be a good idea to put this exchanger in as a safeguard in the event that somehow some contaminated water makes its way into the condensate return system. I've heard horror stories about a sludge leak in a heat exchanger or a makeshift drain into the CR line returning heavy solids and ruining a boiler. Please let me know what your thoughts are on this suggestion.

Thanks for your time,

Eric Auerbach, P.E.

Malcolm Pirnie | The Water Division of Arcadis

Please note new address and office numbers

2800 W Higgins Rd, Suite 1000 | Hoffman Estates, IL 60169

eric.auerbach@arcadis-us.com

Hoffman Estates Office: (847) 805-1050

Downtown Office: (312) 575-3719

Cell: (716) 228-7538

Auerbach, Eric

From: Victor McFadden [vgmcfadden@nalco.com]
Sent: Monday, January 21, 2013 1:09 PM
To: Auerbach, Eric; Lawrence Frauen
Subject: RE: Power draw on proposed RO system

The RO system will generally have 50-60 psi delta pressure. The RO motor is 10HP.

Vic McFadden
Regional Pretreatment Sales

C 847-778-2160
T 847-566-5401
vgmcfadden@nalco.com

ECOLAB | NALCO An Ecolab Company

From: Auerbach, Eric [mailto:Eric.Auerbach@arcadis-us.com]
Sent: Monday, January 21, 2013 1:03 PM
To: Lawrence Frauen; Victor McFadden
Subject: RE: Power draw on proposed RO system

Hi,

It appears the system was sized for a 23 gpm flow. If you let me know the pressure drop through the system I should be able to roughly calculate the power draw. Also the proposed motor HP would be helpful as a check.

Thanks

Eric

From: Lawrence Frauen [mailto:lfrauen@nalco.com]
Sent: Monday, January 21, 2013 12:50 PM
To: Victor McFadden
Cc: Auerbach, Eric
Subject: Power draw on proposed RO system

Vic,

You had provided me with the attached quote in November.
They are looking for power draw from our equipment. Can you provide that for the attached RO system.
Motor HP on the Grundfos pump is probably what we are looking for.

Thanks ….. Larry

Global Equipment
Solutions Division

RO System Proposal For:

Buffalo Sewer Authority
Buffalo, NY

Proposed By:

For additional information, please contact:

Sales Representatives

Name: **Larry Frauen**
Tel: **716-998-7582**
Email: **lfrauen@nalco.com**

Nalco Company
1601 W. Diehl Rd.
Naperville, IL 60563-1198

Global Equipment
Solutions Division

November 28, 2012

Subject: **Buffalo Sewer Authority, Buffalo, New York**
20gpm Reverse Osmosis System

QUOTE: **L212-514**

Nalco is pleased to provide you with the quote information for the subject project.

All systems are sized based on the water analysis listed. Alternative analysis or water sources could change the recommended design.

1. Bisulfite feed is provided for chlorine and chloramine removal. Bisulfite effectiveness assumes chlorine only in the feed water. If Chloramines, either naturally or by city water treatment design, are present in the feed water the bisulfite pump may need to be increased.

2. All membrane systems produce a reject stream as part of routine operation. It is the responsibility of the customer to ensure that any discharge of this reject stream remains within the discharge limits regulated by their local authorities.

3. This system assumes the use of the existing softeners. These units are recommended to operate at less than 3gpm/ft3 for proper pretreatment to an RO unit. If the units are undersized additional scaling control may be needed.

4. If the Reverse Osmosis unit will be offline for more than 24hours appropriate layup procedures will need to be employed. The type of layup will depend on the estimated duration of downtime. Your Nalco representative can assist you with selection of the best method.

5. Filters are recommended for reduction of SDI to <3. Nonuse of filters as pretreatment could increase the cleaning frequency required for the membranes and reduce membrane life. The given SDI of 4 is within acceptable numbers but given the nature of the feed water there is a high probability of an SDI>5 during the year. Full year trending of SDI is recommended.

6. This unit has a very large incoming temperature range; note that a single pump (even with a VFD) cannot provide the correct pressures to maintain flow over the entire temperature range. If the temperature range can be minimized a pump may be available to cover the entire range. We would recommend preheating the water to minimize the temperature swings.

7. Use of portable exchange demineralizers maybe needed to achieve the quality requested. A separate quote will be needed for this service.

Global Equipment
Solutions Division

Design Parameters:

Water Analysis: NW0928030, River
Desired Quality Product : <1ppm TDS, <.1ppm Ca as $CaCO_3$, Demin exchange tanks may be required
Flow range: Sized for 20 gpm
Temperatures: 34-78F
Pressures: 50-70psi
SDI: 4
Chlorinated: Yes

Equipment Provided:

<u>MultiMedia Filtration</u>

(2) 011-MLSFFKC.xx 36"	Multimedia filter w/ 36inch diameter Fiberglass vessel w/ Time clock control	**$9.764.00**

Two units required for 24/7 uninterrupted operation. Multimedia is a needed given the high SDI seen in the feed water.

<u>Chemical Feed (no chemical storage or injection included only pump)</u>

(1)121-PJ1110.88	Prominent 4gpd Concept Pump	**$405.00**

<u>Reverse Osmosis Unit</u>

One (1) XL-2L-3H Reverse Osmosis Unit (23gpm @~14gfd) w/ (6) XFRLE-400/34i membranes w/ Allen Bradley controller w/ 5 micron cartridge filter housing w/ **Quick Link™** Technology w/ **PreTreat Link™** Control for Chemical Feeder w/ Grundfos SS Feed Pump w/ Allen Bradley Panelview 600+ HMI w/Stainless Steel Frame	**$48,816.00**
One (1) XL-2L-3H VFD required adder	$ **4,466.00**
One (1) XL-2L-3H Forward Flush required adder	**$ 884.00**
One (1) XL-2L-3H Permeate Divert required adder	**$ 925.00**
One (1) XL-2L-3H ORP Sensor required adder	**<u>$ 1,316.00</u>**
Total RO System price	**$66,576.00**

Global Equipment
Solutions Division

<u>Storage Tank (RO discharge to atmospheric tank is required, direct feed to DA is not acceptable)</u>

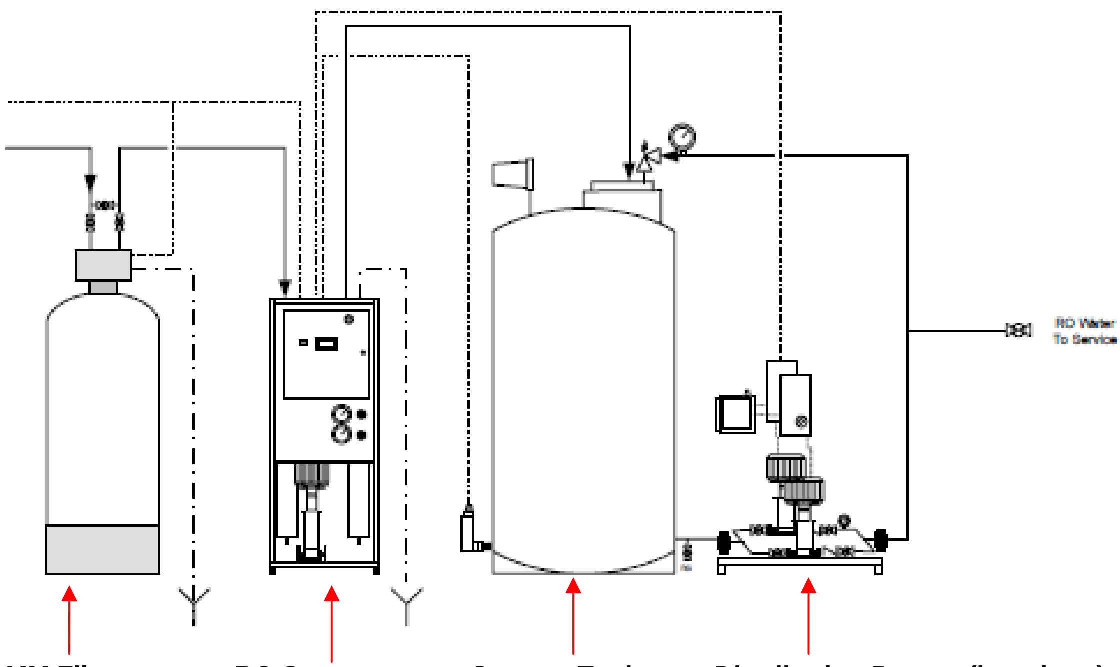
One (1) 241-ROTP3F.88 3,000 gallon storage tank (7’ diameter, 11’11” tall) **$6,900.00**

One (1) 241-ROTP3H.88 5,300 gallon storage tank (9’2” diameter, 12’10” tall) **$11,900.00**

Please note size requirements for storage tanks as some may have a sizable footprint. Additional freight charges may apply for tanks over 6000 gallons.

Prices do not include installation, assembly startup, tax or freight. Prices are good for 30 days.

Estimated lead time is 12-14 weeks based on current manufacturing loads; exact lead time will vary based on load at time of order. Lead time is based on a standard unit with no changes. Lead time does not include time for any approval/submittal drawings. If a drawing package is needed there may be an additional engineering cost, please confirm the customers’ needs in regards to approval of components or drawings before quoting. Lead times to not include time for paperwork delays like account setup or credit hold. Lead times do not include additional time for holidays would extend the lead time.



MM Filter **RO System** **Storage Tank** **Distribution Pumps (by others)**

Nalco Company
1601 W. Diehl Rd.
Naperville, IL 60563-1198

Operational & Maintenance Survey Proposal for:

Buffalo Sewer Authority
Buffalo, NY

Proposed By:

NALCO
An Ecolab Company

Proposal Number: L212-514PM
Proposal Date: November 28, 2012
Validity: 60 days

For additional information, please contact:

Account Representative

Name: **Larry Frauen**
Tel: **716-998-7582**
Email: **lfrauen@nalco.com**

11/28/12

Buffalo Sewer Authority
Buffalo, NY

Subject: RO Service Proposal

Thank you for the opportunity to submit this proposal for your pretreatment application. The equipment and services offered support Nalco's philosophy of Delivering Customer Advantage™ through integrated solutions.

The proposal described herein is based on the existing equipment, water analysis and your specific application requirements. For design purposes, water quality was assumed to be consistent with current operating practices. Changes or deviations in feedwater quality may require system re-evaluation to understand the performance of the system as well as ensure desired water quality is achieved.

With over 75 years in the industry, Nalco understands that the purchase of a water treatment equipment and service is a major decision. Our goal is to help you make the best choice. The attached proposal contains significant detail regarding proposed system design and equipment specifications. Please do not hesitate to contact us if you have any questions or require additional information about the technical or financial aspects of our proposal. We appreciate your consideration and look forward to working with you further on this project.

Sincerely,

Larry Frauen
Nalco Company

NALCO

SERVICES SCOPE

On-going Services Scope:
The proposal includes quarterly standard maintenance, quarterly RO prefilter cartridge replacement and water testing all described briefly in the table below.
RO system improvements, such as minor leaks or repairs not requiring parts or an additional visit, will be addressed. If miscellaneous parts and or additional labor are required, Nalco will submit an itemized proposal and a separate PO will be required for the repair.

STANDARD RO SERVICE PROPOSAL:

The following is a quick summary of recommended TASKS to be performed along with their FREQUENCY:

ITEM	TASK	FREQUENCY	ACTION
	Service Contract	**On-going**	**Routine monitoring and PM services.**
1.	Routine Service:	Quarterly	We will review the operation of all pretreatment equipment included in the reverse osmosis system and provide a status report checklist with any recommended action items or concerns related to the operation of this equipment. The following list identifies the parameters checked: • Check control operation of all components • Check differential pressure across pressure filters • Check softener effluent hardness • Check RO influent for residual chlorine residual • Check differential pressure across RO unit • Check RO permeate quality We will also provide a quotation if any items are in need of maintenance, repair or rehabilitation. Included in service package
2.	Chemical Pump Function Check	Quarterly	A check of the pump stroke and frequency settings will be performed to confirm proper dose of bisulfite is being delivered Included in service package
3.	RO Data Monitoring & Normalization	Quarterly	Routine data monitoring of existing instrumentation & RO performance, summarized on a quarterly basis in report and submitted to customer. Included in service package
4.	RO Cartridge Filter Replacement	Quarterly	Supply and replace RO cartridge prefilters

NALCO

			Included in service package

PRICING

STANDARD CONTRACT

Annual Service Contract Price:	$5,876.00
Monthly Price:	$490.00
Maintenance Visit Frequency:	Quarterly

TAXES

As applicable

COMMERCIAL TERMS AND CONDITIONS

This proposal is subject to the Terms and Conditions attached hereto.

STANDARD EXCLUSIONS

If service is to be performed at a customer location due to the preceding proposal, the following is a list of items not included with our equipment supply, service supply or on-going maintenance services at a customer facility:

- Permits, building inspections, taxes or duties.
- Indoor location for equipment with suitable heat, light and ventilation.
- Civil or concrete work.
- Core drilling or wall penetrations.
- Floor drains, adequately sized and located.
- Weekend or non-day shift work.
- Union or licensed plumbing labor or labor subject to prevailing wage determinations.
- Water main work.
- Installation of back-flow preventer(s).
- Electrical load center(s).
- Water heater(s).
- Insulation or heat tracing.
- Gas lines.
- Storage of equipment.
- Demolition, disposal or other work related to existing equipment.
- Field labeling of components or piping.
- Validation assistance or (IQ/OQ/PQ) services.

CONFIDENTIALITY

This document, any trial results, and all information contained herein are the property of Nalco Company. The design concepts and information contained herein are proprietary to Nalco and are submitted in confidence. They are not transferable and must be used only for the purpose for which the document is expressly loaned. They must not be disclosed, reproduced, loaned or used in any other manner without the express written consent of Nalco. In no event shall they be used in any manner detrimental to the interest of Nalco. All patent rights are reserved. Upon the demand of Nalco, this document, along with all copies or extracts, and all related notes and analyses, must be returned to Nalco or destroyed, as instructed by Nalco. Acceptance of the delivery of this document constitutes agreement to this confidentiality statement.

Startup Proposal for:

Buffalo Sewer Authority
Buffalo, NY

Proposed By:

NALCO
An Ecolab Company

Proposal Number: L212-514
Proposal Date: November 28, 2012
Validity: 60 days

For additional information, please contact:

Account Representative

Name: Larry Frauen
Tel: 716-998-7582
Email: lfrauen@nalco.com

11/28/12

Buffalo Sewer Authority
Buffalo, NY

Subject: RO Service Proposal

Thank you for the opportunity to submit this proposal for your pretreatment application. The equipment and services offered support Nalco's philosophy of Delivering Customer Advantage™ through integrated solutions.

The proposal described herein is based on the existing equipment, water analysis and your specific application requirements. For design purposes, water quality was assumed to be consistent with current operating practices. Changes or deviations in feed water quality may require system re-evaluation to understand the performance of the system as well as ensure desired water quality is achieved.

With over 75 years in the industry, Nalco understands that the purchase of a water treatment equipment and service is a major decision. Our goal is to help you make the best choice. The attached proposal contains significant detail regarding proposed system design and equipment specifications. Please do not hesitate to contact us if you have any questions or require additional information about the technical or financial aspects of our proposal. We appreciate your consideration and look forward to working with you further on this project.

Sincerely,

Larry Frauen
Nalco Company

SERVICES SCOPE

Nalco shall load all filter media and provide commissioning service for the water treatment equipment listed in Nalco quote L212-514. For the purpose of clarity, the term "commissioning" shall refer to backwashing and /or flushing and placement of equipment into service. The following tasks shall be performed during the commissioning service:

- Loading of all filter media
- Start-up of filter system
- Start-up of chemical pump
- Start-up of RO unit
- Programming of filter, pump & RO controls
- In-service training

PRICING

Qty.	Description		P/N	Unit Price	Ext. Price
1)	32	Labor Hour, Regular	N/A	$176.00	$5,632.00
2)	3	Travel Expenses	N/A	$273.00	$819.00
3)	1	Administration Fee	N/A	$182.00	$182.00

Total Selling Price - $6,633.00**TAXES**

As applicable

STANDARD EXCLUSIONS

If service is to be performed at a customer location due to the preceding proposal, the following is a list of items not included with our equipment supply, service supply or on-going maintenance services at a customer facility:

- Permits, building inspections, taxes or duties.
- Indoor location for equipment with suitable heat, light and ventilation.
- Civil or concrete work.
- Core drilling or wall penetrations.
- Floor drains, adequately sized and located.
- Weekend or non-day shift work.
- Union or licensed plumbing labor or labor subject to prevailing wage determinations.
- Water main work.
- Installation of back-flow preventer(s).
- Electrical load center(s).
- Water heater(s).
- Insulation or heat tracing.
- Gas lines.
- Storage of equipment.
- Demolition, disposal or other work related to existing equipment.
- Field labeling of components or piping.
- Validation assistance or (IQ/OQ/PQ) services.

DI Express® **System Proposal For:**

Buffalo Sewer Authority
Buffalo, NY

Proposed By:

For additional information, please contact:

Sales Representatives

Name: **Larry Frauen**
Tel: **716-998-7582**
Email: **lfrauen@nalco.com**

November 28, 2012

Subject: Buffalo Sewer Authority, Buffalo, New York
DI Express® SYSTEM SERVICES

QUOTE: 1073-12

Nalco is pleased to provide pricing for DI Express® to meet your make up requirements.

DESIGN CRITERIA:

Feed Water: RO Feed Water, Cold 35°F, 2.02 ppm TDS, 3.48 ppm CO_2
Flow Rate: 20 gpm
Usage: 20 hours a day / 5 days a week

MAJOR COMPONENT SUMMARY:

(1) RR6131	RCS Controller® Monthly Rental	$65.00/month
	w/JJ6032 Quality Indicator, R/G, Temperature Compensated	Included
	w/S1120 Post Filter Assembly, 10"	Included
	w/R1511 Post Filter	Included
DMR1	DI Express® 1T Service Exchanger, Primary	$1,717/ exchange
JJ6036	Quality Indicator, R/G, Temperature Compensated	Included
DMR1	DI Express® 1T Service Exchanger, Polisher	$1,717 / exchange
RENT	DI Express® Tank Monthly Rental	$475 / tank / month

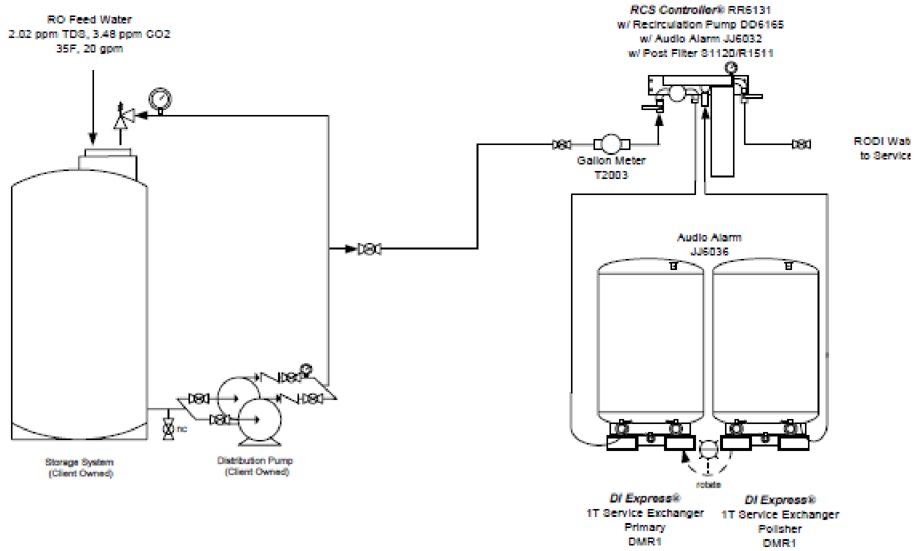
SERVICE & EXCHANGE SCHEDULE: (or sooner as needed)

DMR1	DI Express® 1T Service Exchanger, Primary	~ 8 Weeks
DMR1	DI Express® 1T Service Exchanger, Polisher	Rotated
R1511	Post Filter	~ 8 Weeks

Note: Exchange schedules are based on usage in the Design Criteria. If usage increases, RO Product TDS increases, exchange schedules are subject to change.

INSTALLATION TO A PREPARED AREA:

Installation	By Others
Start Up	By Others
Delivery	Ex Works Factory
Electrical (110/60/1)	By Owner
Availability	1-3 Weeks
Taxes	As Applicable
Payment Terms	Net 30
Sales Terms & Conditions	Attached
Quotation Validity	60 Days



Thank you for considering Nalco for this project. These services will be provided in a neat professional manner. We will work hard to serve you. If there are any questions we can answer or points you wished clarified, please call on me personally.

Larry Frauen
716-998-7582
Email: lfrauen@nalco.com

STANDARD EXCLUSIONS

If service is to be performed at a customer location due to the preceding proposal, the following is a list of items not included with our equipment supply, service supply or on-going maintenance services at a customer facility:

- Permits, building inspections, taxes or duties.
- Indoor location for equipment with suitable heat, light and ventilation.
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- Floor drains, adequately sized and located.
- Weekend or non-day shift work.
- Union or licensed plumbing labor or labor subject to prevailing wage determinations.
- Water main work.
- Installation of back-flow preventer(s).
- Electrical load center(s).
- Water heater(s).
- Insulation or heat tracing.
- Gas lines.
- Storage of equipment.
- Demolition, disposal or other work related to existing equipment.
- Field labeling of components or piping.
- Validation assistance or (IQ/OQ/PQ) services.

Appendix D

Steam Transmission Line Cost Estimate

BUFFALO SEWER AUTHORITY
CONCEPTUAL ESTIMATE OF PROBABLE PROJECT COST

High Pressure Steam Piping - Waste Heat Boiler to Proposed Turbine in Blower Building
11/2/2012, Revised 1/3/2013

Division	Description	Quantity	Unit	Material		Labor		Total
				Unit Cost	Total	Unit Cost	Total	Cost
1	**GENERAL REQUIREMENTS**							
2	**SITE WORK**							
	Core Drill Holes for Piping (8" holes)	3	EA	$ 75	$ 225	$ 220	$ 660	$ 900
	Demo Fuel Oil Pipe in basement (on Pipe Rack) per JK	1	LS	$ -	$ -	$ 5,000	$ 5,000	$ 5,000
3	**CONCRETE**							
			CY	$ 300	$ -	$ 600	$ -	$ -
			CF	$ 110	$ -	$ 30	$ -	$ -
5	**METALS**							
			tons	$ -	$ -	$ -	$ -	$ -
11	**EQUIPMENT**							
			LS		$ -	$ -	$ -	$ -
			LS		$ -	$ -	$ -	$ -
13	**SPECIAL CONSTRUCTION**							
			LS		$ -		$ -	$ -
15	**MECHANICAL**							
	6" Sch 80 Carbon Steel Piping , including welded joints	400	LF	$ 50	$ 20,000	$ 100	$ 40,000	$ 60,000
	Long radius 90 deg elbow	10	EA	$ 72	$ 720	$ 36	$ 360	$ 1,100
	Long radius 45 deg elbow	5	EA	$ 58	$ 290	$ 29	$ 145	$ 500
	6" valve, ASME class 600 butt-welded CS	6	EA	$ 4,000	$ 24,000	$ 2,000	$ 12,000	$ 36,000
	Pipe Hangers and Supports	1	LS	$ 10,000	$ 10,000	$ 15,000	$ 15,000	$ 25,000
	LinkSeal for wall penetration	3	EA	$ 400	$ 1,200	$ 100	$ 300	$ 1,500
16	**ELECTRICAL**							
	Metering and Controls	1	LS	$ 45,000	$ 45,000	$ 5,000	$ 5,000	50,000
		Subtotal Project:			$ 101,500		$ 78,500	$ 180,000

Appendix E

Steam Turbine Performance and Quotation

Steam Turbine O&M Information

Electrical Modification Cost Estimate

DRESSER-RAND

Steam Turbine Business Unit

This Letter from District Representative:
SOMES-NICK & COMPANY
29 S. LaSalle, Ste 340
Chicago, IL. 60603
(312) 214-7800 FAX: (312) 214-4664
sales@somes-nick.com

Malcolm Pirnie
2800 W Higgins Rd, Suite 1000 |
Hoffman Estates, IL 60169

January 17, 2013

Att. : Eric Auerbach
Subject: Buffalo Wastewater Treatment Plant Steam Turbines
Dresser-Rand proposal No.: G29176

Eric,
Please find enclosed our revised budget selections per your recent email.
Pricing hasn't changed much since my last selection. The scope of supply remains as previously offered.
.

Let me know if you have any questions or need anything else.

Regards

Tom Nick

All selections include the following scope of supply:

- Multi-stage steam turbine
- Dresser-Rand or equal T&T valve
- Overspeed trip, solenoid trip, low oil pressure trip
- Woodward DG-505 or equal governor
- Blanket insulation without sheet metal jacket
- Gland condenser and ejector
- Gland seal pressure regulator
- Vacuum breaker
- Condensate drain pump (if turbine is specified with TOP exhaust)
- Vibration probes and transmitters for turbine, gear, and generator
- Bearing RTD's for turbine, gear, and generator
- Vibration probes and RTD's monitored by PLC in generator control panel
- HS and LS couplings
- Reduction gear
- Generator with voltage regulator
- Common baseplate for turbine/gear/generator (Selections A & B)
- Common baseplate for turbine/gear (Selections C & D)
- Separate soleplates for generator (Selections C & D)
- Separate lube console for turbine/gear/generator
- Generator control and switchgear panels
- Main circuit breaker sized for generator output
- Synchronizing equipment
- Protective relays
- Instrumentation
- Suitability for either parallel or solo operation
- PLC for monitoring and control functions
- Neutral grounding resistor
- Graham water cooled steam condenser sized for maximum condensing flow at 2.9" HgA. Complete with air removal system, 1 minute hotwell, and condensate level control.

TURBINE DATA				
SELECTION	E		F	
TURBINE FRAME	R		R	
NUMBER OF STAGES	7		7	
INLET VALVES	SINGLE		SINGLE	
INLET SIZE/RATING	4” / 600#		4” / 600#	
BLEED SIZE/RATING	NONE		NONE	
EXTRACTION SIZE/RATING	6” / 150#		6” / 150#	
EXHAUST SIZE/RATING	30” / 125#		30” / 125#	
GENERATOR TEMP RISE	80		80	
GENERATOR POWER FACTOR	0.80		0.80	
PERFORMANCE DATA	SUMMER	WINTER	SUMMER	WINTER
INLET PRESSURE (PSIG)	650	650	650	650
INLET TEMPERATURE (DEG F)	650	650	650	650
EXTRACTION PRESSURE (PSIG)	**80**	**80**	**60**	**60**
EXTRACTION ENTHALPY (BTU/LB)	1,224	1,224	1,218	1,218
EXHAUST PRESSURE (IN HgA)	3.0	3.0	3.0	3.0
EXHAUST ENTHALPY (BTU/LB)	1,021	1,037	1,023	1,034
INLET STEAM FLOW (LB/HR)	30,000	30,000	30,000	30,000
EXTRACTION FLOW (LB/HR)	7,700	16,300	7,500	14,100
EXHAUST FLOW (LB/HR)	22,300	13,700	22,500	15,900
TURBINE SPEED (RPM)	5,000	5,000	5,000	5,000
GENERATOR OUTPUT (KW)	2,011	1,462	2,038	1,643
COMMERCIAL DATA				
SHIPMENT (WEEKS)	48		48	
TURBINE GENERATOR PRICE (USD)	$ 2,250,000			

From: Tom Nick [mailto:tnick@somes-nick.com]
Sent: Tuesday, August 28, 2012 11:54 AM
To: Auerbach, Eric
Subject: RE: Budget installation costs

$50,000 per year would be safe.
This includes parts and labor, with a 2 week major overhaul every 5 years

Tom Nick
Midwest District Representative

Somes-Nick & Company
29 S. LaSalle, Ste 340
Chicago, Il. 60603
PH: 312-214-7800
FX: 312-214-4664
Email: sales@somes-nick.com

From: Auerbach, Eric
Sent: Tuesday, August 28, 2012 11:20 AM
To: 'Tom Nick'
Subject: RE: Budget installation costs

Thanks,

One more question – any rough number on a maintenance cost?

From: Tom Nick [mailto:tnick@somes-nick.com]
Sent: Tuesday, August 28, 2012 11:20 AM
To: Auerbach, Eric
Cc: Somes-Nick
Subject: Budget installation costs

Eric
Attached is a budget quote from last year to install a similar sized TG set.
It doesn't include the foundation or main steam piping to/ from turbine.
Nor does it include a condenser.
The price was $267,000, but that was 1 year ago.
For your project, I would budget $325,000, which would include installation of condenser as well
regards

Tom Nick
Midwest District Representative

Somes-Nick & Company
29 S. LaSalle, Ste 340
Chicago, Il. 60603
PH: 312-214-7800
FX: 312-214-4664
Email: sales@somes-nick.com

3.0 DRESSER-RAND EQUIPMENT INSTALLATION

Dresser-Rand's rotating equipment is the heart of many of our client's facilities. These highly engineered machines incorporate a century of expertise in order to provide high levels of availability and minimize the total cost of ownership over their useful life, which typically spans many decades. Rotating equipment installation is specialty work, which requires a high level of expertise and care in order to preserve the reliability features embedded in the original equipment design.

Dresser-Rand installation services bundles the following components:

- Technical advisory services typically provided by Field Service Representatives.
- Comprehensive mechanical services, which include key elements in which D-R adds extraordinary value and are an integral part of the equipment installation offering.
- Extended scope consisting of additional services in which D-R can provide significant value buy are optional to the equipment installation offering.

Dresser-Rand's experience installing rotating equipment world wide, including steam and aeroderivative turbines, centrifugal, axial and reciprocating compressors and expanders in power generations and oil and gas, enables us to deliver the following unmatched value, which results in lower total cost of ownership.

- Project and safety management using Dresser-Rand's *Project Book* approach.
- Single point responsibility, reducing warranty gaps.
- D-R trained and certified crews.
- Faster execution time leading to shorter time to production and lower project infrastructure costs.
- Extended new equipment warranty, only available from OEM.

DRESSER-RAND

4.0 INSTALLATION AND COMMISSIONING

We have used our D-R non-union crew's wages and benefits in our pricing. If union labor is required, D-R can provide a revised proposal based on prevailing union wage and benefits.

The proposed work scope is based on the minimum number (2) mobilizations to increase crew utilization and reduce the overall cost for the installation. See attached installation schedule.

Installation Scope of Work, D-R Supplied Equipment

Equipment summary:
One (1) Murray Turbine generator set
Auxiliary equipment supplied by D-R

EQUIPMENT GROUTING by Dresser-Rand Arrow Services. The schedule and pricing is based on grouting the turbine skid and console with one mobilization of crew.

- Mobilize to site
- Safety and Orientation
- Unload trailer. Included is a fully equipped 53' tool trailer.
- Chip laitance to expose concrete aggregate
- Clean up
- Set Forms
- Others to Rig/Lift and place over anchor bolts
- Assist in placement of unit
- D-R Mechanical Crew to perform coupling alignments.
- Provide and pour 2" of PR Chockfast Red / 2" PRC100 cement grout. Cure to manufactures recommendations
- Strip forms/form and pour expansion joints with PR Red 7c expansion joint compound
- Strip forms and dress foundation
- Others to set lube oil skid.
- Form and pour cementitious grout per Manufacturer's recommendations
- Clean up/load trailer/Demob

Estimated duration and crew for above tasks:

We estimate (1) supervisor, (1) foreman, and (4) B-Tech's can complete this project in 12-14 days working 6-10 hour days per week.

MECHANICAL INSTALLATION by Dresser-Rand Field Services Crew. The schedule and pricing is based on performing mechanical installation with (1) one mobilization of the crew.

- Mobilize to site
- Safety and Orientation
- Receive turbine skid, generator, oil console, and loose parts
- Uncrate turbine and generator & inventory all parts and containers
- Visually inspect the outside of the turbine, generator, oil console looking for damage to outside connections and instrument connections
- Survey installation area and verify foundation dimensions. Certify mounting surface areas, anchor bolt locations, and main piping connection locations.
- Review lift plan (Others will provide crane & rigging)
- Remove all required small bore piping, and coupling guards.
- Observe rigging on turbine skid
- Observe lifting & setting of turbine skid
- Verify that the turbine/gearbox/generator mounting surfaces are level
- Remove all shipping media from bearing assemblies.
- Perform rough alignment of train
- Set and record coupling DBSE, verify within tolerance
- Observe setting of the lube oil console skid
- Verify that the lube oil console and all auxiliary turbine/motors/pumps mounting surfaces are level
- Perform rough alignment on all auxiliary rotating equipment
- Demobilize

Estimated duration and crew for above tasks:
We estimate (1) Project Manager, (1) Leadman and (1) Mechanic working 6 -10 hour days (no Sundays) for 10 working days.

MECHANICAL and COMMISSIONING by Dresser-Rand Field Services Crew. The schedule and pricing is based on performing mechanical installation completion and commissioning with (1) mobilization of the crew.

- Mobilize when Balance of Plant is ready is complete
- Install small bore piping removed during installation.
- Install oil seals in both turbine and generator
- Re-check alignment on lube oil pumps and install couplings.
- Perform final alignment between turbine, gearbox and generator using laser.
- Check steam feed/exhaust pipe installation for pipe strain at turbine flange/skid edge. Check all connections to the D-R supplied equipment for pipe strain.
- Install low speed coupling spool between gearbox and generator.
- Install coupling guard
- Remove high speed coupling guard between turbine and gearbox
- Install jumpers on-skid for lube oil flush.
- Perform lube oil flush
- Control system check-out

- Over-speed & trip turbine verification
- Install high speed coupling turbine to gearbox
- Install high speed coupling guard, turbine to gearbox
- Electrical protection device calibration/setting by others
- Mechanical and Instrument & Controls Start-up support
- Commission unit
- De-mobilize from site

Estimated duration and crew for above tasks:
We estimate (1) Project Manager, (1) D-R Technical Rep., (1) Leadman and (1) Mechanic working 6 -10 hour days (no Sundays) for 10 working days during the commissioning and start up. A Generator Representative will also be on site during Generator Commissioning.

5.0 COMMERCIAL

Item	Description	BUDGET Price
1.0	Installation of D-R Supplied Equipment per the above work scope	$267,617.52
	TOTAL	$267,617.52

- Pricing is valid for 30 days from date of proposal.
- Terms per D-R 100

Estimates

DR mechanical and Commissioning	$93,079.55
Arrow Services (grout)	$86,241.87
Crane, tooling and consumables	$16,297.47
Travel and Living Expenses	$21,175.00
Generator Commissioning	$50,823.63

Clarifications:

- D-R has included no time allowances for standby time due to circumstances out of the control of D-R (operations delays, waiting for crane, client or client's subcontractors' supplied parts or services, permits, delayed decisions by client). All additional time will be billed per the D-R rate sheet applicable at the time the work is performed.
- D-R has included no time allowances for deviation from the supplied workscope. All additional hours outside of the scope of work will be billed on a time and material basis per the D-R rate sheet applicable at the time the work is performed.
- Quote valid for installation of equipment at ground level (no mezzanine installation or elevated work).
- Quote valid for occasional use of individual fall protection on elevated piping connections. This quote assumes the majority of the work will be performed without requiring fall protection.
- This quote is based on the foundation being complete, inspected by client, approved by client for setting of equipment before D-R arrival at site.
- This quote is based on D-R being able to bring its own foundation crews to site. Client to work with D-R to enable this arrangement.

DRESSER-RAND

Client Responsibilities:

- Work with D-R to coordinate the schedule and resources in advance of D-R mobilization.
- Furnish interconnect piping and wiring beyond Dresser-Rand connections in order to allow D-R to execute its scope of work without delay.
- Supply and coordinate the resources necessary to make adjustments to the interfaces beyond D-R scope that may affect the D-R scope of work such as crews to adjust piping supports, fit interconnecting piping, fit conduit and control cables, adjust plant settings.
- Furnish required rigging and crane service.
- Provide access to water, oils, and solvents and will dispose of same
- Furnish space and hook-ups on site for D-R office and tool trailers
- Inspect third party work
- Provide access to installation location will be unhindered by building, other equipment, other piping, other contractors, refuse, etc.
- Provide any and all weather proof enclosures that maybe required
- Provide any and all conditioning of material/foundation (HEAT/AC)
- Any and all movement of material within the facility
- Disposal of all spoils
- Provide access to 110v/220v electricity and connections within 50' from work.
- Allow placement of motor mixer next to area where working
- Provide access to clean water for clean up and clean break room/restroom
- Provide scaffolding crew and scaffolding if needed.
- Dumpster or nearby site for disposal of waste and final disposal of all waste.
- Equipment lay down area adjacent to work area.
- Supply electrical parameters for setting of protections in advance of D-R scheduled visit to perform electrical commissioning of its scope.

Donald R. Scalfaro
Title: Regional Manager

DRESSER-RAND

Seller shall be responsible for the following:

A. Compliance with site specific safety procedures.

B. Locking and tagging out of all equipment in preparation for safe execution of the work.

C. All rigging equipment and procedures throughout the execution of the work.

D. Consumables necessary for the execution of the work.

E. Trash containers in the work area. Contractor shall clean up the work area on a daily basis.

Buyer Shall Be Responsible for the following:

- Tested and Certified crane and use of forklift as needed
- Break and lunchroom facilities
- Space on site will be necessary for a tool trailer.
- Wooden pallets.
- Disconnect/reconnect all electrical/instrument connections and set probes.
- Access to telephone lines and office space for Contractors use.
- Access to site washroom and breakroom facilities.
- Dumpster service for trash removal for Contractors use.
- All special tooling supplied with unit.
- Replacement Oil and its Disposal.

DRESSER-RAND

Section 2: Quality Control Plan

Upon award of contract, a detailed quality control plan will be developed along with the CUSTOMER Equipment Specialist and Engineering personnel as necessary. The Quality Control Plan will consist of some or all of the following:

- ***Pre-Job Review** – Project Manager and Supervisors to mobilize to jobsite prior to beginning work. The purpose of this is to gather additional equipment information, review and finalize the work scope and schedule, interface with CUSTOMER personnel, and to finalize the quality control plan.*

- ***Safety Program** – Daily toolbox safety meetings are held at the beginning of every shift. In addition, the crew may be asked to complete Job Hazard Analyses prior to beginning work. Project supervision can perform and document Safe Work Observations and Jobsite Safety Audits as requested.*

- ***Job Specific Training** – Dresser-Rand mechanics are given product specific training on OEM equipment. D-R has developed a number of training modules (1-2 hours in length) for our mechanics which can be taught prior to job start. Involved CUSTOMER personnel may be invited to attend the training sessions specific to the job at no charge.*
- ***Field Service Resume** – All D-R Field Service personnel have resumes in our database which are available upon request. Resumes will be provided for review prior to mobilization for all key personnel. The resumes include education(general and OEM), special skills, work experience, product specific experience, assessments, and more.*
- ***Craft-Level Task Signoff** – Process tasks for which procedures are defined in Service Manuals and elsewhere are to be given in written form to the craftsperson who is asked to perform them. The procedure is signed off both by the craftsperson and his supervisor.*

- ***Inspection Hold Points** – At certain points during the disassembly and assembly of the equipment, CUSTOMER may wish to verify clearances and checks before proceeding. Inspection hold points will be identified in the final workscope for each piece of equipment and signoffs will be presented to CUSTOMER prior to equipment startup.*
- ***Startup Crew** – Some of the equipment will be mechanically complete prior to other pieces of equipment. It is strongly recommended that key personnel from each of these crews is retained through start-up of the equipment.*

<u>Section 3: Safety Plan</u>

Purpose:

Identify any and all safety issues during the referenced work. Promote Safety Awareness and Performance toward the end of Zero safety issues during the referenced work.

Activities:

- *Tool box safety meeting on a Daily or Shift basis.*
- *Follow all Normal CUSTOMER BSP per plant / site plans.*
- *Participate in all CUSTOMER JSP/APT/STAC/BBP programs.*
- *JSA will be filled out for each job/ task.*
- *Each employee will be part of a team to fill out JSA.*
- *JSA audits by Project Manager and Leadman, CUSTOMER will be encouraged to be part of this audit.*
- *Safety audit on a daily / shift basis by the leadman.*
- *Each employee will lead/conduct the safety meeting during the turn around.*
- *Employees will be encouraged to report near misses in our crew and other contractors.*
- *Employees are encouraged to use the <u>WHAT IF</u> scenario to identify safety hazards and procedures on each task.*
- *Project Manager will conduct Safety Audit on a weekly (documented).*
- *Dresser-Rand Safety Coordinator will be encouraged to audit D-R personnel and worksite.*
- *Housekeeping audit at the end of each shift (documented).*

Section 4: Rates for Field Service

All work to be performed at the attached Time and Material Rates.
Any additional work not defined in the workscope will be charged at the attached rates.

Roles and Responsibilities of Field Personnel

- ***Project Manager/Engineer –*** *"Total Project" responsibility from estimating/quoting jobs through logistics before and during the job to final technical reports and invoicing following a job. Prepares daily cost estimates and schedule updates as required. Oversees crew timesheets and handles other administrative/management tasks. Coordinates subcontracted services, rental equipment, and shop work. Provides safety and technical training to D-R Field personnel as needed.*
- ***Safety Representative*** *– Promotes the overall safety program. Reinforces the safety policies and procedures of Dresser-Rand and Customer. Assist in the investigation of all incidents (First aid, recordable, near miss, etc.) to determine root cause and corrective actions. Assist supervisors in conducting workplace hazard assessments to identify, evaluate, and correct hazards. Provide training and technical assistance to managers and supervisors regarding HSE issues. Review, update and evaluate the overall effectiveness of the D-R's site HSE programs (examples: JSAs, BBAs, Toolbox meetings). Plan, organize and coordinate safety meetings, training sessions. Arrange for HSE inspections and follow up to insure necessary corrective action is completed. Maintain injury and illness records. Review incident trends. Establish a system for maintaining the records of inspection, hazard abatement and training.*
- ***General Foreman –*** *Typically utilized on large jobs. Responsible for on site job logistics, materials handling, quality control and safety documentation. Handles administrative tasks and assists with Project Management activities when required.*
- ***Leadman –*** *Gives specific task direction to Mechanics. Responsible for the safe performance of the job tasks. Collects clearance and inspection data. Reports to General Foreman or Project Manager for the duration of the job. Maintains continuous contact with Mechanics to ensure quality workmanship and productivity. Performs repair/maintenance tasks as required.*
- ***Mechanic –*** *Performs repair/maintenance tasks as required. Responsible for the safe performance of job tasks. Reports to the Leadman for direction.*
- ***Field Service Representative –*** *Technical Advisor for the crew and client personnel. Provides interface between Dresser-Rand factories and client as needed. Collects and documents clearance/inspection data. Reports to Client or to Project Manager as required.*

Electrical Cost Estimate
BSA Cogen project
Bird Island WWTP

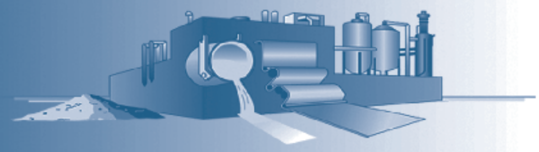
Item	Qty.	Units	Est. Cost (installed)	Notes
1200A Breaker & Switchgear Section	1	LS	$ 72,000	If refurbish existing breaker and section, change to $27,000
Protective Relaying	1	LOT	$ 8,000	
PLC/Synchronizing equuipment (add'l)	1	LOT	$ 12,000	
Cable/Conduit	125	FEET	$ 16,590	Cable: 4-Cond #4/0 EPR, 15KV,133%; Conduit:5 inch
		Subtotal	$ 109,000	

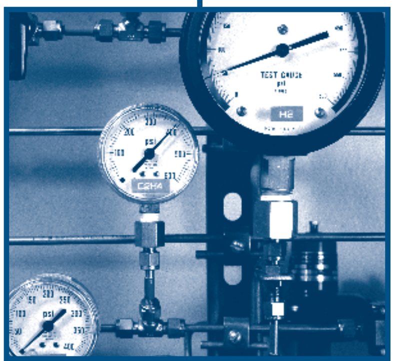
Appendix F

Manual of Practice for Lowering Steam Pressure

New Admin HW Boiler Cost Estimate

Extraction Steam Connection Cost Estimate





A BestPractices
Steam Technical
Brief

Steam Pressure Reduction: Opportunities and Issues

U.S. Department of Energy
Energy Efficiency and Renewable Energy
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

Steam Pressure Reduction: Opportunities and Issues

◆ Introduction

Steam generation systems are found in industry and in the commercial and institutional sectors. Some of these plants employ large watertube boilers to produce saturated steam at pressures of 250 pounds per square inch (psig) or lower. They distribute steam for use in process applications, building heating, humidification, domestic hot water, sterilization autoclaves, and air makeup coils.

Oversized boiler plants and steam distribution systems utilizing saturated steam are potential candidates for reducing the steam system operating pressure. Steam systems can have large excess capacity in boilers, valves, pumps, and piping. This can also be true for peak winter conditions.

What is Steam Pressure Reduction?

Steam pressure reduction is the lowering of the steam pressure at the boiler plant by means of the pressure setting on the boiler plant master control.

Steam pressure reduction affects mainly the high pressure part of the steam system. Within practical limits, pressure-reducing valves (PRVs) will adjust the pressure at lower levels to the previous set points. This means that most of the savings benefits from pressure reduction occurs in the high pressure section of the steam system.

◆ Summary

1. Steam pressure reduction has the potential to save fuel consumed by a steam system. The amount of capital investment may be minimal for the appropriate application of this efficiency measure. The amount of fuel that can be saved varies with the design and maintenance of the existing system.
2. The potential to effectively reduce steam pressure most commonly applies to oversized steam systems in industry and institutions. These steam systems supply steam for process applications and building heating. They are often oversized for summer operation and the peak load period. The operator of the plant must judge whether a boiler plant is oversized.
3. Before the steam plant owner attempts to reduce steam pressure, an assessment of the boiler plant and steam system should be made. This should include an analysis of the average and peak steam loads in relation to the plant capacity. Data on piping, insulation, and steam trap condition should be collected. Piping drawings should be used to map out critical steam loads and the test procedure.
4. While energy savings can result from reducing steam pressure, there are a significant number of areas where steam pressure reduction can reduce the operational effectiveness of the steam system. These areas should be properly accounted for and understood.
5. Steam pressure reduction should be tested to establish the critical minimum pressure at a steam load that is above average but below peak. This will also provide an estimate of savings.
6. If, prior to reducing boiler steam pressure, the boiler is already having carryover issues, these should be addressed before considering reducing the boiler steam pressure.

◆ Steam System Losses and Savings Through Pressure Reduction

A List of Boiler and Steam System Losses

It is useful to summarize the typical causes of boiler and steam system losses. Most of these losses vary with steam pressure (and temperature) and can potentially be reduced by lowering the steam pressure at the boiler.

Some of the main potential losses in a steam system are noted in Figure 1. Only the energy losses that can be reduced by lowering steam pressure will be discussed in this technical brief, and are listed below:

- Steam leaks from high-pressure components (e.g. valves and piping)
- Combustion loss
- Boiler blowdown loss
- Steam supplied to the deaerator
- The enthalpy savings effect.
- Flash steam loss through high-pressure condensate receiver vents
- Boiler radiation and convection loss
- High-pressure steam piping heat loss
- High-pressure steam trap leakage

Losses

When steam pressure is reduced at the boiler, it is only reduced on the high-pressure side of the system. PRVs, which lower the main steam pressure automatically, respond to maintain the pressure on the downstream side of the valve at the set point, for example, 15 psig. Therefore, losses occurring downstream of the PRV or a backpressure steam turbine are not reduced by lowering the boiler pressure.

The following example illustrates the potential savings from steam pressure reduction. In a steam system operating at an average steam load of 38,500 pounds per hour (lb/hr) with one watertube boiler supplying steam and another on standby, the operating pressure at the boiler was reduced from 130 psig to 80 psig. The average fuel input to the boiler plant before steam pressure reduction is 49.3 million British thermal units per hour (MMBtu/hr). The plant is modeled using the boiler combustion efficiency as tested over a range of pressures, and with estimates of the size, length, and pressures of distribution and condensate return piping for purposes of calculating radiation losses. Typical losses from radiation and steam trap leakage based on actual surveys of other facilities are applied.

Combustion Loss

Dry flue gas loss as defined by the American Society of Mechanical Engineers (ASME) Power Test Code

Figure 1. Boiler and Steam System Losses

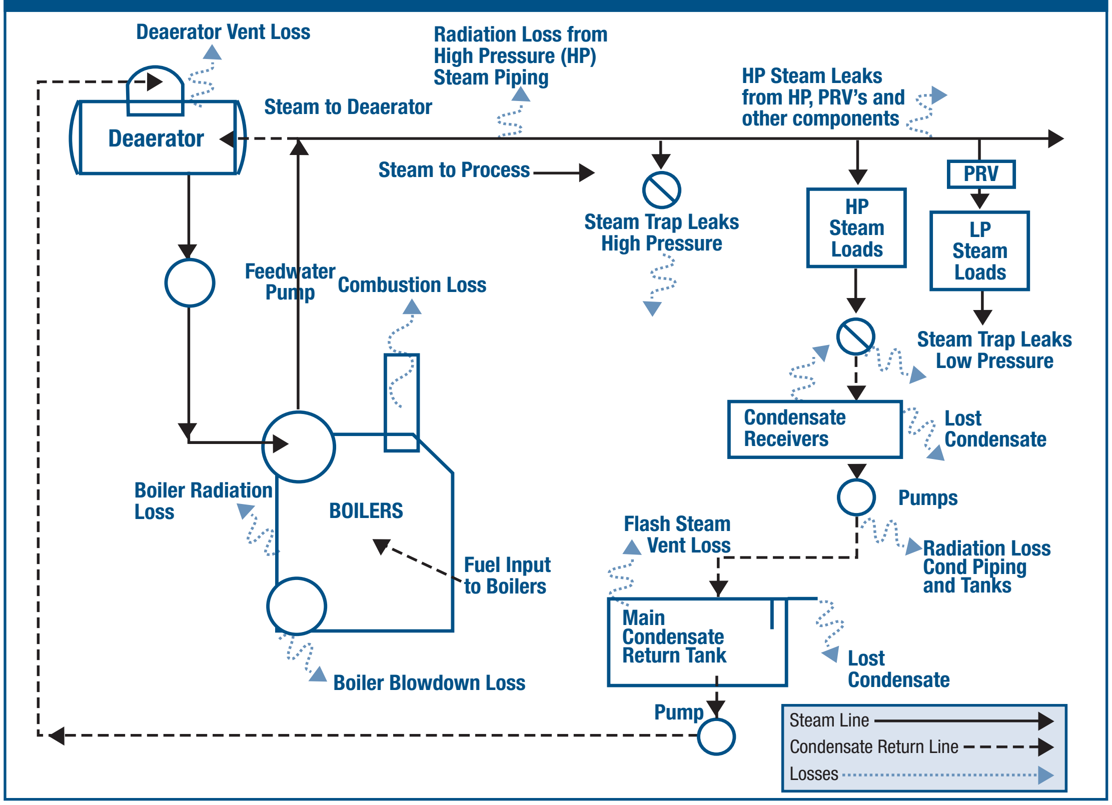
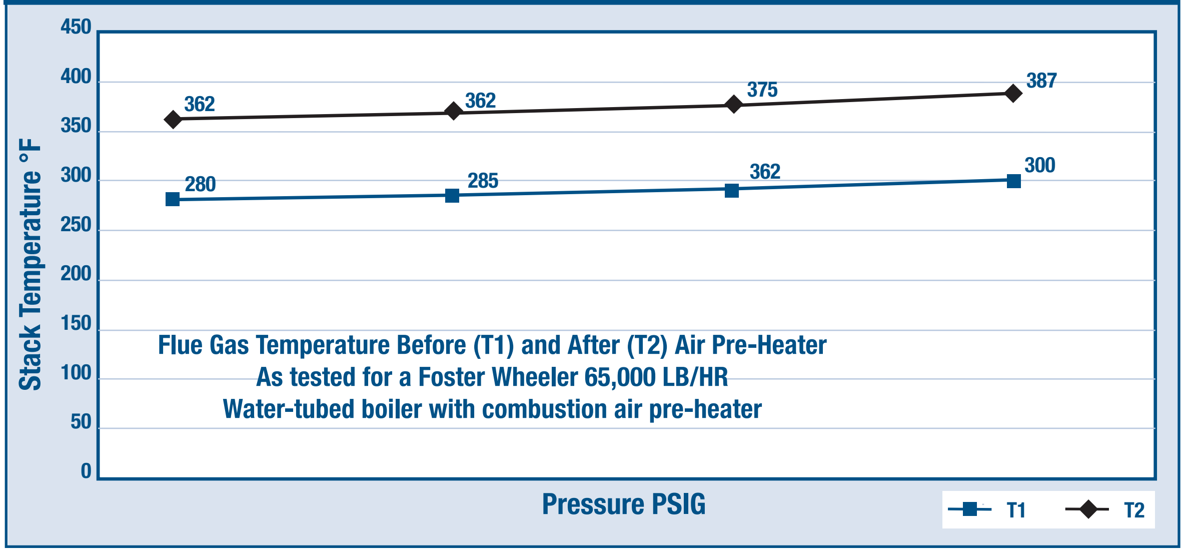


Figure 2. Stack Temperature Vs. Boiler Pressure



varies directly in proportion to the boiler's net stack temperature (the difference between the flue gas temperature and combustion air temperature). When boiler pressure is lowered, a lower stack temperature results. This, in turn, causes slightly improved combustion efficiency. If the boiler already has an economizer or air preheater, the savings will be somewhat lower. The best way to establish the temperature reduction and savings for a given boiler is to conduct a combustion test at different pressures and constant load. Figure 2 shows the relationship between pressure and stack temperature for a test on a 65,000 lb/hr watertube boiler operating at a constant output of 38,500 lb/hr. As tested, the boiler stack temperature varies linearly with steam pressure. A savings of 0.4% to 0.8% of the fuel input can be expected from lower stack temperature.

Boiler Radiation and Convection Loss

For watertube boilers, radiation loss can be estimated using the American Boiler Manufacturers Association (ABMA) standard radiation loss chart. Radiation losses can also be calculated for any type of boiler, from basic principles using measurements of the boiler surface temperature, area, and emissivity. In this example, the radiation loss is calculated from basic principles.

The general formula for calculating radiation loss is:

Radiation Loss (Btu/hr), $H_R = 1.74 \times 10^{-9} \times e\,(T_1^4 - T_2^4)$

where 1.74×10^{-9} = Boltzmann's constant

e = Surface emissivity which depends on the specific material and condition (typically 0.9)

T_1 = The surface temperature as measured (°R)

T_2 = The ambient temperature as measured (°R)

Heat transfer from the surface to the ambient air is increased by the flow of air across the surface. This is called convective heat transfer and must be added to the previously calculated radiation loss. For guidance on calculating convective loss as a function of air velocity, refer to the basic heat transfer texts, for example, *Thermal Insulation* by John F. Malloy (see Reference list).

For this example, when steam pressure was reduced from 130 psig to 80 psig, the actual temperature readings on the boiler surface showed an average reduction from 150°F to 140°F. Using the ABMA standard radiation loss chart, this would yield a savings of 0.2% of the fuel input.

However, the ABMA chart does not apply to firetube boilers. Firetube boiler shell loss estimates should be obtained by contacting the boiler manufacturers, or from basic principles and measurements of surface temperature.

Boiler Blowdown Loss

When boiler pressure is reduced, the blowdown loss is also reduced. If the energy from blowdown is being recovered through a blowdown heat recovery system, there will be no further savings by reducing the boiler pressure. If however, blowdown water is being drained and flash steam is being vented, savings will result from steam pressure reduction. In the current example, reducing boiler pressure from 130 psig to 80 psig reduces the sensible heat in the boiler water from 328 Btu/lb to 294 Btu/lb. Assuming a blowdown rate of 4%, the savings is approximately 0.1% of initial fuel input.

High Pressure Steam Piping Heat Loss

Heat loss from steam and condensate piping takes place in two stages. First, heat is conducted from hot steam through the walls and insulation surrounding the pipe to the outer surface. Then, heat is lost by radiation and convection to the ambient air.

A good way to make the calculations required to estimate the heat loss per foot of pipe is to use the BestPractices Steam 3E-Plus, developed by the North American Insulation Manufacturers Association (NAIMA). The software is free and is available at www.eere.energy.gov/industry/bestpractices/, www.naima.org, or www.pipeinsulation.org.

Steam Leaks from High Pressure Valves, Piping, and Other Components

External steam leaks occur in piping, joints, valves, and other components for various reasons. In large steam systems there are always some leaks. The degree of leakage depends on how well the system is maintained. Leaks in pipes may be caused by corrosion, erosion, water hammer, faulty design, or poor installation. Joints of any type—welded, threaded, or flanged—can leak because the original connection was flawed. Valves leak externally through their connections to piping or through the valve-stem packing or other paths. Pressure relief valves are notorious for leaking. Valves may also leak internally due to poor seats causing losses or pressure increases in downstream equipment.

The volume of steam leaking from a given source is difficult to measure. For purposes of including steam leakage as a loss factor in this report, the total leakage in each section of the steam system has been based on an equivalent round hole, 1/4 inch in diameter. Lowering the boiler pressure reduces the leakage rate in the high pressure part of the system only. In order to estimate the leakage through this hole and the savings from lowering the boiler pressure, the following formula is used:

Steam flow through a sharp-edged orifice: $W = 24.24 \times Pa \times D^2$ (Napier's Equation)

where
- W = leakage rate in lb/hr
- Pa = the absolute pressure drop across the orifice in pounds per square inch absolute (psia)
- D = the diameter of the leaking orifice in inches.

For example: Steam operating pressure = 130 psig
Absolute pressure = 130 + 14.7 = 144.7 psia
Diameter of orifice = 0.25 inches

$$W = 24.24 \times 144.7 \times (0.25)^2 = 210.5 \text{ lb/hr}$$

At lowered pressure, 80 psig, the new leakage rate is:

$$W = 24.24 \times 94.7 \times (0.25)^2 = 137.7 \text{ lb/hr}$$

High Pressure Steam Trap Leakage

Poor steam trap maintenance is a major cause of losses in steam systems. Many steam plant owners do not have a scheduled maintenance program for steam traps.

Lowering the main steam pressure is not a substitute for regular trap maintenance. However, based on the condition of the average steam distribution system, a reduction in boiler pressure can, for this example system, result in savings of 0.6% of fuel input. The savings are realized only on the high pressure section of the steam system.

Steam trap manufacturing and service companies provide routine testing services which can identify blocked, leaking, or "blow-through" defective traps. Normally, the service includes a calculation for each defective trap of the amount of steam leaking through the orifice. Companies perform the estimates in different ways, employing considerable experience and judgment. The calculation is not as simple as one would make for dry steam blowing through an orifice from a high pressure (130 psig) to atmosphere. Other factors affecting the steam loss that are taken into consideration include:

- A leak that is only a partial opening of the trap orifice, as compared to a "blow through"
- The flow co-efficient (Cv) of the steam trap
- Condensate may also be passing through the leaking orifice
- The possibility of a pressurized condensate return line
- The normal variation (reduction) of trap inlet pressure when variable process loads are involved.

These factors act in various combinations to impose additional resistance to the flow of steam through the leaking trap orifice and result in a reduction in the theoretical steam loss as determined from Napier's equation or other methods. In practice, the final result of the leak calculation for an individual trap may be between 10% and 100% of the theoretical value.

Nevertheless, a reduction in the main steam pressure will reduce the leakage in high pressure traps. A conservative estimate would be that the steam leak losses are proportional to the absolute pressure (in psia) of the high-pressure steam.

For example, a high pressure, 3/4-inch trap with an orifice size of 1/8 inch and inlet pressure of 130 psig is estimated to be leaking 20 lb/hr of steam after deducting 66% of the theoretical leakage for the above factors listed above. When estimating the leakage rate if the steam pressure at the inlet is lowered to 80 psig, the new leakage rate is approximately:

[(80 + 14.7) psia / (130 + 14.7) psia] x 20 lb/hr = 13.0 lb/hr

◆ Flash Steam Loss Through High-Pressure Condensate Receiver Vents

Large steam systems have multiple local condensate receivers which collect hot condensate and pump it back to the boiler plant. It is not uncommon to have multiple receivers located in various process departments or buildings. Steam flashes as the condensate is lowered in pressure from the load pressure to the condensate system pressure.

In the high-pressure section of the steam system, flash steam losses will be directly reduced by lowering the steam pressure. When a steam trap passes condensate from the working pressure (130 psig) to the condensate system pressure (2 psig), the condensate contains excess energy above the liquid saturation level at the lower pressure. This excess energy causes some of the liquid to flash into steam.

The percentage of flash steam to total liquid can be calculated by using the following formula:

$$\textbf{\textit{Percent Flash Steam}} = \frac{(h_{F1} - h_{F2})}{h_{FG2}} \times 100\%$$

where

h_{F1} = Enthalpy (sensible) of condensate at Pressure P1, inlet of steam trap
h_{F2} = Enthalpy (sensible) of condensate at Pressure P2, outlet of steam trap
h_{FG2} = Enthalpy (latent) of flash steam at P2

For example: For : P1 = 130 psig and P2 = 2 psig
h_{F1} = 328 Btu/lb
h_{F2} = 187 Btu/lb
h_{FG2} = 966 Btu/lb

$$\text{Percent flash steam @ 130 psig} = \frac{(328 - 187)}{966} \times 100 = 15\%$$

Lower the Main Boiler Pressure to 80 psig

$$\text{Percent flash steam @ 80 psig} = \frac{(294 - 187)}{966} \times 100 = 11\%$$

From the example listed above, it can be observed that a reduction in boiler pressure will directly result in a reduction in flash steam as condensate passes through steam traps from high to low pressure. This savings applies only to the high-pressure system. Also, note that this estimate is only valid if all of the flash steam generated in dropping from the high pressure to 2 psig is vented; therefore, this calculation can be an overestimate of the potential savings. Another factor to consider is the possibility that flash losses are being recovered by means of a vent condenser. If this is the case, there is no savings associated with pressure reduction.

Steam Supplied to the Deaerator

The quantity of steam supplied to the deaerator is determined by the amount of energy required to heat a mixture of hot condensate and cold makeup water to the saturation temperature at the operating pressure of the deaerator, say 227°F at 5 psig. This steam represents a loss which can be minimized by good maintenance and management practices.

There will be a small reduction in steam supplied to the deaerator when the main pressure is reduced. Reductions in steam leaks, steam trap leaks, and flash vent losses all contribute to a reduction in the boiler makeup water rate and therefore to a reduction in the amount of steam supplied to the deaerator. The reduction in deaerator steam can be calculated by doing a steam system mass and energy balance analysis. The Steam System Assessment Tool (SSAT) can be used for such analyses, and can be downloaded from the U.S. Department of Energy website at www.eere.energy.gov/industry/bestpractices/software.html.

The Enthalpy Savings Effect

Table 1 shows the enthalpy and temperature difference between steam produced at 130 psig and at 80 psig. The energy supplied to steam loads comes from the latent energy in the steam and not from the sensible energy. Once the steam condenses it is no longer part of the heat transfer process. When the steam is being used at the pressure that the steam is being generated, it requires less steam (in pounds) to supply the required latent energy at a lower pressure than at a higher pressure. In this case, 0.972 lb of steam at 80 psig supplies the same amount of energy as 1 lb of steam at 130 psig.

The boiler supplies the same 866 Btu of latent energy to the load, regardless of the pressure. Otherwise, the energy supplied to the load will be insufficient.

The reduction in enthalpy is a savings that occurs because of differences in the condensate condition as it returns to the boiler plant from the load.

Condensate loses energy due to flashing as it is reduced in pressure from the load to a much lower pressure through steam traps. It also loses energy and temperature from piping radiation loss as it is transferred from

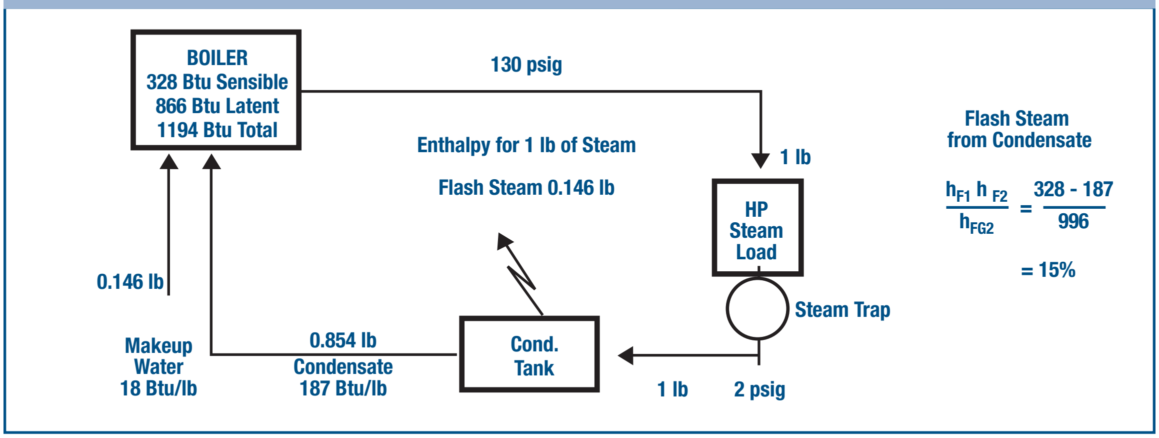
Table 1. Enthalpies and Temperatures for Steam Lowered in Pressure from 130 psig (saturated) to 80 psig by Reducing Boiler Pressure

Pressure	130 psig Case A	80 psig (reduced pressure)	80 psig Case B
Mass (lb)	1	1	0.0972 lb
Enthalpy			
Sensible	328 Btu	294 Btu	286 Btu
Latent	866 Btu	891 Btu	866 Btu
Total Enthalpy	1194 Btu	1185 Btu	1152 Btu
Steam Temperature	356°F	324°F	324°F

the load back to the boiler plant. Condensate from lower pressure steam loses less energy from flash than condensate from high-pressure steam. The result is that at lower pressure, the boiler must supply less energy to the condensate to raise it from the feedwater condition to the saturation point. After this, the boiler still supplies the same 866 Btu needed to vaporize the feedwater.

The examples below show this enthalpy reduction in simple terms (no deaerator is shown for simplification). The final result—a savings of 4.1%—is theoretical and only for purposes of illustration. An energy and mass balance analysis balance model, such as the SSAT, is a good tool to accurately estimate fuel savings from steam pressure reduction, including the enthalpy savings.

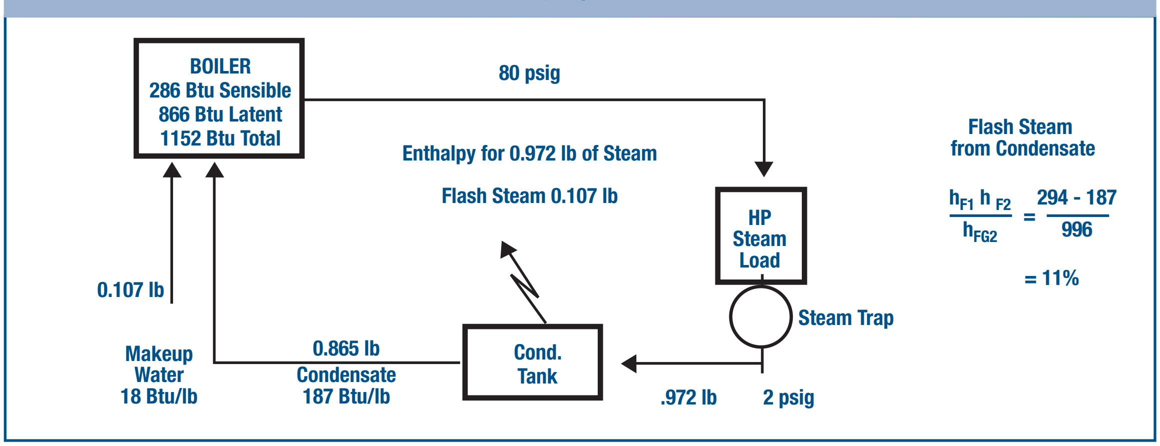
130 psig CASE A



Calculation of energy required from boiler to heat feedwater and to vaporize 1 lb of steam

Energy in condensate return	0.854 lb x 187 Btu/lb	=	160 Btu	
Energy in makeup water at 50°F	0.146 lb x 18 Btu/lb	=	3 Btu	
Total sensible energy supplied by feedwater		=	163 Btu	
Total energy required at saturation temperature:		=	328 Btu	
Energy to be supplied to feedwater (sensible)			165 Btu	(328 - 163) Btu
Latent energy required to vaporize feedwater		+	866 Btu	
Total energy required to be supplied by boiler:			**= 1,031 Btu**	**(A)**

80 psig CASE B



Calculation of energy required from boiler to heat feedwater and to vaporize 0.972 lb of steam

Energy in condensate return	0.865 lb x 187 Btu/lb	=	162 Btu		
Energy in makeup water at 50°F	0.107 lb x 18 Btu/lb	=	2 Btu		
Total sensible energy supplied by feedwater		=	164 Btu		
Total energy required at saturation temperature:		=	286 Btu		
Energy to be supplied by boiler (sensible)			122 Btu	(286 - 164) Btu	
Latent energy required to vaporize feedwater			+ 866 Btu		
Total energy required to be supplied by boiler:		=	**988 Btu**	**(B)**	

Energy Savings = (A) - (B) = 1031 - 988 Btu = 43 Btu = 4.1% of initial energy

It was noted earlier that the enthalpy savings effect, though real, will only occur for the portion of a steam system where the steam is used at the pressure produced by the boiler. For example, in a system where steam is generated at 130 psig, let down through a PRV to a pressure of 30 psig, and used at the 30 psig pressure, the enthalpy savings effect as described above does not occur. This is because the energy requirement for the 30 psig steam use would not change as a result of the pressure upstream of the PRV, as long as that pressure is above 30 psig. This can easily be demonstrated using the BestPractices SSAT software. Users can set up a model system as described above, reduce the model operating pressure to 80 psig, keep the 30 psig steam demand constant. and see only a minor change in overall steam production.

◆ Potential Problems and Limits to Steam Pressure Reduction

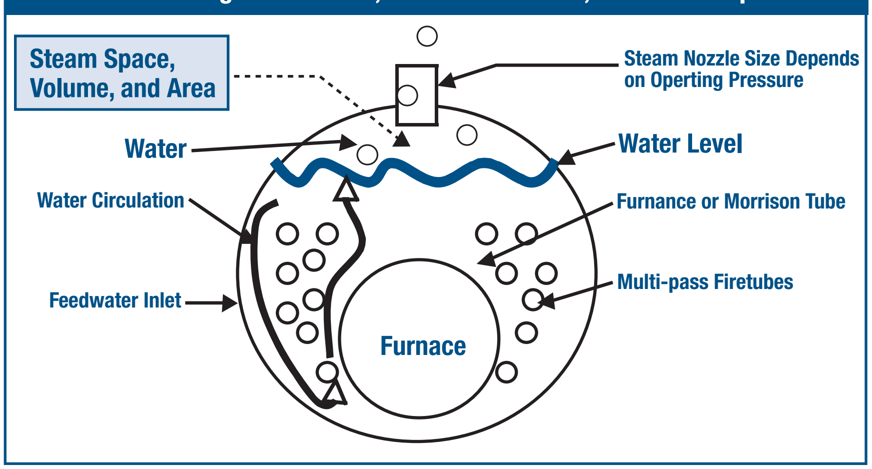
Boiler Carryover in Watertube Boilers from Reduced Operating Pressure

Reducing the boiler operating pressure in watertube boilers can lead to reduced steam quality going into the steam system. Lowering the boiler pressure can increase entrainment of liquid droplets.

As steam bubbles in a boiler rise through the water and reach the surface, they break through the final layer of water and enter the steam space. This causes entrainment of water droplets, and these water droplets can be entrained into the rising steam. The size of the steam bubbles produced—and the potential for droplet entrainment—is directly related to steam pressure. Lowering the steam pressure leads to larger-sized bubbles, higher steam velocities out of the boiler, and higher potential levels of entrainment.

Reducing the quality of steam entering the overall steam system can cause reduction on the overall efficiency of the use of steam—heat transfer from the steam/droplet mixture will be less effective—and can lead to premature failure of steam system components such as valves and steam traps. There is no way to effectively calculate when lowering steam pressure will cause this effect, but it is a real concern that should be addressed by observation of how the steam quality responds to lowering the steam pressure.

Figure 3. Cross Section of a Firetube Boiler from the Burner End Showing the Furnace, Water Circulation, and Steam Space



Boiler Carryover in Firetube Boilers from Reduced Operating Pressure

For this discussion, the assumption is that the boiler is oversized and normally operates at a firing rate well below its rated capacity.

Firetube boilers are capable of operating at varying steam pressures within a wide range with few negative consequences. Manufacturers of firetube boilers specify the same boiler model and size with no change in output rating over an operating range from 15 psig to 250 psig, and there is no derating of the boiler as pressure is lowered, as there is with a watertube boiler.

One item to be considered is the possibility of increased carryover when firetube boilers operate at reduced pressures. The amount of boiler water carryover is partly a consequence of the basic firetube design.

In a firetube boiler, the design parameter which affects carryover and thus steam quality, is the steam space. The steam space is defined by the nominal volume and surface area of the space above the water in the boiler. For a given boiler size, each boiler make and model has a different specification for steam space. A larger steam space volume and water surface area results in less carryover of water into the steam system. A comparison of specifications of five different makes of firetube boilers showed that for a 750 BHP boiler, the steam space volume varies by 48% from the smallest to the largest.

For a boiler operating under normal pressure conditions of 130 psig at a constant output when the pressure is reduced to 80 psig, the velocity of steam evaporating from the surface of the water increases, tending to cause increased carryover.

For the owner considering the possibility of steam pressure reduction, the first question to ask is whether there is a problem with carryover (wet steam) before pressure reduction. Depending on the boiler design, the average firing rate, and the nature of load variation, there may or may not be an existing problem. If there is, steam pressure reduction will probably increase the problem. A steam separator or mist eliminator may be required.

A reduction in steam pressure can also cause an increase in specific volume and, for a given mass flow, an increase in velocity. Firetube boilers are equipped with a nozzle at the steam outlet which delivers steam to the system. This nozzle is designed to deliver steam at a velocity of approximately 4,000 to 5,000 feet per minute (ft/min). When the steam pressure is reduced, the velocity will increase for a given output. It may be necessary to change out the steam nozzle for a larger size to accommadate the increased velocity.

The manufacturer should be consulted before deciding to operate a firetube boiler at a reduced pressure. A test for carryover should be conducted before and after pressure reduction. An indication of carryover can be obtained by measuring the conductivity of condensate gathered as near as possible to the outlet of the boiler.

Boiler Circulation – Potential for Tube Overheating in Watertube Boilers

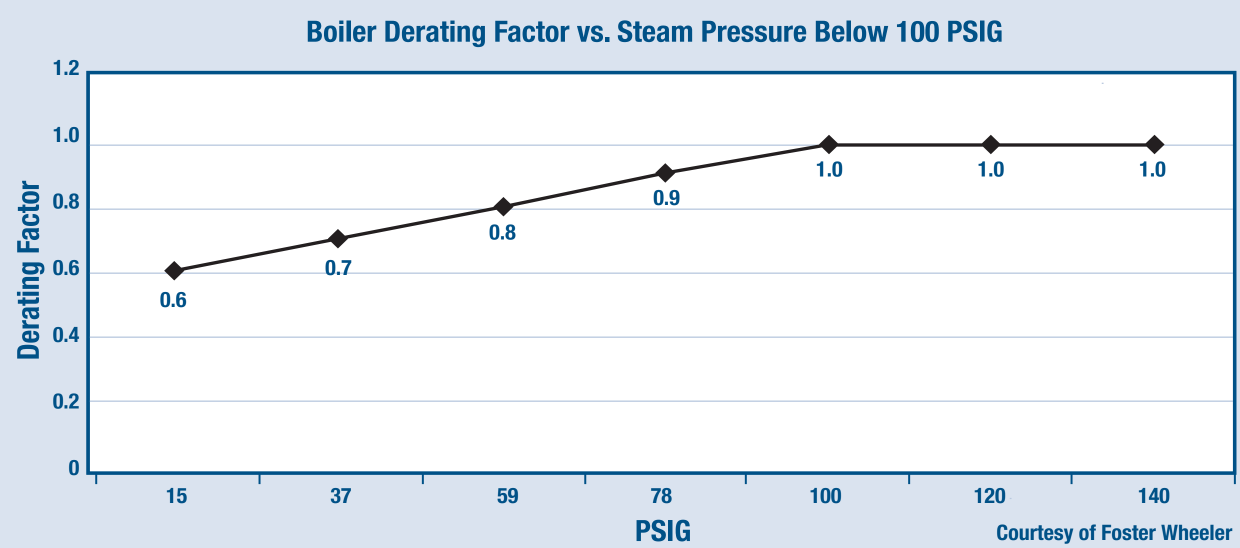
It is unlikely that operators of steam systems producing and utilizing superheated steam will wish to reduce the steam pressure. This section's discussion pertains to saturated steam systems.

Circulation in a watertube boiler occurs because of the density difference between the downcomer and the riser. The fluid in the downcomer is all water and therefore denser than the fluid in the riser, which is a mixture of steam and water. The rate of the resulting water circulation depends on the difference in the average density between the unheated downcomer and the steam-water mixture in the riser.

Heat transfer from the fire (boiler furnace) to the feedwater and the two-phase mixture requires the maintenance of an unbroken film of water on the inside of the entire length of the tube. A reduction in overall steam pressure tends to increase backpressure in the riser tube to the feedwater in the downcomer, creating a nonwetted area near the top of the riser. This is called "steam blanketing"—departure from nucleate boiling—and is undesirable. It can result in the overheating of the riser tube. Another potential problem that can result from poor circulation is increased deposits on the boiler tubes.

Boiler Performance at Maximum Rated Load, Rated Pressure. Watertube boilers are designed for a specific maximum steam flow at a maximum boiler drum pressure. The number, diameter and pressure rating of the tubes are fixed. At maximum steam output and pressure, circulation is adequate to prevent steam blanketing. At maximum steam output, there is adequate cooling to the tubes. At maximum output, the moisture content of steam entering the drum is high and drum separator components must remove it in order to supply dry steam to the process.

Figure 4. Boiler Derating Factor vs. Steam Pressure Below 100 psig



Boiler Performance at Low Load, Rated Pressure. On low-fire, such as 20% of rated output, water and steam flow circulation is reduced, creating a condition which can result in unwetted tube surface in the riser; The same problem is experienced with low operating pressure.

Boiler manufacturers recommend that boilers be derated when operating at lower pressures. That is, depending on the rated pressure and operating pressure, the boiler should not be fired at rated input. Figure 4 represents the fuel input derating factor for a typical packaged watertube boiler. It shows the allowable fuel input compared to the rated capacity under reduced steam pressure conditions. The base case comparison is for boilers rated at a maximum of 250 psig.

Boiler owners who are considering steam pressure reduction should consult their boiler supplier.

Steam Piping – Steam Velocity, Pressure Drop and Temperature

Steam Velocity in Piping. A conservative guideline is to select the pipe diameter to limit steam velocity for saturated steam to no more than 80 feet per second (ft/sec) (4,800 ft/min). High velocity steam, exceeding 120 ft/sec, (7,200 ft/min) causes a number of problems, including erosion of piping and other components, and noise in piping.

Steam velocity is a function of flow, pressure, and internal pipe diameter. The following formula shows this relationship. In order to plan a pipe-run to limit velocity to 80 ft/sec, all of these variables must be estimated in advance.

$$V = \frac{2.4 \times Q \times V_S}{A}$$

where
- V = Steam velocity in ft/min
- Q = Steam flow in lb/hr
- A = Internal pipe area
- V_S = Specific volume of steam at operating pressure in cu ft/lb

Reducing the pressure increases the steam velocity and therefore the potential for problems mentioned above. An estimate should be made of the steam velocity before and after the pressure decrease, keeping in mind that the actual peak steam flow is much lower than the design maximum, and the steam velocity may be within conservative limits even if the pressure is reduced.

For example, a 6-inch diameter, Schedule 80 pipe is designed to carry a peak steam flow of 16,730 lb/hr at 130 psig with a maximum velocity of 80 ft/sec (4,800 ft/min). The actual peak steam load is only 10,000 lb/hr. This is below the design peak of 16,730 lb/hr because the system is oversized. If estimating the steam velocity at the actual peak steam load at 130 psig and at 80 psig:

130 psig:

$$V = \frac{2.4 \times 10{,}000 \times V_S}{A} = \frac{2.4 \times 10{,}000 \times 3.12}{26.1} = 2{,}869 \text{ ft/min} = 47.8 \text{ ft/sec}$$

80 psig:

$$V = \frac{2.4 \times 10{,}000 \times 4.67}{A} = 4{,}294 \text{ ft/min} = 71.6 \text{ ft/sec}$$

The steam velocity has risen after pressure reduction. Because the original piping was oversized, the velocity remains below the 80 ft/sec standard set as a good practice. Every case where steam pressure reduction is under consideration should be analyzed for steam velocity before and after pressure reduction.

Steam Pressure Drop. The pressure drop through pipes, valves, and bends increases as the main boiler pressure is reduced. With a reduction in the main boiler pressure, this drop is felt through the high pressure side of the system up to the first pressure reduction stations.

The science of calculating pressure drop of fluids through piping is well established. However, the task of estimating the pressure drop between two points in a large steam system is complex and time consuming. There are many variables involved, especially where compressible fluids are concerned. In practice, variables such as the pipe friction coefficient may not be known, especially for pipes that have been installed for many years.

The formula below describes the relationship between steam pressure drop (Δ P), flow (Q), pipe diameter (D), and specific volume (V_S) for steam flow in a pipe. It shows that the pressure drop is proportional to the increase in V_S. If the operating pressure is reduced, the pressure drop in piping will increase by the ratio of the specific volume of steam at the new pressure compared to the initial pressure.

$$\Delta P = 0.00134 \times \frac{f V_S (Q)^2}{D^5}$$

where
ΔP = Pressure drop in pounds per 100 ft. of pipe
f = Coefficient of friction for the pipe (0.006 is typical)
V_S = Specific volume of steam at the operating pressure
D = Internal pipe diameter (inches)
Q = Steam flow in lb/hr

A simple pressure and flow problem can be solved graphically using charts such as those found in the Spirax Sarco "Hook-Ups" book. This chart provides the following solution when comparing the pressure drop for 130 psig and 80 psig using the piping example listed above.

Δ P for 130 psig, 6 inch diameter, Schedule 80 pipe = 0.65 psi per 100 ft. of pipe

Δ P for 80 psig, 6 inch diameter, Schedule 80 pipe = 0.96 psi per 100 ft. of pipe

The acceptable pressure drop in the steam system up to the first level of pressure reduction depends on the ability of the pressure-reducing station to maintain the required outlet pressure while operating with a lower inlet pressure. This depends on the type of valve, whether it is oversized for the peak load it carries, its condition, and its design, including the flow coefficient.

In a pilot-operated PRV that is somewhat oversized and in good working condition, problems with pressure at the outlet occur when pressure drops to approximately 50% of the original operating pressure. This is specific to each situation.

Before implementing steam pressure reduction, estimate the pressure drop at various steam loads from the boiler plant to important locations in your steam system.

Steam Temperature. The temperature of saturated steam at any pressure is available in any steam table. In the pressure ranges of interest—250 psig or lower—the operating temperature can be expected to drop by 30°F to 60°F, depending on the initial and final operating pressure.

There are many processes that operate at a specific pressure because a certain minimum temperature is required. Examples include autoclaves in hospitals—40 to 60 psig—and drying or baking ovens in the food industry, which operate at 100 psig. This process limitation will make it impossible to reduce the boiler pressure below the specific temperature/pressure required.

Pressure Reducing Stations

The purpose of the PRV is to take steam at high pressure and reduce it to the operating level of the steam utilizing equipment. A PRV actively controls the downstream pressure at a desired pressure set point. Most equipment, especially in the types of steam systems investigated here, does not operate at the boiler plant pressure. Steam loads such as air heating coils, humidifiers, and heat exchangers for water heating operate at pressures ranging from 5 to 30 psig.

Small direct-acting PRVs are inexpensive and are designed for lower flows of approximately 2,500 lb/hr or less. They are often dedicated to a single coil or heat exchanger. Pilot-operated PRVs are designed for larger loads. They regulate the downstream pressure within close limits under varying loads. Pilot-operated PRVs can respond to a wide range of inlet pressures and outlet loads if they are in good condition.

In practice, the reduction of the main steam pressure will probably cause some PRVs in a large steam system to fail to control the downstream pressure adequately. This depends on type (pilot or direct acting), size, and maintenance condition.

If a PRV cannot handle the required steam volume flow increase, it may be possible to increase the main port size without changing out the valve body. If that fails, the valve may have to be replaced.

Influence of Steam Pressure Reduction on Flowmeters

The lowering of the main steam pressure will require the recalibration of differential pressure type flowmeters. The vast majority of steam flowmeters installed in industry are orifice-plate type meters which depend on the absolute operating pressure to produce an accurate mass-flow reading. Most of these are inaccurate due to neglect and should be recalibrated anyway. These meters read mass steam flow usually in lb/hr. When steam pressure is lowered, steam flowmeters will read too high on mass flow.

Steam plant owners wishing to operate at lower steam pressure should thoroughly assess the existing steam plant metering.

The following formula may be used for saturated steam to manually correct the mass flow reading from an orifice plate on a steam boiler outlet when the operating pressure has been reduced:

$$CF = \sqrt{\frac{V_S\ (\text{Actual})}{V_S\ (\text{Design})}} \times \frac{V_S\ (\text{Design})}{V_S\ (\text{Actual})}$$

where CF = Mass Flow Correction Factor

V_S (Actual) = Specific volume of steam at the actual operating pressure.

V_S (Design) = Specific volume of steam at the original design pressure.

For example: The original design pressure is 130 psig.

The new actual operating pressure is 80 psig.

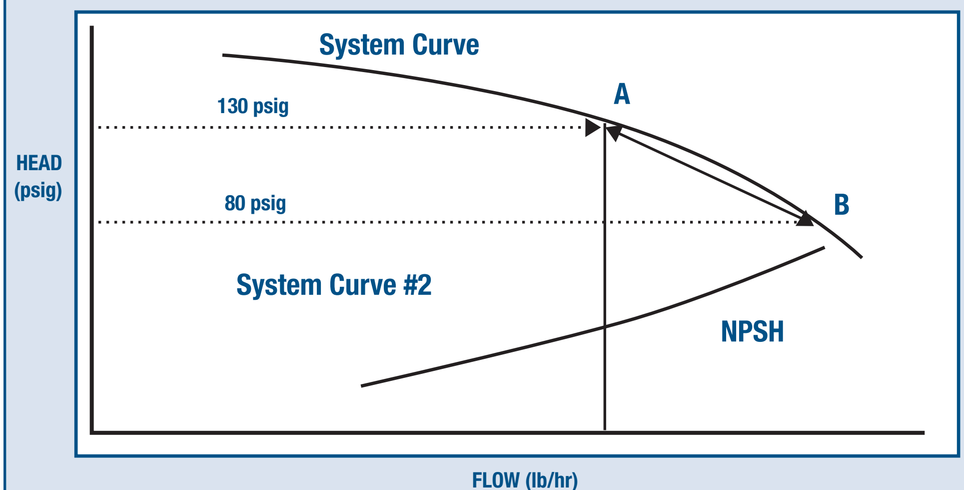
$$CF = \sqrt{\frac{4.67}{3.12} \times \frac{3.12}{4.67}} = 0.82$$

The manufacturer of the meter should be contacted for detailed meter data, including accurate correction factor curves and advice on repair or replacement.

Feedwater Pumps - Cavitation

When steam pressure is decreased, the feedwater pump will supply water to the boiler under a different operating condition. The pump is acting against the head of the piping system, boiler pressure and the feedwater control valve. With reduced pressure, the pump will attempt to operate at a different point on its operating curve.

Figure 5. Feedwater Pump Flow



1. Reducing the steam pressure from 130 psig to 80 psig causes the pump to try to operate farther out on the system curve. The operating point moves from (A) to (B). The pump flow capacity increases as it pumps against a lower head in the steam drum. This situation requires a greater Net Positive Suction Head because the increased flow causes increased pressure drop through the pump and piping.
2. If the NPSH supplied at the inlet of the pump by the deaerator pressure and the drop in elevation to the pump is inadequate, cavitation will occur.
3. It may be necessary to restrict the flow by means of an orifice downstream of the feedwater pump. Cavitation can be detected by listening to the pump.

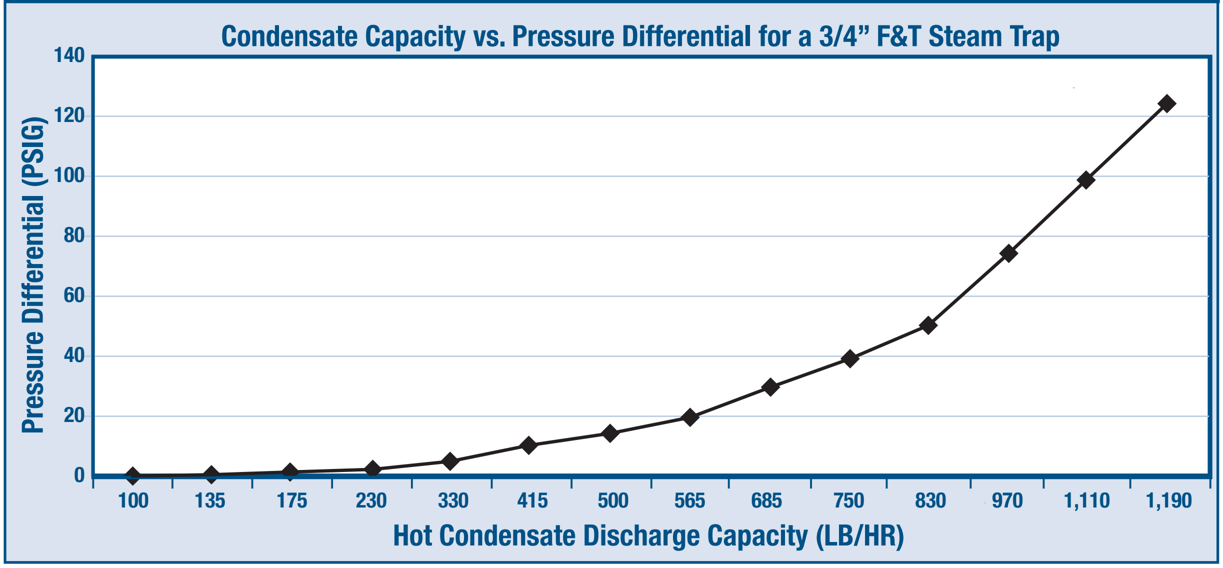
Steam Traps - The Effect of Reduced Operating Pressure

A reduction in steam boiler pressure takes place only at the highest pressure level of the system. Pressure reduction at the boiler affects only the equipment operating at high pressure. The affected items are drip leg traps on high pressure steam lines and users at the main steam pressure.

Steam loads at lower pressures, supplied by PRVs, do not see a change in the pressure as long as the PRVs are still able to supply the specified pressure to these loads.

The concern with steam pressure reduction is the possibility that the installed steam trap may not be able to discharge the required flow of condensate. This would result in water logging of the steam-consuming equipment.

Figure 6. Condensate Capacity vs. Pressure Differential for a ¾-inch F&T Steam Trap



Condensate Discharge Capacity vs. Differential Pressure – Basic Steam Trap Performance. Steam traps of all types are designed to operate at a wide range of pressures. The condensate discharge capacity of a trap varies with the pressure differential across the trap.

Figure 6—from manufacturer's specifications—illustrates the simple relationship between differential pressure across a steam trap and the condensate discharge capacity of the trap.

This steam trap is able to discharge condensate over a very large range of pressures. The designer selects the trap for a nominal pressure at the trap inlet of 130 psig, knowing that the trap will see lower pressures as the steam flow is regulated by the control valve and the pressure drop through the steam system. Figure 6 shows that as the differential pressure across the trap decreases, its ability to discharge condensate decreases. The curve, however, is nonlinear. The reduction in capacity is much greater as the pressure drops incrementally.

Example 1- The effect of steam pressure reduction on high pressure drip legs. Plant operators often express the concern that at reduced pressure steam traps may not handle the required condensate flow, especially on steam main drip legs.

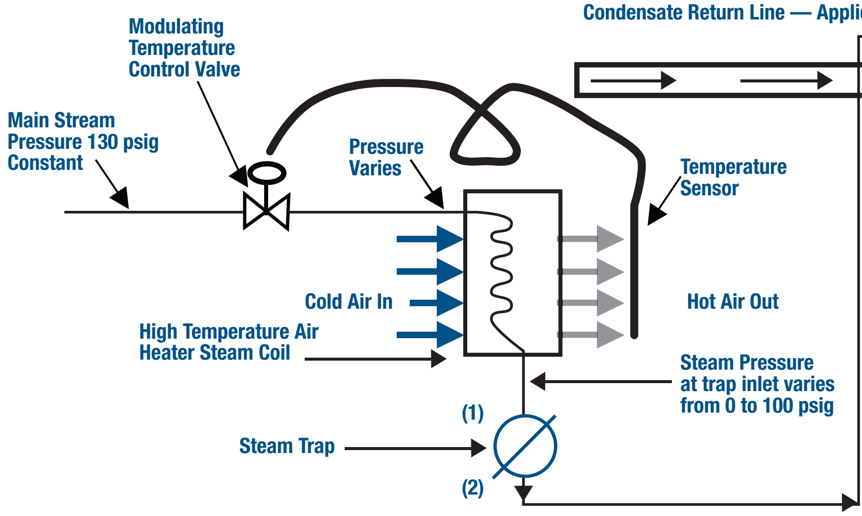
Steam boiler headers and high-pressure mains are equipped with drip legs to remove the condensate which forms in the system under normal load conditions and under warmup conditions. The steam traps operate at the full boiler pressure. The standard practice for this application is to install a drip leg of adequate diameter and length to capture and store a significant amount of condensate during warmup. Because the pressure is zero at warmup, only the head of condensate which collects in the drip leg pushes the condensate through the trap to the return line located below the steam line.

In most cases, based on a 1-hour warmup time and typical piping insulation standards, the condensate load is approximately double the main steam load for which the steam trap has been sized.

If the drip leg steam traps have been applied according to standard practice, a reduction in steam pressure of up to 50% should not affect their capacity to drain condensate either under load or warmup conditions.

Example 2 - The effect of steam pressure reduction on a high-pressure, temperature-controlled steam coil operating at full boiler pressure. Pressure reduction to a high-pressure steam coil may have a negative impact on the operation of the coil operating at full pressure because of the reduced condensate discharge

Figure 7. Makeup Air Heater with Modulating Temperature Control Valve



Steam traps are designed to operate at varying pressure conditions at their inlets (1) and outlets (2). During normal operation, pressure (1) varies as the steam load changes and the temperature control valve modulates. Pressure (2) (backpressure of the condensate return system) varies with condensate system conditions.

capability. The analysis below can be applied to a wide range of equipment. Any steam utilization appliance which drains condensate naturally may suffer the same performance problems described in this example. Dryers, water heaters, reactors, and other equipment can be substituted in this example.

The illustration above shows a steam coil in a makeup air unit operating at the main system pressure (130 psig), controlled by a modulating valve. This application is chosen because even in normal conditions, when constant high pressure steam is supplied to the coil, it can present problems. The makeup air unit is supplied with cold outdoor air, the temperature often below the freezing point.

Operating at Normal Steam Pressure: 130 psig. The ability of the steam trap to remove condensate from the coil depends upon two opposing pressures: a) the internal pressure of the coil and b) the backpressure applied to the trap by the condensate return system.

In order to remove condensate through the trap, the pressure in the coil must be greater than the backpressure of the condensate return. The focus of the opposing pressures is the steam trap. When the heating load is high, the temperature control valve is open and the pressure in the coil is high. When the heating load is low, the control valve modulates toward the closed position, reducing the steam pressure in the coil. The opposing pressure of the condensate return system will be constant. At some low load condition, there can be zero or even negative pressure in the coil. In this condition, the steam trap is unable to remove condensate because the opposing force, the condensate system backpressure, is greater than the pressure in the coil. This condition is called “stall”. When stall occurs, condensate backs up into the coil, causing it to flood. If the coil is not properly protected by good design (proper drainage) and by having a vacuum breaker located at its inlet, it will cease to supply the heating load.

Main Steam Pressure is Lowered: 80 psig. The operation of the heating coil, the control valve and the steam trap are all affected as follows when the main steam pressured is lowered to 80 psig:

1. The capacity of the coil to deliver energy to the load is reduced because the maximum flow through the coil is lower. The pressure drop through the coil increases as the steam density decreases. Coil manufacturers provide performance specifications which specify their capacity at various steam pressures. Based on the pressures used in this example, 130 psig to 80 psig, the maximum rated flow through a heating coil will be reduced by approximately 20%. Therefore, at low pressure, the makeup air unit may not be able to deliver enough heat to satisfy the building heating, ventilation, and air conditioning requirement.
2. The ability of the steam trap to remove condensate at full load is decreased. As the main steam pressure

inlet to the coil drops from 130 psig to 80 psig, and the pressure drop across the coil increases, the positive pressure at the steam trap is lowered significantly. Its ability to remove the required amount of condensate is therefore reduced.

3. The sizing of the temperature control valve becomes an issue. If the control valve has been initially oversized for the actual maximum heating load and steam flow, it may be adequate to supply the reduced steam flow at reduced pressure for the peak load. However, the control valve presents an additional pressure drop to the system and, if it cannot open wide enough to supply the load at the reduced pressure, the result will be inadequate heat delivered to the load.

The two examples above show that a reduction in the main steam pressure may or may not impact the capacity of steam traps on the high pressure side to remove condensate. There are many other applications which may be affected by pressure reduction and steam trap performance.

The effect of lowering steam pressure on these traps can best be assessed by testing and observation. Steam pressures, as observed at pressure gauges at various points in the steam system, are a good guideline to the effect of lowering steam pressure. The occurrence of waterhammer is also an indication of a problem.

In practice, for steam pressure reduction up to two-thirds of the original operating pressure, there are very few cases of traps unable to remove condensate.

Backpressure Steam Turbines - Capacity and Flow Implications of Pressure Reduction

Backpressure steam turbines are used extensively in industry as prime movers for blowers, pumps, and electric generators. The most common type is the small, single stage turbine employed within the boiler plant.

These units take saturated steam at the inlet at boiler pressure. As steam passes through the turbine, work and power are produced at the shaft. The pressure drops to a lower level and the steam which is exhausted at the outlet is used to heat the deaerator.

The following is a sample calculation for the amount of power produced at the shaft of the turbine:

Variables:
Actual steam rate: **ASR** in lb of steam per kilowatt output
Output of the turbine: **kw** (kilowatt)
Steam mass flow: **m** 6000 lb/hr
Enthalpy of steam at the turbine inlet: **h1** (dry saturated) at 130 psig (145 psia)
Enthalpy of steam at the turbine exhaust: **h2** (isentropic at 5 psig (20 psia))
Isentropic turbine efficiency taking into account steam leakage and mechanical loss: **e = 45%**

The basic input/output performance for a backpressure steam turbine operating at 130 psig is described by the following formula:

$$\text{ASR} = \frac{3413}{(\text{h1} - \text{h2}) \times \text{e}} = \frac{3413}{150 \times 45\%} = 50.56 \text{ lb/kw-hr}$$

Output of turbine: kw = 6,000 lb/hr / 50.56 lb/kw-hr = 118.7 kw

The output power of the turbine depends on the mass flow of steam, the turbine efficiency, and the difference in enthalpy between the inlet and the exhaust of the turbine. In practice, the enthalpy of steam at the exhaust is determined by the backpressure and the turbine efficiency. In this case, the exhaust is piped to the deaerator at 5 psig.

If steam pressure at the turbine inlet is reduced, the enthalpy (h1) is also reduced, causing a reduction in the turbine output power. The turbine will try to respond automatically, through its governor, to increase the steam flow in order to maintain the speed and power output. If the turbine is already operating at maximum output and speed, it will be unable to do this, resulting in a loss of power.

Example 1: 130 psig

Calculate the power output for a backpressure turbine operating at an inlet pressure of 130 psig, 45% isentropic efficiency and outlet pressure of 5 psig with a steam flow of 6,000 lb/hr.

Answer: 118.7 kw

Example 2: 80 psig

Calculate the power output for a backpressure turbine operating at an inlet pressure of 80 psig, 45% efficiency and outlet steam pressure of 5 psig with a steam flow of 6,000 lb/hr.

Answer: Using the same method as above, turbine output kw = 92.8 kw

Example 3:

What is the steam flow at the lower pressure required to provide the original 118.7 kw?

Answer: 7,676 lb/hr

If the original power output is to be maintained, the turbine must be capable of handling a steam flow which is 28% greater than the steam flow at the higher pressure. It is recommended that owners investigate their turbine operations before proceeding with steam pressure reduction.

◆ Testing Steam Pressure Reduction

Introduction

We recommend a conservative approach to the lowering of boiler steam pressure. Testing should be conducted in three phases:

- Preliminary data collection and analysis
- Short term test – 8-hour test
- Long-term performance monitoring – 1-year evaluation.

Preliminary Data Collection and Analysis

Boiler Load vs. Capacity. It is important to analyze the cyclical and seasonal steam load in relation to boiler capacity before embarking on a program to reduce steam pressure. The basic premise of pressure reduction is that boilers, steam piping, and components are oversized.

The plant owner should establish this by analyzing the steam load in relation to system capacity over a 1-year period. This exercise involves a detailed analysis of plant logs including fuel consumption and steam production data. The conclusion of this analysis should be that the boiler plant and steam system capacity exceeds the average steam load by a wide margin. The peak steam load is also important. If peak loads (winter) approach the plant capacity, the boiler plant manager can consider reducing steam pressure at times of low load but increase steam pressure during high load periods.

While boiler overcapacity is a necessary condition for steam pressure reduction, grossly oversized boilers will suffer from circulation problems on low fire. This will be aggravated by lowering the steam pressure.

Under normal load conditions, if the smallest boiler is grossly oversized for the summer load, steam pressure reduction should not be considered. That is, if the average summer steam load requires one boiler to fire on low fire all summer—for example, 20% of full load input—the boiler is already operating with poor circulation. Steam pressure should not be reduced. Instead, the installation of a smaller summer boiler should be considered.

In addition, if the boiler is already experiencing frequent boiler carryover, it is not likely to be a good candidate for steam pressure reduction.

Consult the Boiler Manufacturer. The boiler manufacturer should be consulted with regard to the effect of lower pressure on the operation of the boiler. The manufacturer should provide the owner with a guide to the upper and lower limit of firing rate for various pressure possibilities. Some manufacturers can provide, for a fee, a computerized simulation analysis of the circulation flows for a specific model of boiler.

Steam Distribution System Data - Drawings and Surveys. An estimate of the energy savings from steam pressure reduction can be made using some of the concepts presented in this technical brief. If drawings of the steam distribution and condensate piping are available, these can be used to estimate the lengths and diameters of piping. A physical survey is required to establish the level of insulation. In any case, this would be a good time to conduct both a steam trap survey and an insulation survey. Data collected can be used for maintenance purposes and also to estimate the losses and savings from steam pressure reduction.

Short-term Testing

Purpose of the Short-term Test. The purpose of this test is to observe metered fuel consumption and to discover obvious problems in the boiler plant and steam distribution system. Primarily, the operation of main PRVs should be observed to be sure that they respond adequately to reduced pressure. This test will establish, for a given steam load, the lowest feasible pressure. A short test can be conducted within approximately 6 to 8 hours by several people. If possible, the test should be conducted with a single boiler in operation.

Ideally, the test should be conducted at a time of steady load, above the average steam load for the system, but not at the peak steam load. For the types of steam systems discussed here, the best time to test is at night when daily cyclical loads, such as domestic hot water production, do not interfere with readings. This is also a good time to test because the effects of the sun and wind on building heating load may be minimized. If the weather and loads are highly variable, causing large swings in the heating load, it will be difficult to obtain good readings.

Method – Short-term Test

1. Set up a ***plant log sheet*** describing the various plant and steam system readings and observations. Include such items as: time, boiler pressure, header pressure, boiler stack temperature before and after economizer, steam flow, steam flow correction factor, deaerator pressure and temperature, gas or oil flow, feedwater pump pressure, and any other plant data which may be useful.
2. Set up a steam system log sheet describing readings and observations about the steam system. Field observers will have to move around the steam distribution system to various important points and observe the operation of equipment, for example, air handling unit temperatures. Most steam systems have some pressure gauges located at various points. If not, it will be necessary to install a few pressure gauges strategically, to determine whether the low pressure part of the system is in fact operating correctly.
3. Begin the test by taking all readings in the boiler plant at the normal operating pressure. Take these readings several times over a period of 30 minutes to 1 hour. Communicate with the field observers to be sure that they have completed their rounds and readings. Walkie-talkies and cell phones are a big help.
4. Lower the boiler plant pressure by approximately 10 pounds per square inch increments until inadequate pressure in some part of the low pressure system is observed. Each step will take approximately 1 hour depending on the size of the steam distribution system.

Long-term Performance Monitoring. The short-term testing can be used to establish a comfortable reduced pressure operating point. Because this point was established at a steam load which was above average, but less than the peak load, the plant will operate at levels above and below the test level. At lower steam loads, downstream pressure at the farthest point from the boiler plant will not be a problem; at higher loads it may be. Monitoring the pressure at critical points in the steam system will establish whether it is necessary to increase steam pressure under peak conditions.

Following the initial testing and while operating at the reduced pressure, daily readings and inspections should be made. These inspections should be done when the steam load varies from the original test load. PRVs which do not perform properly may be discovered, and may have to be replaced or refurbished.

The boilers should be inspected for signs of tube overheating at the time of normal annual inspection.

◆ Conclusions

Steam generation conditions in some manufacturing facilities and institutions are at saturated steam pressures below 250 psig. These facilities may be candidates for steam pressure reduction if the systems are oversized for the steam load they carry.

Every steam system has site-specific operating characteristics. The savings achievable by steam pressure reduction vary case by case. The amount of savings depends on many factors, including the design and sizing of the steam distribution system, system maintenance, and the percent pressure reduction.

Some areas where steam savings can result due to steam pressure reduction include:

- Boiler combustion loss and fuel reduction
- Boiler radiation loss
- Boiler blowdown loss
- "Enthalpy savings effect" for high-pressure steam use
- High-pressure radiation loss for steam piping and components
- High-pressure steam leaks from piping, components, and through PRVs
- High-pressure steam trap leaks
- Steam supplied to the deaerator.

Some areas where steam pressure reduction can result in steam system problems include:

- Increased boiler carryover
- Potential for boiler tube overheating in watertube boilers
- Increased steam velocity in piping
- Increased steam pressure drops
- Failure of some steam system PRVs
- Need for flowmeter recalibration
- Feedwater pump cavitation problems
- Reduction in steam trap performance
- Reduced output power from steam turbines.

It is the responsibility of the steam plant owner to conduct tests and inspections before establishing a lower steam pressure operating point. Plant owners should conduct short term and long term tests and inspections to verify the proper operation of the steam distribution system. Some problems which may be encountered are listed in this technical brief.

Plant owners should fix defective steam traps, steam leaks, and insulate steam and condensate piping before reducing steam pressure.

We further advise boiler plant owners to consult the boiler manufacturer in order to assess the effects of a lower operating pressure on the boiler. Typically, watertube boilers rated for a maximum steam pressure of 250 psig are designed to operate at full fuel input at pressures as low as 100 psig. Below 100 psig, watertube boilers may need to be derated with respect to fuel input.

◆ Acknowledgements

The U.S. Department of Energy extends special thanks to the following participants for their contributions to this technical brief: Robert Griffin, P.E. of Enbridge, Inc.; Wayne Kirsner, P.E. of Kirsner Consulting Engineering; Dr. Anthony Wright, Oak Ridge National Laboratory; and the Steam BestPractices Technical Steering Committee.

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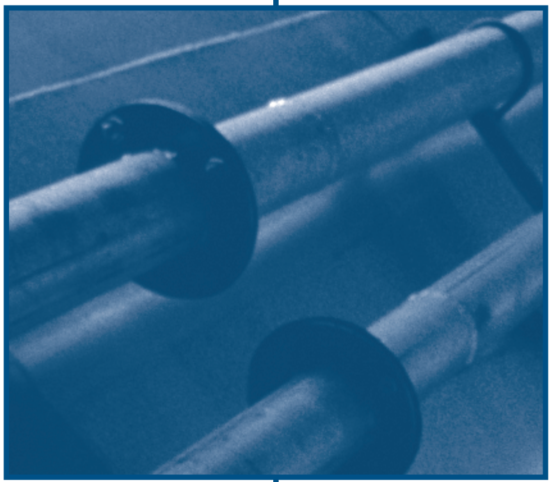
A Strong Energy Portfolio for a Strong America

Energy efficiency and clean, renewable energy will mean a stronger economy, a cleaner environment, and greater energy independence for America. Working with a wide array of state, community, industry, and university partners, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy invests in a diverse portfolio of energy technologies.



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Industrial Technologies Program

Energy Efficiency
and Renewable Energy

U.S. Department of Energy

Washington, DC 20585-0121

DOE/GO-102005-2193

November 2005

BUFFALO SEWER AUTHORITY
CONCEPTUAL ESTIMATE OF PROBABLE PROJECT COST

New Hot Water Boiler System for Administration Building and Tie-ins
November 12, 2012

Division	Description	Quantity	Unit	Material		Labor		Total
				Unit Cost	Total	Unit Cost	Total	Cost
1	**GENERAL REQUIREMENTS**							
2	**SITE WORK**							
3	**CONCRETE**							
5	**METALS**							
11	**EQUIPMENT**							
	850 mmbtuh Hot Water Condensing Boilers	7	EA	$ 15,000	$ 105,000	$ 5,000	$ 35,000	$ 140,000
	Primary Boiler Pumping System	1	LS	$ 100,000	$ 100,000	$ -	$ -	$ 100,000
	Controls	1	LS	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 50,000
13	**SPECIAL CONSTRUCTION**							
15	**MECHANICAL**							
	Hot Water Piping Distribution to bldg 2 & mods	1	LS	$ 40,000	$ 40,000	$ 10,000	$ 10,000	$ 50,000
16	**ELECTRICAL**							
			LS	$ -	$ -	$ -	$ -	-
		Subtotal Project:			**$ 270,000**		**$ 70,000**	**$ 340,000**

TriangleTube

KEYSTONE

High Efficiency Gas Boilers and Water Heaters

Triangle Tube's Keystone Series Condensing Boilers and Water Heaters are designed for large residential and light commercial applications.

The stainless steel heat exchanger and burner provides high efficiency, low emissions, and high turndown to minimize short cycling. With maximum inputs of 850 MBH for boilers and 500 MBH for water heaters, the Keystone series can meet most needs with a single unit.

For larger requirements the advanced control allows units to be joined and function with parallel modulation for maximum efficiency.

Features

500 - 850 MBH Boilers are CSD-1 Compliant STANDARD

- Condensing Boilers from 399 to 850 MBH
- Condensing Water Heaters from 199 to 500 MBH
- High Efficiency with Thermal Efficiencies up to 97%
- Compact Footprint
- Modulating with 5 to 1 Turndown
- Advanced Cascade Capability
- Building Automation System Interface
- Meets 2012 SCAQMD NOx Emissions Requirements
- LP Conversion Kit

Technical Specifications

	Model	Connections Size (NPT) Water	Gas	Air Inlet Diameter	Vent Diameter	Dimensions D x W x H	Weight Lbs
Water Heaters	KW 199	1 1/4"	1/2"	3"	3"	26"x 24 1/2" x 38"	246
	KW 285	2"	3/4"	4"	4"	26"x 24 1/2" x 38"	276
	KW 399	2"	3/4"	4"	4"	31"x 24 1/2" x 38"	346
	KW 500	2"	1"	4"	4"	31"x 24 1/2" x 38"	381
Boilers	KS 399	1 1/4"	3/4"	4 "	4"	31"x 24 1/2" x 38"	346
	KS 500	1 1/2"	1"	4 "	4"	37"x 24 1/2" x 38"	381
	KS 600	1 1/2"	1"	4 "	4"	38"x 24 1/2" x 38"	394
	KS 750	2"	1 1/2"	4 "	6"	51"x 24 1/2" x 38"	469
	KS 850	2"	1 1/2"	4 "	6"	55"x 24 1/2" x 38"	502

	Model	Input BTU/h	Output BTU/h	Thermal Efficiency %	Combustion Efficiency %
Water Heaters	KW 199	199,000	193,030	97.0	N/A
	KW 285	285,000	272,460	95.6	N/A
	KW 399	399,000	374,237	96.3	N/A
	KW 500	500,000	483,500	96.7	N/A
Boilers	KS 399	399,000	375,000	96.5	96.5
	KS 500	500,000	475,000	95.0	95.0
	KS 600	600,000	572,000	95.3	96.0
	KS 750	750,000	724,000	96.6	96.6
	KS 850	850,000	813,000	95.7	95.7

Standard Equipment & features

- Modulation down to 20% of full fire (5:1 turndown)
- Sealed combustion chamber
- Pre-mix stainless steel burner
- Burner site glass
- Low NOx system exceeds the most stringent regulations for air quality - 10 ppm NOx
- Horizontal or vertical direct vent
- Vent and air pipe lengths of up to 100 equivalent feet (each)
- Built-in condensate trap
- Vent temperature cutoff
- Direct spark ignition system
- Stainless steel heat exchanger with welded construction
- ASME “H” stamp
- 75 psi (517 kPa) ASME rated pressure relief valve for the KS 399, KS 500, KS 600, KS 750 and KS 850
- 125 psi ASME rated pressure relief valve (for the KW 199, KW 285, KW 399 and KW500)
- Water flow switch (KW 399 only)
- Temperature & pressure gauge
- Drain valve
- Multiple pump control for boiler pump, system pump and indirect domestic water pump, each with delay
- Electronic PID modulating control stages up to eight boilers
- Large user-interface and display
- Alarm output
- Accepts (4-20mA or 0-10V) modulation control
- Manual reset high limit
- Zero clearance to combustibles
- 10 year limited warranty (for the KS 399, KS 500, KS 600,KS 750 and KS 850) or 5 year limited warranty (for the KW 199, KW 285, KW 399 and KW 500)
- Floor-standing appliance
- All connections are on top of the unit
- Easy to service
- Works with BAS
- Water Heaters Meet AB1953 standard
- 500 - 850 Boilers are CSD-1 Compliant

Boiler Specific features

- Indirect water heater priority
- Sensor for indirect domestic water heater
- Outdoor reset
- Outdoor air temperature sensor

2011-73 Keystone Lit. 020612

CERTIFIED ISO 9001 STANDARD
TriangleTube
One Triangle Lane • Blackwood NJ 08012
p 856.228.8881 f 856.228.3584 www.triangletube.com
An ACV Company

Auerbach, Eric

From: Cannone, Paul
Sent: Monday, January 21, 2013 2:51 PM
To: Auerbach, Eric
Subject: RE: Additional information items on HW Boilers for BSA

Hi Eric,

See attached cut sheet. I would use 90% efficiency for gas use. For O&M, figure about $750/boiler/year for a total of $5250/ year.

Paul Cannone, P.E., C.E.M., G.B.E. | Senior Energy Engineer | Paul.Cannone@arcadis-us.com

Malcolm Pirnie | The Water Division of ARCADIS U.S., Inc.
855 Route 146, Suite 210| Clifton Park, NY 12065
T: 518-250-7357 | M: 518-265-9775
F: 518-250-7301
www.arcadis-us.com
Professional Registration/PE-NY | PE-PA

From: Auerbach, Eric
Sent: Monday, January 21, 2013 2:30 PM
To: Cannone, Paul
Subject: Additional information items on HW Boilers for BSA

Hi Paul,

I am addressing Rob's review comments on the BSA report. There were some items concerning the proposed HW boilers for the Admin building basement.

Essentially we need to add the following things:

- Estimate for annual Boiler O&M Cost
- Rough Boiler Efficiency (so I can calculate how much gas they would use)
- Cut sheet for the proposed condensing boiler units (or a similar unit)

Eric

Eric Auerbach, P.E.

Malcolm Pirnie | The Water Division of Arcadis

Please note new address and office numbers
2800 W Higgins Rd, Suite 1000 | Hoffman Estates, IL 60169
eric.auerbach@arcadis-us.com
Hoffman Estates Office: (847) 805-1050
Downtown Office: (312) 575-3719
Cell: (716) 228-7538

BSA Incinerator Heat Recovery Steam Turbine Conceptual Estimate - Option 2

	Units	Unit Cost	Equipment Cost	Installation Cost	Total Cost
New WHRB	2	$1,600,000	$3,200,000	$1,800,000	$5,000,000
In-Kind WHRB Replacement Credit	2	$1,250,000	$2,500,000	$1,600,000	($4,100,000)
Incremental WHRB Cost					$900,000
New Boiler Feedwater Pumps	3	$28,000	$84,000	$42,000	$126,000
Turbine and Condenser	1	$2,250,000	$2,250,000	$325,000	$2,575,000
Boiler Water Treatment	1	$79,000	$79,000	$25,000	$104,000
New Burners in AB Chambers					$162,000
Steam Piping from Boiler to Turbine					$180,000
Electrical Modifications					$109,000
Connection of Extraction Steam					$159,000
FE Water System Modifications					$50,000
Net Subtotal					$4,365,000
Miscellaneous Additions	15%				$654,750
General Conditions	12%				$523,800
Contractor Overhead and Profit	15%				$654,750
Engineering	25%				$1,091,250
NYSERDA Grants					$0
Net Total Capital Cost					**$7,290,000**

Bid Price (no credits)
$12,020,000

Electric		
$0.085	per kWh	
NG		
$5	per mmBtu	

NG Current		
To AB Burners	0 mmBtu/day	0.0 mmBtu/hr
To INC	188 mmBtu/day	6.5 mmBtu/hr
To Boilers	321 mmBtu/day	13.4 mmBtu/hr
Total	509 mmBtu/day	19.9 mmBtu/hr

NG Baseline		
To AB Burners	0 mmBtu/day	0.00 mmBtu/hr
To INC	233 mmBtu/day	9.70 mmBtu/hr
To Boilers	321 mmBtu/day	13.40 mmBtu/hr
Total	554 mmBtu/day	23.10 mmBtu/hr

NG Scenario		
To AB Burners	247 mmBtu/day	10.3 mmBtu/hr
To INC	468 mmBtu/day	19.5 mmBtu/hr
To Boilers	0 mmBtu/day	0.0 mmBtu/hr
Total	715 mmBtu/day	29.8 mmBtu/hr

Electric Output	1.74	MW		
Electric Output	15,242,400	kWh/yr		
Feedwater Pump Parasitic	228,724	kWh/yr	35	hp
RO System Parasitic	32,675	kWh/yr	5	hp
FE Water Line Parasitic	424,772	kWh/yr	65	hp
Net Output	14,556,229	kWh/yr		
Electric Savings	***$1,237,000***	***per year***		
Turbine Maintenance	($50,000)	per year		
Boiler Water Treatment	($6,000)	per year		
Net Annual Savings	**$888,000**	**per year**		
Simple Payback Period	**8.2**	**years**		

Total Savings (no parasitic)
$1,296,000

Natural Gas Use	29.8	mmBtu/hr
Baseline Natural Gas Use	23.1	mmBtu/hr
Net Change in Annual Natural Ga	58,692	mmBtu/year
Net Change in Natural Gas Cost	($293,000)	per year

BSA Incinerator Heat Recovery Steam Turbine Conceptual Estimate - Option 3

	Units		Unit Cost	Equipment Cost	Installation Cost	Total Cost
New WHRB	2		$1,600,000	$3,200,000	$1,800,000	$5,000,000
In-Kind WHRB Replacement Credit	2		$1,250,000	$2,500,000	$1,600,000	($4,100,000)
Incremental WHRB Cost						$900,000
New Boiler Feedwater Pumps	3		$28,000	$84,000	$42,000	$126,000
Turbine and Condenser	1		$2,250,000	$2,250,000	$325,000	$2,575,000
Boiler Water Treatment	1		$79,000	$79,000	$25,000	$104,000
New Burners in AB Chambers						$162,000
Steam Piping from Boiler to Turbine						$180,000
Electrical Modifications						$109,000
Connection of Extraction Steam						$159,000
New Admin Building HW Boilers						$340,000
FE Water System Modifications						$50,000
Net Subtotal						$4,705,000
Miscellaneous Additions		15%				$705,750
General Conditions		12%				$564,600
Contractor Overhead and Profit		15%				$705,750
Engineering		25%				$1,176,250
NYSERDA Grants						$0
Net Total Capital Cost						**$7,857,000**

Bid Price (no credits)
$12,503,000

Electric		
$0.085	per kWh	
NG		
$5	per mmBtu	

NG Current		
To AB Burners	0 mmBtu/day	0.0 mmBtu/hr
To INC	188 mmBtu/day	6.5 mmBtu/hr
To Boilers	321 mmBtu/day	13.4 mmBtu/hr
Total	509 mmBtu/day	19.9 mmBtu/hr

NG Baseline		
To AB Burners	0 mmBtu/day	0.00 mmBtu/hr
To INC	232 mmBtu/day	9.65 mmBtu/hr
To Boilers	321 mmBtu/day	13.35 mmBtu/hr
Total	553 mmBtu/day	23.00 mmBtu/hr

NG Scenario		
To AB Burners	247 mmBtu/day	10.3 mmBtu/hr
To INC	468 mmBtu/day	19.5 mmBtu/hr
To Boilers	24 mmBtu/day	1.0 mmBtu/hr
Total	739 mmBtu/day	30.8 mmBtu/hr

Electric Output	1.84 MW			
Electric Output	16,118,400 kWh/yr			
Feedwater Pump Parasitic	228,724 kWh/yr	35 hp		
RO System Parasitic	32,675 kWh/yr	5 hp		
FE Water Line Parasitic	424,772 kWh/yr	65 hp		
Net Output	15,432,229 kWh/yr	*Total Savings (no parasitic)*		
Electric Savings	***$1,312,000 per year***	*$1,370,000*		
		Natural Gas Use	30.8	mmBtu/hr
Turbine Maintenance	($50,000) per year	Baseline Natural Gas Use	23.0	mmBtu/hr
Boiler Water Treatment	($6,000) per year	Net Change in Annual Natural Ga	68,328	mmBtu/year
Admin HW Boiler Maintenance	($6,000) per year	Net Change in Natural Gas Cost	($342,000)	per year
Net Annual Savings	**$908,000 per year**			
Simple Payback Period	**8.7 years**			

Low Pressure Steam Piping - Turbine Extraction Piping System to Main LPS Steam Header
11/12/2012, Revised 1/3/13

Division	Description	Quantity	Unit	Material Unit Cost	Material Total	Labor Unit Cost	Labor Total	Total Cost
1	**GENERAL REQUIREMENTS**							
2	**SITE WORK**							
3	**CONCRETE**							
5	**METALS**							
11	**EQUIPMENT**							
13	**SPECIAL CONSTRUCTION**							
15	**MECHANICAL**							
	10" Sch 80 Carbon Steel Piping Distribution	400	LF	$ 80	$ 32,000	$ 100	$ 40,000	$ 72,000
	Stm Auto Control Valves & Controls	1	LS	$ 50,000	$ 50,000	$ 10,000	$ 10,000	$ 60,000
	Pipe Hangers and Supports	1	LS	$ 10,000	$ 10,000	$ 15,000	$ 15,000	$ 25,000
	LinkSeal for wall penetration	3	EA	$ 400	$ 1,200	$ 100	$ 300	$ 1,500
16	**ELECTRICAL**							
		Subtotal Project:			$ 93,200		$ 65,300	$ 159,000

Appendix G

Condenser Water Calculations

Current FE Water Usage Estimate

FE Header Head Loss Calculations

Additional FE Pumping Calculations

FE System Modifications Cost Estimate

Condenser Water Calculations

Equation

Energy in Condensing Steam = Temperature Change in Cooling Water Flow
Steam Mass Flow * hfg Steam = Water Mass flow * Cp * delta T

Energy in Condensing Steam

hfg Steam 944 Btu/lb @ 3" HgA

	Winter	Summer	Max	
Total Steam to Turbine	30,000	30,000	30,000	lbs/hr
Extraction Steam	16,300	7,500	3,200	lbs/hr
Exhaust Steam	13,700	22,500	26,800	lbs/hr
Exhaust Steam Energy	12.9	21.2	25.3	mmBtu/hr

Cooling Water Flow

Steam Condensing Temp 110 ^oF @ 3" HgA
Condenser TTD 7 ^oF (TTD = terminal temperature difference)
Condenser Hot Side Temp 103 ^oF
Cp 1 Btu/^oF-lb (specific heat of water)
Water density 62.22 lbs/cf (taken at 80oF)

	Winter	Summer	Max	
FE Water Temp	60	80	80	^oF
Delta T	43	23	23	^oF
Mass Flow FE Water	300,763	923,478	1,099,965	lbs/hr
Volume Flow FE Water*	603	1850	2204	gpm

** Volume = Mass Flow [lb/hr] / density [lb/cf] * 7.48 [gal/cf] / 60 [min/hr]*

MALCOLM PIRNIE

BUFFALO SEWER AUTHORITY
FE WATER SYSTEM EVALUATION
SUMMARY OF EXISTING FE WATER APPLICATIONS
Jan. 2013

revised value

Headers	Applications	No. of Units	Usage Points	Flow Required (gpm)	Pressure Required (psig)	Flow & Pressure Requirements Data Source	No. of Units In Operation Min.	Avg.	Max.	Min. Flow (gpm)	Avg. Flow (gpm)	Max. Flow (gpm)
FE Header	Traveling Screens	4	Spray Nozzle	176 - 196	80 - 100	O&M Manual, Page V-19	1	2	2	176	350	390
	New Venturi-Pak Scrubber	1	Venturi inlet sprays	108	280	Furnance control emissions updgrade study	1	1	1	108	108	108
		1	Venturi throat sprays	30	5		1	1	1	30	30	30
		1	condenser trays	550			1	1	1	550	550	550
	Gas Compressors	2	Heat Exchange	10	-		1	1	1	10	10	10
	Primary Sludge Pumps	4	Pump Seals	5	-		4	4	4	20	20	20
	Raw WW Pumps	5	Pump Seals	10	12	Manufacturer's Letter	1	2	5	10	20	50
	Scrubber Water Discharge Tank	1	Makeup Water	100			0	1	1	0	0	100
	Intermittent Washdown		Digester Piping & Aeration Tanks	100 100	-		0	0	4	0	0	200
	Grit Removal System	8	Washdown	100	50	Manufacturer's Specification	0	2	8	0	200	800
									Total FE Header	**904**	**1,288**	**2,258**
Chiller Header Upstream	Blower Oil Coolers	4	Oil Cooling	50		O&M Manual, Page XII-2	0	0	2	0	0	100
	Chillers	3	Condenser Water	1,170	7.0	O&M Manual, Page XVII-35 Manufacturer's Specification	0	1	1	0	1,170	1,170
Chiller Header Downstream	New Venturi-Pak Scrubber	1	Quencher Weir/Lances	50	40	Furnance control emissions updgrade study	1	1	1	50	50	350
	Auxiliary Boiler Scrubbers	3		30	55	O&M Manual, Page XVI-5	0	0	2	0	0	60
	Centrifuge	3	Cleaning	240	50	Manufacturer's Specification	0	1	1	0	240	240
									Total Chiller Header	**50**	**1,170**	**1,270**
									Total FE Water System	**954**	**2,458**	**3,528**

Adapted from BSA WWTP Final Effluent Water System Evaluation - Cybernet Model (September 2001) - Table 6

Assumed only 1 incinerator in operation

Incinerator scrubber water demands from Furnace Emission Control Upgrade Needs Assessment and Design Study (September 2006) - Table 5.1

Asssumed quencher water demand is reduced from 350 to 50 gpm due to installation of WHRBs that cool exhaust to 350°F

SYSTEM HEAD CURVE DETERMINATION

BUFFALO SEWER AUTHORITY
Incinerator Energy Utilization Study
FE CAPACITY AND HEAD LOSS

MP/AUS Project No. 2255204

The following formulas and assumptions were used in the calculations contained in this spreadsheet:

1. Pump operation scenarios: Design flow is 2940 for each existing FE pump, max flow through the system is 5880 gpm (2 pumps)
   Assume from Furnace Control Emissions Upgrade Study (revised from FE Study 1777-067) that 1 incinerator runs;
   average flow through the FE header is 2458 gpm, max flow is 3528 gpm; and discharge pressure is 50 psi
   Condenser water flow requires avg flow of 1275gpm, with flows of 700 gpm in winter, 1850 gpm in summer, and a max 2000 gpm
2. During multiple pump operations, for head loss calculations within the suction and discharge headers assume equal head from all pumps.
3. Piping head loss calculations use Hazen-Williams Formula
   h=[(4.73*Q^1.85)*L]/(C^1.85*D^4.87) where: h = Head Loss
   Q = Flow (cfs)
   C = Roughness Coefficient
   D = Pipe Diameter (ft.)
   L = Pipe Length (ft.)
4. Fitting, entrance, and exit head loss calculations:
   h=KV^2/2g where: h = Head Loss
   K = Resistance Coefficient
   V = Flow Velocity (Q/A)
   g = Gravity (32.2 ft/sec^2)

K-values were obtained from "Cameron Hydraulic Data Handbook, 18th Edition" (1994) by Ingersoll-Dresser Pumps

CONDENSER FLOW REQUIREMENTS:

Winter Flow	700	gpm
Average Flow	1275	gpm
Summer Flow	1850	gpm
Maximum Flow	2200	gpm

FE FLOW REQUIREMENTS: Modified 1/13/2013 from FE Study to reflect flow requirements in Furnace Control Emissions Upgrade Study

FE Header Min flow	904	gpm
FE Header Avg flow	1288	gpm
FE Header Max flow	2258	gpm
Total FE System Min	954	gpm
Total FE System Avg	2458	gpm
Total FE System Max	3528	gpm
Discharge Pressure	50	psi

PROPOSED FE HEADER FLOW REQUIREMENTS

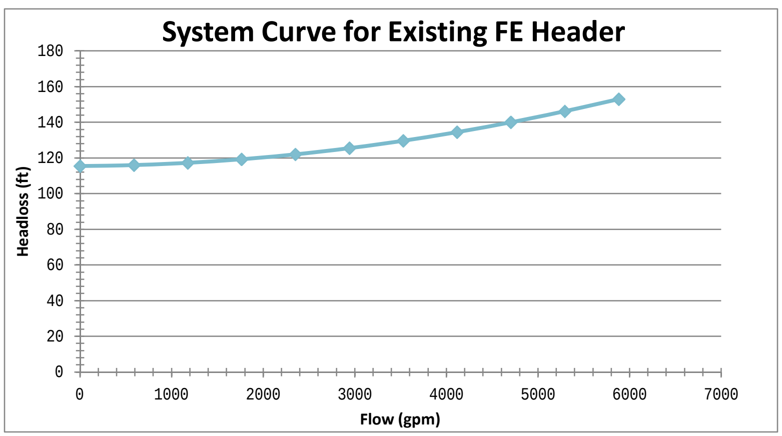
Min (Winter) Flow	1604	gpm
Average Flow	2563	gpm
Max (Summer) Flow	4108	gpm
Absolute Max Flow	4458	gpm

Existing FE Header Conditions

Fitting	No.	Inlet Dia.	Outlet Dia.	Length ft	C	K	Head Loss, ft. @ Flow (gpm) 0	588	1176	1764	2352	2940	3528	4116	4704	5292	5880
Pump Suction and Discharge to FE Header																	
Increasing Elbow: 14x10	2	10	14	-	-	0.36	0.00	0.02	0.07	0.15	0.27	0.42	0.60	0.82	1.07	1.36	1.68
14" Check Valve	2		14	-	-	1.20	0.00	0.06	0.22	0.50	0.90	1.40	2.02	2.74	3.58	4.53	5.60
14" Gate Valve	2		14	-	-	0.10	0.00	0.00	0.02	0.04	0.07	0.12	0.17	0.23	0.30	0.38	0.47
Piping Friction	2	-	18	10	120	-	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.06	0.07	0.09	0.11
Tee: 14x18	2	14	18	-	-	0.72	0.00	0.01	0.05	0.11	0.20	0.31	0.44	0.60	0.79	1.00	1.23
Piping Friction	1	-	18	2115	120	-	0.00	0.33	1.18	2.49	4.24	6.40	8.97	11.93	15.27	18.99	23.08
Tee: 18x18	1		18	-	-	0.24	0.00	0.00	0.01	0.02	0.03	0.05	0.07	0.10	0.13	0.17	0.20
Elbow: 90°	10		18	-	-	0.36	0.00	0.03	0.12	0.28	0.49	0.77	1.11	1.51	1.97	2.49	3.07
Elbow: 45°	9		18	-	-	0.19	0.00	0.01	0.06	0.13	0.23	0.36	0.53	0.72	0.93	1.18	1.46
Tee for cooling water	1		18	-	-	0.72	0.00	0.01	0.02	0.06	0.10	0.15	0.22	0.30	0.39	0.50	0.61
Total System Headloss:							0.00	0.47	1.75	3.79	6.55	10.01	14.17	19.00	24.51	30.68	37.51
Headloss from Discharge Pressure							115.50	115.50	115.50	115.50	115.50	115.50	115.50	115.50	115.50	115.50	115.50
Total for System Curve							**115.50**	**115.97**	**117.25**	**119.29**	**122.05**	**125.51**	**129.67**	**134.50**	**140.01**	**146.18**	**153.01**

Turbine/Condenser Water Flow Added to **Existing FE Header** (shows specific winter/summer/max flows)

Fitting	No.	Inlet Dia.	Outlet Dia.	Length ft	C	K	Head Loss, ft. @ Flow (gpm)					2258	2940	2858	4108	4458	5880
Pump Suction and Discharge to FE Header												Current	1 Pump Capacity	Winter	Summer	Max	2 Pump Capacity
Increasing Elbow: 14x10	2	10	14	-	-	0.36						**0.25**	0.42	**0.40**	**0.82**	**0.97**	1.68
14" Check Valve	2		14	-	-	1.20						**0.83**	1.40	**1.32**	**2.73**	**3.22**	5.60
14" Gate Valve	2		14	-	-	0.10						**0.07**	0.12	**0.11**	**0.23**	**0.27**	0.47
Piping Friction	2	-	18	10	120	-						**0.02**	0.03	**0.03**	**0.06**	**0.07**	0.11
Tee: 14x18	2	14	18	-	-	0.72						**0.18**	0.31	**0.29**	**0.60**	**0.71**	1.23
Piping Friction	1	-	18	2115	120	-						**3.93**	6.40	**6.07**	**11.89**	**13.83**	23.08
Tee: 18x18	1		18	-	-	0.24						**0.03**	0.05	**0.05**	**0.10**	**0.12**	0.20
Elbow: 90°	10		18	-	-	0.36						**0.45**	0.77	**0.73**	**1.50**	**1.77**	3.07
Elbow: 45°	9		18	-	-	0.19						**0.22**	0.36	**0.34**	**0.71**	**0.84**	1.46
Tee for cooling water	1		18	-	-	0.72						**0.09**	0.15	**0.15**	**0.30**	**0.35**	0.61
Total System Headloss:												**6.06**	10.01	**9.49**	**18.93**	**22.13**	37.51
Headloss from Discharge Pressure												115.50	115.50	115.50	115.50	115.50	115.50
Total for System Curve												**121.56**	**125.51**	**124.99**	**134.43**	**137.63**	**153.01**



Head Loss in FE Header

Condition	Total Head (ft)	Change in Head (ft)
Current	121.56	0.00
Winter	124.99	3.43
Summer	134.43	12.87
Max	137.63	16.07

Pump Energy Use (For pumping additional flow through the FE Header)

Pump HP =	(head in feet)*(flow rate in gpm)* (S.G.) / 3956		Hydraulic Horsepower Equation
BHP=	whp/pump efficiency		from Civil Engineering Reference Manual, Table 4.2
Pump efficiency =	75%		
S.G. water =	1		

Current FE Header Pumping Power

head	121.56	ft
flow rate	2258	gpm
Pump BHP	92.5	HP

Winter FE Header Pumping Power

head	124.99	ft
flow rate	2858	gpm
Pump BHP	120.4	HP

Summer FE Header Pumping Power

head	134.43	ft
flow rate	4108	gpm
Pump BHP	186.1	HP

Average New BHP

Average	153.3	HP	(average of winter and summer)
Additional HP	60.8	HP	(average - current)

BUFFALO SEWER AUTHORITY
CONCEPTUAL ESTIMATE OF PROBABLE PROJECT COST

FE Water Piping Modifications
January 17, 2013

Division	Description	Quantity	Unit	Material		Labor		Total
				Unit Cost	Total	Unit Cost	Total	Cost
1	**GENERAL REQUIREMENTS**							
2	**SITE WORK**							
3	**CONCRETE**							
5	**METALS**							
11	**EQUIPMENT**							
13	**SPECIAL CONSTRUCTION**							
15	**MECHANICAL**							
	Condenser Feed /Return Line							
	18"x10" Reducer Tee	1	EA	$ 800	$ 800	$ 500	$ 500	$ 1,300
	10" Gate Valve (isolation valve)	1	EA	$ 5,000	$ 5,000	$ 1,200	$ 1,200	$ 6,200
	10" DIP	40	LF	$ 30	$ 1,200	$ 75	$ 3,000	$ 4,200
	10" Plunger Valve	1	EA	$ 14,000	$ 14,000	$ 3,500	$ 3,500	$ 17,500
	10"x4" Reducer (assume 4" inlet/outlet from condenser)	1	EA	$ 100	$ 100	$ 100	$ 100	$ 200
	4" Check Valve (assume check/gate assembly on inlet/outlet)	2	EA	$ 750	$ 1,500	$ 500	$ 1,000	$ 2,500
	4" Gate Valve	2	EA	$ 750	$ 1,000	$ 500	$ 1,000	$ 2,000
	4"x8" Increaser (assume 8" line from condenser to CHR)	1	EA	$ 61	$ 61	$ 100	$ 100	$ 200
	8"x14" Tee into CHR Line (verify diameter)	1	EA	$ 410	$ 410	$ 400	$ 400	$ 900
	Pipe Restraints (Megalugs)	1	LS	$ 2,376	$ 2,376	$ 1,188	$ 1,188	$ 3,600
	Pipe Hangers and Supports	1	LS	$ 500	$ 500	$ 500	$ 500	$ 1,000
	Pipe Insulation	1	LS	$ 300	$ 300	$ 300	$ 300	$ 600
	8"x8" Tee with blind flange (for future use)	1	EA	$ 400	$ 400	$ 400	$ 400	$ 800
16	**ELECTRICAL**							
	Plunger Valve Electrical Installation and DCS/SCADA Integration	1	LS	$ 3,000	$ 3,000	$ 6,000	$ 6,000	$ 9,000
		Subtotal Project:			**$ 30,700**		**$ 19,200**	**$ 50,000**

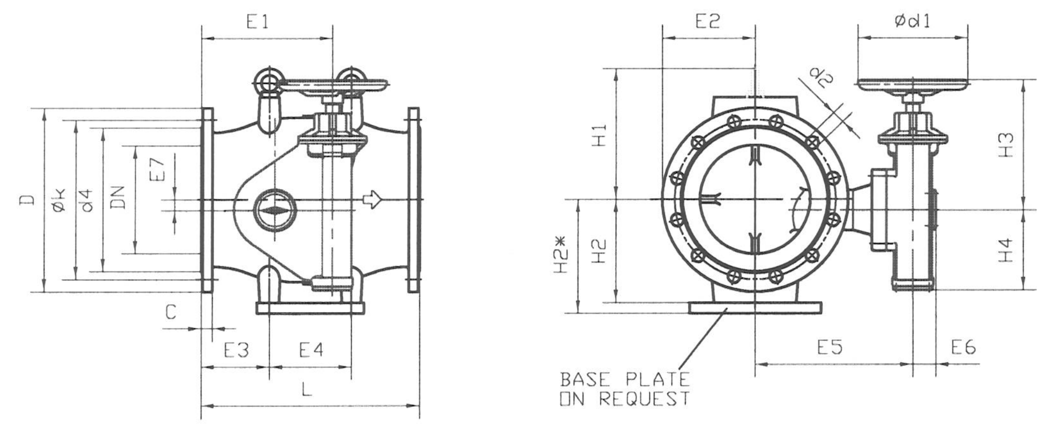
REV.—DATE	BY	APP	REV.—DATE	BY	APP

PRATT HENRY PRATT COMPANY AURORA, ILL.

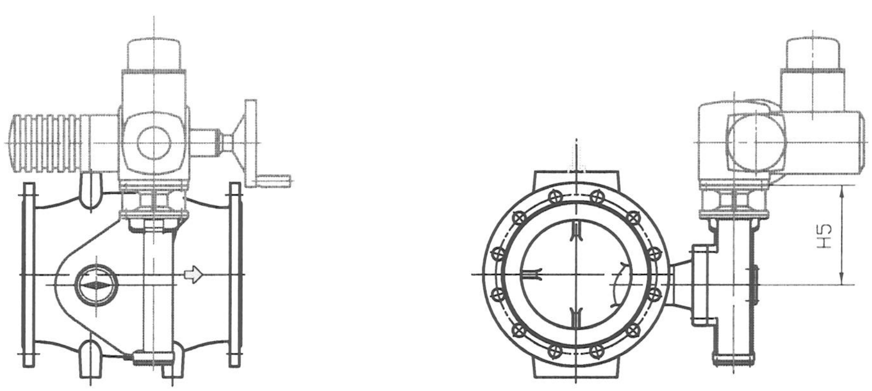
PLUNGER VALVE RKVP DN100-300
WITH SLIDER-CRANK MECHANISM
ACTUATOR ON RIGHT SIDE, SEEN IN FLOW DIRECTION

SCALE NONE DATE 01-12-12
DRAWN BY TQF CHECKED BY
APPROVED | GA=BORDER
DRWG. NO. 3E162210 REV 0 A/C

DESIGN WITH HANDWHEEL



DESIGN WITH ELECTRIC ACTUATOR



* = ON DESIGN WITH BASE PLATE

DN	PN10						PN16						PN25						PN40																			
	D	k ø	d2 ø	d2 Z	d4	C	D	k ø	d2 ø	d2 Z	d4	C	D	k ø	d2 ø	d2 Z	d4	C	D	k ø	d2 ø	d2 Z	d4	C	E1	E2	E3	E4	E5	E6	E7	H1	H2	H2*	H3	H4	H5	L	d1
100	220	180	M16	8	156	20.5	220	180	M16	8	156	20.5	235	190	M20	8	156	20.5	235	190	M20	8	156	20.5	215	99	113	100	214	41	10	187	142	158	222	120	164	325	200
125	250	210	19	8	184	23.5	250	210	19	8	184	23.5	270	220	28	8	184	23.5	270	220	28	8	184	23.5	215	99	113	100	214	41	10	187	142	158	222	120	164	325	200
150	285	240	23	8	211	26	285	240	23	8	211	26	300	250	28	8	211	26	300	250	28	8	211	26	220	116	110	130	231	41	20	203	158	173	222	120	164	350	200
200	340	295	23	8	266	20	340	295	23	12	266	20	360	310	28	12	274	22							240	152	125	150	288	46	20	248	195	210	244	149	185	400	200
250	400	350	23	12	319	22	400	355	28	12	319	22	425	370	31	12	330	24.5							250	188	135	180	365	61	20	296	234	248	314	158	253	450	250
300	455	400	23	12	370	24.5	455	410	28	12	370	24.5	485	430	31	16	389	27.5							250	224	150	200	402	61	20	328	266	280	314	158	253	500	250

PRATT
Henry Pratt Company

Henry Pratt
Series 300 Plunger Valves

**Engineering Creative Solutions
for Fluid Systems Since 1901**

A Tradition of Excellence

With the development of the first rubber seated butterfly valve more than 70 years ago, the Henry Pratt Company became a trusted name in the flow control industry, setting the standard for product quality and customer service. Today Pratt provides the following range of superior products to the water, wastewater and power generation industries.

Butterfly Valves: from 3" to 162"

Rectangular Valves: 1' x 1' to 14' x 16'

Ball Valves —
Rubber Seated: from 4" to 60"
Metal Seated: from 6" to 48"

Plug Valves: from 1/2" to 36", 3 ways

Hydraulic Control Systems

Valve Controls

Energy Dissipating Valves and Fixed Energy Dissipaters

Cone Valves

Check Valves

Plunger Valves

A Commitment to Meeting The Customers' Needs

Henry Pratt valves represent a long-term commitment to both the customer and to a tradition of product excellence. This commitment is evident in the number of innovations we have brought to the industries we serve. In fact, the Henry Pratt Company was the first to introduce many of the flow control products in use today, including the first rubber seated butterfly valve, one of the first nuclear N-Stamp valves, and the bonded seat butterfly valve.

Innovative Products For Unique Applications

Though many of the standard valves we produce are used in water filtration and distribution applications, Pratt has built a reputation on the ability to develop specialized products that help customers to meet their individual operational challenges.

Creative Engineering for Fluid Systems

Pratt's ability to provide practical solutions to complex issues is demonstrated by the following case histories.

Earthquake Proof Valves

Pratt designed and manufactured hydraulically actuated valves for a water storage application so that the valves would automatically operate in the event of earthquakes. This led to the development of a valve that will withstand acceleration forces of up to 6g's.

Custom Actuation/Isolation Valves

Pratt designed and manufactured valves that would isolate a working chamber in the event of a nuclear emergency during the decommissioning of armed nuclear warheads. The valves were able to close in a millisecond using specially designed Pratt electro-pneumatic actuators.

Valves Designed for Harsh Environments

Pratt designed and manufactured a 144" diameter butterfly valve for the emergency cooling system at a jet engine test facility. The valve was designed to supply water to help dissipate the tremendous heat generated by the engines during testing.

PRATT
Henry Pratt Company

Through experience, commitment and creative engineering, Pratt is uniquely suited to provide superior products for our customers' special needs. For more information, contact our corporate headquarters in Aurora, Illinois.

Henry Pratt Company

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Table of Contents

Pratt Series 300 Plunger Valves

Introduction to Henry Pratt Series 300 Plunger Valves: Plunger Valves – For Safe, Reliable and Exact Control

Plunger Valves are the correct valve to use whenever pressure heads or flow rates need to be safely and reliably reduced and controlled. They are used for two main tasks:

- By restricting the valve opening a change in flow conditions occurs where both flow velocity through the valve and pressure across the valve increases, resulting in conditions that create cavitation
- To be able to control the pressure and flow precisely and finely, the valve's flow control characteristics must be as linear as possible over the whole opening range.

Thanks to their well thought out design, Pratt Series 300 Plunger Valves fulfill these requirements to the greatest possible degree and are therefore the ideal valve for numerous control tasks. Butterfly and gate valves, due to their design as isolation or, open/closed valves, are not suitable for continuous use as a variable flow control valve.

New Challenges:

The production and operation of control valves requires engineering expertise and strict production controls to ensure diverse international requirements to be met:

- International standards, approvals and test regulations set the highest quality requirements.
- The increased cost of energy requires optimum flow performance with minimum pressure losses to ensure economical operation.
- Valves designed for long life and low maintenance costs ensure that the personnel costs necessary for operation are minimised. All the costs incurred over the operational life of the valve (life cycle costs) must play a decisive role in the choice of product.

... And the Solutions from Pratt

The wide range of Pratt Plunger Valves, manufactured for Henry Pratt by ERHARD, founded in 1871, fills these requirements in a particular way. Innovative and customer-focused product development, state of the art engineering, production and assembly technology and continuous quality assurance throughout the production, assembly and test process take place at ERHARD, concentrated in one location – for top quality "Made in Germany" before, during and after installation.

With the implementation of using computational fluid dynamics (CFD), our team of engineers has created the most efficient plunger valve to date. All valve components have undergone CFD design review to ensure optimal flow performance. This results in precise guiding of the medium, from the inlet up to and far beyond the controlled outlet. This enables controlled energy conversion (cavitation) in the center of the pipe. A range of flow guides at the valve outlet is available for a variety of installation conditions.

Wide Range of Uses

Pratt Series 300 Plunger Valves are especially suitable for drinking water, raw water and air. Typical applications include:

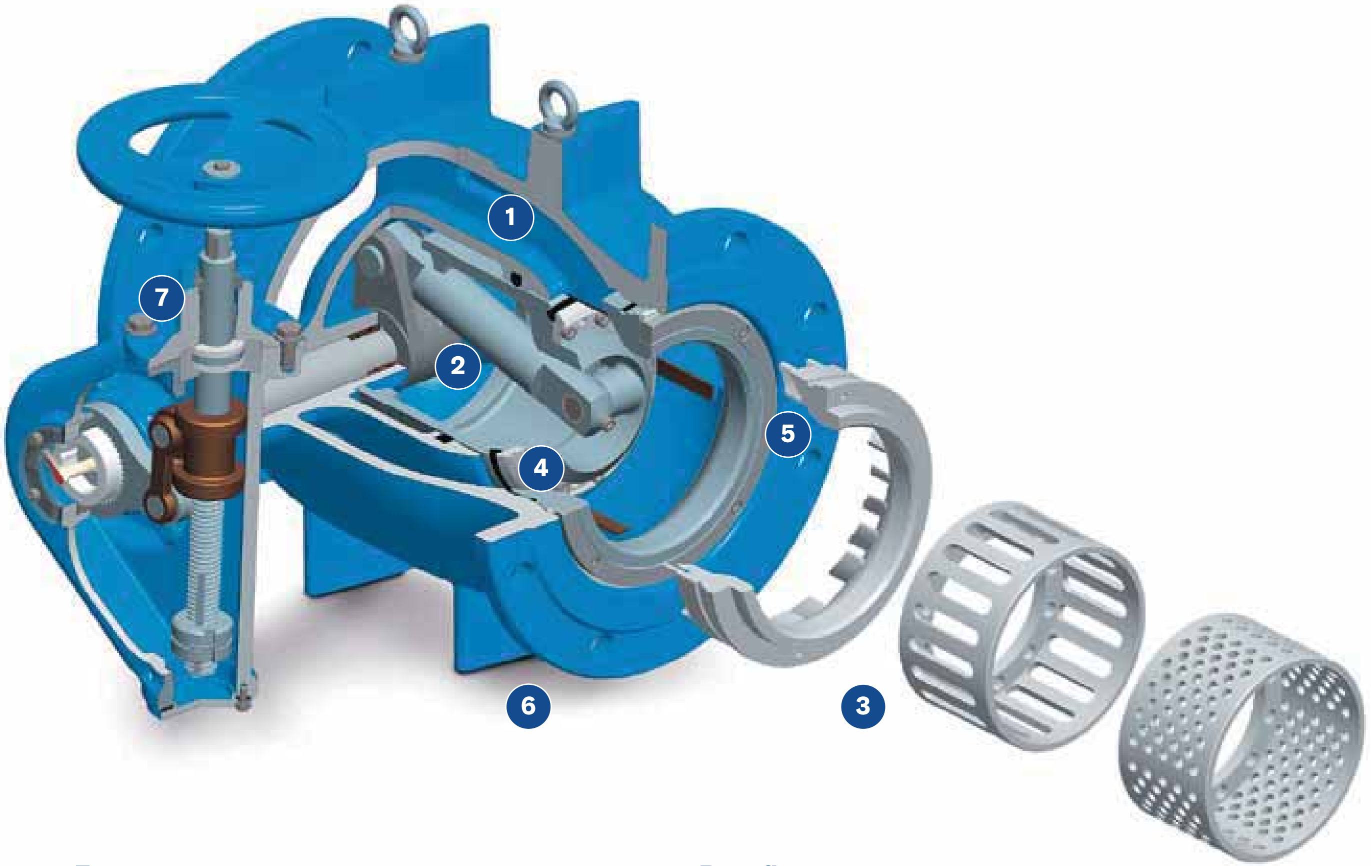
- Pump start-up and control valve
- Reservoir inlet
- Control device in the bottom outlet valve of dams (with or without venting)
- Control device in the inlet and bypass of turbines
- Safety device in the bypass outlet of turbines for quick opening
- Surge anticipating device in pumping or pressurized systems.

Cavitation Risk Factor

Depending on the pressure and velocity conditions, eddy, turbulence and cavitation zones can occur in pipes and fittings which can cause vibrations, oscillations and, under certain operating conditions, can even cause material damage.

Cavitation occurs if vapor bubbles form and implode in the pipe. According to Bernoulli's law, the total energy of a flowing medium is always the same; and therefore the sum of the potential, pressure, velocity (kinetic) and lost (dissipated) energy is constant. If the flow velocity increases at a constriction, e.g. a Plunger Valve, the pressure energy simultaneously falls. If the pressure falls below the medium's saturation vapor pressure, vapour bubbles form which further deform after the constriction. Downstream of the constriction the velocity reduces again and the pressure increases, so that the bubbles finally implode. The microjet produced as a result can hit components with high velocities and remove component material at the point of impact. Therefore, a decisive factor for the use of the Plunger Valve is for the energy conversion (cavitation) to take place in the middle of the flow stream, and away from the wall of the associated downstream pipe, which is assured by the design of the flow profile and special attachments.

Features and Benefits at a Glance

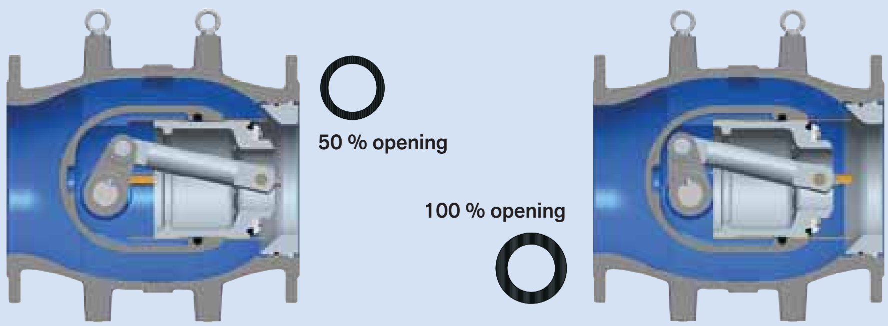


	Features	Benefits
1.	Dual inboard seal on input shaft	Improved corrosion protection on input shaft and shaft bore. Also provides a "dry shaft" condition eliminating water stagnation in body shaft bore.
	Body design evaluated for efficiency with Computational Fluid Dynamic (CFD) software	Computer simulation and lab testing validates the Pratt plunger design to be the most flow efficient valve available today.
2.	Valve actuator mechanism utilizes a dual link and lever approach to provide a highly characterized or non-linear closure.	Effective control range is 96% of entire stroke; also provides precise surge resistant slow closure at end of close.
3.	Field Replaceable control inserts to accommodate every application.	Effectively provides pressure reduction while controlling the damaging effects of cavitation.
4.	Main O-ring seal located on plunger.	O-ring stays out of cavitation zone thus ensuring many relable years of operation.
5.	Four hard faced guides to support cylinder.	Allows for uniform, diametrically opposite, loading and support. Four guided system has been proven to minimize wear, compared to a three guide system, in the presence of vibration.
	Valve body coated with fusion bonded epoxy.	Fusion bonded epoxy provides holiday free corrosion protection.
6.	Scalable valve design for many different pressure classes and valve sizes.	Pratt plunger valve will accommodate numerous special and severe service applications.
7.	Flexible design accommodates many forms of valve actuation and control.	Valve can be controlled via manual operation, cylinder control, where the supply media can be water oil or air, or through electric gear actuation. The plunger valve can accept many modes of inputs such as mechanical, analog, discreet, and local control.

Proven Engineering for Diverse Tasks

The principle of the Plunger Valve

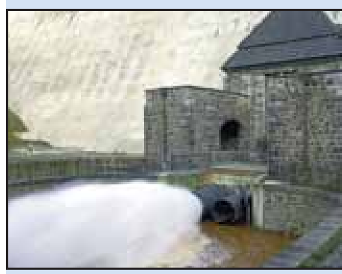
Typically the change in cross section, of any valve, is made to adjust line pressure or flow rate. Control valves such as gate valves, or other types of control valves, have an inherent asymmetrical cross section which cannot provide a linear control curve over their respective control range. The Pratt Series 300 Plunger valve features a ring shaped symmetrical cross section that enables a linear control curve over the entire control range. Initially the cross-section is steadily reduced from the inlet up to the cylinder seal ring and the flow is guided along in a geometrically optimized shape on between the valve bore and teardrop shaped internal body.



The design of the Pratt Series 300 Plunger Valves provides a ring-shaped cross-section in every piston position. The result is safe, reliable energy conversion in the middle of the flow stream, which significantly minimises any effects of cavitation.

A sliding piston is axially guided inside the teardrop shaped internal body to allow for flexible and precise changes of the flow cross-section. The piston's linear movement results from conversion of the rotary movement of the actuator shaft by the internal slider crank mechanism and ensures a well defined ring-shaped cross-section in every position.

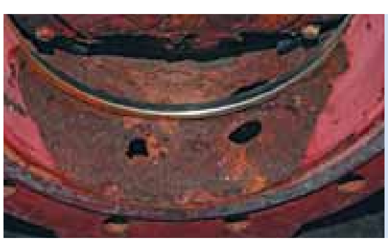
Pratt Series 300 Plunger Valves can be used for numerous important tasks including (left) the bottom outlet valve of dams as well as (right) complex control tasks.



Depending on the intended use, various control inserts are mounted on the piston, which split the flow into individual flow streams for conversion of the energy. These flow streams do not hit each other until they reach the middle of the valve or pipe, which reliably prevents cavitation damage to the valve.

Designs for every purpose

Henry Pratt Series 300 Plunger Valves are available in many standard sizes and pressure classes. Selection of a control insert for a particular application (vaned ring, slotted cylinder or perforated cylinder) will be engineered and produced specific to your flow control needs. Contact the Pratt Product Manager who will help you with your specific needs.



Improper continuous use of butterfly valves as a control valve can result in dramatic material damage, as in this valve opened by 5° after a year in seawater.

Pratt Series 300 Plunger Valves can be used in numerous control applications including

- Downstream pressure control
- Upstream pressure control
- Reservoir control
- Flow control
- Tank Filling

Attention must also be paid to venting and on the positioning of the Plunger Valve. For example, if the valve is positioned directly at the end of a pipe in a bottom outlet above the water line and is equipped with a vaned ring, the energy conversion takes place by splitting up the water jet and intensive mixing with the ambient air, so that separate venting is not necessary. If on the other hand the pipe is continued downstream of the Plunger Valve below the water line, an appropriate designed increase in nominal size and a venting pipe may be required. This action will ensure adequate air supply downstream of the seat and avoid enormous cavitation and imploding forces that could result in damage. Your Henry Pratt team will provide you with competent and comprehensive design application advice.

Depending on the nominal size and design, Pratt Series 300 Plunger Valves are available as single or multipart types.

Short body version (SBVE)

In special installation situations a shorter face to face version may be required. The SBVE version is a viable option when high pressure ratings have to be dissipated (without the focus being on maximum flow) or if confined space conditions exist. Consult Pratt to inquire on special face to face applications.

All Henry Pratt Plunger Valves up to 12" are coated with a fusion bonded epoxy coating as a standard feature. Fusion bonded epoxy coating is an optional adder for valve exteriors up to 42" and interiors up to 24". This epoxy coating, applied using powder coating methods, is one of the most frequently used corrosion protection methods. The cast parts are first shot-blasted to a new white blast. [1]. The coating is then applied with a precisely defined thickness in the electrostatic power station and is fusion bonded at 410 °F. The standard coat thickness is at least 10 Mils, coat thicknesses up to 20 Mils are possible. The standard coating that is applied to large valves (larger than 12") uses a two part liquid epoxy. The low solvent 2 part liquid coating is electrostatically applied over zinc rich primer. [2].

Other special coatings are available for particular requirements, e.g. EPC coating (epoxy polymer ceramic) with ceramic reinforcing fillers, particularly suitable for abrasive media or seawater.

Safe and Reliable Pressure Reduction and Cavitation Under Control

Pratt Series 300 Plunger Valves are fitted with a standard seat ring as basic equipment. This general purpose configuration is the suitable solution for low resistance coefficients such as air handling applications.

For other applications, special control inserts matched to the particular operating conditions are recommended. The unique designs for these inserts are further examples of the adaptability and high performance results you can expect from the Series 300 Plunger Valve. The proper insert ensures that the velocity increase that occurs when the cross-section is changed does not result in cavitation damage. The choice of the correct control insert depends on the operating conditions, the differential pressure and the resulting cavitation behaviour. We would be happy to review your application and offer the proper control solution.

Vaned ring

The vaned ring features uniformly arranged blades that split the flow into individual flow streams just before the sealing point and due to their shape sets these flow streams into a spiral movement.

The outer flow is pressed against the wall of the outlet part or the downstream pipe so that the cavitation bubbles which occur do not come anywhere near the wall, but instead are bundled together to form a "pigtail" in the middle of the pipe. There they are dissipated without causing any damage. Vaned rings are used for average pressure differences and in back-pressure situations.

Slotted cylinder

Slotted cylinders, on the other hand, are the recommended design for high pressure differences.

This attachment extends the end piston in a similar way to a pipe and is especially designed for specific operating conditions. The water jets flowing from the outside to the inside through the slots are split up at the slots and reach a high velocity. Then, in the material-free center of the cylinder, they collide with the jets emerging from the slots on the opposite side. The induced collision converts part of the kinetic energy into pressure energy.

The cavitation bubbles occurring at the slots and dragged along with the jets are dissipated by this increase in pressure in the center of the flow without causing any damage.

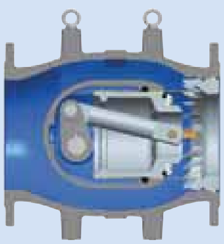
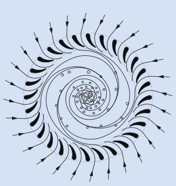
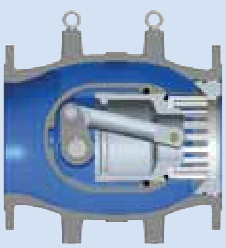
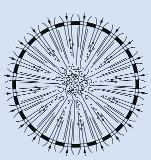
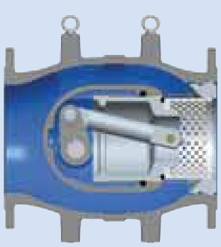
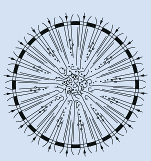
Perforated cylinder

The perforated cylinder, which functions in the same way as the slotted cylinder but has a higher K value, is also suitable for high pressure differences.

Other available control inserts

- Special slotted cylinder
- Special perforated cylinder
- Throttle ring especially for energy recovery systems
- Control attachments for pump test rig
- Control inserts for bottom outlets



Vaned ring

Slotted cylinder

Perforated cylinder

The Perfect Solution, Even for Special Requirements

Pratt Series 300 Plunger Valves are suitable for classic uses such as the bottom outlet control and safety devices in turbines and pipes as well as for numerous other specialty applications:

- Shut-off device in pipes with high operating pressure and high flow velocities
- Pump control valve
- Return flow prevention for pumps with counter weight
- Piston type check valve
- Surge anticipator valve for venting surges in the pipe system (free of auxiliary power)
- Bypass outlet surge protection in pipelines
- Pilot operated pressure-reducing valve (free of auxiliary power)
- Pipe burst protection (pressure relief)
- Turbine bypass
- Turbine control
- Filling valve for high pressures and pipe discharging in the open air or for large pipelines
- Flushing/purging valve
- Pump test rig
- Air flow rate control in aeration tanks
- Industrial applications
- Pressure control device in natural gas pipes

Henry Pratt and ERHARD are in demand worldwide as a reliable partner for projects large and small. We regularly demonstrate our expertise by achieving success in some of the most demanding and complex applications. Here are a few examples:

[1] Water power is one of the cleanest sources of energy on the earth and advanced technologies have made this resource more and more economically attractive. Our Plunger Valve with specialized control engineering was installed in the secondary turbine outlet during the rehabilitation of a river hydroelectric station. The valve operates automatically based on flow control and, if the turbines are shut down, pressure surges are internalized and therefore avoids any risk to the plant.

[2] In the storage facilities of large drinking water supply plants, geodetic energy is often available virtually free of charge. Highly reliable valves suitable for use with drinking water are required in the parts of the plant in which energy recovery is possible. An example of this type of use for Pratt valves includes a 24" Plunger Valve with weight-loaded hydraulic actuator and magnetic clutch. Up to 19,000 gallons per minute have to be safely controlled upstream of the turbine and must be stopped reliably and without surges if the turbine is shut down. For this application, a Plunger Valve proved to be the answer.

[3] In a drinking water project in the United Arab Emirates, over 13 million cubic feet of extremely precious drinking water are distributed into desert regions daily. The distribution network includes a 112-mile pipeline, in which more than 500 valves are used, including 32 Plunger Valves with a variety of different tasks. A specially adapted version for seawater desalination plants ensures continuous, fault-free operation and required meeting (and exceeding) very high customer standards.

[4] Apart from their use in the drinking water sector, Plunger Valves are also used in the wastewater sector, in this case, for aeration control in a wastewater treatment plant.

The Advantages of the New Henry Pratt Series 300 Plunger Valves

The new Pratt Series 300 Plunger Valve incorporates numerous innovative ideas for greater economic efficiency, greater operating safety, longer life and improved controllability of the valve.

Optimized flow guidance – a positive result for economic efficiency

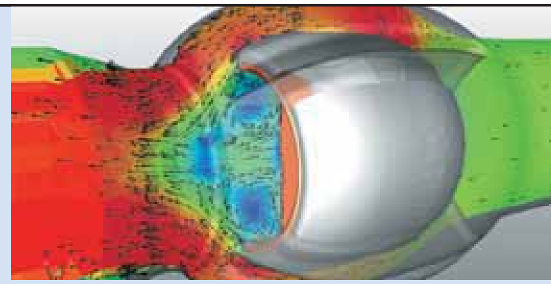
The flow channel of the Pratt Series 300 Plunger Valves was redesigned on the basis of years of field experience, computer modeling and verification through empirical testing.

Optimum design of the sealing and outlet components, flow-optimized component shapes and freely selectable control inserts for the user (e.g.: smooth seat rings, vaned ring, slotted cylinders, and perforated cylinders for the lowest K values) provide cost-effective operation as the pressure loss is lower.

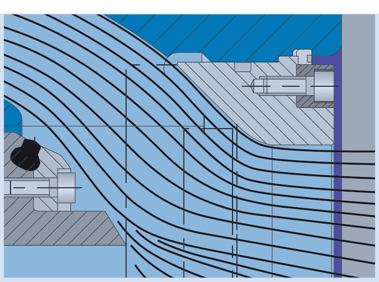
The ingenious O-ring arrangement within the Plunger Valve also reliably avoids creating stagnant water. This design feature ensures NSF 61 compliance at all times, which is especially important for all drinking water applications.

Absolutely minimum gasket wear – a positive gain for operating safety

The wide main gasket of the Pratt Series 300 Plunger Valves is located safely in the hydraulically uncritical pressure zone and therefore in the cavitation-free space of the control valve. The sealing surface is up to 5-7/8 inches wide and is completely embedded in a stainless steel chamber and, therefore, protected against corrosion on all sides. The piston seal uses a solid O-ring with a proven and tested “undercut piston” design. This combination of superior features delivers an optimum sealing system developed for minimum wear.



Extensive empirical testing of the Pratt Series 300 Plunger Valve provided sufficient data to corroborate the resultant output from FEA flow simulations. 3D modeling software optimized the efficiency and effectivity of the plunger valve to the greatest degree possible. Combine this engineering feat with a high precision production and assembly process, the performance values derived in controlled conditions are easily realized in typical field applications.



The main seal, up to 7/8 inches wide, resides on the piston periphery and recessed from direct impact of the flow media, outside the zone of cavitation and is captured in corrosion-proof stainless steel.

The additional shaft seal on the inside surface improves corrosion protection and avoids stagnant water.

Four surface-hardened guides – a positive result for longer life

By using four wide guide bars, the force of the weight of the piston acts vertically and due to the larger total contact area the force is also uniformly spread over the guide bars. Designs with fewer than 4 guide bars often cause non-uniform contact and result in far greater wear.

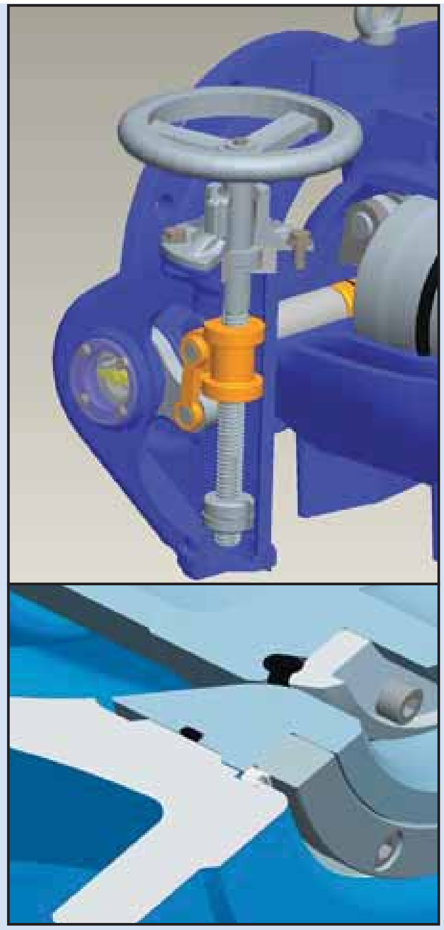
An aluminum bronze alloy was chosen because of its high hardness properties and because it is an industry-tested material that has proven its worth over decades of use in high-pressure plunger applications. The standard material thickness of about 1/8 inch has provided superior wear resistance and demonstrates good anti-friction properties for decades of operation no matter what the installation orientation might be.

Surface-hardened aluminum bronze guides also greatly increase corrosion resistance, as the homogeneous material structure does not provide any points for corrosion to attack.

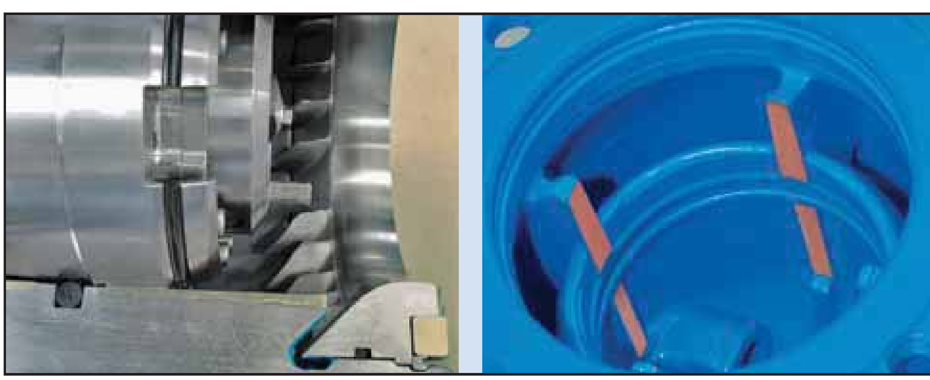
Large linear control range – a positive gain for controllability

While other current Plunger Valve designs have a “dead” stroke of up to 18%, the Pratt Series 300 Plunger Valve can be precisely controlled from 4% open to full open. This optimized control of even the smallest quantities without critical annular clearance provides an impressively large control range of up to 96%.

The improved control performance is also assisted by the standard slider crank mechanism which has an optimally adjusted characteristic torque curve and therefore supplies the suitable torque in every opening angle. A slower closing speed near the “closed” position enables extremely soft closing and eliminates the risk of pressure surges.



The combination of superior piston guides and a slider crank mechanism results in a control range of approximately 96%.



The four surface-hardened guides ensure uniform movement of the piston and contribute to long life.

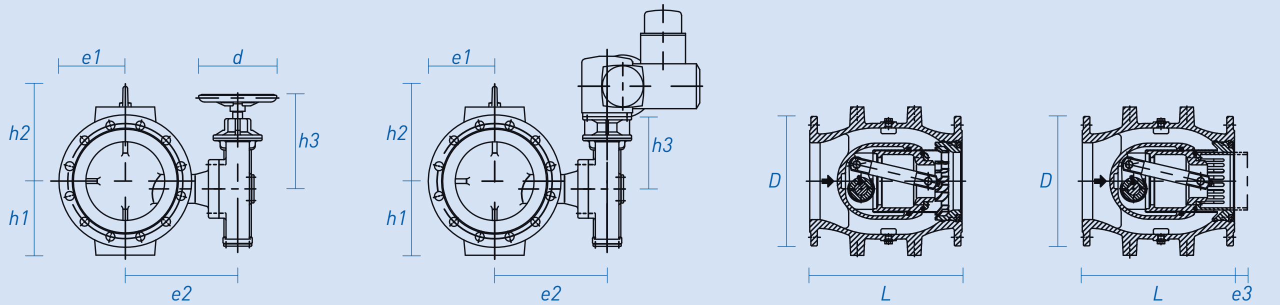
Henry Pratt Series 300 Plunger Valves – the Dimensions Table

DIA. Inches	L	D PN10 150psi	D PN16 250psi	D PN25 350psi	h1	h2	h3 manual	h3 electric	e1	e2	e3	u #Turns	G (Lb.) PN10	G (Lb.) PN16	G (Lb.) PN25
		PN FLANGE and RATED WORKING PRESSURE, PSI			Linear Dimensions Shown in Inches										
4	12.8	--	8.7	9.3	5.6	7.4	8.7	6.1	3.9	8.4	1.1	15	132	132	132
5	12.8	--	9.8	10.6	5.6	7.4	8.7	6.1	3.9	8.4	1.1	15	132	132	132
6	13.8	--	11.2	11.8	6.2	8.0	8.7	5.7	4.6	9.1	1.9	15	165	165	165
8	15.7	13.4	13.4	14.2	7.7	9.8	9.6	6.5	6.0	11.3	2.5	20	264	264	264
10	17.7	15.7	15.7	16.7	9.2	11.7	12.4	9.2	7.4	14.4	3.1	25	418	418	418
12	19.7	17.9	17.9	19.1	10.5	12.7	12.4	9.2	8.8	15.8	4.0	25	572	572	572
14	27.6	19.9	20.5	21.9	11.0	13.5	14.2	11.5	11.0	16.5	2.6	43	935	990	990
16	31.5	22.2	22.8	24.4	12.2	14.6	14.4	11.7	12.2	18.1	2.6	42	1254	1309	1309
18	35.4	24.2	25.2	26.4	13.4	16.2	15.9	13.0	13.2	20.1	2.8	36	1716	1817	1817
20	39.4	26.4	28.1	28.7	15.0	17.8	16.1	13.2	14.6	21.5	3.9	43	1925	2079	2079
24	47.2	30.7	33.1	33.3	18.1	21.7	20.4	16.4	17.3	25.2	3.3	43	3652	3916	3916
28	55.1	35.2	35.8	37.8	21.1	25.4	22.3	18.3	20.1	28.3	3.4	57	4675	4785	4983
31	63.0	40.0	40.4	42.7	24.0	28.3	22.5	18.5	23.0	31.5	3.2	52	7150	7249	7579
36	70.9	43.9	44.3	46.7	27.6	32.6	20.9	16.9	25.8	33.9	4.4	58	9350	9482	9900
40	78.7	48.4	49.4	52.0	30.9	36.7	20.9	16.9	28.9	37.4	4.7	60	12430	12650	13200
48	94.5	57.3	58.5	60.2	37.4	44.0	22.4	18.3	34.3	43.7	4.7	78	18040	18370	18700

Dimensions used

L [in.] Face-to-face dimensions
D [in.] Flange
G [lb.] weight (approximate value, differs depending on the design)
u Handwheel revolutions (Open/Closed)

HR with handwheel
EA with electric rotary actuator (dimensions can vary depending on the actuator manufacturer)
Other actuator options available on request



This table contains the dimensions of the standard products in the Pratt Series 300 Plunger Valve range. Numerous other designs are available on request for higher pressure ratings or special face to face dimensions.

Henry Pratt Series 300 Plunger Valves – the Overview

Brief Specifications
Materials and Finishes

- Body: 4"-12" and 14"-48"/PN 25: Ductile cast iron EN-JS 1050 superior to ASTM A536, Gr. 65-45-12, 14"-48"/PN 10-16: Grey cast iron EN-JL 1040, equivalent to ASTM A126, CL. B

- Piston guide: on strips, 4"-6": stainless steel; 8"-12": C63280 bronze, highly wear resistant; DN 14"-48" and 8"-12"/PN 40: C38000 brass

- Vaned ring, seat ring: Stainless steel/ bronze

- Slotted cylinder: stainless steel

- Gaskets/seals: Elastomer, EPDM

- Piston, shaft, slider crank, push rod, bolt: stainless steel

- Gearbox body: Grey cast iron

- Gearbox crank: Ductile cast iron

- Gearbox stem: ferritic CrNi steel

- Stem nut: ASTM B427 brass

- Gearbox configuration: in flow direction "right"; "left" or other arrangements are also possible

- Corrosion protection of the body parts: Fusion Bonded Epoxy or Epoxy plastic coating, color “blue”, coat thickness > 10 Mils, Contact Henry Pratt for additional coating options where required

The design features of all components of the Henry Pratt Series 300 Plunger Valves reflect decades of experience combined with state of the art techniques that ensure functional development and performance in the field.

An ideal example is Pratt’s use of FEA, the finite elements analysis, illustrated above.

It visualizes the stress curve in the whole component – here in the gearbox crank of a Plunger Valve – and colors it according to the existing stress: blue stands for low stresses, orange or red for high stresses. This makes it easy to see whether stress peaks occur and, if so, in which part of the component. This knowledge determines where changes are necessary to increase strength.

Notes on Project Planning and Installation

Pratt engineering support is available from your planning and design phase through to final assembly. Especially valuable is our consultation regarding correct arrangement and optimum installation of the Plunger Valve.
In most cases the advice provided will be based on your installation drawings or sketches and these will be evaluated for the best installation location of the Pratt Series 300 Plunger Valve.

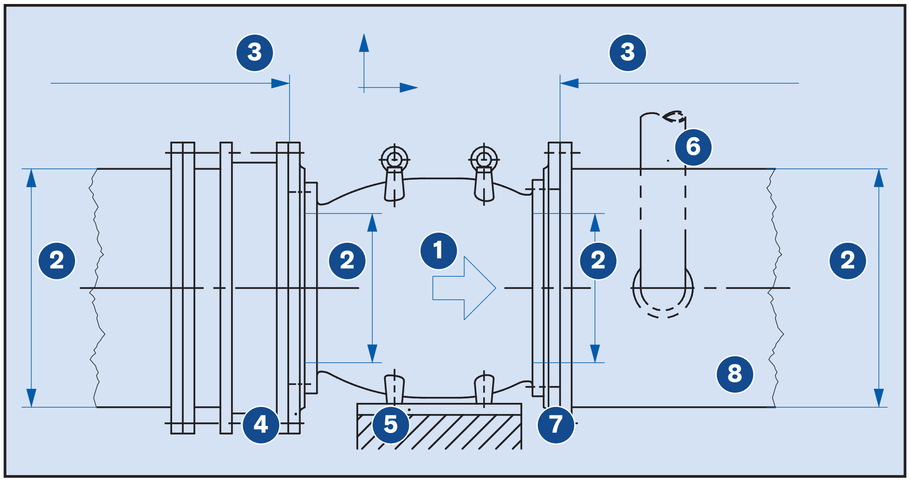
For the the most accurate response, the following data is required:

- Flow rates $Q_{max.}$ and $Q_{min.}$
- Pressure p_1 upstream of the valve at $Q_{max.}$ and $Q_{min.}$
- Back-pressure p_2 downstream of the valve at $Q_{max.}$ and $Q_{min.}$
- Operating medium, any water analysis available
- Type of use (control device, bottom outlet, etc.)
- Required mode of actuation
- Operating mode (continuous or short-term operation, etc.)

You may also refer to our "Pratt Series 300 Plunger Valve questionnaire" which lists all the data required.

Installation considerations during the project planning phase (see illustration below)

1. Standard Pratt Series 300 Plunger Valves are designed for installation in horizontal or vertical pipes. It is important to confirm that the valve is installed in the pipe according to the flow arrow cast onto the pipe.
2. Nominal size reduction is possible, as Pratt Series 300 Plunger Valve are designed according to the flow velocity. We recommend achieving the transition to the pipe nominal size with abrupt extension flanges, which we can supply with the valve if required.
3. To ensure perfect operation, for velocities above 5 feet per second we recommend a straight pipe section of at least 3-5 x pipe diameters upstream and 5-10 x pipe diameters downstream of the valve, within which there must be no fittings or valves.
4. If using an adapter or extension section, wherever possible, we recommend installing it in the pipe upstream of the Pratt Series 300 Plunger Valve.
5. Plunger Valves may not be used as the pipe support. The feet cast onto the housings are solely for supporting the valve and not as a pipe fixing point. On request, Pratt Series 300 Plunger Valves are supplied with baseplates mounted on the underside.
6. When using Pratt Series 300 Plunger Valves in the bottom outlet, an appropriately dimensioned venting device (which Henry Pratt can also supply if deemed required) must be installed downstream of the valve if the valve does not flow directly into the open air.
7. When the valve flows directly into the open air a venting device is not necessary. In this case the valve should be equipped with an outlet flange only.
8. An inline fixed throttling cylinder may be used for additional pressure reduction for installation in pipes.



Inline fixed throttling cylinder can be installed at a distance of roughly three times the nominal size downstream of the Plunger Valve when further pressure reduction is required.

Appendix H

Analysis of Potential NYSERDA Incentive Scenarios

Analysis of Potential NYSERDA Incentive Scenarios

Natural Gas Cost	$ 5.00
Electrical Cost	$ 0.085

	Baseline	Steam Turbine CHP - Option 2	Steam Turbine CHP - Option 3	Steam Turbine CHP - Digest all Sludge	Dual CHP - with SiO cleaning for Engines	Dual CHP - without SiO cleaning for Engines
Electrical Generation						
Average from Turbine (MW)	0	1.74	1.84	1.71	1.06	1.06
kWh/yr	0	15,242,400	16,118,400	14,979,600	9,285,600	9,285,600
from ICE (MW)	0	0.00	0.00	0.00	1.20	1.20
kWh/yr	0	0	0	0	10,512,000	10,512,000
Tot Electric Generation	**0**	**15,242,400**	**16,118,400**	**14,979,600**	**19,797,600**	**19,797,600**
Feedwater Pump Parasitic	0	228,724	228,724	228,724	228,724	228,724
RO Parasitic	0	32,675	32,675	32,675	32,675	32,675
FE Water Line Parasitic	0	424,722	424,722	424,722	424,722	424,722
Net Output		**14,556,279**	**15,432,279**	**14,293,479**	**19,111,479**	**19,111,479**
Natural Gas Needed						
to Incinerator (mmBtu/hr)	9.7	19.5	19.5	17.2	24.9	24.9
to AB Burners (mmBtu/hr)	0	10.3	10.3	11.8	0	0
to Aux Boilers Summer(mmBtu/hr)	8.5	0	0	0	0	0
to Aux Boilers Winter(mmBtu/hr)	18.3	0	2.0	0	0	0
Net Natural Gas (mmBtu/day)	**554**	**715**	**739**	**696**	**598**	**598**
ADG to Incinerator (mmBtu/hr)	12.7	12.7	12.7	14.9	0	0
Sludge to Incinerator (dtpd)	46.0	46.0	46.0	46.0	46.0	46.0
%VS	58.5%	58.5%	58.5%	58.5%	58.5%	58.5%
Sludge to Incinerator (mmBtu/hr)	20.2	20.2	20.2	20.2	20.2	20.2
ADG portion for NYSERDA funding	30%	24%	23%	28%	100%	100%
Annual Electrical Cost	$ -	$ (1,237,284)	$ (1,311,744)	$ (1,214,946)	$ (1,624,476)	$ (1,624,476)
Annual Natural Gas Cost	$ 1,011,780	$ 1,305,240	$ 1,349,040	$ 1,270,200	$ 1,090,620	$ 1,090,620
Turbine O&M	$ -	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Boiler Water Treatment	$ -	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000
Admin HW Boiler O&M	$ -	$ -	$ 6,000		$ -	$ -
ICE O&M					$ 262,800	$ 262,800
Gas H2S pre-treatment O&M					$ 33,000	$ 33,000
Gas SiO pre-treatment O&M					$ 63,000	
Annual Costs	**$ 1,011,780**	**$ 123,956**	**$ 99,296**	**$ 111,254**	**$ (119,056)**	**$ (182,056)**
Annual Savings Comp. to Baseline	**$ -**	**$ 887,824**	**$ 912,484**	**$ 900,526**	**$ 1,130,836**	**$ 1,193,836**
Turbine and Condenser	$ -	$ 2,575,000	$ 2,575,000	$ 2,575,000	$ 2,575,000	$ 2,575,000
Incremental New WHRB Cost	$ -	$ 900,000	$ 900,000	$ 900,000	$ 900,000	$ 900,000
New Boiler Feedwater Pumps	$ -	$ 126,000	$ 126,000	$ 126,000	$ 126,000	$ 126,000
Boiler Water Treatment	$ -	$ 104,000	$ 104,000	$ 104,000	$ 104,000	$ 104,000
Electric Mods	$ -	$ 109,000	$ 109,000	$ 109,000	$ 109,000	$ 109,000
Steam Piping from Boiler to Turbine	$ -	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000
Connection of Extraction Steam	$ -	$ 159,000	$ 159,000	$ 159,000	$ 159,000	$ 159,000
FE Water System Modifications	$ -	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
New Burners in AB Chambers	$ -	$ 162,000	$ 162,000	$ 162,000	$ 162,000	$ 162,000
New Admin Boilers	$ -	$ -	$ 340,000	$ -	$ -	$ -
IC Engines (installed)	$ -	$ -	$ -	$ -	$ 3,067,350	$ 3,067,350
Building Enclosures	$ -	$ -	$ -	$ -	$ 975,000	$ 975,000
Electric Mods	$ -	$ -	$ -	$ -	$ 500,000	$ 500,000
Piping Mods	$ -	$ -	$ -	$ -	$ 200,000	$ 200,000
Gas H2S Pre-treatment	$ -	$ -	$ -	$ -	$ 282,500	$ 282,500
Gas SiO Pre-treatment	$ -	$ -	$ -	$ -	$ 460,000	$ -
Air Permit	$ -	$ -	$ -	$ -	$ 10,000	$ 10,000
Subtotal		**$ 4,365,000**	**$ 4,705,000**	**$ 4,365,000**	**$ 9,859,850**	**$ 9,399,850**
Miscellaneous Additions 15%	$ -	$ 654,750.0	$ 705,750.0	$ 654,750.0	$ 1,478,977.5	$ 1,478,977.5
General Conditions 12%		$ 523,800.0	$ 564,600.0	$ 523,800.0	$ 1,183,182.0	$ 1,183,182.0
Contractor Overhead and Profit 15%		$ 654,750.0	$ 705,750.0	$ 654,750.0	$ 1,478,977.5	$ 1,478,977.5
Engineering 25%		$ 1,091,250.0	$ 1,176,250.0	$ 1,091,250.0	$ 2,464,962.5	$ 2,464,962.5
Total	**$ -**	**$ 7,290,000**	**$ 7,857,000**	**$ 7,290,000**	**$ 16,466,000**	**$ 16,006,000**
Simple Payback (years) w/o Incentive		**8.2**	**8.6**	**8.1**	**14.6**	**13.4**
NYSERDA Incentive Main Tier (10 yrs)	**0.0**	**$ 924,000**	**$ 941,000**	**$ 1,067,000**	**$ 2,321,000**	**$ 2,321,000**
Simple Payback (years) w/ Incentive		**7.2**	**7.6**	**6.9**	**12.5**	**11.5**
NYSERDA Incentive ADG-to-El (3 yrs)	**0.0**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**
Simple Payback (years) w/ Incentive		**7.1**	**7.6**	**7.0**	**13.7**	**12.6**
20-year savings		**$ 10,466,000**	**$ 10,393,000**	**$ 10,721,000**	**$ 6,151,000**	**$ 7,871,000**
20-year savings w/ incentive		**$ 11,390,000**	**$ 11,334,000**	**$ 11,788,000**	**$ 8,472,000**	**$ 10,192,000**

Appendix I

Incinerator Cake Sampling Plan for BSA

MALCOLM PIRNIE | ARCADIS

The Water Division of ARCADIS

Incinerator Sludge Cake Sampling Plan

Date: September 13, 2012

Subject: **Buffalo Sewer Authority Wastewater Treatment Plant Energy Utilization**

Incinerator Sludge Cake Sampling Plan

Project No.: MP/AUS Project No. 02255204.0000

1.1 GENERAL

This technical memorandum summarizes the recommended Incinerator Sludge Cake Sampling and Analysis protocol at the Bird Island WWTP operated by the Buffalo Sewer Authority (BSA). The cake sampling and analysis program includes the collection of sludge cake samples for subsequent laboratory analysis to determine the cake heating value and cake composition, in terms of mass fractions of carbon, hydrogen, oxygen, nitrogen, and sulfur. The analytical services will be provided by an independent and certified professional laboratory.

1.2 SAMPLING COLLECTION AND LOCATIONS

Sludge cake sampling events should occur on days of typical plant operations. When possible, sampling should avoid days directly after a rain event, days with planned shutdowns of key equipment or days of abnormal plant operations. Anomalies in plant operations should be noted for the day on which the sampling occurs.

The recommended cake sampling program includes four sampling events, taken quarterly over the span of one year. Each sampling event will include analysis for sludge cake heating value and for ultimate analysis of the sludge cake material composition. Dividing the sampling events over a one-year period will capture seasonal variation of cake heating value and composition.

For each sampling event there shall be duplicate samples taken. Samples for the first event will be collected on two consecutive days, during the same shift, with duplicate samples at each time for a total of four samples. Subsequent samples will be taken quarterly as duplicate samples, once per day. Samples will be taken from three locations, including: the incinerator feed sludge cake, thickened primary sludge, and thickened waste activated sludge. The following tables summarize the recommended cake sampling locations and quantities for each sampling event.

Table 1. Summary of Sampling Locations

Sample Location	Location Designation
Incinerator Feed Sludge Cake Conveyor	1
Thickened Primary Sludge (Downstream of gravity thickeners)	2
Thickened Waste Activated Sludge (Downstream of dissolved air flotation thickener)	3

Table 2. Recommended Sludge Cake Sampling Program for Bird Island WWTP

Sample Event	Sample	Sample Designation	Quantity per Sample	Total Samples for Event
1	Day 1	1A, 1B (Duplicate Samples) 2A, 2B (Duplicate Samples) 3A, 3B (Duplicate Samples)	1 qt.	12
	Day 2	1A, 1B (Duplicate Samples) 2A, 2B (Duplicate Samples) 3A, 3B (Duplicate Samples)	1 qt.	
2-4	1	1A, 1B (Duplicate Samples) 2A, 2B (Duplicate Samples) 3A, 3B (Duplicate Samples)	1 qt.	6

Total samples for sampling effort – 30.

1.3 SAMPLING PERSONNEL AND EQUIPMENT

Samples will be taken at the Bird Island WWTP by qualified staff from the BSA. Sampling personnel shall use appropriate sludge handling equipment, including appropriate personal protective equipment, gloves, and reusable trowel for gathering samples. Each duplicate sample will require two, one-quart sized glass sample jars; sampling personnel will fill each jar, seal the lid, label with the sampling event and sample designation according to Section 1.2, and seal the sample jar in a plastic bag for secondary containment.

Treatment plant staff will ship samples to the analytical laboratory at the conclusion of the sampling event. Samples contain inert material and are not considered a hazardous material for shipping consideration. Sampling personnel are reminded that sludge cake is a biological material, and care should be taken to minimize contact with the material, fully close all sample containers, and ship the samples promptly. Samples shall be shipped overnight, with sampling jars packaged appropriately to prevent the sample jars from breaking during shipment. Malcolm Pirnie/ARCADIS personnel will be present for the first sampling event in order to observe the sampling locations and protocols.

1.4 SLUDGE CAKE ANALYSIS

Table 3 below gives the sludge cake constituents of interest that will be tested for by an independent and certified professional laboratory.

Table 3. Sludge Cake Constituents of Interest

Laboratory Test	Sample Constituents
ASTM D5865	Sludge Cake Heating Value
Ultimate Analysis for Sludge Cake: ASTM D5373 ASTM D4239 ASTM D3174	Carbon Hydrogen Oxygen Nitrogen Sulfur

The method of analysis for the sludge cake heating value will be standard ASTM D5865 methods, which are typically used to determine the gross calorific value of coal.

The method of analysis for sludge cake ultimate analysis will be ASTM D5373 to determine the mass fraction of carbon, hydrogen, and nitrogen, ASTM D4239 to determine the mass fraction of sulfur, and ASTM D3174 to determine mass fraction of ash and to compute mass fraction of oxygen in each sludge cake sample.

Samples will be sent to Geochemical Testing, an independent analytical testing facility located in Somerset, Pennsylvania. This lab specializes in environmental and coal analysis, particularly for ultimate analysis and heating value. Geochemical Testing requires that a chain of custody document accompany each sample received at their testing facility. Samples should be sent to 2005 N. Cener Ave., Somerset, PA 15501, and are accepted at the testing facility Monday through Friday from 7 am to 7 pm. Questions should be directed to Bob Stull, Director of Coal Services, at (814) 445-6666.

1.5 SAMPLES LOG PROCEDURE

Personnel involved in collecting the samples shall keep an accurate log of the following activities:

- Photograph each sampling location
- Log the time and date when each sample is taken
- Mark the one-quart glass sample jar with sampling time and sample designation
- Maintain accurate notes

1.6 BUDGETING

The project budget contains the following provisions for sampling:

- 30 labor hours
- $3,420 for sample shipping and sample analysis

A preliminary quote from Geochemical Testing estimates a cost of $104 per sample to determine the sludge cake heating value and mass fraction of the constituents described in Section 1.4. The sampling effort prescribed in Section 1.2 calls for 30 samples, which translates to $3,420 in estimated sample analysis costs. This cost includes sample analysis and an estimated overnight shipping cost of $20 per duplicate sample. This does not include contingency for sampling supplies, including sampling containers and appropriate protection for sampling personnel. The prescribed sampling plan also calls for four separate sampling events with the consultant being present for only the first sampling event. This translates to 30 labor hours for sampling at each plant (assuming a one-hour requirement per sample), as well as associated shipping cost.

Shuttle/Cooler ID#: ________	# CHAIN OF CUSTODY	Geochemical Testing

Form F-5002, 06.08

Geochemical Testing • 2005 North Center Avenue • Somerset PA 15501 • (814) 443-1671 • Fax (814) 445-6729

Billing Client:	**Contact (Company):**	**Phone: ( )**
Address:	e-mail:	Fax: ( )
City: **State:** **Zip:**	**Sampled by:**	**Preservatives by __Sampler__GT**
WO#:	Project:	PO/Quote#:

Sample Matrix:	**GW** Ground Water	**SW** Surface Water	**PW** Potable Water	**WW** Wastewater	**SO** Soil	**SL** Sludge	**nHZ** Not Hazardous / **HZ** Hazardous	**PCB**s
Sample Type:	**G** Grab	**C** Composite	**D** Distribution/DW	**R** Raw/DW	**S** Special/DW	**O** Other	Containers Supplied by: ☐ Client	☐ GT Lab

Sample Location/ Description	Lab Number	Sample Matrix	Date	Time (Military)	Sample Type	**Analyses Requested	Remarks/ Preservatives, etc	Number of Containers
**NOTE: IF multiple analytes from one bottle, OR if multiple bottles for one analyte, THEN list separately on one line UNLESS LISTED ON ATTACHED FIELD LOG								
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	
		nHZ / HZ					Field Filtered: Y / N	

Note Deficiencies Here:

Relinquished by (Company & Signature)	Date	Time (Military)	Received by (Company & Signature):	Date	Time (Military)

SAMPLES MUST BE PRESERVED ON ICE.

Ice present on receipt: ___Yes or ___No | Cooler Temp (ºC) on receipt: _____

Appendix J

Incinerator Cake Sampling Results for Amherst Sludge

BUFFALO SEWER AUTHORITY

REPORT ON

FOR
BTU ANALYSIS ON SOLIDS

SAMPLE IDs:
AMHERST CAKE - 240228
WEST CAKE - 240229

SAMPLE DATE: 11/30/2012

Analyzed by:

Columbia Analytical, Inc.
Part of the ALS Group A Campbell Brothers Limited Co.
3860 South Palo Verde Road, Suite 302
Tucson, AZ 85714

Summited by:

IsleChem, LLC
2801 Long Road
Grand Island, NY
14072

IsleChem Project ID: NY907120

West Cake

$\% TS = 100 - 76.3 = 23.7\%$

$\% VS = 50.6\%$

$$\frac{Btu = 5{,}515 \frac{Btu}{lb}}{.5064 \frac{lb\ volatile}{lb}} = 10{,}890 \frac{Btu}{lb\ volatile}$$

Amherst Cake

$\% TS = 100 - 73.7 = 26.3\%$

$\% VS = 70.3\%$

$$Btu = \frac{7{,}816 \frac{Btu}{lb}}{.7026 \frac{lb\ volatile}{lb}} = 11{,}125 \frac{Btu}{lb\ volatile}$$

ALS

December 27, 2012

Client: IsleChem, LLC
2801 Long Road
Grand Island, NY 14072

Attn: Delores Schuman

Project: BTU Analyses

Date Received: December 6, 2012

Certificate of Analysis

Sample ID:	Sample Date	Lab #:	Moisture, Total	Volatile Matter		Fixed Carbon		Ash	
			D7582 Proximate by Automated TGA System						
			As Received wt%	As Received wt%	Moist. Free wt%	As Received wt%	Moist. Free wt%	As Received wt%	Moist. Free wt%
West Cake	11/30/12	T1201919-001	76.32	11.99	50.64	0.90	3.78	10.79	45.57
Amberst Cake	11/30/12	T1201919-002	73.75	18.44	70.26	1.38	5.27	6.42	24.47

Sample ID:	Sample Date & Time	Lab #:	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Heating Value	
				D5373		Calculated	D4239	D5865	
			Moist. Free wt%	Moist. Free wt%	Moist. Free wt%	Moist. Free wt%	Moist. Free wt%	As Received BTU/lb	Moist. Free BTU/lb
West Cake	11/30/12	T1201919-001	28.40	4.24	4.39	16.28	1.123	1,306	5,515
Amberst Cake	11/30/12	T1201919-002	39.60	5.84	5.58	23.15	1.363	2,051	7,816

Note:
Calculated oxygen reported due to high ash content.

W. Hyatt
Digitally signed by Wendy Hyatt
Date: 2012.12.27 12:01:55 -07'00'

Wendy Hyatt, Project Chemist

Arcadis of New York, Inc.

50 Fountain Plaza

Suite 600

Buffalo, New York 14202

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