MMSD
PARTNERS FOR A CLEANER ENVIRONMENT

Memorandum

DATE: January 28, 2015

TO: Kevin L. Shafer PE, Executive Director

COPY: Susan B. Anthony, Director of Legal Services
Michael J. Martin PE, Director of Technical Services
Karen L. Sands AICP, Manager of Sustainability

FROM: Timothy R. Bate PE, Director of Planning, Research and Sustainability TRB

SUBJECT: Approval of the Final Energy Plan, Consultant Agreement M03072P01

Attached for your review, approval, and use is the final Energy Plan, Consultant Agreement M03072P01. Contract deliverables have been met and include a Final Energy Plan document (8 copies). This also includes:

- Technical Memo 1: Energy Plan Goals (Appendix A to the Plan)
- Technical Memo 2: Energy Baseline (2005 and 2010 as per staff) (Appendix B to the Plan)
- Technical Memo 3: Evaluation of Alternatives (Appendix C to the Plan)

In addition, $25,000 was spent on the following approved contingency items:

- 2014 Estimated Greenhouse Gas Emission Reduction for Landfill Gas Turbines (Appendix D to the Plan)
- Maximum Energy (Appendix E to the Plan)

The purposes of the Plan include:

- Meet the 2035 Vision goals, including 100 percent of MMSD's energy needs from renewable energy sources and 80 percent of MMSD's energy needs from internal, renewable sources
- Produce a long-term, positive impact on MMSD's budget as it relates to energy consumption
- Provide a foundation for MMSD's 2050 Facilities Plan, including a recommendation for next steps for further analysis

Internal Plan review team members included: Tim Bate, Bill Farmer, Bill Krill, Karen Nenahlo, Mickie Pearsall, Urbain Boudjou, Scott Royer, Debra Jensen, Joe Cantwell, and Kevin Jankowski. In addition to these staff, Greg Hottinger and Tom Zimmerman were also invited to the draft plan review meeting on December 15, 2014 to provide comments. Pat Obenauf, Mike Martin, Bill Farmer, Steve Jacquart, Bill Graffin, and you were invited to provide comments at

an executive review meeting on December 15, 2014. Later, Sid Aurora also provided comments on one section.

Through the planning process, 95 alternatives were identified. Following detailed analysis, 19 of those alternatives are recommended in the Plan while others require further evaluation. Among the major recommendations are:

- Increase the amount of landfill gas available to produce energy using the Jones Island WRF turbines and burn it in the dryers
- Decrease the amount of supplemental fuel required for Milorganite® drying by increasing the dewatered cake solids and maximizing the amount of turbine waste heat used by improving the waste heat pressure control
- Increase the amount of low solids industrial/commercial waste to co-digest at the South Shore WRF

In the next five years, alternatives that may result in an immediate positive impact on MMSD's budget should be further evaluated and, if warranted, implemented. These include increasing the dewatered cake solids, optimizing turbine waste heat pressure control, modifying the South Shore WRF activated sludge process, and others. Additional alternatives should be considered on the basis of cost effectiveness and other attributes, and will be given consideration in the 2050 Facilities Plan.

Please let me know if you have any questions or concerns.

Reviewed and approved by:

Kevin L. Shafer, PE

Date 2/20/15

Attachments

All were reviewed by Tom Nowicki

Date	Log #	Description
3-27-14	4763	Energy Plan Contract (final for signature)
2-26-14	4706	Draft Energy Plan Contract
2-6-14	4668	Energy Plan CH2M Hill Consultant Contract

Final

Energy Plan

Contract No. M03072P01

CH2MHILL®

January 2015

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Executive Summary

Background

In 2011, the Milwaukee Metropolitan Sewerage District (MMSD) established a 2035 Vision that includes a goal to meet a net 100 percent of MMSD's energy needs with renewable energy sources. Since then, MMSD has undertaken several projects and initiatives to make strides toward that goal. To further aid reaching the goal, MMSD developed a plan to establish a viable path toward achieving the goals by increasing renewable energy generation and implementing energy conservation. The first step of the plan was to document MMSD's baseline energy use and progress to date toward achieving energy goals. The gap between existing energy use and the goal was quantified, and several alternatives to bridge that gap were identified. The cost of and energy savings for implementing the most viable alternatives were estimated, and the alternatives to be further evaluated for implementation were then determined. Finally, a schedule and plan to implement the selected alternatives were developed.

MMSD's 2035 Vision includes the following energy goals, which became the goals of this Energy Plan:

- Meet a net 100 percent of MMSD's energy needs with renewable energy sources[1]
- Meet 80 percent of MMSD's energy needs with internal, renewable sources
- Produce a long-term, positive impact on MMSD's budget
- Provide a foundation for MMSD's 2050 Facilities Plan, that began in 2014

An energy baseline to track progress against goals was established for calendar years 2005 and 2010.

Recommendations

Ninety-five alternatives were initially identified for consideration, and 19 are recommended for the plan. Some of the recommended alternatives require further evaluation to confirm that they should be implemented and others are already in the process of being implemented or will be implemented soon. Several of the recommended alternatives could result in an immediate positive impact on MMSD's budget, although further financial evaluation is required. As energy prices rise, other alternatives may become more cost effective. It is important to note that most cost and energy estimates are conceptual and they should be refined before final decisions on projects are made.

While implementing the recommended projects will result in a decrease in energy demand, the following are keys to achieving MMSD's energy goals because implementing them would significantly increase renewable energy production:

- Increasing the amount of landfill gas available to produce energy using the Jones Island turbines and burn in the dryers. MMSD is actively pursuing obtaining more landfill gas.
- Decreasing the amount of supplemental fuel required for Milorganite® drying by increasing the dewatered cake solids and maximizing the amount of turbine waste heat utilized by improving the waste heat pressure control.
- Increasing the amount of low solids industrial/ commercial waste to co-digest at South Shore. It should be determined what additional efforts may be required to accomplish this.

If sufficient co-digested waste can be obtained, more digester gas could be produced than is required for South Shore power and heat demands. Potential uses for that excess energy include pumping the gas into an extended landfill gas pipeline for use in the Jones Island Water Reclamation Facility (WRF) dryers or turbines, pumping the gas to the Oak Creek Drinking Water Treatment Plant for use in their engine generators, and delivering power generated from the gas back to the grid as renewable energy. Similarly, landfill gas beyond that required for Jones

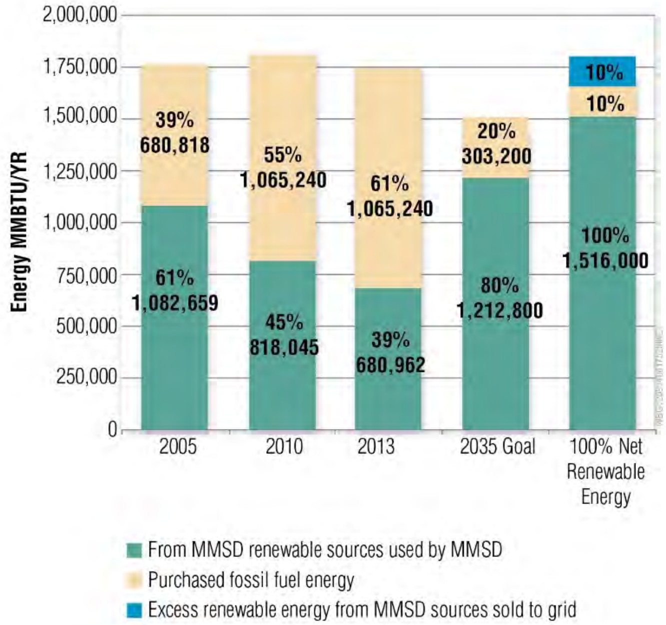
[1] This means that internally generated renewable energy minus purchased/external energy = net equivalent total energy used at all MMSD facilities annually

Island's electrical power energy needs may become available and the excess gas could be used for drying or excess power could be generated that could be sold. However, the sale of excess digester or landfill gas may not be cost effective and a further market evaluation is recommended.

Exceeding the landfill gas and digester gas needed for treatment plant energy needs would be a way to achieve a net 100 percent renewable energy use from internal sources. That is because implementing the recommended alternatives, in combination with some increase in landfill gas and co-digested waste, could only satisfy the dry weather flow energy demands. Additional, substantial amounts of energy are required for short-term peak electrical energy demands during wet weather, primarily to operate the inline pumps that by themselves more than double the Jones Island electrical energy demand. In addition, MMSD's non-treatment facilities (including collection system pump stations) use fossil fuel that must be offset by renewable energy. Another option to achieve the 100 percent renewable energy goal would be to install new renewable energy systems, such as wind or solar power that could generate excess power during dry weather. The excess power could be sold back through the electrical grid, resulting in a net annual 100 percent renewable energy use. The 100 percent renewable energy scenario, along with energy use after alternative implementation and baseline energy use, is shown in Exhibit ES-1.

Another method to achieve 100 percent net renewable energy would be to increase the amount of digester gas produced from existing sludge loads. This could be done in lieu of or in conjunction with installation of renewable energy sources. Increasing the amount of sludge that is digested would require that limitations on the percent of digested sludge in the Milorganite® process be addressed. The portion of cake fed to the dryers that is made from digested sludge is limited to approximately 40 percent because, at levels above that, excessive dust and chaff are formed. The percentage of digested sludge could be increased by installing a pug mill or pelletizer upstream of the dryers, although that would require a fairly significant capital investment. Another option is to install advanced digestion processes that would reduce the amount of digested sludge and have the added benefits of increasing digester gas production and decreasing dryer energy use through production of a dryer cake. This would also require a fairly substantial capital investment and will be evaluated further in the 2050 Facilities Plan.

EXHIBIT ES-1
Historical and Projected Renewable Energy



Implementation Plan

In the next 5 years, alternatives that may result in an immediate positive impact on MMSD's budget should be further evaluated and, if warranted, implemented. The alternatives include increasing the dewatered cake solids, optimizing turbine waste heat pressure control, modifying the South Shore WRF activated sludge process and others. Additional alternatives should be considered on the basis of cost effectiveness and other attributes, and will be given consideration in the 2050 Facilities Plan. Other implementation issues to be addressed include considering restructuring Veolia's operation contract for energy incentives per unit of treatment, implementing the planned energy-monitoring and energy data-tracking software, communication and outreach, tracking future energy innovations, and refining energy demand management strategies. In addition, integrating the results of the 2050 Facilities Plan evaluation of alternatives to or modifications to the Milorganite® and digestion processes into the Energy Plan will be key.

Energy Plan

Introduction and Background

In 2011, the Milwaukee Metropolitan Sewerage District (MMSD) established a 2035 Vision that includes a strategic objective to address climate change mitigation/adaptation with an emphasis on energy efficiency. Since then, MMSD has undertaken several projects and initiatives to achieve strategic objectives related to that goal. To further aid reaching the goal, MMSD has developed a plan to establish a viable path toward these strategic objectives by using renewable energy and conserving energy. The first step of the plan was to document MMSD's current energy usage and progress to date toward achieving the goals. This included an assessment of MMSD's progress toward the goal of using the Water Environment Federation's (WEF's) "Energy Roadmap" utility progression characteristics (WEF 2013). The gap between baseline energy use and the goals was quantified, and several alternatives to bridge the gap were identified. The cost of and energy savings for implementing the most viable alternatives was estimated, and the alternatives to be implemented were then recommended. Finally, a schedule and plan to implement the selected alternatives were developed.

Please note that this is a high-level analysis not intended to provide specific recommendations for projects to be immediately implemented.

Energy Plan Goals and Purpose

MMSD's 2035 Vision includes the two energy goals that, together with two additional goals based on staff input, became the goals of this Energy Plan:

- Goal No. 1: Meet a net 100 percent of MMSD's energy needs with renewable energy sources[1].
- Goal No. 2: Meet 80 percent of MMSD's energy needs with internal, renewable sources.
- Goal No. 3: Produce a long-term, positive impact on MMSD's budget.
- Goal No. 4: Provide a foundation for MMSD's 2050 Facilities Plan, which began in 2014.

Both energy conservation and use of renewable energy sources were treated equally in the plan. These concepts will be further developed in the 2050 Facilities Plan. The 2050 Facilities Plan goals will be set as part of that subsequent effort and are not currently available. The Energy Plan goals are discussed further in Appendix A.

Energy Baseline

An energy baseline was established to track progress toward the goals for calendar years 2005 and 2010. These two baseline years were recommended by staff, who will later decide what baseline year to use in what circumstance. The year 2005 was selected because it was the year the 2035 Vision of reducing MMSD's carbon footprint is referenced, and 2010 was selected because that was when the 2035 Vision was finalized prior to adoption in early 2011 (December 16, 2010)[2].

MMSD's energy needs are met through a combination of purchased energy and internally produced energy. MMSD purchases electricity, natural gas, landfill gas, fuel oil, and propane for use at the Jones Island and South Shore water reclamation facilities (WRF), the headquarters building, pump stations, and other facilities. MMSD fleet vehicles consume diesel fuel, compressed natural gas, and unleaded gasoline fuel. At the South Shore WRF, engine generators fueled by digester gas and natural gas can produce much of the plant's required electrical power. Waste heat from the engines is used to heat digesters and buildings. At

[1] This means that internally generated renewable energy minus purchased/external energy = net equivalent total energy used at all MMSD facilities annually.

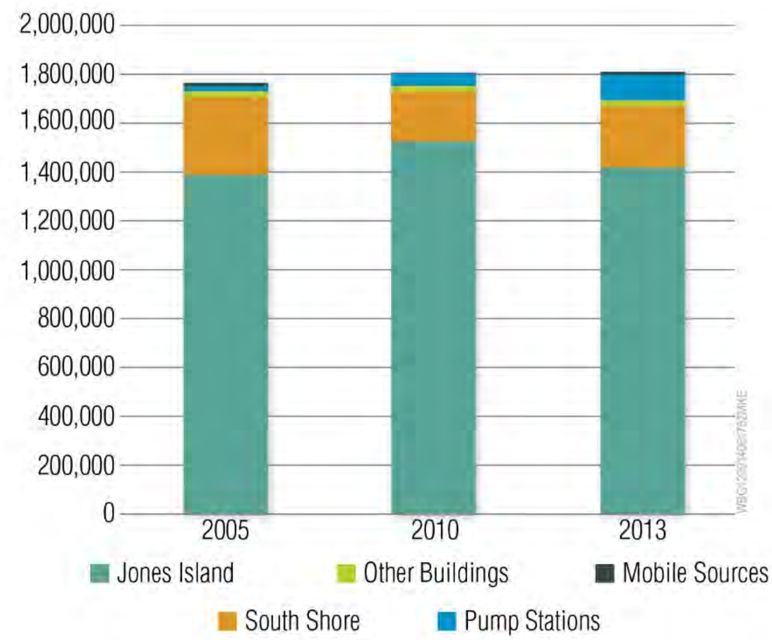
[2] The 2035 Vision also included a goal to reduce MMSD's carbon footprint by 90 percent.

the Jones Island WRF, turbines fueled by natural gas historically have the ability to produce almost all of the plant's electrical power and heat needed for buildings and for drying Milorganite®. The energy to dry Milorganite® is MMSD's largest energy requirement. Considering the future of Milorganite® is beyond the scope of this plan.

In late 2013, MMSD installed three new turbines that use landfill and natural gas. One of the two existing natural gas turbines was retained to reduce electrical demand charges and as a backup source of power. The other turbine was disconnected and made unavailable for service. The new landfill gas turbines are more efficient than the natural gas turbines, and therefore less waste heat is available for Milorganite® drying and building heat. The two WRFs combined use more than 95 percent of all of MMSD's energy, and therefore, this plan focuses on the WRFs.

Exhibit 1 shows energy use by facility for the baseline years (2005 and 2010) and for 2013, the most recent full year for which data is available (Appendix B includes a more detailed breakdown of historical energy use by fuel type and major energy users). MMSD is continually refining its data gathering and tracking, and so future representations of baseline and progress may be updated.

EXHIBIT 1
Energy Baselines and 2013: Total Energy Used (MMBtu/yr)



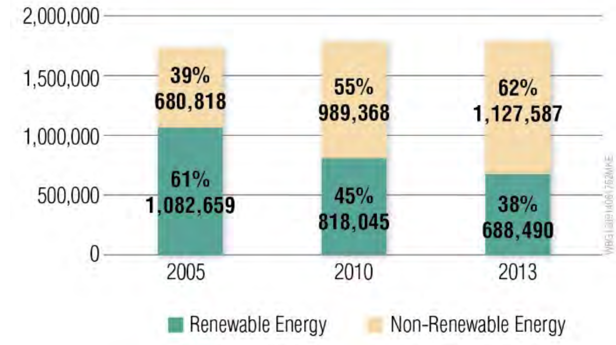
MMSD defines renewable energy to include not only traditional renewable energy sources, but also waste heat regardless of original energy source. That was a staff decision made prior to writing this plan, and is carried as a constant throughout. The following are the sources of renewable energy currently used by MMSD:

- The portion of the electrical power generated using landfill gas in the Jones Island landfill/natural gas turbines.
- All of the Jones Island turbine waste heat used to dry Milorganite®, including the waste heat generated from natural gas. In previous energy work, MMSD defined waste heat as renewable energy. This is supported because 26 states have ruled that waste heat can be defined as renewable regardless of the original source (Wisconsin has not ruled).
- The portion of the electrical power generated using digester gas in the South Shore digester gas/natural gas engines.
- All of the South Shore engine waste heat used for building and digester heating.
- Solar power generated at headquarters and at Jones Island.

Exhibit 2 shows the amounts and percentages of renewable energy for 2005, 2010, and 2013.

The amount of renewable energy used in 2010 and 2013 is less than that in 2005. More electricity was purchased and less renewable energy was generated in 2010 and 2013 than in 2005. This is partially because the General Electric (GE) natural gas turbines were less available in 2013 due to turbine maintenance and construction of the landfill gas turbines. This resulted in a decrease of waste heat available from the turbines available to dry Milorganite® and heat buildings, and the waste heat from natural gas combustion is considered renewable energy. Nonrenewable natural gas had to be used to replace the reduction in waste heat. In addition, a fire at the South Shore WRF powerhouse and other digestion issues resulted in lower digester gas (a renewable fuel) production. MMSD's renewable energy use has increased since 2013, following the startup of the landfill gas turbines and resolution of digestion issues.

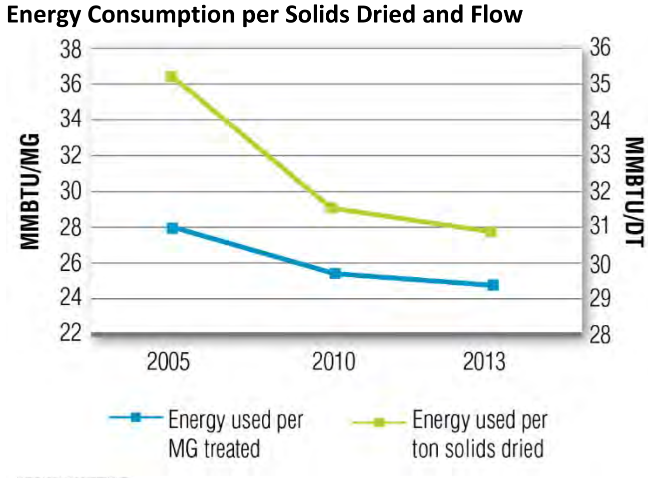
EXHIBIT 2
Total Renewable Energy Used (MMBtu/yr)



The amount of energy used at the WRFs depends on several factors, of which two important ones are the amount of biosolids dried and the influent flow. Other factors that impact energy use are influent biochemical oxygen demand and ammonia. As shown in Exhibit 3, the energy consumption per volume of wastewater treated and per ton of solids dried decreased between 2005 and 2013.

This shows that energy used per unit of wastewater treated and dried is declining. Exhibit 3 uses the total WRF energy rather than energy associated with treating only liquid flows and solids, so the use of this metric is therefore limited. There are likely several reasons that contributed to the decline, including MMSD energy reduction efforts, such as aeration air reductions.

EXHIBIT 3
Energy Consumption per Solids Dried and Flow



Assessment of Progress using Water Environment Federation Roadmap

To assess MMSD's progress toward the WEF Roadmap characteristics, an exercise of assessing MMSD's progress was performed in a workshop as part of the development of the goals and objectives.

The WEF Roadmap includes six characteristics on which a utility can rate its level of progression based upon "importance" and "achievement." *Importance* indicates the significance of the topic area to the utility and its customers, and as part of its overall mission, vision, and objectives. *Achievement* indicates how well the utility has advanced in

EXHIBIT 4
Energy Management Roadmap Assessment

	Importance	Achievement
Strategic Management	5	4
Organizational Culture	4	3
Communications and Outreach	3	1.5
Demand-Side Management	4.5	4
Energy Generation	4.5	4
Innovating for the Future	3	2

accomplishing the highest levels of progression. Exhibit 4 lists the six characteristics and how they were rated by MMSD staff regarding importance and achievement, from one to five (five being highest).The evaluation shows that, in general, MMSD has accomplished high levels for the following characteristics:

- Strategic Management
- Demand-Side Management
- Energy Generation

Much of this Energy Plan focuses on continuing MMSD's efforts in reducing demand and increasing renewable energy generation. Characteristics that could require further progress are:

- Communication and Outreach
- Innovating for the Future

Alternatives Evaluation Methodology

In multiple workshops and meetings with MMSD staff, 95 alternatives (see Appendix F) were identified that could be implemented to help meet MMSD energy goals. The alternatives were prioritized using monetary and nonmonetary criteria, and 37 alternatives were determined the most likely to be effective. The 37 alternatives were evaluated by completing a technology review of the following (Appendix C):

- A description of the alternative and how it would be implemented.
- An estimate of capital and operation and maintenance (O&M) costs.
- An estimate of the amount of renewable energy that could be generated or the amount of energy reduced.
- Development of several financial metrics, including the value of energy saved, payback, and capital cost expended per unit of energy.

Early in the project, a decision was made to use fixed unit values in representing the dollar value of energy demand reductions or increases in renewable energy used. It recognized that, at current energy prices, the savings may be overestimated because MMSD's WRFs generate a significant portion of the energy they use. The actual cost savings will vary based on several factors, including:

- Energy is generated in a different manner at each WRF and therefore the value of that energy is different at each plant.
- The cost of O&M assigned to the Jones Island WRF turbines and South Shore WRF engines. Equipment depreciation could also be considered.
- How much waste heat is recovered and used. For example, in the summer, when there is not a building heat demand, not all the South Shore WRF engine waste heat is utilized and the amount of waste heat utilized is weather dependent.
- How much landfill gas and digester gas is available. Using landfill and digester gas lowers MMSD's cost of energy generation, and the amount of landfill and digester gas available can vary.
- Future energy costs.
- The amount of solids digested, which impacts the amount of energy generated at the South Shore WRF.

Conclusions and Recommendations

Demand-side Management and Energy Generation

MMSD's goal of achieving 100 percent net energy needs using renewable energy sources, with 80 percent of the renewable energy coming from internal sources, can be achieved through a combination of demand-side management and energy generation alternatives. Of the 37 alternatives evaluated, 19 alternatives shown in Exhibit 5 (following page 7 of this section) are recommended for further planning evaluation to determine if implementation would make sense. Further evaluation should consider refined energy cost savings, life-cycle costs and capital costs, synergies from performing multiple alternatives, and how MMSD's operation and maintenance contract would impact financial savings to the MMSD. Some of the alternatives may not be cost effective, yet will assist MMSD in achieving its renewable energy goals. In those cases, policy directives would guide MMSD in making implementation decisions. If the 19 alternatives were implemented, it is estimated that about 80 percent of MMSD's energy would be from internal renewable sources (***Energy Plan Goal No. 1***). However, given the conceptual nature of the alternative evaluations, the actual amount will likely vary. Eleven of the alternatives have begun to be implemented or are planned to be implemented soon. They were necessarily included in this analysis to track progress from the baseline years to the 2035 goals.

Several of the recommended alternatives that have relatively short payback periods will be cost effective to implement. The potential financial viability of other alternatives may be demonstrated by one of the financial metrics shown in Exhibit 5—the difference between the annual energy savings minus the O&M costs and the annual payment on a State Revolving Fund (SRF) loan. For several alternatives, this is a positive number; there could be an estimated positive annual cash flow in the first year. As energy prices rise, the cash flow would increase over the life of the project. It is important to note that most cost and energy estimates are conceptual and they should be refined before being used for capital planning. Also, as previously discussed, the estimate of the savings was simplified by using a fixed cost of energy that could result in an overestimation of the savings.

While implementing the recommended projects will result in a decrease in energy demand, the following are keys to achieving the energy goals, because addressing them would result in a significant increase in renewable energy production:

- Significantly increasing the amount of landfill gas available to produce energy using the Jones Island WRF turbines. The amount of landfill gas needed would need to be sufficient to produce enough electrical power to satisfy all of the Jones Island WRF electrical power demand, with an additional significant amount available to provide drying heat.
- Decreasing the amount of supplemental fuel required for drying by increasing the dewatered cake solids and maximizing the amount of turbine waste heat utilized by improving the waste heat pressure control.
- Significantly increasing the amount of industrial/commercial waste to co-digest at the South Shore WRF. The waste ideally would contain a low amount of solids so that the energy for Milorganite® drying would not increase. It should be determined what additional efforts may be required to accomplish this. Combined with digesting more waste activated sludge, the amount of digester gas needed would need to be sufficient to produce enough electrical power to satisfy all of the South Shore WRF electrical power demand, with an additional amount available to provide excess power that could be sold. Or the excess digester gas could be transmitted to other users, including the Jones Island WRF for drying or building heat, or the Oak Creek Drinking Water Treatment Plant. Sale of excess energy would require further evaluation, including a market analysis to determine if it would be cost effective.

Exhibits 6 and 7 show simplified energy balances for the Jones Island WRF and the South Shore WRF following implementation of the recommended alternatives. An energy balance like this is required in part to show the relationship between power generation and waste heat. For example, as the Jones Island WRF electrical energy demand is reduced through implementation of the recommendations, less turbine waste heat is available for drying, requiring additional supplemental fuel (natural or landfill gas) be used. The energy balance can be used as part of scenario planning to perform "what-if" evaluations of different combinations of alternatives required to achieve the renewable energy goals. The energy balance shows just one scenario and there are several others that could be implemented to achieve the goals. The energy balance can also be updated as alternatives are implemented and conditions change to help track progress toward the goals.

Exhibit 5
Alternatives Recommended for Implementation

						Annual Values (Year 1)								
Alt No.	**Alternative Name**	**Description**	**Capital Cost**	**Capital Cost Per Annual Energy Reduction ($/MMBtu)**	**Increase in Renewable Power Generation (+) or Power Reduction (-) compared to 2005 Baseline: (MW)**	**Non-energy O&M**	**Increase in Renewable Heat Generation (+) or Heat Reduction (-) compared to 2005 Baseline: MMBTU**	**Energy Savings**	**Net Energy and Non-Energy O&M Savings (*Note 1*)**	**Annual Payment on 20 Yr SRF Loan**	**Net Annual O&M / Energy Savings Less SRF Loan Payment**	**Simple Payback (yr)**	**Include in Plan? (Yes/No)**	**Potential Implementation Risks/Notes**
19b	Maximize South Shore digestion and codigestion to maximize existing engine capacity.	Install new mixers in two more digesters and achieve optimal volatile solids destruction and digester gas production. In addition, co-digest Primary Sludge and sufficient industrial/commercial waste to achieve digester gas production to run existing engines at 4.3 MW output.	$1,473,000	$45	1.10	$96,000	0	$675,000	$579,000	$95,800	$483,200	3	Yes	Uncertain if wastes are available. Could require significant resources to manage a co-digestion program. Assume power production from digester gas increases from 2005 baseline of 3.2 MW to 4.3 MW. This may result in excess renewable energy. No increase in renewable energy from waste heat because waste heat from natural gas is renewable energy. Capital cost assumes the addition of two new mixing systems. Non-energy O&M costs assume $0.01/kWh for engine maintenance.
95	Increase Landfill Gas for Jones Island Turbines and Dryers	In baseline years, no landfill gas was used in turbines. Assumes 1,034 MMBTU/Yr of landfill gas becomes available which would allow JI turbines to generate more power than is needed to satisfy the nominal average plant demand following power demand reductions (8.8 MW). The remaining landfill gas would be used in the dryers.	See Energy Balance and TM 3 for details.					$3,101,040	See Energy Balance and TM 3 for details.					Uncertain if additional LFG will be available. Dryer system must be modified to allow landfill gas to be used in drying. Additional LFG to be used in both turbines and dryers. Cost savings shown is the savings in replacing turbine natural gas with landfill gas. See Energy Balance for accounting of waste heat.
25	South Shore aeration control using dissolved oxygen and ammonia probes	Use multiple probes and an control algorithms to optimize aeration air use.	$4,400,000	$245	-0.60	$83,000	0	$368,000	$285,000	$286,300	($1,300)	15	Yes	Implementation began in 2014 and some of the estimated reduction has already been achieved in 2014. The alternative assumes multiple probes per basin and fully optimized controls.
34	Change Jones Island Channel Mixing to Large Bubble Mixers	Replace diffuser plates in all channels with more efficient large bubble mixers	$8,346,000	$336	-0.83	$35,000	0	$509,000	$474,000	$543,000	($69,000)	18	Yes	Some of the power reduction has already been achieved through adjustment of channel valves and repair of leaks. Power savings could be overestimated in part due to the recent installation of a more efficient blower.
15a	Improve Jones Island primary treatment efficiency	Increase typical number of primary clarifiers in service from 3 to 4 to 7 to 8 to increase capture efficiency. This decreases aeration air energy demand and increases digester gas production.	$0	$0	-0.07	$10,000	0	$43,000	$33,000	$0	$33,000	0	Yes	The amount of digested sludge may be limited by Milorganite chaff/dust issues. If more WAS needed for Milorganite, consider reducing SRT instead of bypassing primary clarifiers to further reduce energy through aeration air reduction. Only energy saved through decrease in aeration air is included. Impacts of increasing digester gas not included in this alternative, but were instead included in alternative 19. Additional primary clarifier maintenance costs estimated at $10,000 per year.
41	Install Variable Frequency Drives for Pumps, Fans, and Other Equipment	Variable frequency drives allow equipment speed to adjust with changing process needs resulting in lower energy demand.	$540,000	$30	-0.60	$5,000	0	$368,000	$363,000	$35,100	$327,900	1	Yes	Detailed evaluation needed. Actual savings will vary. Assumes VFDs installed on multiple motors for an overall savings of 0.60 MW.
11	Decrease Activated Sludge Solids Retention Time (SRT)	Results in decreased aeration demand/energy.	$0	$0	-0.60	$0	0	$368,000	$368,000	$0	$368,000	0	Yes	Would increase WAS and WAS would be digested to generate additional energy. Digesting more WAS then could result in excessive Milorganite dust/chaff. Additional energy from increased digestion not counted in savings because it is counted in alternative 19. Energy decrease is due to decreased blower energy. Decrease in associated engine waste heat not considered under this alternative, but is considered in the overall energy balance.
12	Increase Belt Press Feed Solids Concentration to Increase Cake Solids	Increasing belt press feed solids from 3 percent solids to 5 to 6 percent solids will increase cake solids and drying energy. Installation of additional thickening capacity and TWAS pumping and polymer system improvements likely required.	$824,000	$13	0.00	$104,000	64,033	$384,000	$280,000	$53,600	$226,400	3	Yes	Assumes 1 % increase in cake solids can be achieved. This should be verified through a pilot test. Also assumes an additional gravity belt thickener is required.
2	Optimize Influent Flow Split Between Plants	Diverting more influent flow to South Shore results in lower pumping costs.	$0	$0	-0.03	$0	0	$20,000	$20,000	$0	$20,000	0	Yes	Could result in increase in collection system odors. Alternative evaluation in TM 3 considered multiple variables. To avoid double-counting energy saving, this now includes only influent pumping savings.
15b	Improve Primary Clarifier Operations/Removal Efficiency by installing Inlet Baffling at Jones Island	Increasing primary clarifier capture decreases aeration energy and increases biogas/renewable energy production.	$1,220,000	$816	-0.05	$0	0	$31,000	$31,000	$79,400	($48,400)	39	Yes	Only energy saved through decrease in aeration air is included. Impacts of increasing digester gas not included in this alternative, but were instead included in Alternative 19. If digestion gas production increase were included, savings and payback would be more attractive.
24	Jones Island Aeration Control Using DO and Ammonia/Nitrate Probes	Use multiple probes and a control algorithms to optimize aeration air use.	$5,002,000	$173	-0.97	$86,000	0	$595,000	$509,000	$325,400	$183,600	10	Yes	The alternative assumes multiple probes per basin and optimized controls. Some of the savings have been realized in 2014. The estimated power reduction may be less due to new blower efficiency and other reasons.
8	Modify/Optimize Activated Sludge Process - South Shore Step Feed	Operate South Shore continuously in step feed mode. Up to about 40 percent of the feed can be fed in steps without losing the bio-P process.	$0	$0	-0.22	$0	0	$135,000	$135,000	$0	$135,000	0	Yes	Refined process modeling and/or pilot testing needed to confirm.
9b	Optimize Waste Heat Pressure Control With Dryer Control Modifications	Currently some turbine waste heat must be exhausted to atmosphere to control waste heat. This would modify or replace dryer waste heat flow control dampers controls to minimize having to do that resulting in more waste heat available for drying.	$1,657,000	$44	0.00	$0	37,600	$226,000	$226,000	$107,800	$118,200	7	Yes	Safety concerns associated with modifying dryer controls must be addressed. Assumes 5 percent of waste heat is exhausted following implementation. The actual amount could be lower. Alternative 9a has a lower capital cost but lower savings than alternative 9b and could be implemented in place of alternative 9b.
22	Recover Heat from Dryer Exhaust	Heat is recovered from quench chamber and used to heat polymer or sludge resulting in an assumed 0.5 percent cake solids increase and decreased drying energy.	$1,588,000	$48	0.00	$21,000	32,883	$197,000	$176,000	$103,300	$72,700	9	Yes	Similar to Alternative 16 but Alternative no. 22 more conservative - assumes 0.5% increase in cake solids which must be confirmed with pilot testing
6	Optimize Pumping Energy Using PLC Logic (RAS/WAS Pumps)	Control logic is written that uses pump and system curves to automatically calculate the optimum number of pumps and pump speed to minimize energy.	$20,000	$22	-0.03	$0	0	$18,000	$18,000	$1,300	$16,700	1	Yes	Assumes 4% energy savings - actual savings could vary. If successful for RAS/WAS pumps could be implemented for other pumping systems resulting in additional savings.
5b	Decrease Number of Idle Aeration Basins Online at South Shore	Decreasing number of idle basins would reduce aeration/energy.	$0	$0	-0.12	$16,000	0	$75,000	$59,000	$0	$59,000	0	Yes	Need for the active biomass for wet weather treatment must be considered.
14	Automate Real-Time Energy Optimization Control and Monitoring	Energy use could be optimized in multiple ways including minimizing pumping, maximizing digester gas production, and optimizing sludge transfer between plants.	$968,000	$53	-0.14	$8,000	14,000	$108,000	$100,000	$63,000	$37,000	10	Yes	A 1% energy reduction assumed. Actual reductions will vary. Additional concept development required.
18	Install High-Efficiency Plant Lighting	Estimated savings are very rough and a detailed study is required to better quantify potential savings.	$323,000	$181	-0.06	-$15,000	0	$37,000	$52,000	$21,000	$31,000	6	Yes	A detailed evaluation required to determine actual total potential savings.
13a	Improve Plant wide HVAC Control at Jones Island	This only evaluated limited HVAC controls improvements. Other HVAC improvements could cost effective.	$2,117,000	$540	-0.01	$0	3,750	$26,000	$26,000	$137,700	($111,700)	81	Yes	Most potential is likely in Drying an Dewatering Building. Savings could vary widely depending on scope of the projec and actual savings are likely much higher. A detailed study is required to better estimate actual savings.
	Additional alternatives for potential implementation to help achieve 100 percent net renewable energy:													
21	Wind Energy Generation	One, 3-MW Turbine at South Shore and Jones Island	$18,224,000	$381	1.60	$164,000	0	$982,500	$818,500	$1,185,645	($367,145)	22	No	System size could be refined. Permitting could require time. Grants/incentives could make it more financially viable.
20	Solar Power Electricity Generation	1-MW Capacity panels that require ~ 5 acres of land	$2,700,000	$609	0.15	$27,000	0	$91,000	$64,000	$175,661	($111,661)	42	No	System size could be refined. Grants/incentives could make it more financially viable.

Notes:
1. Positive value represents a cost; negative represents a cost reduction.
2. All energy alternative costs are made comparing to 2005, unless noted otherwise, in which case costs are made comparing to 2014.
3. At 86 MMBtu/hr energy input to the Solar turbines at 8.8 MW of power, the cost of energy is lower. Assumes $3/MMBtu new cost with substituting LFG for NG. See TM 3 for more details.

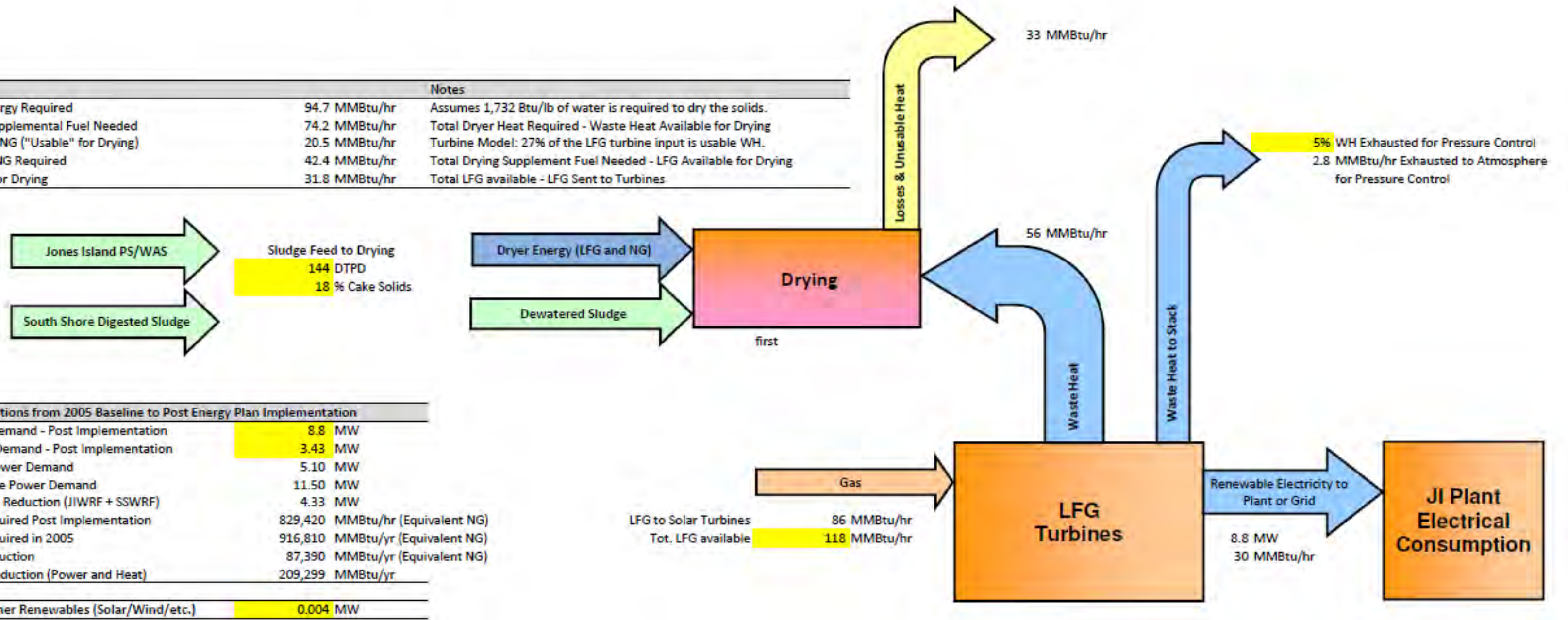
Water Reclamation Facility Power Demand Reductions

Jones Island Total Power Demand Reduction (MW)	-2.66
South Shore Total Power Demand Reduction (MW)	-1.67

EXHIBIT 6

Jones Island WRF Energy Balances

Dryer Energy		Notes
Total Dryer Energy Required	94.7 MMBtu/hr	Assumes 1,732 Btu/lb of water is required to dry the solids.
Total Drying Supplemental Fuel Needed	74.2 MMBtu/hr	Total Dryer Heat Required - Waste Heat Available for Drying
WH Equivalent NG ("Usable" for Drying)	20.5 MMBtu/hr	Turbine Model: 27% of the LFG turbine input is usable WH.
Supplemental NG Required	42.4 MMBtu/hr	Total Drying Supplement Fuel Needed - LFG Available for Drying
LFG Available for Drying	31.8 MMBtu/hr	Total LFG available - LFG Sent to Turbines



Demand Reductions from 2005 Baseline to Post Energy Plan Implementation		
JIWRF Power Demand - Post Implementation	8.8	MW
SSWRF Power Demand - Post Implementation	3.43	MW
SSWRF 2005 Power Demand	5.10	MW
JIWRF 2005 Ave Power Demand	11.50	MW
Power Demand Reduction (JIWRF + SSWRF)	4.33	MW
Dryer Heat Required Post Implementation	829,420	MMBtu/hr (Equivalent NG)
Dryer Heat Required in 2005	916,810	MMBtu/yr (Equivalent NG)
Dryer Heat Reduction	87,390	MMBtu/yr (Equivalent NG)
Total Energy Reduction (Power and Heat)	209,299	MMBtu/yr

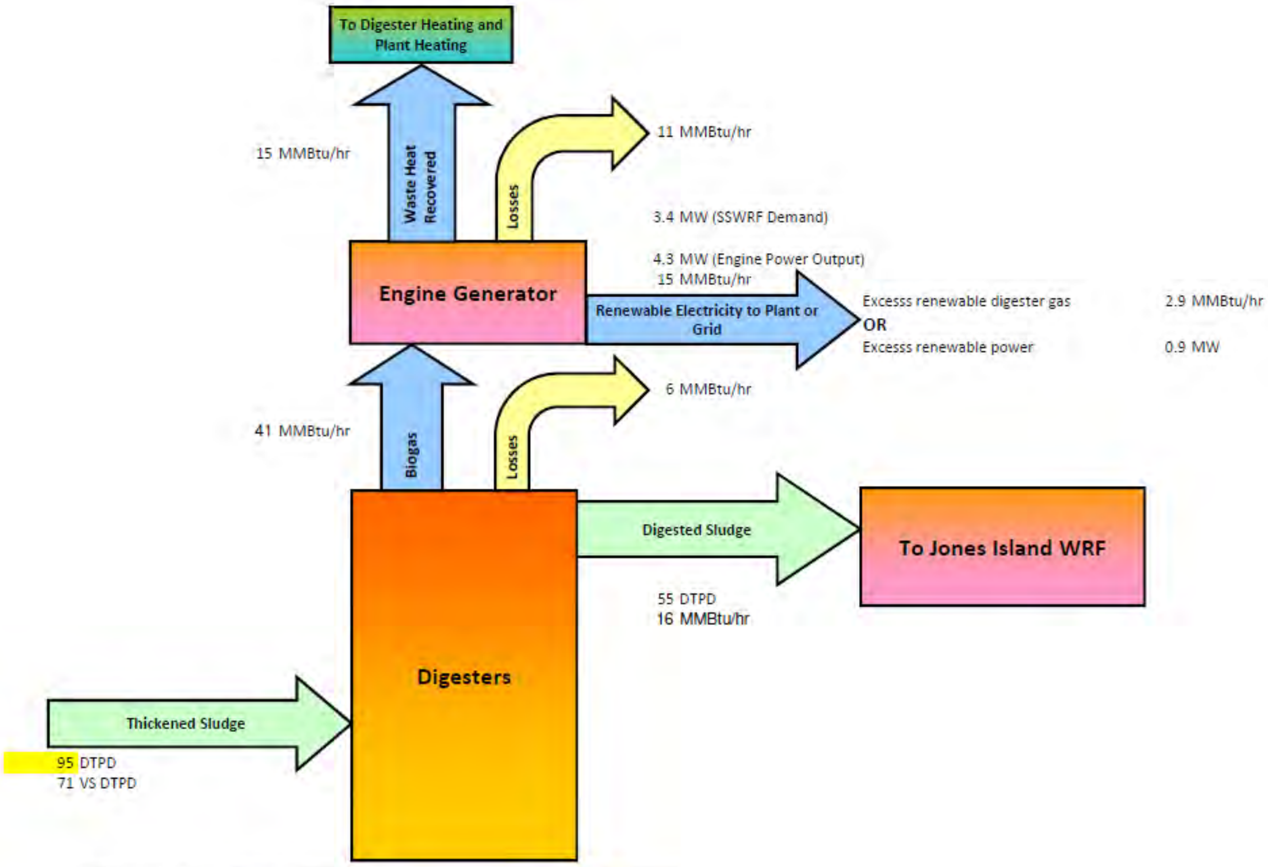
Power from other Renewables (Solar/Wind/etc.)	0.004	MW

Renewable Energy - Post Energy Plan Implementation		
Renewable Source	Energy	
JIWRF Power from LFG	264,220	MMBtu/yr
JIWRF Waste Heat	466,159	MMBtu/yr
JIWRF LFG Used in Dryers	278,766	MMBtu/yr
SSWRF Power from Digester Gas	127,996	MMBtu/yr
SSWRF Engine Waste Heat Used	98,663	MMBtu/yr (Assumes 75% can be used)
Other Renewables (Solar/Wind/etc.)	105	MMBtu/yr
Total Renewable Energy	1,235,909	MMBtu/yr
2005 Baseline Total All Energy	1,763,477	MMBtu/yr
% Renewable w/o Demand Reductions	70%	
Total Energy Reductions	209,299	MMBtu/yr
Revised Total Energy After Demand Reductions	1,554,178	MMBtu/yr
Energy Demand Reduction	11.9%	

% Renewable Energy Post-Energy Plan	80%

Notes:
1. This is intended to be used only as a planning tool. The energy balance uses several simplifying assumptions and the actual energy balance will vary.
2. 1 MMBtu = 1,000,000 Btu
3. Yellow = Input

EXHIBIT 7
South Shore WRF Energy Balances



Digester Gas from Sludge + Co-digestate	1,948,186 cfd
Energy from Sludge + Co-digestate	41 MMBtu/hr
Energy from Sludge	25 MMBtu/hr
Energy from Co-digestate	15.8 MMBtu/hr
Energy Needed to Meet SSWRF Power Demand	11.7 MMBtu/hr
Co-digestate Waste Volume	40,000 gpd

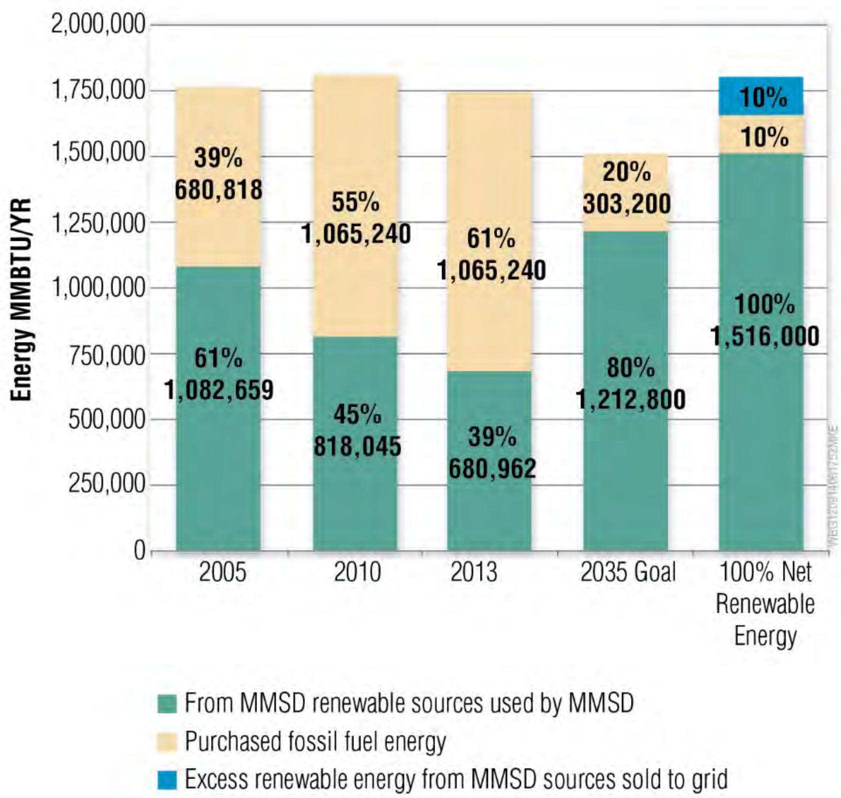
Notes:
1. This is intended to be used only as a planning tool. The energy balance uses several simplifying assumptions and the actual energy balance will vary.
2. 1 MMBtu = 1,000,000 Btu
3. Yellow = Input

Achieving 100 Percent Net Renewable Energy

Further increasing the amounts of landfill gas and digester gas needed for WRF energy needs is a way to achieve a 100 percent net renewable energy goal. That is, because the recommended alternatives in Exhibit 5 combined with some increase in landfill gas and co-digested waste would satisfy only the dry weather flow energy demands. Substantial amounts of energy are required for the short-term peak electrical energy demanded during wet weather, primarily to operate the inline pumps, which by themselves more than double the Jones Island WRF electrical energy demand. In addition, MMSD's non-treatment facilities, including collection system pump stations, use fossil fuel at all times.

To achieve the 100 percent net renewable energy goal, new and purchased renewable energy sources should be considered. The installation of new renewable energy systems could generate excess power during dry weather. Excess power could, in theory, be wheeled back through the electrical grid to sell or to be used at another MMSD facility, resulting in a net annual 100 percent renewable energy use (a cost analysis related to power transmission was not conducted). The most cost-effective renewable energy source is wind power, followed by solar power. Because the cost of wind and solar power technology has decreased dramatically in the last 5 years, the current cost of wind power on a dollars-per-kilowatt-hour basis could be less than the cost of purchasing power, and the cost of solar power would likely be only slightly more costly than purchased power. Previous MMSD evaluations of wind and solar power may not have considered the recent decreases in technology costs. If purchased electrical power costs rise in the future, wind and solar power will continue to become more cost effective. However, the disadvantage of solar and wind power is that the power supplied is variable and is therefore unreliable without battery storage. Another renewable energy source that could be considered and that could provide a constant source of heat is recovery of heat from plant effluent, although this would be more costly than purchasing energy given the current state of technology and current energy prices. Exhibit 8 displays historical renewable energy use and progress toward a 100 percent net renewable energy use. This shows that more renewable energy would have to be generated during dry weather, average-energy demand periods than could be used by the plants and that excess energy could be sold to the grid or others.

EXHIBIT 8
Historical and Projected Renewable Energy



Another method to achieve the 100 percent net renewable energy goal would be to further increase the amount of renewable digester gas produced. This could be done in lieu of or in conjunction with installing renewable energy sources. Further increasing the amount of digested sludge and digester gas would require that limitations in the Milorganite® process be addressed. The portion of cake fed to the dryers that is made from digested sludge is currently limited to approximately 40 percent because, at levels above that, excessive dust and chaff are formed. In addition, the Milorganite® nutrient content must be monitored to ensure the product guarantees are achieved. In order to increase the percentage of digested sludge and increase digester gas production, a pug mill or pelletizer could be installed upstream of the dryers, although that would require a fairly significant capital investment. Another option is to install advanced digestion processes that would reduce the amount of digested sludge and could have the added benefits of increasing digester gas production and decreasing dryer energy use by producing a dryer cake. This would also require a fairly substantial capital investment.

Implementation Plan

The following describes a preliminary plan for implementing the recommendations. The implementation plan will be refined in conjunction with the 2050 Facilities Plan (***Energy Plan Goal No. 4***).

Schedule

The 15 alternatives estimated to result in an immediate positive cash flow should continue to be implemented, if already underway, or further evaluated and, if warranted, implemented within the next 5 years. The alternatives are:

- Alternative 2: Optimize Belt Press Feed Solids Concentration to Increase Cake Solids
- Alternative 5b: Decrease Number of Idle Aeration Basins Online at South Shore
- Alternative 6: Optimize Pumping Energy Using Programmable Logic Controller Logic (Return Activated Sludge/Waste Activated Sludge Pumps)
- Alternative 8: Modify/Optimize Activated Sludge Process—South Shore Step Feed
- Alternative 9b: Optimize Waste Heat Pressure Control With Dryer Control Modifications
- Alternative 11: Decrease Activated Sludge Solids Retention Time at South Shore
- Alternative 12: Increase Belt Press Feed Solids Concentration to Increase Cake Solids
- Alternative 14: Automate Real-time Energy Optimization Control and Monitoring
- Alternative 15a: Improve Jones Island Primary Treatment Efficiency
- Alternative 18: Install High-efficiency Plant Lighting
- Alternative 19: Maximize South Shore Digestion and Increase Co-digestion
- Alternative 22: Recover Heat from Dryer Exhaust
- Alternative 24: Jones Island Aeration Control Using Dissolved Oxygen and Ammonia/Nitrate Probes
- Alternative 41: Install Variable Frequency Drives for Pumps, Fans, and Other Equipment
- Alternative 95: Increase Jones Island WRF Landfill Gas Volume

After that, the other alternatives should be further evaluated in the 2050 Facilities Plan, or through other means and, if warranted, implemented based on cost effectiveness and other considerations. An evaluation should be done to determine how the alternatives can be implemented in conjunction with MMSD's annual capital planning process. Based on that evaluation, a detailed schedule for implementation should be developed.

Financing and Capital Planning

The third goal of the Energy Plan is to produce a positive long-term impact on MMSD's budget. Implementing some of the alternatives may have an immediate positive impact on the budget because the annual energy savings could exceed the annual SRF loan payment, in part due to the current low interest rates. For other alternatives, the savings will be realized in the long-term if energy prices rise in the future. For all alternatives, investing capital will essentially allow MMSD to fix their energy costs for the life of the systems at a rate that may currently be higher than purchased energy prices. However, as energy prices rise in the future, savings will be realized and the exposure of MMSD's risk to rising energy prices will be mitigated. If grants or low/no-interest loans can be obtained, the financial benefits of implementing alternatives will be more favorable.

Alternatives that are not currently in the process of being implemented should be further refined to clearly understand costs and financial savings. As part of the refinement process, project financing and capital planning considerations should be evaluated. There are several sources of financing energy capital projects that should be investigated, including the following:

- **State of Wisconsin Clean Water Fund Program (CWFP).** The CWFP has the potential to provide meaningful financial benefit to MMSD. The CWFP can provide a subsidized 20-year loan backed by the State of Wisconsin and local user fee revenues. All of the alternatives would likely be eligible for CWFP funding.
- **Wisconsin Focus on Energy.** Focus on Energy could provide up to $400,000 each calendar year in the form of a single project grant. Several of the energy efficiency alternatives evaluated would be eligible, although further evaluation would be required to determine eligibility. Program disadvantages include costs for time to complete a competitive application and to document the results, the threshold for eligibility for payback is as low as 1 to 1.5 years, and long-term secondary project benefits are not considered.
- **Wisconsin State Energy Initiatives.** The State of Wisconsin is not currently providing site-specific, stand-alone energy, or wastewater funding initiatives. In the future, the Wisconsin State Legislature may consider returning the CWFP's interest subsidy from 75 percent of market to the former interest subsidy levels of 40 or 45 percent of market.
- **Future We Energies Initiatives.** Future revisions to We Energies renewable energy policies could change in ways that could be advantageous to MMSD and potential revisions should be tracked.
- **U.S. Environmental Protection Agency/U.S. Department of Energy Competitive Grants (grants.gov).** These funding programs are offered periodically by agencies for the purpose of advancing technology or demonstrating unique applications of existing technologies. They generally provide cost sharing grants of between $50,000 and $500,000 based on the project's ability to meet very detailed funding program objectives. There is often fairly significant competition for the grants and the preparation of a competitive application requires some effort.

Other Implementation Issues

Other implementation issues to be addressed along with the related WEF Energy Roadmap topic areas include the following:

- **Demand-side Management/Energy Generation.** Consider the balance and trade-offs between cost-effectiveness and energy efficiency. Consider restructuring the O&M contract based on this analysis. MMSD currently pays the majority of energy costs and Veolia (in some cases) optimizes operations using considerations other than energy, such as minimizing effluent loads and reducing operator labor and maintenance costs.
- **Organizational Culture.** Continue to use the energy team to implement recommendations to achieve goals by allowing the team to drive implementation by actively tracking progress toward goals. Determine more ways to motivate staff at all levels to make changes for energy savings.
- **Communication and Outreach.** Develop a communication plan that describes how consultation and outreach will be done with key stakeholders including ratepayers, regulators, legislators, environmental advocacy groups, and the media. An effective communications plan is a key to achieving support from stakeholders that may be required to help set the energy policies needed to implement the plan. Messages should be developed that explain the purpose of MMSD's energy policies and plan, as well as the benefits.

- **Innovating for the Future.** Develop a plan for tracking future energy innovations that could be integrated into the plan. The plan should be regularly updated.
- **Demand-side Management.** Refine the existing systems and efforts to manage energy demand to minimize peak energy charges. Existing demand management systems primarily use spreadsheet-based tools to manage peak demands and minimize demand charges. The tools could be refined by integrating them into supervisory control and data acquisition (SCADA) and developing enhanced load-shedding strategies. The efforts to implement energy monitoring and energy data tracking software should be continued to produce timely and consistent feedback and reporting. A software pilot will soon be undertaken and, if that is successful, full-scale implementation should be done. Having the ability to robustly track progress toward the Energy Plan goals is essential.
- **Strategic Management**. Refine the evaluation of some alternatives as noted in Appendix C. Most of the alternative evaluations were done conceptually using rough estimates of costs and energy. Alternatives related to the activated sludge process were done using a computer process model that should be refined by integrating the results of sampling for wastewater characteristics for calibration.

Energy Plan Goals

PREPARED FOR:	Karen Sands/Milwaukee Metropolitan Sewerage District
COPY TO:	Erin Laude/CH2MHILL John Grosskreutz/Kapur Steve Graziano/CH2M HILL Julian Sandino/CH2M HILL Alan Scrivner/AES
PREPARED BY:	Rusty Schroedel/Brown and Caldwell
REVIEWED BY:	Bill Desing/CH2M HILL
DATE:	July 1, 2014 (Revised January 4, 2015)
PROJECT NUMBER:	MMSD Contract M030721P01; MMSD File Code: P6150

The MMSD's 2035 Vision includes a goal to increase renewable energy use. To help achieve that goal, MMSD has begun to develop an Energy Plan. The purpose of the Plan is to document the current energy baseline and to establish a viable path toward achieving that strategic objective. The plan should accomplish the following:

- Establish a baseline of energy usage and management capabilities.
- Compare the baseline to future conditions and goals, characterize the gap, and identify methods, costs, and possibilities to increase energy efficiency and increase renewable energy generation and use.
- Make recommendations to achieve the 2035 Vision, including range of costs, implementation schedule, financial strategies, while considering risks and benefits.
- Be a collaborative effort of the consultant team and the District's energy integration team, using the strategic goals of WEF's Energy Roadmap.
- Build upon recent MMSD energy-related projects including Energy Data Management, Greenhouse Gas Emissions, Energy Footprint project, the Landfill Gas Turbine Project, and others.

Introduction and Background

MMSD's 2035 Vision

MMSD's 2035 Vision has the following goals related to energy:

- Meet a net 100 percent of MMSD's energy needs with renewable energy sources. Net is defined as the total renewable energy from internal and external sources divided by the total energy used by MMSD – generated and purchased – calculated on an annual basis.
- Meet 80 percent of MMSD's energy needs with internal, renewable sources.
- Use the Greenseams® Program to provide for 30 percent sequestration of MMSD's carbon footprint.
- Reduce MMSD's carbon footprint by 90 percent from its 2005 baseline.

The Energy Plan addresses the first two goals and also has the following two additional goals:

- Produce a long-term positive impact on MMSD's budget
- Provide a foundation for MMSD 2050 Facilities Plan which began in 2014.

MMSD Staff

To monitor and manage energy-related projects, and to make ongoing progress towards the energy-related objectives of the 2035 Vision, the District has organized internal teams. The Energy Integration Team has met regularly to discuss goals, collaboration, and joint interests regarding energy projects. For this plan, the Energy Integration Team will accomplish the following:

- Participate in documenting current energy conservation and renewable energy projects.
- Receive from the District project manager project updates at regular Energy Integration Team meetings.
- Review and comment on select sections of the draft final report.

The Energy Integration Team Working Group is a subset of the Energy Integration Team and will provide guidance for the Energy Plan and be available to the project team as necessary. The Working Group will:

- Participate in documenting current energy conservation and renewable energy projects.
- Convene as needed to provide input to the project team.
- Review and comment on draft work products as needed.

Purpose of the Plan

The purpose of the plan was identified in the request for proposals. The scope of work is as follows:

- Meet MMSD's 2035 Vision goals, including 100 percent of MMSD's energy needs from renewable energy sources and 80 percent of MMSD's energy needs from internal, renewable sources.
- Produce a long-term, positive impact on the District's budget as it relates to energy consumption.
- Provide a foundation for MMSD's next round of facilities planning scheduled to begin in 2014. This should include a recommendation for next steps of further analysis.

Key Background Documents

The following key background documents have been identified as resources to be used and relied upon for the Energy Plan:

- Minutes from Energy Integration Team meetings
- Electronic copies of previous reports and memos associated with Project M03043, Energy Management and Greenhouse Gas Data Management Systems
- The Excel spreadsheet developed and maintained by the District's budget office to characterize and project energy purchased, energy generated, and energy used at all District facilities

Summary of the Project Scope

The project scope comprises three major task areas:

- Project Management
- Energy Planning
- Plan Document

Project Management

The project management task includes the typical requirements for the administrative management of the project. The scope includes requirements for scheduling, document management, monthly status reporting, meetings, coordination, and quality control (QC).

Energy Planning

The energy planning task includes a description of the requirements for the development of three technical memorandums (TM) upon which the final plan document will be based:

- TM1, Plan Goals—This document
- TM2, Current Baseline—A review and analysis of the District's energy data to document the baseline condition
- TM3, Future Desired Conditions and Recommendations

The scope of work includes an attachment with a detailed description of the post-2005 District projects, initiatives, and operational changes. It also provides direction for comparing the baseline to the future condition, requires recommendations to be developed, and defines the content of the TM2 and TM 3 deliverables.

Plan Document

The scope requires completion of a plan document. The three TMs will be appendices to the plan document. An outline will be submitted first. Then a draft report will be prepared for the District to review.

Summary of Workshop No. 1

Plan Goals and Objectives

Workshop No. 1 was held April 29, 2014. The object of the workshop was to review and confirm the project goals and to establish the conditions for the development of the energy baseline. The goals outlined in the scope as "Purpose of the Plan" are summarized above and were confirmed at an April 4, 2014 meeting.

Energy Roadmap Progression Ratings

The project scope requires a determination of the District's progress toward its energy goals with respect to the Water Environment Federation's "Energy Roadmap" utility progression characteristics (WEF 2013 Publication *"The Energy Roadmap—A Water and Wastewater Utility Guide to More Sustainable Energy Management."* To assess MMSD's progress toward the WEF Roadmap characteristics, an exercise of assessing the District's ratings was performed in a workshop as part of the development of the goals and objectives.

The Roadmap comprises six characteristics on which a utility can rate its level of progression based upon "importance" and "achievement." *Importance* indicates the significance of the topic area is to the utility and its customers, and as part of its overall mission, vision, and objectives. *Achievement* indicates how well has the utility has advanced in accomplishing the highest levels of progression. Table 1 lists the six characteristics and how they were rated as to importance and achievement, from one to five (five being highest) following group discussion during the workshop where each was rating number from 1 to 5. The results are also represented graphically.

The analysis shows that, in general, the District has accomplished high levels for the following characteristics:

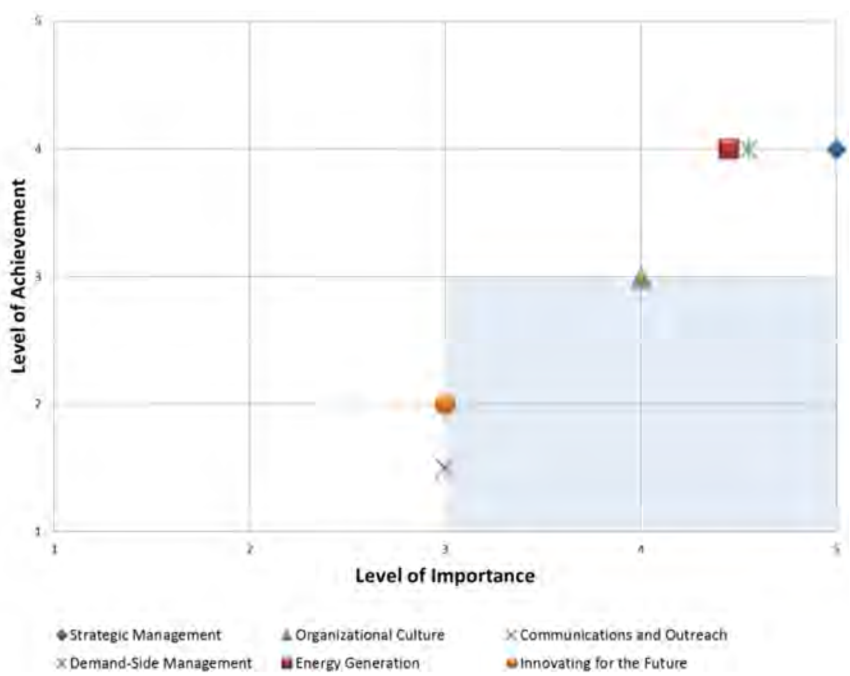
- Strategic Management
- Demand-Side Management
- Energy Generation

Characteristics that could require further progress are:

- Communication and Outreach
- Innovating for the Future

TABLE 1
Energy Management Roadmap Assessment

	Importance	Achievement
Strategic Management	5	4
Organizational Culture	4	3
Communications and Outreach	3	1.5
Demand-Side Management	4.5	4
Energy Generation	4.5	4
Innovating for the Future	3	2



Conclusions

Group discussion at Workshop No. 1 confirmed the initial Energy Plan project goals and objectives and determined them to be appropriate. It was agreed that the Energy Plan should have long-term positive impacts on the District's budget and provide the foundation for upcoming facility planning. Through past projects and efforts, the District has made substantial progress in several energy areas, as evaluated using information from WEF's Energy Roadmap publication. Areas for future development are Communication and Outreach, and Innovating for the Future. These areas have the following elements:

- Communication and Outreach
  - Customer and community outreach and education
  - Regulatory and legislative outreach
  - Media outreach
  - Environmental advocacy outreach
  - Water sector outreach
- Innovating for the Future
  - Research and development
  - Risk management
  - Alternative treatment technologies
  - Alternative management technologies

The WEF Roadmap publication includes detailed information on each of these characteristics.

Recommendations

It is recommended that the Energy Plan retain the three primary purposes as originally defined in the project scope. The Plan should consider how to improve in the WEF Roadmap characteristics identified as having a lower level of achievement in the roadmap exercise.

Energy Baseline

PREPARED FOR:	Karen Sands/Milwaukee Metropolitan Sewerage District
COPY TO:	Steve Graziano/CH2M HILL; Rusty Schroedel/Brown and Caldwell; John Grosskreutz/Kapur; Alan Scrivner/AES; Julian Sandino/CH2M HILL
PREPARED BY:	Erin Laude/CH2M HILL
REVIEWED BY:	Bill Desing/CH2M HILL
DATE:	August 22, 2014 (Revised January 4, 2015)
PROJECT NUMBER:	MMSD Contract M030721P01; MMSD File Code: P6150

Introduction and Background

MMSD's 2035 Vision includes a goal to increase renewable energy use. To help achieve that goal, MMSD has begun to develop an energy plan. The plan should accomplish the following:

- Establish a baseline that includes current energy usage and management capabilities.
- Compare the baseline to future conditions and goals, characterize the gap, and identify methods, costs, and possibilities to increase energy efficiency and decrease energy requirements.
- Make recommendations to achieve the 2035 Vision, including range of costs, implementation schedule, and financial strategies, while considering risks and benefits.
- Be a collaborative effort of the consultant team and the District's energy integration team, using the strategic goals of WEF's Energy Roadmap.
- Build upon recent MMSD energy-related projects including Energy Data Management, Greenhouse Gas Emissions, Energy Footprint project, the Landfill Gas Turbine Project, and others.

This memorandum describes and establishes one of the plan's tasks - the energy baseline.

MMSD's 2035 Vision

MMSD's 2035 Vision has the following goals related to energy:

- Meet a net 100 percent of MMSD's energy needs with renewable energy sources. Net is defined as the total renewable energy from internal and external sources divided by the total energy used by MMSD – generated and purchased – calculated on an annual basis.
- Meet 80 percent of MMSD's energy needs with internal, renewable sources.
- Use the Greenseams® Program to provide for 30 percent sequestration of MMSD's carbon footprint.
- Reduce MMSD's carbon footprint by 90 percent from its 2005 baseline.

Based on discussions with the District's Energy Integration Team it was determined that the District desires an energy baseline to track progress against calendar years 2005 *and* 2010. The year 2005 was selected because it was the year the 2035 Vision of reducing MMSD's carbon footprint by 90 percent was established. The year 2010 was selected because that was when the efforts to achieve the 2035 Vision began.

Key Background Documents

The following background documents are key resources to be used and relied upon for the Energy Baseline:

- Electronic copies of previous reports and memos associated with the following projects:
  - M03034PO1, Greenhouse Gas Inventory
  - M03034PO2, Energy Footprint Project
  - M03043, Energy Management and Greenhouse Gas Data Management Systems
- The District's Energy Excel spreadsheet developed and maintained by the District's budget office to characterize and project energy purchased, energy generated, and energy used at all District facilities
- 2005 and 2010 Air Emission Inventories (AEIs) submitted to the Wisconsin Department of Natural Resources (WDNR)
- Vehicle fuel data spreadsheets maintained by the District and Veolia
- Turbine waste heat and electricity generation performance curves for the GE turbines

Energy Demand and Production

MMSD's energy needs are met through a combination of purchased energy and internally produced energy. MMSD purchases electricity, natural gas, fuel oil and propane for use at the Jones Island and South Shore water reclamation facilities (WRFs), headquarters, pump stations and other facilities (13th Street and Colectivo). MMSD fleet vehicles consume diesel fuel, natural gas, and unleaded gasoline fuel.

At the South Shore WRF, engine generators fueled by digester gas and natural gas produce much of the plant's required electrical power and building and digester heat. At the Jones Island WRF, turbines fueled by natural gas historically have produced almost all of the plant's electrical power and heat needed for buildings and drying Milorganite®. In late 2013, the natural gas turbines were replaced by new turbines that use landfill and natural gas. One natural gas turbine was retained to reduce electrical demand charges.

Table 1 shows energy used by facility and type (purchased/generation). Throughout this document, energy is usually expressed in units millions of British thermal units per year (MMBtu/year) because that is how energy use has generally been recorded and because it allows each type of energy to be represented in common units that can be more easily compared.

Energy Baseline

Establishing the energy baseline is an important first step for tracking progress against the goals established by the 2035 Vision. Understanding the historical energy use will help target potential savings opportunities and establish base year energy consumption for use in evaluating energy optimization savings. This section summarizes historical energy use for the Jones Island WRF, South Shore WRF, Headquarters and Laboratory, 13th Street Facility and collection system pump stations. Breakdowns of energy purchased, generated and used in 2005, 2010, and 2013 by facility and major uses is presented below.

Electricity Usage and Generation

Figure 1 shows the electricity used for each facility. The Jones Island WRF uses most of the District's electricity, the South Shore WRF uses significantly less, and the pump stations and other ancillary facilities combined use less than 5 percent of the total. Energy consumption at both treatment facilities is affected by changing conditions, especially changes in wet weather flows and Milorganite® production.

The electricity used and generated by facility for 2005, 2010, and 2013 is shown in Table 1 and Figure 2. With the exception of the conveyance pump stations, the electrical power used shows some downward trends. This is due to a variety of factors that are described below.

Table 2 summarizes the electricity used per million gallons treated at each plant. These values can be bench-marked to other wastewater utilities. For example, 2,113 kWh/MG is the average used by secondary treatment facilities according to the Pacific Gas and Electric's *Energy Baseline Study for Wastewater*

Treatment Plants. Similarly, a 2007 Water Research Foundation survey of 449 Wastewater Treatment Plants (WWTPs) showed a range of 1,000 to 3,000 kWh/MG. A recent publication of the Electric Power Research Institute cites a range of 1,700 to 2,000 kWh/MG. It should be noted that the power per flow energy intensity metric is a fairly simple method of benchmarking energy performance and does not account for variations in plant sizes, organic loading, or treatment levels. For example, energy demand per million gallons treated for Jones Island WRF is high compared to similarly sized treatment plants, while South Shore WRF is on the low end. In general, South Shore WRF energy demand is low because the plant only partially processes solids before sending to Jones Island WRF. Jones Island WRF energy demand is high because it processes the additional solids from South Shore WRF, and the Milorganite® production process is energy intensive.

TABLE 1
MMSD Electricity Used (MMBtu/yr)
Energy Baseline [a]

Facility	2005	2010	2013
Jones Island			
Electricity Purchased	109,818	167,845	129,713
Electricity Generated, Turbine, Natural Gas	259,655	173,242	157,169
Electricity Generated, Turbine, Landfill Gas [b]			7,507
Electricity Generated, Solar	64	95	89
Total Jones Island Electricity Used	**369,537**	**341,182**	**294,479**
South Shore			
Electricity Purchased	46,073	72,558	83,485
Electricity Generated, Natural Gas	9,592	17,604	14,644
Electricity Generated, Digester Gas	95,675	27,334	35,501
Total South Shore Electricity Used	**151,340**	**117,496**	**133,630**
HQ & Lab Electricity Purchased	8,791	8,208	7,306
HQ & Lab Renewable Electricity Purchased	0	598	598
S. 13th Street Electricity Purchased	1,555	1,073	1,089
Total Other Buildings Electricity Used	**10,346**	**9,879**	**8,993**
Pump Stations Electricity Purchased	7,530	7,897	14,393
Total Electricity Used	**538,752**	**476,454**	**451,495**
Percent Change from 2005		**-12%**	**-16%**

[a] Electrical energy reduction or generation in terms of kilowatt hours (kWh) are converted to millions of Btu per year (MMBtu/yr) by the following conversion factor: 1 MMBtu equals 293.3 kWh. Unless noted otherwise, it is assumed that energy reduction or generation occurs 8,760 hours per year.

[b] Electricity generated from landfill gas in 2013 was not shown in the historical energy data. Electricity generation was assumed to be 34 percent of landfill gas energy burned based on preliminary turbine performance test data. The landfill gas used was obtained from the 2013 Air Emission Inventory.

FIGURE 1
MMSD Electricity Used (MMBtu/yr)
Energy Baseline

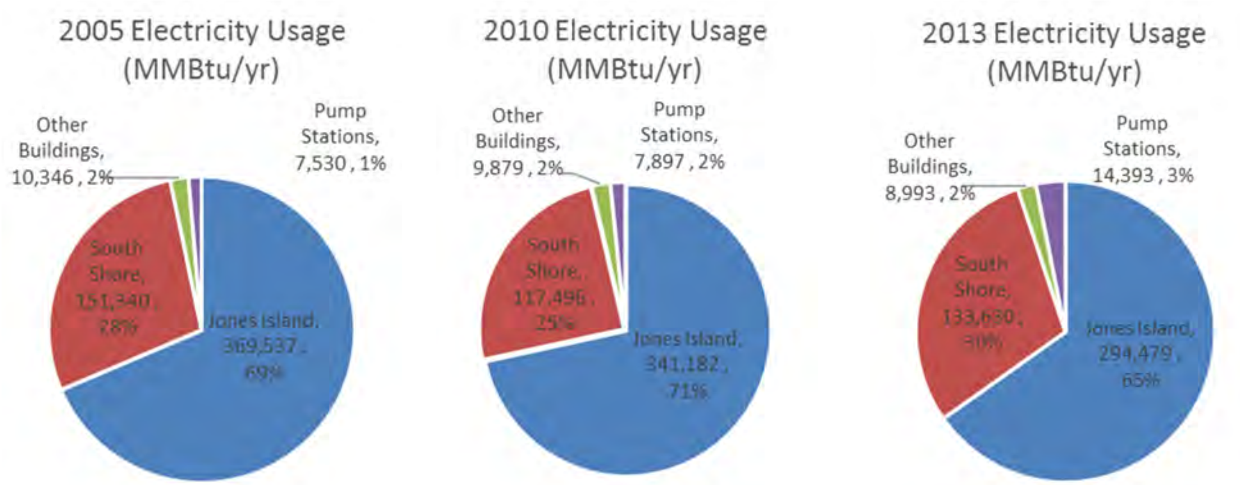


FIGURE 2
MMSD Electricity Used (MMBtu/yr)
Energy Baseline

NG=natural gas, DG=Digester gas

The South Shore WRF value for 2005 is on the low end of the cited energy intensity range has fluctuated over time. The Jones Island WRF energy intensity is generally higher than the averages but has declined significantly since 2005. The average electrical energy intensity values for other plants usually do not include the energy needed for biosolids disposal that is most commonly done at other plants using land application or landfilling that requires energy for trucking. The electrical energy load at the Dewatering and Drying facility—primarily for HVAC—is significant and is included in the Jones Island WRF electrical power use contributing to the Jones Island WRF's higher than average electrical intensity. In addition, power consumption at the Jones Island WRF is higher than at the South Shore WRF because of higher influent pumping power (higher head) and inline storage pumping. The electricity usage per ton of dried solids at the Jones Island WRF has also decreased since 2005 (Table 3). However pumping and aeration electrical power use have a larger impact on the Jones Island WRF electrical power than changes in solids dried especially because much of the Dewatering and Drying electrical power use is likely not highly dependent upon solids dried.

TABLE 2
MMSD Electricity Usage per Millions Gallons Treated
Energy Baseline

Facility	2005	2010	2013
Jones Island electricity used (kWh)	108,295,236	99,985,823	84,299,173
Jones Island MG treated	30,320	34,497	36,150
Jones Island electricity average MW	12.4	11.4	9.6
Jones Island MGD	83	95	99
Jones Island kWh/MG	3,572	2,898	2,387
South Shore electricity used (kWh)	44,351,191	34,433,172	39,161,302
South Shore MG Treated	32,694	36,290	34,195
South Shore electricity average MW	5.1	3.9	4.5
South Shore MGD	90	99	94
South Shore kWh/MG	1,357	949	1,145

1 kWh = 3412.3 Btu

TABLE 3
Jones Island Electricity Usage per Ton of Dried Solids
Energy Baseline

Facility	2005	2010	2013
Jones Island electricity used (kWh/yr)	108,295,236	99,985,823	84,299,173
Dry tons of solids to the dryers (tons/yr)	50,084	57,363	56,455
Dry tons of solids to the dryers (tons/day)	137	157	155
Jones Island kWh/ton	2,162	1,743	1,529

1 kWh = 3412.3 Btu

Energy Usage and Generation

Jones Island WRF Energy. Energy consumption at the Jones Island WRF includes electricity, natural gas, landfill gas, propane, and fuel oil. Natural gas is used in turbines to generate electricity and the dryers and boilers. Additional natural gas is used for other facility heating needs.

In 2005 and 2010, the Jones Island WRF had two GE electricity-generating turbines (nominally rated at 223 MMBtu/hr, 16 MW each) that operated on natural gas with fuel oil backup. In 2013, MMSD installed three Solar electricity-generating turbines (nominally rated at 43 MMBtu/hr, 4.6 MW each) that operate on landfill gas or natural gas.

The electrical power conversion efficiency for the GE turbines is about 17 percent. The electrical power conversion efficiency for the new Solar turbines is approximately 34 percent. The efficiencies vary with outdoor temperature and power output.

Heat is recovered from the turbine exhaust gas for use in the dryers and for the waste heat boiler. Turbine exhaust gas (waste heat) is used for solids drying and supplemented with natural gas to achieve the required drying temperature. Before 2013, the GE turbines typically produced all of the waste heat required for drying and building heat because the GE turbines produced more, higher-temperature waste heat than the Solar turbines. Currently there is insufficient landfill gas to allow the Solar turbines to produce all power for the Jones Island WRF and natural gas is used in the Solar turbines to supplement the landfill gas to meet the required Jones Island WRF power demand. Also, the lower temperature waste heat from the Solar turbines is not sufficient to meet drying and building heating needs and therefore supplemental natural gas is required.

The Jones Island WRF heating system has two Cleaver Brooks boilers, 11.7 MMBtu/hr each, that operate on natural gas with fuel oil backup and one waste heat boiler that only uses waste heat from the turbines. The facility also has natural gas space heaters and boilers rated less than 5 MMBtu/hr for which energy consumption is not individually measured. Propane fuel is a backup fuel for the space heaters.

Table 4 and Figures 3 and 4 summarize the energy purchased, generated, and used at the Jones Island WRF by source. These show that when less energy was generated by the turbines, more electricity was purchased and more natural gas was used in the dryers—likely to make up for the decrease in waste heat available for drying because of the decrease in electrical power production. Turbine energy production appears to have varied based on the relative price of natural gas to purchased electricity. If natural gas prices were high in comparison to purchased electricity, less power was likely generated to reduce costs.

The amount of renewable energy used in 2010 and 2013 is less than that in 2005. More electricity was purchased and less renewable energy generated in 2010 and 2013 than in 2005. This was partially because in 2013, the GE natural gas turbines available less often due to turbine maintenance and construction of the landfill gas turbines. This resulted in a decrease of waste heat available from the turbines to dry Milorganite® and heat buildings, and the waste heat from natural gas combustion is considered renewable energy. Nonrenewable natural gas had to be used to replace the reduction in waste heat. In addition, a fire at the South Shore WRF engines and other digestion issues resulted in lower digester gas (a renewable fuel) production. Since 2013, following startup of the landfill gas turbines and resolution of digestion issues the District's renewable energy use has increased significantly.

TABLE 4
Jones Island Energy Purchased/Generated (MMBtu/yr)
Energy Baseline

	2005	**2010**	**2013**
Purchased electricity	109,818	167,845	129,713
Generated electricity, Solar	64	95	89
Purchased natural gas, turbines	1,514,250	1,088,042	1,247,000
Purchased natural gas, dryers	40,506	317,147	478,116
Purchased natural gas, other (facility heating)	99,143	133,381	90,010
Purchased landfill gas	—	—	22,080
Purchased fuel oil	54	682	266
Purchased propane	0	0	0
Total Energy Purchased/Generated	**1,763,835**	**1,707,192**	**1,967,275**
Generated electricity, natural gas	259,655	173,242	157,169
Generated electricity, landfill gas			7,507
Waste heat used, from natural gas [a]	876,304	732,917	555,318

TABLE 4
Jones Island Energy Purchased/Generated (MMBtu/yr)
Energy Baseline

	2005	2010	2013
Waste heat used, from landfill gas [a]	0	0	13,407
Energy lost or used in waste heat boiler [b]	378,291	181,883	549,086
Total Energy Used [c]	**1,385,543**	**1,525,309**	**1,418,189**
Percent Renewable Energy Used [d]	**63%**	**48%**	**39%**

[a] Waste heat used is estimated as the heat required to dry the solids minus the amount of natural gas energy used in the dryers. Waste heat derived from fossil fuel is considered renewable energy. Small amounts of waste heat generated in 2013 were derived from renewable landfill gas.

[b] Energy lost is estimated as the energy input to the turbines, minus the sum of the amount of waste heat used for drying, and the amount of electricity energy generated. It represents turbine inefficiencies, waste heat used in the waste heat boiler (not measured) and waste heat not used because it either was exhausted for duct pressure control or was not needed.

[c] Energy used is calculated by subtracting the energy lost from the total energy purchased/generated.

[d] Renewable energy used is the electricity generated from the Solar turbines using landfill gas and the waste heat used that originates from burning landfill gas and natural gas in the turbines.

FIGURE 3
Jones Island Energy Purchased/Generated (MMBtu/yr)
Energy Baseline

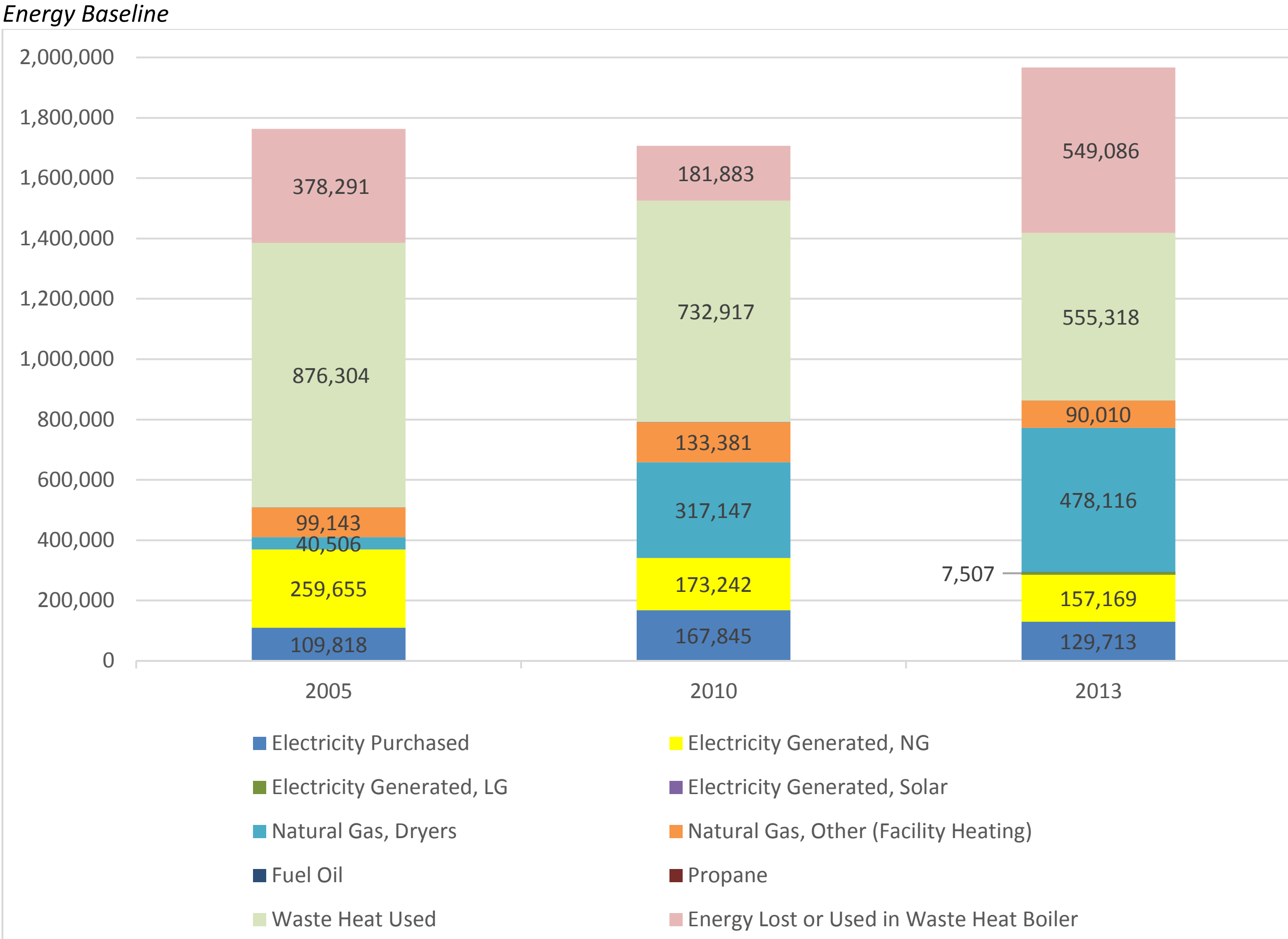
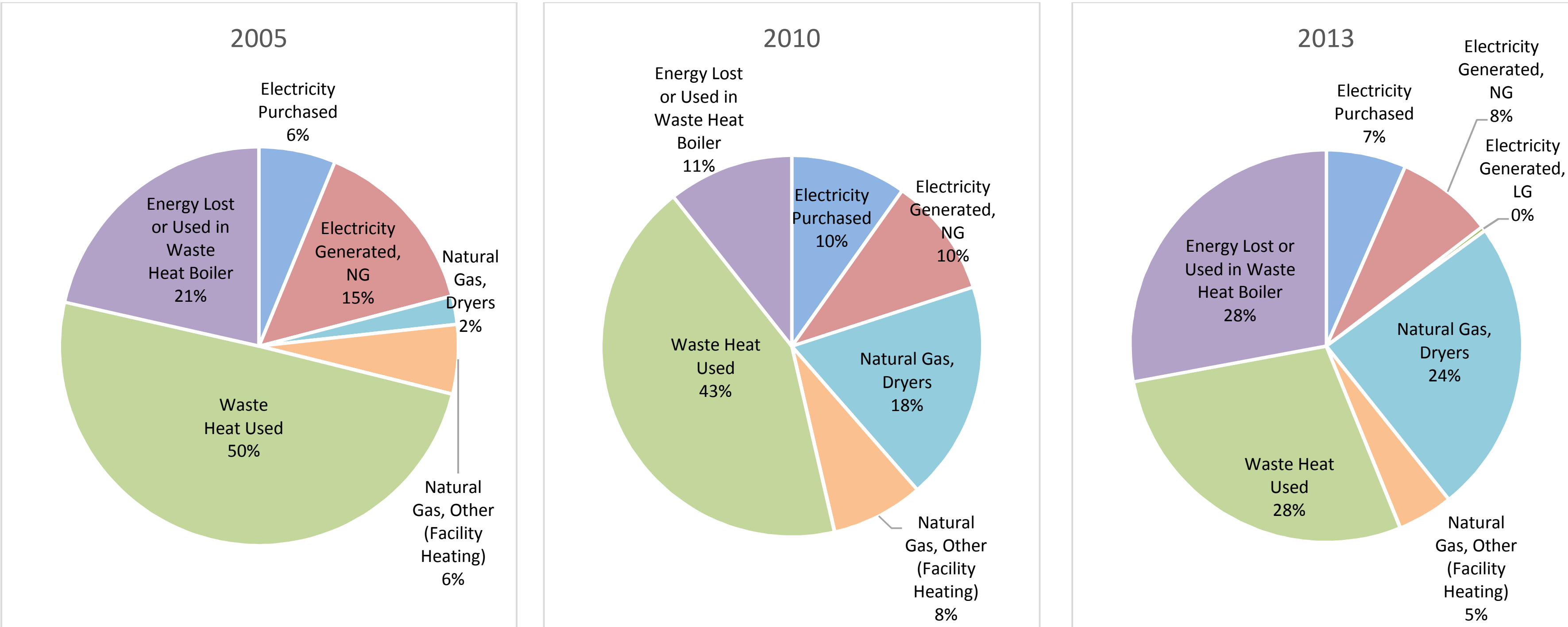


FIGURE 4
Jones Island Energy Purchased/Generated (MMBtu/yr)
Energy Baseline



The waste heat used for drying is estimated based on the amount of solids dried, the estimated energy required to dry the solids (0.76 MMBtu/hr per dry ton[1]), and the amount of natural gas burned in the dryers as reported in the annual Air Emissions Inventories. Some waste heat has historically been used to generate building heat using the waste heat boilers but this value is not measured or reported and therefore not shown.

With the GE turbines, not all the waste heat could be used because some waste heat—typically about 20 percent—was exhausted to atmosphere for pressure control or because there was excess waste heat that could not be used. Not all the waste heat was needed when Milorganite® production was lower or in the warmer months when waste heat was not required to generate building heat.

Jones Island generates an additional small portion of its energy from renewable sources using solar panels installed on the Dewatering and Drying Building. The solar panel system has a rated capacity of 20 kW but produces less (about 4 kW) because of cloud cover and night darkness.

South Shore WRF Energy. Table 5 summarizes the energy purchased and generated at the South Shore WRF. The South Shore WRF has five IC engine generators: four with a nominal rated capacity of 0.9 MW, and one with a nominal rated capacity of 1.5 MW that burn digester or natural gas to produce electricity. Waste heat recovered from the engines is used to produce hot water in boilers that heat the digesters and supply building heat. Digester gas can also be burned in boilers for building or digester heating.

Digester gas that cannot be used is burned in the flares. The gas burned in the flares is shown to illustrate what energy may be available that could be beneficially used to generate electricity or heat. During periods of peak digester gas production, gas may need to be flared, especially if one or more engine generators are offline for maintenance or during the warmer months when digester gas for building heat is not required.

In 2005, MMSD had the following IC engines:

- IC Engines 1 to 4 (10.59 MMBtu/hr each, 1 MW each)
- IC Engine 5 (16.28 MMBtu/hr, 1.5 MW))

Four of these engines were replaced in 2009 and the fifth one remained. The 2010 and 2013 data are based on the following IC engines:

- IC Engines 1 to 4 (DG 9.27/NG7.7 MMBtu/hr each, 930/770 kw each)
- IC Engine 5 (16.28 MMBtu/hr, 1.5 MW)

The electrical power conversion efficiency for the generators is roughly 32 percent, based on the average of the 2010 and 2013 data provided by District's Energy Excel spreadsheet.

Heat is recovered from jacket water and exhaust gases of the engine blower. The heat is recovered using an extensive hot water system for building and digester heating. If the recovered heat does not satisfy demand, boilers will be fired on natural gas or digester gas. The plant boiler system includes seven boilers, all of which may use either natural gas or digester gas:

- 2 Cleaver Brooks, 5.2 MMBtu/hr each
- 3 Kewaunee, 20.9 MMBtu/hr each
- 2 Scum Building, 5.3 MMBtu/hr each

The facility has space heaters and boilers rated less than 5 MMBtu/hr for which energy consumption is not measured.

[1] 83.9 MMBtu/hr for 110 dry tons, estimated by AES Engineering using performance testing data.

TABLE 5
South Shore Energy Purchased/Generated (MMBtu/yr)
Energy Baseline

	2005	2010	2013
Purchased electricity	46,073	72,558	83,485
Purchased natural gas used in generators	29,592	56,257	43,661
Digester gas used in generators	295,151	87,355	105,848
Purchased natural gas for boilers	1,377	6,233	3,947
Digester gas used in boilers	13,194	14,018	44,623
Purchased natural gas, other (facility heating)	57,417	24,708	25,639
Digester gas flared	22,538	15,680	68,070
Total Energy Purchased/Generated	**465,342**	**276,808**	**375,273**
Generated electricity from natural gas	9,592	17,604	14,644
Generated electricity from, digester gas	95,675	27,334	35,501
Engine waste heat used from natural gas [a]	8,878	16,877	13,098
Engine waste heat used from digester gas [a]	88,545	26,206	31,754
Energy lost [b]	144,591	71,270	122,582
Total Energy Used [c]	**320,751**	**205,538**	**252,692**
Percent Renewable Energy Used [d]	**64%**	**41%**	**49%**
Percent Renewable Energy Used, without Natural Gas Waste Heat	**62%**	**33%**	**44%**

[a] Waste heat used is calculated based on an estimated capture rate of 30 percent of energy input to the generators.

[b] Energy lost is calculated based on the total amount of digester gas flared, the total amount of energy input to the generators, minus the amount of waste heat used, minus the amount of electricity energy generated and represents turbine inefficiencies and unused waste heat or digester gas.

[c] Energy used is calculated based on the total amount of electricity purchased or generated, plus the amount of waste heat used, plus the amount of all other energy not used in the generators and excludes energy lost.

[d] Renewable energy used includes electricity generated from digester gas, digester gas used in the boilers, and waste heat from digester gas and natural gas.

When all available engine heat is recovered and used the overall energy efficiency of the engine generators increases to roughly 75 percent. Part of the waste heat is not used in the warmer months when energy is not required for building heat. Waste heat recovery is not measured and is assumed to be roughly 30 percent of the total energy input to the generators each year.

Table 5 and Figures 5 and 6 summarize the energy purchased and used at South Shore by source.

FIGURE 5
South Shore Total Energy Purchased/Generated (MMBtu/yr)
Energy Baseline

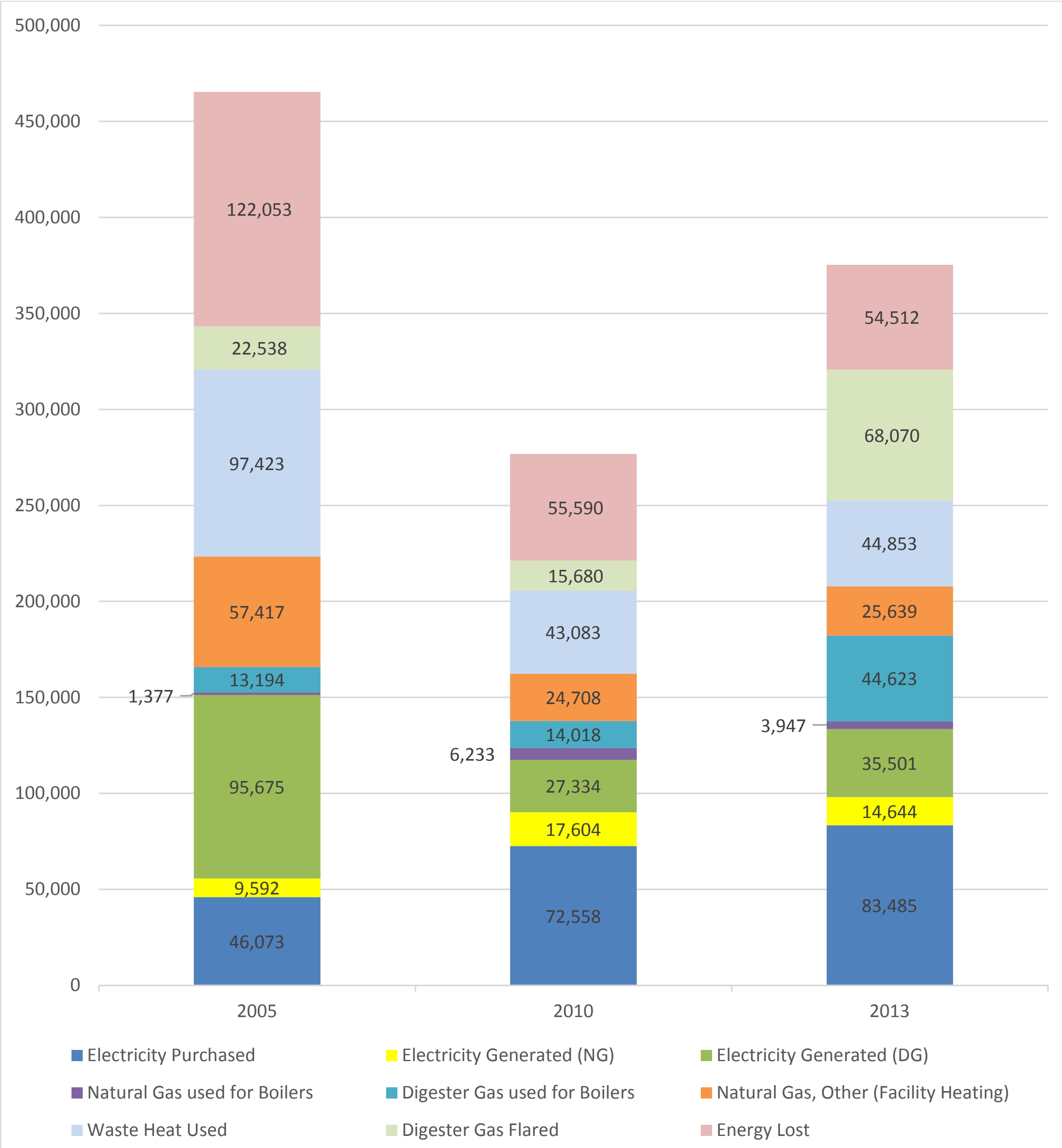


FIGURE 6

South Shore Total Energy Purchased/Generated (MMBtu/yr)

Energy Baseline

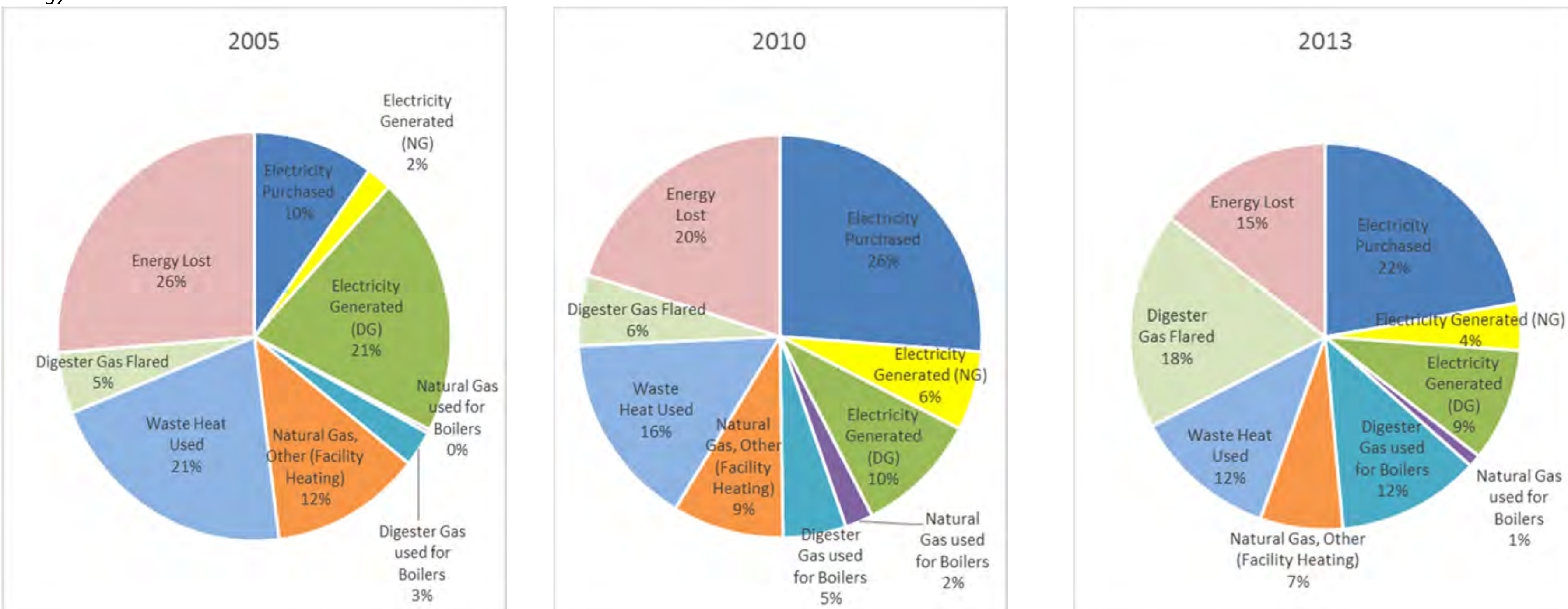


FIGURE 7
Total Energy Used for Other Buildings (MMBtu/yr)
Energy Baseline

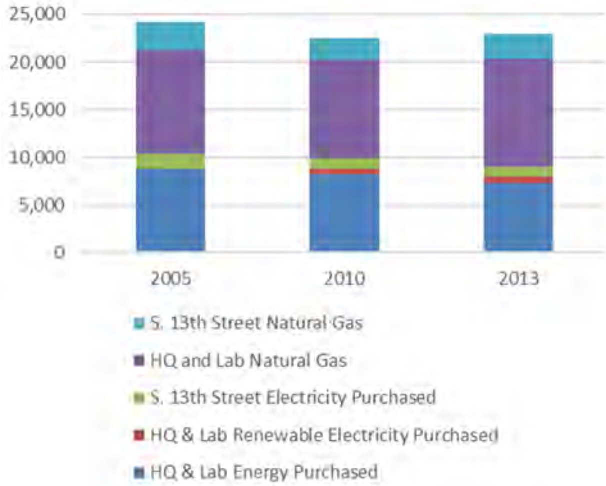
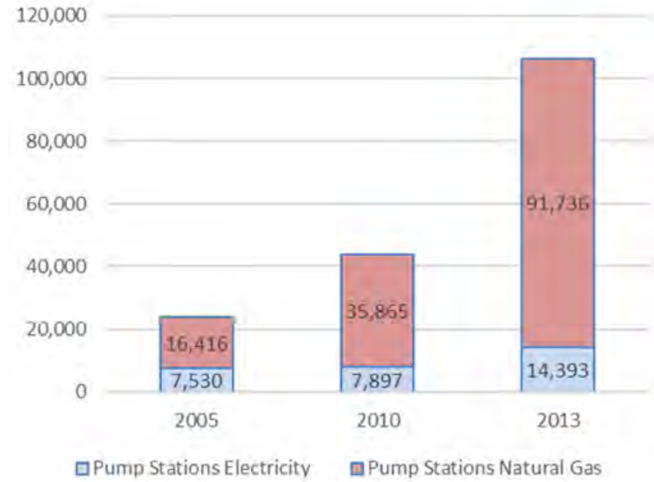


FIGURE 8
Total Energy Used for Pump Stations (MMBtu/yr)
Energy Baseline



Other Buildings. The District owns two non–pump station buildings—Headquarters/Laboratory and 13th Street—that use natural gas for heating, but the quantities are relatively small. Total energy consumption for the buildings has varied (Figure 7).

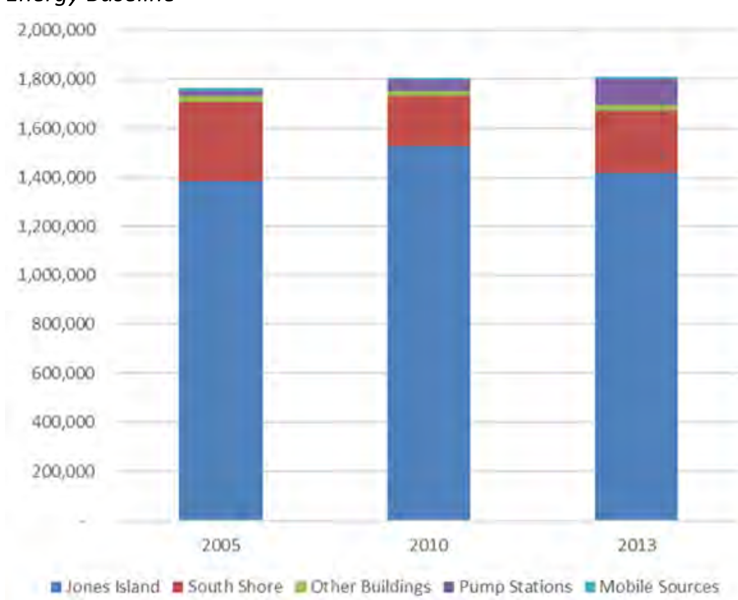
Pump Stations. Some of the conveyance pump stations use natural gas for heating, but the quantities are relatively small. Total energy consumption for the pump stations has increased (Figure 8) significantly. This increase was due to pump station upgrades required to meet NFPA guidelines for air changes, which greatly increased the amount of heat required during the winter.

Vehicle Fuel Usage. MMSD's vehicles consume unleaded gasoline, compressed natural gas, and diesel fuel. This fuel usage represents a relatively small portion of MMSD's total energy consumption. Vehicle energy consumption has varied (Table 6).

TABLE 6
Energy Use for Vehicles (MMBtu/yr)
Energy Baseline

	2005	2010	2013
Gasoline Energy Used	5,687	7,026	4,860
Diesel Energy Used	3,369	3,262	3,706
Total Vehicle Energy Used	9,056	10,289	8,566

FIGURE 9
Total Energy Used (MMBtu/yr)
Energy Baseline



Energy Use Summary and Conclusions

As shown in Table 7 and Figure 9, the total amount of energy used by the District has increased slightly from 2005 to 2013 whereas the total amount of energy purchased or produced has increased significantly. This means that less of the renewable energy in the form of waste heat and digester gas has been recovered and beneficially utilized. Again, the large increase in energy consumption for the pumping stations in 2013 was due to an increased heat demand as part of the pump station upgrades to meet NFPA guidelines. Table 7 also shows what the 2013 energy use would be if the actual pump station 2013 energy use was similar to the historical use.

TABLE 7
District Energy Usage Summary (MMBtu/yr)
Energy Baseline

	2005	2010	2013	2013Alt[a]
Jones Island	1,385,544	1,525,309	1,418,189	1,418,189
South Shore	320,751	205,538	252,692	252,692
Other buildings	24,181	22,516	22,993	22,993
Pump stations	23,946	43,762	106,129	43,762
Mobile sources	9,056	10,289	8,566	8,566
Energy lost[b]	522,882	253,153	671,668	671,668
Total energy used (does not include energy lost)	1,763,477	1,807,414	1,808,569	1,746,202
% Change from 2005		+2%	+3%	-1%
Total energy purchased or produced (includes energy lost)	2,286,359	2,060,567	2,480,237	2,417,870
% Change from 2005		-10%	+8%	+6%
Renewable energy	1,082,659	818,045	680,982	680,982
% Renewable	61%	45%	38%	39%

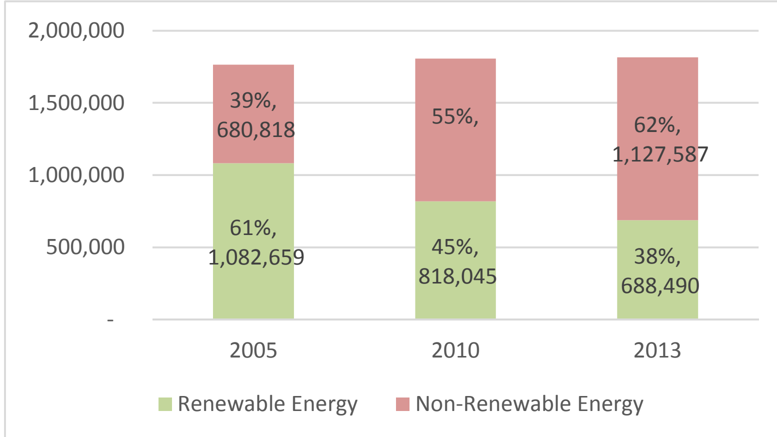
[a] Assumes pumping station energy for 2013 is incorrect and equals the pumping station energy in 2010.

[b] Energy lost includes JI turbine waste heat used in waste heat boiler because boiler waste heat could not be accurately estimated

The amount of renewable energy in the form of either energy recovered from waste heat at the Jones Island and South Shore WRFs or generated from digester gas has declined significantly. Renewable waste heat recovered at the Jones Island WRF declined because less electricity was generated in the turbines and more electricity was purchased, likely because of relatively high natural gas prices. With less electricity generated in the turbines, waste heat (a renewable energy source) is available for drying and building heat and more non-renewable natural gas must be purchased to replace the waste heat. Renewable digester gas production at the South Shore WRF has decreased likely because of digester mixing issues and other reasons.

As shown in Figure 10, the overall percentage of renewable energy used by the District as decreased significantly but is expected to rise in 2014 with the increased use of landfill gas in the landfill gas turbines and improvements in digester mixing and digester gas production. Initial rough calculations show that if landfill gas quantities would increase to contracted quantities and if digester gas mixing is improved, the percent renewable energy could rise to perhaps more than 60 percent. This estimate will be refined as the project progresses and alternatives are evaluated.

FIGURE 10
Total Renewable Energy Used (MMBtu/yr)
Energy Baseline



It is important to note that estimated 2005 renewable energy is likely higher than would have been previously thought because it was determined that MMSD staff determined that waste heat generated in turbines and engines using natural gas should be classified as renewable energy. The GE turbines produced larger quantities of waste heat than the landfill gas turbines resulting in large amounts of renewable energy for solids drying and building heat. However, the landfill gas turbines produce electricity more efficiently than the GE turbines which results in lower overall energy use.

As shown in Table 8, the energy consumption per volume of wastewater treated and per ton of solids dried decreased between 2005 and 2010. As discussed, the amount of biosolids dried is one of the key parameters that impacts the amount of energy required. However the use of this metric is limited because it is based on total energy rather than energy used only by solids or liquids processes and there are other variables which impact energy use.

TABLE 8
Total Energy Usage by Flow and Solids (MMBtu/yr)
Energy Baseline

	2005	2010	2013	2013 Alt[a]
Total energy used (MMBtu/yr)	1,763,477	1,807,414	1,808,569	1,746,202
Million gallons treated (MG/yr)	63,014	70,787	70,345	70,345
Average (MG/day)	173	194	193	193
Energy used per MG treated (MMBtu/MG)	28.0	25.5	25.7	24.8
l Solids dried (dry tons/day)	137	157	155	155
Energy used per solids dried (MMBtu/ton)	35.2	31.5	32.0	30.9

[a] Assumes pumping station energy for 2013 is incorrect and equals the pumping station energy in 2010.

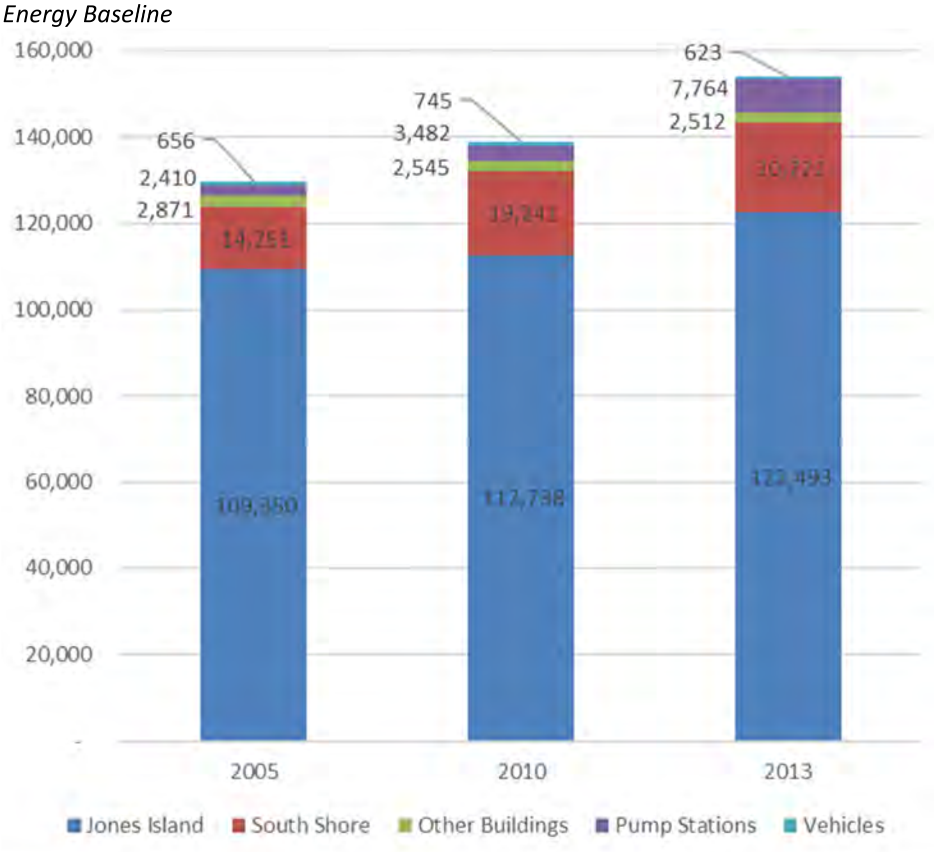
Greenhouse Gas Emissions

While not part of the scope of work for this project, greenhouse gas emissions were estimated because the data was readily available. Table 9 and Figure 11 summarize the nonbiogenic[2] greenhouse gas emissions in terms of the total carbon dioxide equivalent (CO_{2e}) metric tons per year due to energy consumption. The increase is primarily due to the decrease in renewable energy use discussed previously. The Jones Island WRF is by far the largest emitter of greenhouse gases although as the use of landfill gas increases the amount of greenhouse gas emissions will decrease.

TABLE 9
Greenhouse Gas Emissions (CO_{2e} metric tons/yr)
Energy Baseline

	2005	2010	2013
Jones Island	109,350	112,738	122,493
South Shore	14,251	19,241	20,722
Other buildings	2,871	2,545	2,512
Pump stations	2,410	3,482	7,764
Mobile sources	656	745	623
Total	129,538	138,752	154,115
% Change from 2005		+7%	+19%

FIGURE 11
Total Greenhouse Gas Emissions (metric tons CO2e/yr)
Energy Baseline



2 Per USEPA reporting rules, nonbiogenic greenhouse gas emissions exclude CO_2 emissions but include CH_4 and N_2O emissions released from burning biomass, such as digester gas and landfill gas.

Evaluation of Alternatives

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DATE: December 9, 2014

PROJECT NUMBER: MMSD Contract M030721P01
MMSD File Code: P6150

Introduction

MMSD's 2035 Vision includes a goal to increase renewable energy use. To help achieve that goal, MMSD is developing an energy plan. The plan should accomplish the following:

- Establish a baseline that includes current energy usage and management capabilities.
- Compare the baseline to future conditions and goals, characterize the gap, and identify methods, costs, and possibilities to increase energy efficiency and decrease energy requirements.
- Make recommendations to achieve the 2035 Vision, including range of costs, implementation schedule, and financial strategies, while considering risks and benefits.
- Build upon recent MMSD energy-related projects including Energy Data Management, Greenhouse Gas Emissions, Energy Footprint project, the Landfill Gas Turbine Project, and others.

MMSD's 2035 Vision has the following goals related to energy:

- Meet a net 100 percent of MMSD's energy needs with renewable energy sources.
- Meet 80 percent of MMSD's energy needs with internal, renewable sources.

In multiple workshops and meetings with MMSD staff, more than 90 alternatives were identified that could be implemented to help meet MMSD energy goals. Those alternatives were prioritized using monetary and nonmonetary criteria, and 37 alternatives were determined to be most likely to be effective. The criteria and prioritization scores are shown in Appendix F. This memorandum evaluates the 37 alternatives by completing the following for each:

- Describe the alternative and how it would be implemented.
- Estimate its capital and operation and maintenance (O&M) costs.
- Estimate the amount of renewable energy that could be generated or the amount of energy use reduction

Exhibit 1 summarizes the financial and energy reduction results of the evaluations. This information can be used to help rank and prioritize alternatives. Ranking can be done using several different financial metrics including payback, capital cost expended per unit of energy, and others. In addition to financial metrics, non-monetary criteria developed in a previous workshop will be used in the upcoming November 3, 2014, workshop to also help prioritize the alternatives. From the prioritized list of alternatives, a group of alternatives will then be selected that in aggregate will result in the District meeting its renewable energy goals of 80 percent renewable energy with internal sources and 100 percent with internal and external renewable sources. Note that the cost and energy estimates are based on conceptual engineering, and although useful for comparing alternatives, they should not be used for other purposes, such as capital planning, without further refinement of the alternatives.

Following Exhibit 1 are the detailed evaluations for each alternative.

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ALTERNATIVE 1

Optimize Biosolids Transfer between Plants for Energy Generation and Use

Alternative Description

The Jones Island and South Shore WRFs can use the interplant pipelines to transfer raw solids, WAS, and digested solids between plants. The original design concept was for the South Shore WRF to dispose of digested solids by land application, but now all solids from both plants are processed at Jones Island WRF into Milorganite®, chaff, and dust. The mixture of solids for Milorganite® production must be such that the Milorganite® product can achieve the guaranteed nutrient concentrations (5 percent nitrogen and 2 percent phosphorus minimum). In addition the sludge blend to the dryers must allow for proper Milorganite® drying, pellet formation, and dust and chaff minimization. For example, it is key that the amount of digested sludge be limited for effective Milorganite® production. According to Veolia staff, current operations are as follows:

- All WAS generated at the Jones Island and South Shore WRFs goes to Milorganite® production. All South Shore WRF primary sludge and about 75 percent of Jones Island WRF primary sludge goes to the South Shore WRF for digestion. To minimize dust, operations staff limit the digested sludge content to the Jones Island WRF dryers to a maximum content of about 40 percent.
- WAS feed to Milorganite® is a blend of 5 percent solids TWAS at 5 percent and bypassed raw WAS to achieve a 3.25 percent maximum blend.
- Anaerobic digestion at the South Shore WRF consists of four North Digesters (No. 9 to 12) and two South Digesters (No. 6 and 8) online. Because of mixing problems, only 70 percent of the volume is active.
- It is assumed that all digester gas is captured for power and heat energy production.
- Milorganite® produces a pellet of 94 percent solids with a minimum guarantee of 5 percent nitrogen and 2 percent phosphorus content.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

Sending part of the WAS generated to the South Shore WRF for digestion would increase digester gas production and thereby increase renewable power and heat energy production. The amount of WAS sent to the digesters is limited by the Milorganite® needing to maintain a minimum 5 percent nitrogen and 2 percent phosphorus concentration. Anaerobically digested sludge typically has low phosphorus and nitrogen content, as the anaerobic digestion process converts the particulate nutrients into soluble PO_4 and NH_3 which are recycled in the filtrate.

For the purpose of this exercise, it was assumed that digesting WAS would not affect Milorganite® pellet formation or cause excessive dust and chaff. It has been found that when the amount of digested sludge in the cake fed to the dryers exceeds about 40 percent, problems with excessive dust and chaff begin to occur.

The following assumptions were used in the evaluation:

- Jones Island WRF to South Shore WRF interplant pumping: 3 pairs of pumps with a capacity of 2,000 gallons per minute (gpm) at 420 feet TDH, each using a 400 horsepower (hp) motor. It was assumed the pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 413 hp.
- Jones Island WRF Equalization/Blending Tank pumping: Capacity of 1,870 gpm at 138 feet TDH, each using a 100 hp motor. It was assumed the pumping efficiency is 70 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 109 hp.

- South Shore WRF to Jones Island WRF interplant pumping: 3 pumps with a capacity of 1,160 gpm at 465 feet TDH, each using a 250 hp motor. It was assumed the pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 265 hp.
- It was assumed additional digestion capacity could be put online if needed to maintain a minimum digester SRT of 15 days.

Dryer Modifications Needed to Increase Digested Sludge

To allow the amount of digested sludge fed to the dryers to increase 40 percent, modifications could be made to the drying system to mitigate the problems with excessive dust and chaff. One method to do this would be to install pelletizers upstream of the dryers. A pelletizer is a piece of equipment that forms a pellet out of a mass of particles (often fine particles) in the presence of moisture. This type of equipment is part of many other types of dryer systems that dry a high percentage of digested sludge (sometimes 100 percent digested sludge). The advantage of having the pelletizer is that the pellet can be formed before the material enters the dryer and thereby reduce the amount of chaff that is created and ensure an even sized particle of the desired diameter is formed. An example of a pelletizer as made by Mars Mineral is shown in Exhibit 1-1.

EXHIBIT 1-1
Mars Mineral Pelletizer

The original Dewatering and Drying facility design included pelletizers to form pellets out of the sludge cake and recycle material. The pelletizers were removed from the design as part of a cost reduction modification. Because the sludge dryers were designed around including a pelletizer, space exists to install pelletizers. The electrical requirements for a pelletizer are much higher than for the existing screw conveyors and some electrical improvements would be required including increasing the motor starter size and power conduit between the starter and the motor.

Estimate of Energy Reduction or Recovery

The optimum sludge transfer, based on the assumptions listed, additional electrical power could be generated (Exhibit 1-2). Also, more heat would be available for digester and building heating. The amount of WAS to be digested was found to be limited by the minimum nitrogen content of the Milorganite® (5 percent) but showed that up to about 30 percent of the South Shore WRF WAS to be directed to the anaerobic digestion system. Other scenarios for sludge transfer could also be developed and evaluated. This is merely one example of how energy production could potentially be increased.

EXHIBIT 1-2
Biosolids Transfer Optimization
Energy Production and Consumption Summary

Constituent	Baseline	Optimized
WAS to digestion, gpd (before thickening)	0	248,430
Primary sludge to digestion—gpd	625,800	633,000
Digestion SRT—days	18.9	15.5
Estimated nutrient content of Milorganite®		
% N	5.3%	5.0%
%P	2.7%	2.8%
Estimated VSR, %	36%	35%
Estimated digester gas production, ft^3/d	1,224,000	1,340,000
Estimated digester gas LHV	520	540

EXHIBIT 1-2
Biosolids Transfer Optimization
Energy Production and Consumption Summary

Constituent	Baseline	Optimized
Estimated energy production, kW	2,716	3,087
Estimated energy produced, kWh/yr @ 8,000 hr/yr	21,727,100	24,694,200
Interplant pumping: Jones Island WRF to South Shore WRF	116 hp	121 hp
Interplant pumping: South Shore WRF to Jones Island WRF	165 hp	49 hp
Total interplant pumping energy, kWh/yr @ 8,760 hr/yr	1,818,550	1,100,150
Net energy, kWh/yr	19,908,500	23,594,100
Renewable power increase, kWh/yr	N/A	3,685,600

Cost Estimate

With all facilities being existing and all equipment well within its capacities, there is no capital cost associated with this alternative. Maintenance costs associated with changes in the interplant pumping are assumed to be negligible. Exhibit 1-3 shows the net energy savings associated with the extra energy generation minus the pumping energy.

EXHIBIT 1-3
Estimated O&M Costs for Alternative 1

Parameter	Value	Comment
Estimated additional H_2S control	$48,534	$0.00115 per ft^3
Estimated additional engine maintenance	$29,671	$0.01/kWh
Total additional O&M	$78,205	
Estimated additional energy generated	-$257,989	3,685,600 kWh/yr @ $0.07/kWh
Net O&M	-$179,784	

Discussion and Considerations

The following should be considered before moving forward with implementation of this alternative:

- The optimized flow split was based solely on achieving a maximum energy generation while maintaining a minimum nutrient content in the Milorganite®. The optimized biosolids transfer model has a WAS fraction of 45 percent. In reality, the amount of digested sludge sent to drying is limited to a maximum of 40 percent (of the total sludge) to prevent impacts on Milorganite® production.
- The baseline model simulation estimates a 62/38 percent split of WAS/digested sludge to Milorganite®. Historically, this value is closer to 75/25 percent. It is suspected that the discrepancy comes from issues with digestion and poor digestion performance.

ALTERNATIVE 2

Optimize Influent Flow Split between Plants

Alternative Description

Note: Original information stated that about one-third of all flow could be directed to either plant. After the analysis was complete, additional information was provided showing that it appears only about 7 percent of flow can be diverted to each plant, although the number could be higher. The simplified evaluation discussed at the end of this alternative uses 7 percent.

About one-third of the flow in the MMSD collection system can be sent only to the Jones Island WRF and another third only to the South Shore WRF. The remaining third can be diverted to either WRP. The one-third that can be directed to either plant currently is split about evenly between the two plants. The Jones Island WRF performs influent pumping using the low-level (LL) and high-level (HL) screw pumps, but the South Shore WRF does not have influent pumping. This was thought to mean that energy use could be reduced by diverting more flow to the South Shore WRF. This alternative evaluates optimizing the influent flow split between plants to minimize energy use. The potential constraints to consider are:

- Additional loading to either plant will result in higher MLSS concentrations, which will affect the solids loading on the secondary clarifiers.
- Changes in loading will affect the aeration required for treatment and its associated power demand. It is assumed the blowers have the appropriate turndown to meet the simulated conditions.
- Changes in loading will affect interplant transfer of sludge because of changes in sludge mass at each plant.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

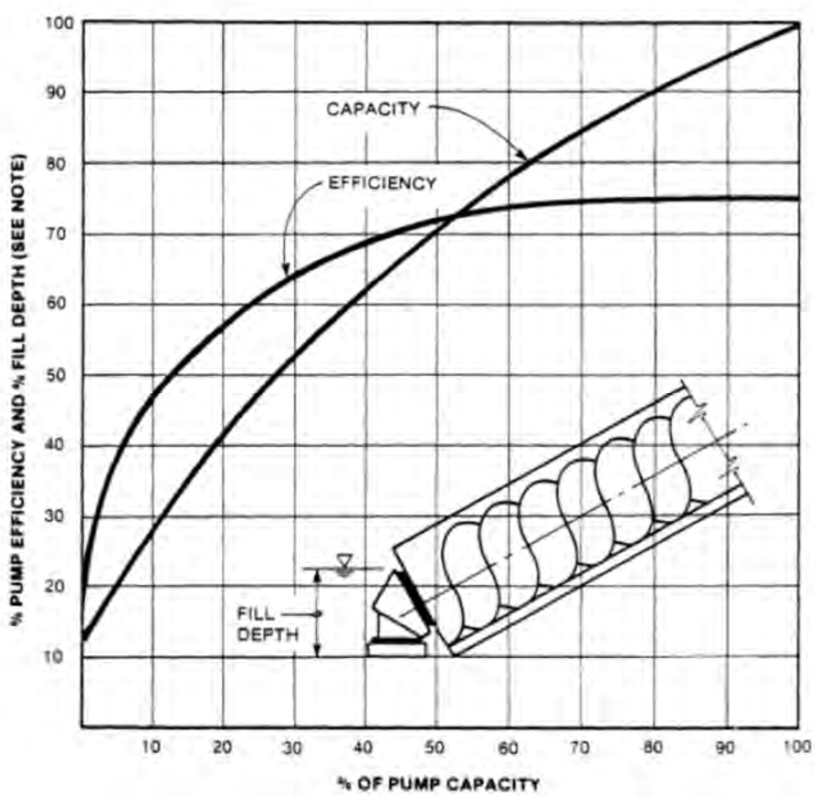
The existing remote-controlled gates in the collection system can be adjusted to change the split of influent flow between the plants. Therefore, no capital improvements are required. Under current operations, the flow is split evenly between the two plants. Therefore, there are no physical modifications required but impacts of optimizing the flow split on plant operations must be considered.

Characteristics of the existing system were assumed to be as follows:

- Jones Island WRF and South Shore WRF primary clarifiers both operate with 50 percent total suspended solids (TSS) removal efficiency.
- Jones Island WRF to South Shore WRF interplant pumping: 3 pairs with a capacity of 2,000 gpm at 420 feet TDH each, using a 400 hp motor. Assumed pumping efficiency is 60 percent, motor efficiency is 90 percent, and other losses is 95 percent, for a power input of 413 hp.
- Jones Island WRF equalization/blending tank pumping: Capacity of 1,870 gpm at 138 feet TDH each, using a 100 hp motor. Assumed pumping efficiency is 70 percent, motor efficiency is 90 percent, and other losses is 95 percent, for a power input of 109 hp.
- South Shore WRF to Jones Island WRF interplant pumping: 3 pumps with a capacity of 1,160 gpm at 465 feet TDH, each using a 250 hp motor. Assumed pumping efficiency is 60 percent, motor efficiency is 90 percent, and other losses is 95 percent, for a power input of 265 hp.
- The Jones Island WRF uses 2 pump stations: LL and HL. The LL pumps pump to the HL pumps. Historical data show that roughly 45 percent of the influent flow goes to the LL pumps and the remaining 55 percent to the HL pumps.
- Jones Island WRF LL pumps: 4 at 46.7 million gallons per day (mgd) at 24 feet TDH using a 350 hp motor. Estimated efficiency at capacity is 75 percent. Exhibit 2-1 is an example pump curve for screw pumps. Losses due to gearbox and motor efficiency were assumed to be 93.6 percent to match actual dry weather power draw measurements (252 HP at 69 mgd) done recently by the District.

- Jones Island WRF HL pumps: 5 at 82.6 mgd at 14.5 feet TDH using a 350 hp motor. Estimated efficiency at capacity is 75 percent. Exhibit 2-1 is an example pump curve for screw pumps. Losses due to gearbox and motor efficiency were estimated at 80.6 percent to match actual dry weather power draw measurements (232 HP at 33 mgd).
- Assumes the Jones Island WRF aeration system uses 85,000 scfm average with blowers at 60 percent efficiency, drawing 5,140 bhp using a 5,500 hp motor. Total draw assumed at 5,244 hp, at 98 percent motor efficiency.
- South Shore WRF typically uses a 30,000-scfm blower that is 75 percent efficient, drawing 1,451 bhp from a 1,500-hp motor. Total draw is 1,481 hp, assuming a 98 percent motor efficiency.

EXHIBIT 2-1
Example Pump Curve for Screw Pumps



Estimate of Energy Reduction or Recovery

A computer process model was configured and an optimization routine used to estimate the optimum flow split between the Jones Island and South Shore WRFs in order to minimize energy. To minimize energy usage, about 35 percent of the flow that can be directed to either plant should be sent to the Jones Island WRF. At that split, the net power production is at its highest. The net power production is the power generation from the South Shore WRF engines minus the power for the Jones Island WRF influent pump station, interplant pumping, and aeration power. Exhibit 2-2 summarizes the alternative.

Cost Estimate

All facilities and equipment needed for this alternative are existing; no capital expenditures would be required. Maintenance costs associated with changes in the interplant pumping, blowers, and influent pumping are assumed to be negligible. Some limited additional costs are assumed for engine maintenance and digester gas treatment. Exhibit 2-3 presents the net energy savings.

EXHIBIT 2-2
Flow Split Optimization
Energy Production and Consumption Summary

Parameter	Baseline/Current Operation Assumptions	Optimized	Comments
Optimum flow split to the Jones Island WRF (of the 1/3 of flow that can be directed to either plant)	50%	35%	
Total Flow, mgd			
Jones Island WRF	90	81	
South Shore WRF	90	99	
Primary Clarifier TSS removal			
Jones Island WRF	35%	50%	Increased capture
South Shore WRF	77%	50%	Decreased capture
MLSS, mg/L			
Jones Island WRF	2,560	2,444	
South Shore WRF	3,700	5,073	Very high MLSS
Secondary Clarifier solids loading rate, lb/d/ft^2			
Jones Island WRF	10.4	10.9	
South Shore WRF	15.8	19.5	
Digester gas production, ft^3/d	1,224,000	1,391,000	
Digester Biogas LHV, Btu/ft^3	520	508	
Engine energy production, kW	2,716	3,019	
Estimated energy produced, kWh/yr @ 8,000 hr/yr	21,727,100	24,152,700	
Interplant pumping: Jones Island WRF to South Shore WRF	116 hp	130 hp	
Interplant pumping: South Shore WRF to Jones Island WRF	165 hp	167 hp	
Total Interplant Pumping Energy, kWh/yr @ 8,760 hr/yr	1,818,550	1,921,040	
Jones Island WRF LL influent pumping	245 hp	268 hp	
Jones Island WRF HL influent pumping	390 hp	424 hp	
Total influent pumping energy, kWh/yr @ 8,760 hr/yr	4,102,970	4,472,749	
Change in aeration power			
Jones Island WRF	N/A	91	Change in capture
South Shore WRF	N/A	207	+ change in flow
Total change in aeration energy, kWh/yr @ 8,760 hr/yr	None	2,582,770	
Net energy, kWh/yr	15,807,707	20,342,292	
Energy reduction, kWh/yr	N/A	4,534,585	

EXHIBIT 2-3
Estimated O&M Costs and Energy Savings for Alternative 2

Parameter	Value [a]	Comment
Estimated additional digester gas chemicals	$69,934	$0.00115/ft^3
Estimated additional engine maintenance	$24,256	$0.01/kWh
Total additional O&M	$94,190	
Estimated additional energy generated	-$317,420	4,534,585 kWh/yr @ $0.07/kWh
Net O&M	-$223,220	

Considerations

The following considerations should be discussed if this alternative is evaluated further for implementation. This alternative could have many sub-alternatives where operational changes, as noted below, would affect the optimum flow split:

- The optimized flow split presented assumes a 50 percent primary clarifier TSS removal for both plants to reflect more typical operations. The baseline model used the reported actual primary clarifier removals of 77 percent for the South Shore WRF and 35 percent for the Jones Island WRF. Using the baseline primary clarifier removal efficiencies results in an optimum 85 percent flow (flow that can be directed to either plant) to the South Shore WRF. This is because of the high TSS removal efficiency at the South Shore WRF, which would produce more primary sludge and generate more power. Adjusting the primary clarifier efficiency to 50 percent at both plants effectively takes the CHP power generation out of the equation, as the power generation remains constant.
- Optimization would result in high MLSS at the South Shore WRF. This is an artifact of not changing the operational conditions at the South Shore WRF for the optimization. In reality operations would change, including reducing the 11-day SRT to about 8 days. An additional basin might need to be brought online to keep the MLSS realistic. If the 50 percent TSS primary clarifier efficiency scenario includes operational changes, the optimum flow split then becomes 50 percent to each plant. Further optimization at the South Shore WRF, including the use of full-time step feed to reduce the load to the secondary clarifiers, would modify the optimum split to 55 percent to South Shore WRF.

This alternative considered several variables, including digester gas production which was evaluated in other alternatives. To simplify the alternative and avoid potentially “double counting” energy saving a simplified evaluation was also done that considered only influent pumping. This assumed 470 kW Jones Island WRF pumping demand, average annual flow to each plant of 90 mgd, 7 percent more flow diverted to the South Shore WRF. This results in an annual $20,000 in savings. Additional evaluation of the impacts of other variables is recommended.

ALTERNATIVE 3

Purchase More Green Energy from We Energies

Alternative Description

The District has an agreement with We Energies to purchase 14,600 kilowatt-hours (kWh) per month or 175,200 kWh per year of electrical energy that is considered “green” energy. This alternative energy is used at the Headquarters and Lab buildings and represents less than 1 percent of the District’s total energy use. The program allows customers to purchase this energy at a rate of 2.4 cents more per kWh than the standard rate. We Energies uses the funds generated from the program to increase electricity production from renewable energy sources, such as wind, water, solar, and landfill gas.

This alternative would expand the amount of energy purchased under this program. The District would need to decide how much more it would like to pay for electrical energy under the program and then negotiate that amount with We Energies. The program only allows for purchases at 25, 50, or 100 percent of energy consumed. It is unclear if that amount is negotiated as a combined total or a per meter location basis. Because of the District billing structure, the “standard rate” for the District will need to be determined.

Note: Additional information from the District regarding their current green energy purchase program may be available in the future that could use to refine this alternative.

Description of Modifications Required

No modifications to facilities are required for this alternative.

Estimate of Energy Reduction or Recovery

This alternative will not reduce or recover any energy.

Cost Estimate

There is no capital cost required for this alternative. The cost incurred will depend upon the amount of alternative energy the District negotiates with We Energies.

ALTERNATIVE 4

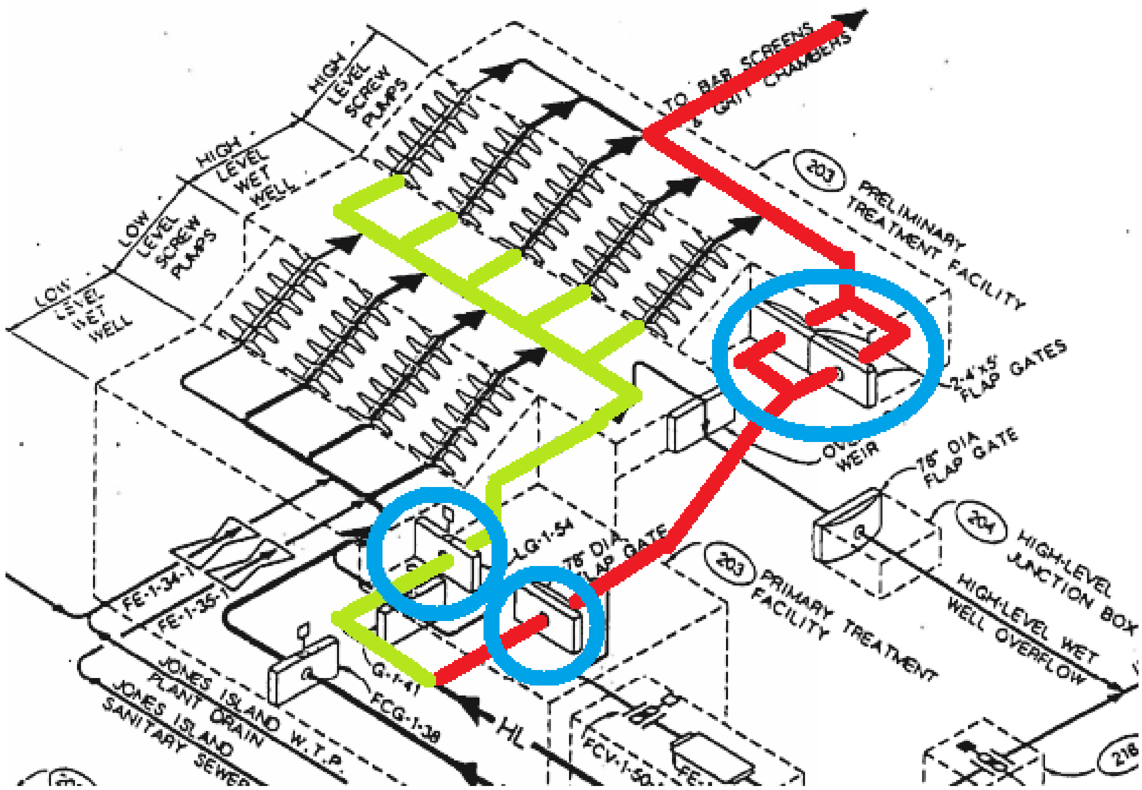
Bypass Jones Island WRF High-Level Screw Pumps

Note: Following the completion of the alternative evaluation, at the November 3, 2014, workshop, MMSD staff stated that the intent of this alternative was to evaluate bypassing the high-level screw pumps in dry weather rather than during wet weather flows as was done. After the workshop, MMSD reported that the high-level screw pumps have been bypassed during dry weather with the new siphon structure in place. However, the regular, almost daily use of the ISS pumps to dewater the tunnel is a concern because when the ISS pumps are operating, high-level MIS flow cannot bypass the screw pumps. This makes implementation of this alternative unlikely although MMSD has stated that they could evaluate it further in the future. This alternative will not be included in the Energy Plan. This alternative will be further evaluated in the 2050 Facilities Plan.

Alternative Description

The Jones Island WRF operates two levels of screw pumps that feed the treatment facility: a LL (low-level) section and a HL (high-level) section. As shown in Exhibit 4-1, there are four LL screw pumps and five HL screw pumps. The LL screw pumps have a capacity of 140 mgd with one pump out of service, the HL screw pumps 330 mgd with one pump out of service. Raw influent enters the Jones Island WRF through the LL and HL siphons. Influent from the LL siphons is pumped from the LL screw pumps to the HL screw pumps. At the HL screw pumps, the wastewater from the LL screw pumps is combined with the wastewater from the HL siphon and pumped by the HL screw pumps into the treatment facility. The green line in Exhibit 4-1 indicates the path of the HL flow entering the Jones Island WRF.

EXHIBIT 4-1
Screw Pumps Schematic



Source: JIWRF O&M Manual

During periods of high water levels upstream of the siphons, the water flowing through the HL siphon may have sufficient head to allow bypassing of the HL screw pumps. The red line in Exhibit 4-1 indicates the bypass around the HL screw pumps. This can be achieved by closing a sluice gate (LG-1-54), which will allow the other gates to flap open. If the HL siphon flow can bypass the HL screw pumps, then it will decrease the amount of water needing to be pumped by the HL screw pumps and result in a reduction in pumping electrical power.

The following need to be considered carefully if Alternative 4 is selected for further evaluation:

- According to data gathered by Cari Roper/MMSD, there are four potential diversion chambers where high water levels will overtop their weirs and enter the Inline Storage System. If this occurs the diverted water will have to be pumped out of the tunnel, resulting in increased energy usage. The four diversion chambers where this is possible are Diversion 85044 (Brady and Van Buren, weir elevation: 28.10 feet), Diversion 85048 (13th Street and Clybourn, weir elevation: 28.50 feet), Diversion DC0601 (12th Street and National Avenue, weir elevation: 25.10 feet) and CT07 (10th Street and Wisconsin Avenue, weir elevation: 21.80 feet). A more detailed investigation of the collection system and the effect of overflowing the weirs and pumping out of the tunnel would have to be conducted.
- Marty Dierker (retired Veolia employee) indicated that the bypass requires cleaning and flushing every time the bypass is used. Cleaning of the bypass requires labor and rapid action to prevent odors. Since water flows frequently can be sent to the South Shore WRF or into the Inline Storage System, the flow through the Jones Island WRF can vary. This variability in water flows/levels will make it difficult to predict when the Jones Island WRF will have the capability to send HL siphon flows through the bypass.

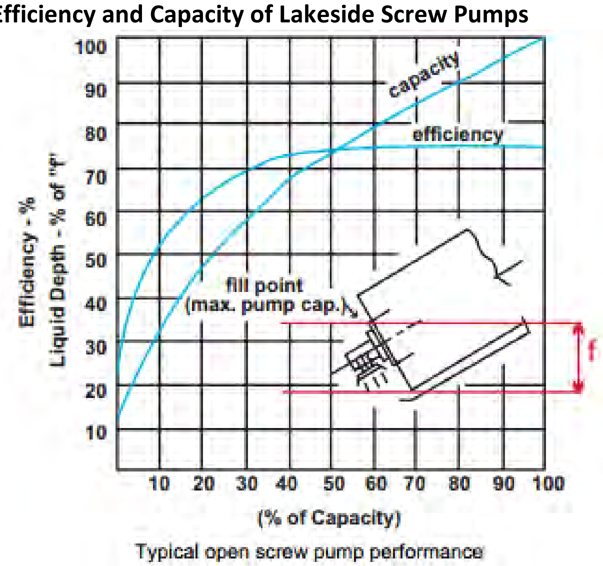
Description of Modifications Required

Minimal modifications would be required to implement this alternative. First, four gates (one sluice gate and three flap gates) will have to be inspected for integrity and operability (Exhibit 4-1). Sluice gate LG-1-54 will have to be inspected to ensure operability to prevent HL water flow from entering the HL screw pumps. A 78-inch-diameter flap gate and two 4- by 5-foot flap gates must also be inspected to ensure easy opening and closing when HL flow bypasses the HL screw pumps. Second, modifications will need to be made to the operational procedures to ensure water levels are being monitored closely so the HL bypass can be used when water levels are high enough, yet maintained low enough to prevent overflow to the tunnel. Some monitors at the diversion chambers may need to be repaired or replaced to ensure accurate water levels are being recorded. This will likely also require modifications to the SCADA system.

Estimate of Energy Reduction or Recovery

Water levels at the diversion chambers are not being recorded, therefore the amount of time that the water level will be high enough upstream to allow the HL water flow to bypass the HL screw pumps will have to be estimated. The project team extracted flow and cumulative time duration curves from the sewer system modeling done for the *2020 Facilities Plan.* That data indicated the HL flow bypassing the HL screw pumps will be ~100 mgd. This was believed to be a good approximation because a large flow of wastewater would be required for the wastewater surface elevation in the collection system to rise sufficiently to bypass the HL screw pumps. The plant influent flow is estimated to be greater than 100 mgd roughly 5 percent of the time, or just over 400 hours per year (Exhibit 4-2). An efficiency of 75 percent was estimated assuming that the screw pumps would be working at maximum efficiency during the period (Exhibit 4-2).

EXHIBIT 4-2
Efficiency and Capacity of Lakeside Screw Pumps



Source: http://www.lakeside-equipment.com/bulletins/bul_217.pdf

According to Exhibit 4-3 (from the Jones Island WRF O&M Plant Manual), an elevation of 16.7 feet is the elevation at which the water will reach the top of the top of the HL screw pumps. The water pumped from the LL screw pumps will be at a maximum water surface elevation of 3.70 feet. Therefore, if the HL flow bypasses the HL screw pumps, then the water will not have to be pumped up the 13 feet. Using the brake horsepower equation for a centrifugal pump, the amount of energy saved will be:

$$bhp = \frac{gpm \ \times head\ (ft) \times specific\ gravity}{3{,}960 \ \times pump\ efficiency}$$

$$bhp = \frac{69{,}440\ gpm \ \times 13\ ft \times 1}{3{,}960 \ \times 0.75}$$

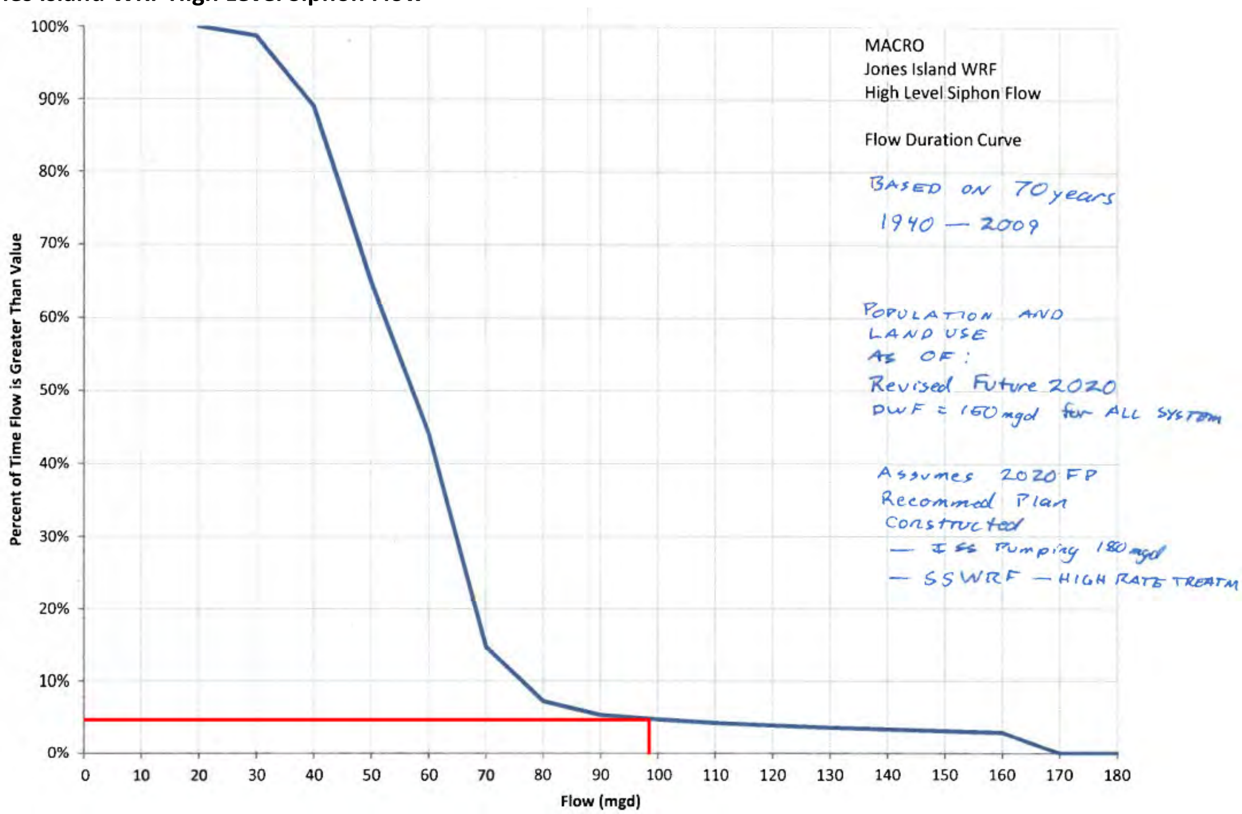
$$bhp = \ 304\ hp = 227\ kW$$

$$227\ kW \ \times 438\ hr = 99{,}400\ kWh, saved\ per\ year$$

$$\frac{\$0.07}{kW - hr} \times 99{,}400\ kWh = {\sim}\$7{,}000\ savings\ per\ year$$

EXHIBIT 4-3

Jones Island WRF High Level Siphon Flow



Extracted from 2020 Facilities Plan Hydraulic Model

Cost Estimate

Exhibit 4-4 presents the preliminary cost estimate. Additional monitoring of wastewater levels and flows will need to be conducted to better understand the amount of time and effort needed to operate the bypass.

The most substantial costs for Alternative 4 will be inspecting and potentially repairing the four gates. Cost depends entirely on the condition of the four gates. If little work is required to get the gates functioning properly then the overall cost could be minimal, but if one or more gates needs significant repair or even replacement, the cost of the alternative increases dramatically. It is expected anticipated that only minor repairs will be required to get the four gates functioning properly.

EXHIBIT 4-4
Cost Estimate for Alternative 4

Capital Costs		
Inspecting and repairing four high-level gates		$120,000
New flow and level gauges		$30,000
Flushing/cleaning provisions		$20,000
Installation (10% of equipment)		$17,000
Subtotal—Project Cost		*$187,000*
Markups		—
Site, piping, electrical, I&C, demolition, etc.	10%	$18,700
Subtotal		*$205,700*
Contingency	40%	$82,280
Subtotal		*$287,980*
Contractor mobilization, bonds, and insurance	20%	$57,596
Subtotal		*$345,576*
Subtotal with Markups		*$345,576*
Total Construction Cost		$345,576
Non-Construction Costs		—
Engineering/administration	18%	$62,204
Subtotal Non-Construction Costs		*$407,780*
Total Capital Cost (2014 dollars)		**$407,780**
O&M Costs (using 2014 average loads)		**Annual Cost**
Power savings		-$7,000
Additional maintenance—parts (1% of new equipment)		$2,000
Total O&M (2014)		**$5,000**

ALTERNATIVE 5

Decrease Number of Idle Aeration Basins Operating

Alternative Description

Both the Jones Island and South Shore WRFs use all their aeration basins. Most are used for treatment, but some are idling (operating, but not used for treatment), awaiting wet weather events. For the Jones Island WRF, the number of basins operating is part of the current wet weather strategy. The strategy includes the use of designated biosolids basins and also idle basins, with a low MLSS to minimize solids loss during wet weather events. The South Shore WRF has a similar strategy, although it can use step feed to aid in minimizing wet weather events.

Every basin operating requires aeration for treatment. At the Jones Island WRF, the operating basins are operated at nearly their minimum air rate for mixing/diffuser grid flux. This air rate results in high dissolved oxygen in the basins, indicating that the aeration rate is greater than what is needed for treatment. Reducing the number of basins operating would reduce the minimum mixing energy thereby allowing the treatment aeration to dictate. MMSD and Veolia are also evaluating changes similar those discussed in this alternative. However similar to other activated sludge related alternatives it was believed that an independent evaluation using the computer process model develop for this project would be useful.

The following are potential constraints on the system:

- Both the Jones Island and South Shore WRFs need to manage wet weather events: For the Jones Island WRF, these events can occur quickly (< 1 hour). For the South Shore WRF, such events can take upward of a day to reach the plant.
- The Jones Island WRF already operates at a fairly low SRT as a wet weather management strategy. The South Shore WRF operates at a higher SRT (11 days).

To prevent plugging of the porous plate diffuser grids, air must be constantly fed to the basins if they are idle. In order not to require air they must be taken fully offline, which means they could not be placed back online quickly for a wet weather event.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

To reduce the number of basins online at the South Shore WRF, the SRT must be lowered from 11 to 6.5 days. This would reduce the MLSS enough to allow 5 of the 26 baseline basins to be taken offline while still maintaining the MLSS at 3,000 mg/L. Changing the SRT requires no physical modifications. The wasting rate would be increased, and the additional WAS would be sent to Milorganite® production. The interplant pumping system has ample capacity for any excess sludge.

The number of basins online at the Jones Island WRF is basically maintained for wet weather. The South Shore WRF uses step feed in wet weather, but the Jones Island WRF does not have that capability. However, step feed could be implemented with some system modifications by taking advantage of the dual influent channels with the dual inlets to each aeration basin and relocating how the RAS mixes with the PCE in the flow split structure. PCE enters the flow split structure through dual conduits. Nearly as soon as it enters, pumped RAS is mixed with the PCE to create MLSS. The MLSS is then distributed to each basin and follows the dual influent channels to the aerations. At each aeration basin, a pipe from each channel enters the basin.

The following is a strategy that could be implemented:

- Pumped RAS would be relocated so that it could discharges only to one of the dual channels. This strategy would require the east and west plants to operate independently, and not with comingled RAS.
- PCE would continue through the flow split structure as is, minus the RAS.
- At locations where the single mix channel becomes the dual influent channel, an automatic control weir would be installed to dictate how much PCE flow would go down each channel.

Given the rapidity with which wet weather flow strikes the Jones Island WRF (<1 hr), it is recommended that the system operate in some form of step feed full-time.

The following are characteristics of the alternative:

- Jones Island WRF primary clarifiers operate with 35 percent TSS removal efficiency, the South Shore WRF clarifiers at 77 percent.
- The South Shore WRF SRT is allowed to decrease to 6.5 days and the Jones Island SRT to 7.5 days. Additional South Shore WRF WAS is assumed to go to Milorganite® production.
- New Jones Island WRF step feed would step 50 percent to the front of the basin and 50 percent to the middle.
- The new wet weather system allows the Jones Island WRF to operate with 7 west and 16 east basins online, thereby taking 3 West Plant and 2 East Plant basins offline. The idle basins also would be taken offline.
- Jones Island WRF to South Shore WRF interplant pumping: 3 pairs of pumps with a capacity of 2,000 gpm at 420 feet TDH, each using a 400 hp motor. It was assumed that pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 413 hp.
- Jones Island WRF Equalization/Blending Tank pumping: capacity of 1,870 gpm at 138 feet TDH, each using a 100 hp motor. It was assumed that pumping efficiency is 70 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 109 hp.
- South Shore WRF to Jones Island WRF interplant pumping: 3 pumps with a capacity of 1,160 gpm at 465 feet TDH, each using a 250 hp motor. It was assumed that pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 265 hp.
- The Jones Island WRF uses 2 pump stations: The LL pumps pump to the HL pumps. Historical operations show 45 percent of the influent flow goes to the LL pumps and 55 percent to the HL pumps. See Alternative 2 for details.
- Jones Island WRF aeration uses 85,000 scfm blowers at 60 percent efficiency, drawing 5,140 bhp using a 5,500 hp motor. Total draw per blower is 5,244 hp with 98 percent motor efficiency.
- South Shore WRF aeration uses 30,000 scfm blowers with 75 percent efficiency, drawing 1,451 bhp from a 1,500 hp motor. Total draw per blower is 1,481 hp, assuming a 98 percent motor efficiency.

Estimate of Energy Reduction or Recovery

Exhibit 5-1 provides an estimate of the aeration savings. The additional WAS generated at the South Shore WRF and transferred to Milorganite® production would increase interplant pumping, resulting in a net energy reduction of 2.14 million kWh/yr.

EXHIBIT 5-1
Decrease Basins Online
Energy Production and Consumption Summary

Constituent	Baseline	Alternative	Comments
Operational SRT, days			
Jones Island WRF	7.5	7.5	
South Shore WRF	11	6.5	
Total flow, mgd			
Jones Island WRF	90	90	
South Shore WRF	90	90	
Primary Clarifier TSS removal			
Jones Island WRF	35%	35%	

EXHIBIT 5-1
Decrease Basins Online
Energy Production and Consumption Summary

Constituent	Baseline	Alternative	Comments
South Shore WRF	77%	77%	
Basins Online			
Jones Island WRF	32	23	Includes idle basins
South Shore WRF	26	21	
MLSS to Secondary Clarifiers, mg/L			
Jones Island WRF	2,560	2,611	
South Shore WRF	2,700	3,000	
Estimated biogas production, ft^3/d	1,224,000	1,224,900	18.9% increase
Estimated biogas LHV	520	520	
Estimated energy production, kW	2716	2716	
Estimated energy produced, kWh/yr @ 8,000 hr/yr	21,727,100	21,728,700	
Interplant Pumping: Jones Island WRF to South Shore WRF	116-hp	115-hp	
Interplant Pumping: South Shore WRF to Jones Island WRF	165-hp	228-hp	
Total interplant pumping energy, kWh/yr @ 8,760 hr/yr	1,818,550	2,217,630	
Jones Island WRF LL influent pumping	245-hp	245-hp	
Jones Island WRF HL influent pumping	390-hp	390-hp	
Total Influent Pumping Energy, kWh/yr @ 8,760 hr/yr	4,102,970	4,102,970	
Change in Aeration Power, kW			
Jones Island WRF	N/A	80	
South Shore WRF	N/A	191	
Total change in aeration energy, kWh/yr @ 8,760 hr/yr	None	(2,349,280)	
Net energy, kWh/yr	15,807,707	17,952,591	
Energy reduction, kWh/yr	N/A	2,144,885	

Cost Estimate

Lowering the SRT and taking basins offline at the South Shore WRF do not require any capital costs. At the Jones Island WRF, the new step feed system will require additional RAS piping, new control weirs, and additional aeration basin feed piping. Exhibit 5-2 summarizes the capital costs.

EXHIBIT 5-2
Estimated Capital Costs for Alternative 5

Parameter	Value [a]	Comment
New RAS Piping	$471,500	Extended piping to channels
New Aeration Feed Piping	$1,963,600	30-inch feed piping, valves, magnetic flowmeters
New Control Weirs	$60,000	West Plant: two @ 8 ft 3 in. wide East Plant: two @ 12 ft wide
Total Construction Costs Installation Markups	$5,838,650	

EXHIBIT 5-2
Estimated Capital Costs for Alternative 5

Parameter	Value [a]	Comment
Non-Construction Costs	$1,050,950	
Total	**$6,889,500**	

[a] Values are in January 2014 dollars without escalation

Maintenance costs associated with changes in the interplant pumping, blowers, and influent pumping are assumed to be negligible. Additional costs for the RAS piping, aeration feed piping, and weirs are assumed to be negligible as well. Exhibit 5-3 lists the net energy savings associated with the extra energy generation minus the pumping and blower energy used.

EXHIBIT 5-3
Estimated O&M Costs for Alternative 5

Parameter	Value	Comment
Total additional O&M	$32,000	New valve and gate maintenance
Estimated additional energy savings	-$150,142	2,144,885 kWh/yr at $0.07/kWh
Net O&M	-$118,142	

Discussion and Considerations

The following considerations should be evaluated when discussing this alternative:

- The discussion of step feed at the Jones Island WRF is very high level and needs to be vetted further to determine its constructability.
- Operating the South Shore WRF in a full-time step feed mode could allow additional basins to be taken offline.

ALTERNATIVE 6

Optimize Pumping Energy Using PLC Logic

There are numerous pumping systems at the Jones Island and South Shore WRFs, and they require significant energy. A SCADA PLC control block determines how each pumping system is operated to control the number of pumps online, pump speed, and other parameters. Under this alternative, the pumping control logic would be modified so that the pump systems would be operated to optimize pumping schemes to minimize energy use.

The individual pump performance curves and system head loss curves would be programmed into the SCADA PLC system logic and used in conjunction with an energy optimization algorithm to select parameters such as number of pumps online, pump speed, wet well levels, and other factors to minimize pumping system energy. The programming would likely best be done in a spreadsheet model that could be referenced by the PLC. Programming could be done to show the system energy pumping energy. While there are potentially several pumping systems where this could be applied, the JI RAS/WAS pumps (especially the larger RAS pumps) would be the best application and the algorithm could be applied to those pumps first to help refine the actual potential savings. The size and capacity of the JI RAS/WAS pumps is as follows:

This alternative will be further evaluated in the 2050 Facilities Plan.

RAS pumps:

- West Plant—3 centrifugal pumps at 14.8 MGD, 28 feet TDH, 125 hp each
- East Plant—4 centrifugal pumps at 30.2 MGD, 24 feet TDH, 200 hp each
- Total connected hp = 1,175

WAS pumps:

- West Plant—2 centrifugal pumps at 730 GPM, 80 feet TDH, 25 hp each
- East Plant—3 centrifugal pumps at 1310 GPM, 80’ TDH, 50 hp each
- Total connected hp = 200

Exhibit 6-1 lists the potential energy savings and implementation costs if the optimization logic could be applied to the JI RAS/WAS pumping systems, assuming a typical, total power draw of 1,000 hp.

The actual energy savings would vary by pumping system and depend upon number of pumps, system hydraulics, pump performance curve characteristics, and other factors. Based on experience with other systems, it has been found that optimization logic could reduce pump energy use by 2 to 8 percent. To better quantify the potential savings, additional evaluation of this alternative would be required. Further evaluation would be required to determine the number of pumping systems to which this logic could be applied.

EXHIBIT 6-1
Example Estimate of Energy Savings for Pumping Optimization Using PLC logic for JI RAS/WAS Pumps

	Value
Total pumping electrical power demand	1,000 hp or 0.75 MW
Energy reduction, percent	4
Energy reduction, kW	30
Electrical power cost savings per year[a]	$18,400
PLC programming cost: $/system	$20,000

[a]$0.07/kWh

ALTERNATIVE 7

Use Chemically Enhanced Primary Treatment to Reduce Aeration Energy and Increase Primary Sludge/Digester Gas

Chemically Enhanced Primary Treatment (CEPT) is a common practice to enhance particulate and colloidal substrate removal in primary clarifiers. The largest energy user in most wastewater treatment facilities is the aeration tanks. Improved primary clarifier performance can result in increased BOD removal, which decreases organic loading to the secondary system, thereby reducing the aeration system oxygen demand. Reduced oxygen demand means less energy required for aeration.

The South Shore WRF has primary sludge only anaerobic digestion and engine/generators that can use the digester gas to make electricity and capture heat for digester heating and other purposes. Increasing primary clarifier TSS removal will increase the mass of primary sludge sent to the South Shore WRF for digestion provided all sludge is routed to South Shore WRF. The increase in primary solids to digestion will increase digester gas production and thereby reduce the energy demand through more electricity and heat energy production from the engine/generators.

This alternative will be further evaluated in the 2050 Facilities Plan.

Jones Island WRF

Building upon the Jones Island WRF optimized primary treatment analysis for Alternative 15, this analysis assumes CEPT reduces the average primary effluent (PE) total suspended solids (TSS) from 100 mg/L to 45 mg/L (80 percent TSS removal or 55 mg/L additional TSS removal) with a corresponding reduction in PE BOD of 85 mg/L (55 percent BOD removal). Additional BOD removal is higher than TSS removal as a result of CEPT removing colloidal substrate, which is not captured in a TSS analysis. It is assumed a ferric chloride dosage of 40 mg/L with 2 mg/L of anionic polymer is necessary to achieve the estimated TSS and BOD removal. Jar and full-scale testing is recommended to verify these assumptions should this alternative be selected for potential implementation.

Description of Modifications Required

An unloading, storage, and metering system for ferric chloride and polymer is required for full-scale CEPT. The new facilities would consist of a building, chemical storage tanks, metering pumps, mixing equipment, and associated support systems. This analysis assumes the ferric chloride and polymer systems are very similar to those developed for the South Shore WRF Demonstration Project CEPT alternative.

Estimate of Energy Reduction or Recovery

The average influent TSS load at the Jones Island WRF from 2007 to 2013 was 163,000 lb/d. If the primary clarifier TSS removal increases from 55 to 80 percent, an additional 30,000 VSS/d of primary volatile solids sludge could be pumped to the South Shore WRF for digestion. Primary sludge TSS loadings to the South Shore WRF digesters would increase from roughly 90,000 lb/d to 155,000 lb/d (40,000 lb/d additional primary solids plus 25,000 lb/d inert solids generate from ferric addition). The increase in solids would require pumping primary sludge at 75 percent higher TSS concentrations or increasing the primary sludge pumping rate if the anaerobic digesters have capacity for the increased flow. The digesters would likely have the required additional capacity unless the existing excess capacity were used for co-digesting industrial/commercial waste in the future. This would increase the portion of belt press cake that is digested sludge and the portion of digested sludge to the dryers would likely approach or exceed 40 percent—the point at which Veolia staff have experienced difficulties with Milorganite® production, such as excessive chaff and dust. Additional refinement of the solids balance incorporating the results of other alternatives would be required to determine potential impacts on Milorganite® production.

The Jones Island WRF BioWin simulator was used to estimate aeration airflow savings. The airflow savings were again estimated using steady-state simulations with flow proportionally distributed to 9 aeration tanks in service on the west side and 18 tanks on the east side. CEPT reduces the average process aeration airflow by an estimated 16,800 scfm when maintaining dissolved oxygen at 2 mg/L; however, when bioreactor mixing and minimum airflow per diffuser requirements are considered, the annual aeration airflow reduction with CEPT is estimated at 10,000 scfm, provided the aeration blower has sufficient turndown capabilities. The Jones Island WRF WAS load decreases by roughly 40,000 lb TSS/d as a result of the lower secondary influent loadings.

Exhibit 7-1 summarizes the power, energy, solids processing, and chemical savings/changes associated with this alternative.

EXHIBIT 7-1
Summary of CEPT Potential Operating Changes

Item	Units	Jones Island WRF	South Shore WRF
Primary Sludge Digestion			
Additional loading	lb VSS/d	30,000	11,000
Digester VSS destruction	percent	60	60
Additional VSS destroyed	lb VSS/d destroyed	18,000	6,600
Digester gas production	ft^3/lb VSS destroyed	15	15
Additional digester gas production	ft^3/d	270,000	99,000
Digester gas energy	Btu/ft^3	560	56000
Additional digester gas energy	MMBtu/yr	55,200	20,200
Power conversion efficiency	%	33.5	33.5
Power production reduction	kWh/yr	5,400,000	2,000,000
Thermal conversion efficiency	%	42	42
Thermal production reduction	MMBtu/yr	23,200	8,500
Aeration Savings			
Reduction in aeration airflow	scfm	10,000	10,000
Aeration energy	kW/scfm	0.03	0.03
Annual aeration savings	kWh/yr	2,600,000	2,600,000
Solids Processing Savings			
Additional digested solids to JIWRF	lb TSS/d	47,000	32,100
WAS reduction	lb TSS/d	40,000	25,000
Overall reduction in solids	lb TSS/d	-7,000	-7,100
Chemical Usage			
Ferric chloride (40% solution)	gal/d	7,000	6,700
Polymer	lb/d	1,600	1,500

Cost Estimate

Exhibit 7-2 summarizes a conceptual order-of-magnitude capital costs and O&M savings for this alternative. The capital costs are based upon the CEPT facilities costs developed under the SSWRF Demonstration Project. O&M savings are greatly influenced by three components: ferric chloride, polymer, and biosolids processing. Confirmation of the ferric chloride and polymer dosages and unit costs are necessary to fully develop the annual operating costs/savings. Similarly, the biosolids processing cost for additional solids should be refined because estimating the costs that can be attributed to biosolids can be challenging given the complexities of the system.

EXHIBIT 7-2
Order-of-Magnitude Cost Estimate for CEPT

Item	Unit Cost	Jones Island WRF	South Shore WRF
Capital Costs	—		
CEPT facilities	—	$12,200,000	$12,200,000
Contingency	30%	3,050,000	3,050,000
Subtotal	—	*$15,900,000*	*$15,900,000*
Contractor mobilization, bonds, and insurance	20%	$3,200,000	$3,200,000
Total construction cost	—	$19,100,000	$19,100,000
Engineering/administration	20%	$3,800,000	$3,800,000
Total Capital Costs	—	**$22,900,000**	**$22,900,000**
O&M			
Natural gas fuel savings	$6/MBtu	-$140,000	-$50,000
Cogeneration from digester gas	$0.07/kWh	-$380,000	-$140,000
Aeration	$0.07/kWh	-$185,000	-$180,000
Biosolids processing	$160/DT	$205,000	$147,000
Ferric chloride (40% solution)	$0.85/gal	$2,200,000	$2,100,000
Polymer	$1.00/lb	$580,000	$550,000
Operations and maintenance	—	$100,000	$100,000
Total O&M Savings	—	**$2,380,000**	**$2527,000**

South Shore WRF

The South Shore WRF primary clarifiers do not use CEPT and reportedly remove roughly 80 percent of the influent TSS and 65 percent of the BOD (Exhibit 7-3). These reported removal rates are typical of CEPT TSS and BOD removal rates. South Shore WRF adds low doses of pickle liquor (< 5 mg/L) to the primary clarifiers for phosphorus removal, however the pickle liquor doses are well below typical CEPT ferric chloride doses of 40 to 50+ mg/L. Limited plant influent samples collected with ISCO type samples during the Process Enhancement Demonstration Project suggests the reported plant influent sample concentrations are greater than actual values. If this is representative of the larger data set, the reported primary clarifier TSS and BOD removal rates would decrease.

This analysis assumes CEPT reduces the average PE TSS from 65 to 45 mg/L with a corresponding reduction in PE BOD of 60 mg/L. The additional BOD removed is higher than the additional TSS removed as a result of CEPT removing colloidal substrate, which is not captured in a TSS analysis. It is assumed a ferric chloride dosage of 40 mg/L with 2 mg/L of anionic polymer is necessary to achieve the estimated TSS and BOD removal. Jar and full-scale testing would be recommended to verify these assumptions if this alternative is selected to be potentially implemented.

EXHIBIT 7-3
South Shore WRF Primary Clarifier Average Influent and Effluent Characteristics

Item	Units	Plant Influent	Primary Effluent	Removal (%)[a]
August 1, 2011–July 31, 2012				
Flow	mgd	80	—	—
TSS	mg/L	355	63	—
	lb/d	243,100	44,900	83
BOD	mg/L	300	108	—
	lb/d	198,300	72,900	65
NH_3-N	mg/L	19	18	—
	lb/d	12,700	11,900	12
TP	mg/L	5.4	3.4	—
	lb/d	3,550	2,300	33
January 1, 2013–March 31, 2013				
Flow	mgd	89	—	—
TSS	mg/L	384	65	—
	lb/d	261,00	49,800	80
BOD	mg/L	—	—	—
	lb/d	—	—	—
NH_3-N	mg/L	18	17	—
	lb/d	11,800	11,500	3
TP	mg/L	4.3	3.0	—
	lb/d	2950	2050	28

[a] Removal based upon average of daily calculated values.

Description of Modifications Required

A ferric chloride and polymer unloading, storage and metering system is required for full-scale CEPT. The new facilities would consist of a building, chemical storage tanks, metering pumps, mixing equipment and associated support systems. This analysis assumes the ferric chloride and polymer systems are very similar to those developed for the Demonstration Project CEPT alternative.

Estimate of Energy Reduction or Recovery

Assuming an average influent flow of 90 mgd and 75 percent primary sludge volatile, an additional 11,000 lb VSS/d of primary volatile solids sludge could be routed to the South Shore WRF digesters. Primary sludge TSS loadings to the digesters would increase by roughly 40,000 lb TSS/d (15,000 lb/d additional primary solids plus 25,000 lb/d inert solids generate from ferric addition). This increase in solids would require pumping primary sludge at higher TSS concentrations or increasing the primary sludge pumping rate if the anaerobic digesters have capacity for the increased flow. The digesters would likely have the required additional capacity unless the existing excess capacity is used for co-digesting industrial/commercial waste in the future. Also this would increase the part of the Jones Island WRF belt press cake that is digested sludge and the portion of digested sludge to the dryers would likely approach or exceed 40 percent—the point at which Veolia staff have experienced difficulties with Milorganite® production such as excessive chaff and dust. Additional refinement of the solids balance incorporating the results of other alternatives would be required to determine potential impacts on Milorganite® production.

The BioWin simulator developed under the South Shore WRF Process Enhancement Demonstration Project TM2, Evaluation of Nutrient Removal Alternatives, was used to estimate aeration airflow savings. The BioWin model was developed for maximum month loading conditions. To simulate current annual average conditions the BioWin primary effluent COD, TKN, and TP loads were reduced by 30 percent. CEPT reduces the average process aeration airflow by an estimated 10,000 scfm/d when operating at a target DO of 2 mg/L provided the aeration blower has sufficient turndown capabilities. SSWRF WAS load decreases by of roughly 25,000 lb TSS/d as a result of the lower secondary influent loadings.

Exhibit 7-1 summarizes the power, energy, solids processing, and chemical savings/changes associated with this alternative. SSWRF power and thermal production savings are significantly less than JIWRF CEPT since SSWRF primary effluent TSS without CEPT has lower TSS concentrations resulting in less TSS capture.

Cost Estimate

Exhibit 7-2 summarizes a conceptual order-of-magnitude costs and savings for CEPT at the South Shore WRF. CEPT capital costs are based upon the CEPT facilities costs developed under the demonstration project. As is the case at the Jones Island WRF, O&M savings are greatly influenced by three components: ferric chloride, polymer, and biosolids processing. Confirmation of the ferric chloride and polymer dosages and unit costs are necessary to fully develop the annual operating costs. Similarly, the biosolids processing cost for additional solids should be verified.

ALTERNATIVE 8

Modify/Optimize Activated Sludge Process for Energy

Alternative Description

Secondary treatment typically is the largest user of energy in a wastewater treatment plant. Aeration energy accounts for 50 to 60 percent of the total energy. Therefore, targeting secondary treatment is the best method to reduce overall treatment plant energy.

The following are the approximate aeration needs for the Jones Island WRF:

- Process aeration ~75,500 scfm
- Channel mixing ~40,000 scfm

These values were used to simplify the evaluation of this alternative. It is recognized that these rates can vary and recent improvements in aeration control continue to decrease aeration requirements.

Channel mixing improvements are addressed under Alternative 34. Changes to process aeration are also addressed elsewhere: dissolved oxygen and ammonia control under Alternative 24, and converting to step feed operations under Alternative 5. Other aeration-related options evaluated were changes in SRT (Alternatives 10 and 11) and taking basins offline (Alternative 5). MMSD and others have evaluated other options to reduce aeration energy, such as new diffusers or blowers. Because methods for optimizing the activated sludge process have been considered elsewhere, few if any options remain to evaluate. One concept not yet discussed would be to operate the South Shore WRF continuously in the step feed mode. Step feed is only used for wet weather events. If operated continuously in step feed, the aeration air would be spread across the entire aeration basin, maximizing use of the aeration basin and the full-floor diffuser coverage. In addition, the minimum mixing energy that typically dictates a minimum air flow at the end of the aeration basin no longer would be an issue.

MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.

Description of Modifications Required

The South Shore WRF already has the infrastructure in place for step feed but is now only operated for wet weather events. Thus, no capital improvements would be required to operate in step feed. The following assumptions used in the evaluation:

- The primary clarifiers have 77 percent TSS removal efficiency.
- SRT is allowed to decrease to 10.2 days, whereas SRT at the Jones Island WRF is 7.5 days. Additional WAS generated as a result of the decreased SRT is assumed to go to Milorganite® production.
- Step feed mode at the South Shore WRF is 60 percent flow to the front of the basin and 40 percent to the middle.
- The first 25 percent of the basin is assumed to be unaerated (anaerobic), providing for biological phosphorus removal
- Aeration uses 30,000 scfm blower at 75 percent efficiency, drawing 1,451 bhp using a 1,500 hp motor. Total draw per blower is 1,481 hp with 98 percent motor efficiency.

Estimate of Energy Reduction or Recovery

Exhibit 8-1 provides an estimate of the aeration energy savings. Aeration energy is reduced by 317 kW, providing roughly 2.74M kWh/yr of energy savings. The additional WAS generated at the South Shore WRF would increase the interplant pumping resulting in a net energy reduction of 2.14M kWh/yr.

EXHIBIT 8-1
Continuous Step Feed Operation at South Shore WRF
Energy Production and Consumption Summary

Constituent	Baseline	Alternative
SRT, days	11	9
Total influent flow, mgd	90	90
Primary clarifier TSS removal	77%	77%
Basins online	26	26
Basin Aeration	0% Unaerated 100% Aerated	25% Unaerated 75% Aerated
Step feed split Front Middle	 100% 0%	 60% 40%
MLSS to secondary clarifiers, mg/L	3,700	3,170
Final effluent TP, mg/L	2.30	0.76
Interplant pumping: Jones Island WRF to South Shore WRF	116 hp	100 hp
Interplant pumping: South Shore WRF to Jones Island WRF	165 hp	213 hp
Total interplant pumping energy, kWh/yr @ 8,760 hr/yr	1,818,550	2,025,399
Aeration rate, scfm	93,170	86,230
Change in aeration power, kW	N/A	282
Total change in aeration energy, kWh/yr @ 8,760 hr/yr	None	-2,448,335
Net energy, kWh/yr	15,807,706	17,744,870
Energy reduction, kWh/yr	N/A	1,937,164

Cost Estimate

Decreasing the SRT and implementation of full-time step feed at SSWRF do not require any capital costs. Maintenance costs associated with changes in the interplant pumping, blowers, and influent pumping are assumed to be negligible. The net energy savings is shown in Exhibit 8-2.

EXHIBIT 8-2
Estimated O&M Costs for Alternative 8

Parameter	Value	Comment
Total additional O&M	$0	
Energy savings	-$135,395	1,937,164 kWh/yr @ $0.07/kWh

Discussion and Considerations

The following should be considered and evaluated before potentially implementing this alternative:

- To operate in step feed, it is recommended that dissolved oxygen control be installed. Ammonia control could be optional, but having control would be preferred to help ensure full nitrification is taking place. In addition, the Bio-P system is highly influenced by nitrification. Lowering the DO and controlling nitrification will result in better TP removal.
- Operating the South Shore WRF in a full-time step feed mode could allow additional basins to be taken offline, which would result in additional energy savings.

ALTERNATIVE 9

Optimize Waste Heat Pressure Control

Alternative Description

Waste heat is a byproduct of turbine power generation and can come from either the GE turbine or the landfill gas turbines. Of the fuel fed to a turbine, only about 20 percent of the energy input produces electrical power from the GE turbine while about 40 percent of the energy input produces electricity from the landfill gas turbines. Most of the remaining energy is exhausted as waste heat with a small amount minor radiant heat losses.

The waste heat from all of the turbines is placed in a duct and the hot gas is conveyed to either the dryer house ,where it is used in the Milorganite® production process, to the power house boiler room, where it is used for generating hot water used to provide building heat, or exhausted to the atmosphere.

The portion of waste heat conveyed to the atmosphere is required to maintain the waste heat duct at a correct operating pressure. The duct pressure is not allowed to go to a negative pressure to prevent the duct from collapsing and is not allowed to go too high in pressure to prevent damage to the expansion joints. For the landfill gas turbines, approximately 10 percent of the waste heat is exhausted to the atmosphere to maintain duct pressure. This represents about 6 percent of the total energy input into the turbines. Modifying the pressure controls can potentially reduce the amount of waste heat that must be exhausted to atmosphere and allow more of the energy to be used for either Milorganite® production or hot water production.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

There are two methods that could be used to optimize the waste heat pressure control and increase waste heat utilization:

1. Use the existing damper on the waste heat boiler for maintaining duct pressure control, or
2. Modify the dryer system controls so that all waste heat is used in the dryers (that is not used in the waste heat boiler) and the dryer waste heat dampers are used to maintain waste heat duct pressure.

Existing Waste Heat Boiler Damper

The waste heat boiler isolation damper is a three-blade design that would provide reasonably good control characteristics. The damper appears to be in good working condition, though it may need to be replaced due to normal wear over its lifetime. It is equipped with an electric actuator that may have to be replaced with a pneumatic actuator to allow more rapid control. Only waste heat not required in the Milorganite® production process would be directed to the waste heat boiler. In the summer months the waste heat directed to the waste heat boiler would bypass the boiler and be vented to atmosphere. In the winter months, all of the waste heat would be directed through the waste heat boiler and therefore all waste heat would be utilized.

Modify Dryer System Controls

Those dryers that are utilizing waste heat control the flow of waste heat by modulating a multiblade damper equipped with a pneumatic actuator. The existing controls for these dampers do not provide for control of waste heat duct pressure. Duct pressure is important because if the duct is allowed to go to a negative pressure, the duct can collapse, and if pressure is allowed to go too high, waste heat can be blown into buildings or galleries. With this alternative, the waste heat flow set point would be adjusted to those dryers to maintain duct pressure within an appropriate range. The existing waste heat pressure control dampers on the solar turbine discharge would be converted to function as an emergency pressure relief should the duct pressure rise too high.

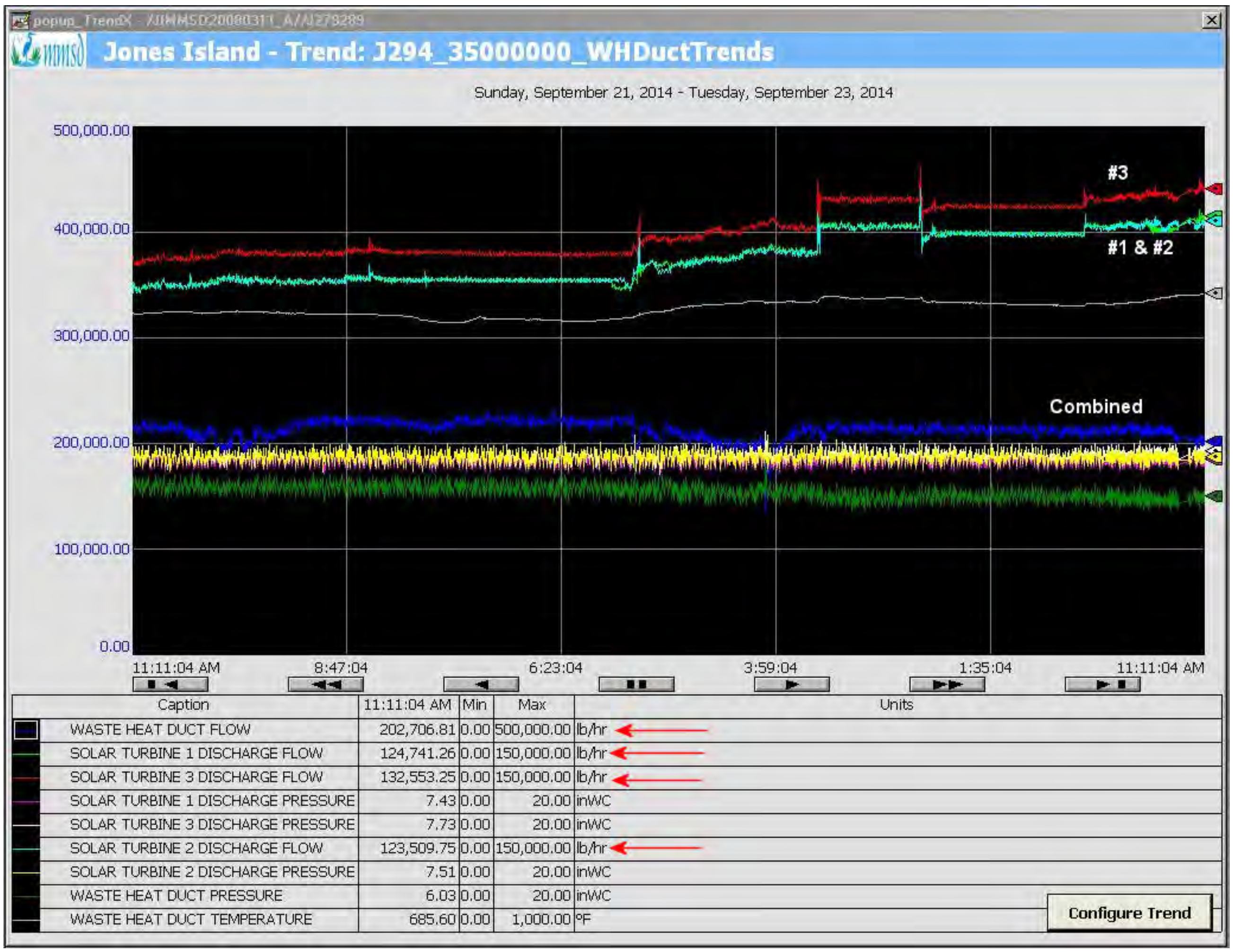
Under this alternative, the dryer waste heat flow control dampers (12 total) would have to be rebuilt or replaced since they are currently showing signs of wear that would prevent them from performing adequately for this type of service.

Testing with one landfill gas turbine and one dryer would be recommended prior to implementing this alternative on all dryers. Modifying the dryer controls will present a safety risk, and it would also be recommend that a Process Hazard Analysis be performed prior to implementing the new controls.

Estimate of Energy Reduction or Recovery

Exhibit 9-1 shows a trend of waste heat produced from the three landfill gas turbines and the main duct waste heat flow (which is used either in the dryer house or in the waste heat boiler). The difference between the two represents the waste heat directed to atmosphere for duct pressure control. Each pound of waste heat (13.4 standard cubic feet) represents about 116 BTU of useable energy (based on lower heating value).

EXHIBIT 9-1
Trend of Waste Heat Produced



This chart shows about 178,000 pounds per hour of waste heat (40,000 scfm) being exhausted to atmosphere for maintaining waste heat duct pressure control. For comparison, each dryer uses between 17,000 and 24,000 scfm of waste heat when on waste heat plus gas. When using the waste heat in either a dryer or a waste heat boiler, the energy content of this waste heat is approximately 116 BTU/lb. (37,600 DTherm/year). When running properly, only about 10 percent of the waste heat needs to be exhausted for pressure control. Using the above chart, that would result in about 38,000 pounds per hour (8,500 scfm) of waste heat being used for pressure control.

Existing Waste Heat Boiler Damper

If pressure control is done through the waste heat boiler, the waste heat can be used in the boiler during the heating months, about 6 months of the year. It was assumed that the amount of waste heat that is exhausted to atmosphere would be reduced by 50 percent. It is possible that a greater reduction could be achieved since the waste heat boiler damper should be able to provide better control on a smaller flow than the three landfill gas turbine waste heat flow control dampers. Any waste heat that is not exhausted to atmosphere can be used in the dryer system. Assuming a 50 percent reduction yields an energy savings of 18,800 DTherm/year.

Modify Dryer System Controls

Modifications of the dryer system controls, if successful, would essentially allow all of the waste heat to be utilized in the sludge drying process, and no waste heat would be exhausted to atmosphere for duct pressure control. The resultant energy savings would be 37,600 DTherm/year.

Cost Estimate

The cost estimate for each alternative is shown below. The energy savings is based on the assumption that the existing system, as used today, is using only 10 percent of the waste heat for waste heat duct pressure control.

EXHIBIT 9-2
Cost Estimate for Alternative 9—Option Waste Heat Boiler Damper

		Waste Heat Boiler Damper	Dryer Controls Modifications
Capital Costs			
New actuator		$10,000	$600,000
Installation (30% of equipment)		$3,000	$180,000
Subtotal—Project Cost		*$13,000*	*$780,000*
Markups			
Site, piping, electrical, I&C, demolition, etc.	20%	$2,600	$156,000
Subtotal		*$15,600*	*$936,000*
Contingency	25%	$3,900	$234,000
Subtotal		*$19,500*	*$1,170,000*
Contractor mobilization, bonds, and insurance	20%	$3,900	$234,000
Subtotal		*$23,400*	*$1,404,000*
Subtotal with Markups		*$23,400*	$1,404,000
Total Construction Cost		$23,400	$1,404,000
Non-Construction Costs			
Engineering/administration	18%	$4,212	$252,720
Subtotal—Non-Construction Costs		*$27,612*	*$1,656,720*
Total Capital Cost (2014 dollars)		**$27,612**	**$1,656,720**
O&M Costs		**Annual Cost**	**Annual Cost**
Natural gas fuel savings		-$112,000	-$225,600
Total O&M (2014)		**-$112,000**	**-$225,600**

ALTERNATIVE 10

Increase SRT to Reduce Solids Processing Energy

Alternative Description

The Jones Island WRF operates at a fairly low SRT of 7.5 days while the South Shore WRF operates at an SRT of 11 days. Both facilities have additional basins that could be put online for treatment. Operating these basins with a higher SRT would reduce the amount of WAS generated and decrease overall solids production which would reduce energy use.

The following are potential constraints to consider:

- The Jones Island WRF operates at a fairly low SRT as a wet weather management strategy. Storm flows cause the influent flow to rise quickly (typically within an hour). Operating at the higher MLSS needed for higher SRT could result in losing solids during a wet weather event.
- The South Shore WRF already operates at a fairly high MLSS (~3,700 mg/L) which would not allow increasing the SRT without turning on additional basins or operating differently.
- Decreasing WAS generation could affect Milorganite® production. If the WAS fraction becomes too low, it could impact Milorganite® production by causing pellet formation issues or excessive dust/chaff.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

Changing the SRT requires no modifications or capital expenditures. The wasting rate would be reduced, leaving the solids in the system longer to degrade further resulting in a decrease in WAS. However, both plants are already limited in increasing SRT.

The wet weather management strategy limits the ability of the Jones Island WRF to increase the SRT. Two east and two west basins are available, but they are used as “idle” basins for wet weather management. All other basins are online to reduce the MLSS for wet weather management. Therefore, the Jones Island WRF cannot increase its SRT.

The South Shore WRF already operates at a high SRT, and its high MLSS limits its ability to increase the SRT. However, the South Shore WRF has the ability to operate in a step-feed mode. This mode is used for wet weather, but step feed could be used continuously to reduce the MLSS entering the secondary clarifiers, allowing the SRT to increase. For this alternative it was assumed the South Shore WRF would operate continuously in step feed mode. The following assumptions were used:

- Jones Island WRF primary clarifiers operate with 35 percent TSS removal efficiency, compared to 77 percent at the South Shore WRF.
- The South Shore WRF is allowed to operate a maximum of 27 basins, allowing 1 to be offline for maintenance.
- The South Shore WRF operates in a step feed mode: 60 percent of the flow plus 100 percent of the RAS enters the head of the basin; the remaining 40 percent enters about halfway down the basin.
- The South Shore WRF SRT is allowed to increase to 15.5 days.
- Jones Island WRF to South Shore WRF interplant pumping: 3 pairs of pumps with a capacity of 2,000 gpm at 420 feet TDH, each using a 400 hp motor. It was assumed the pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 413 hp.
- Jones Island WRF Equalization/Blending Tank pumping: capacity of 1,870 gpm at 138 feet TDH, each using a 100 hp motor. It was assumed the pumping efficiency is 70 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 109hp.

- South Shore WRF to Jones Island WRF interplant pumping: 3 pumps with a capacity of 1,160 gpm at 465 feet TDH, each using a 250 hp motor. It was assumed the pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 265 hp.
- The Jones Island WRF uses two pump stations. The LL pumps pump to the HL pumps. Historical operations show that roughly 45 percent of the influent flow goes to the LL pumps and the remaining 55 percent to the HL pumps. See Alternative 2 for details.
- Jones Island WRF aeration uses 85,000 scfm blowers at 60 percent efficiency, drawing 5,140 bhp using a 5,500 hp motor. Total draw per blower is 5,244 hp with 98 percent motor efficiency.
- South Shore WRF aeration uses 30,000 scfm blowers with 75 percent efficiency, drawing 1,451 bhp from a 1,500 hp motor. Total draw per blower is 1,481 hp, assuming a 98 percent motor efficiency.

Estimate of Energy Reduction or Recovery

Operating the South Shore WRF in step feed mode allows for an increase in SRT. The increase in SRT reduces sludge generation by about 1.5 percent or 2.4 tons per day. CHP energy production does not change because the amount of sludge to digestion does not change. Overall net energy production decreases slightly over the baseline mainly due to increased aeration required at the higher SRT.

Exhibit 10-1 provides a summary of the alternative.

Cost Estimate

With all facilities existing and all equipment well within its capacities, there is no capital cost associated with this alternative. Maintenance costs associated with changes in the interplant pumping, blowers, and influent pumping are assumed to be negligible. Savings from sludge generated are based on reduced polymer consumption for thickening, dewatering, and reduction in natural gas needed for drying. Exhibit 10-2 presents the net energy savings associated with the extra energy generation minus the pumping energy.

EXHIBIT 10-1
Increase SRT
Energy Production and Consumption Summary

Constituent	Baseline	Alternative	Comments
Operational SRT, days			
Jones Island WRF	7.5	7.5	No change
South Shore WRF	11	15.5	SRT increased.
Total Flow, mgd			
Jones Island WRF	90	90	
South Shore WRF	90	90	
PC TSS Removal			
Jones Island WRF	35%	35%	
South Shore WRF	77%	77%	
MLSS, mg/L			
Jones Island WRF	2,560	2,560	Average MLSS = 4770 mg/L due
South Shore WRF	3,700	3750	to step feed
Secondary Clarifier SLR, lb/d/ft^2			
Jones Island WRF	10.4	10.4	
South Shore WRF	15.8	16.1	
Estimated biogas production, ft^3/d	1,224,000	1,224,000	
Estimated biogas LHV	520	520	
Estimated energy production, kW	2716	2716	
Estimated energy produced, kWh/yr @ 8,000 hr/yr	21,727,100	21,727,100	

EXHIBIT 10-1
Increase SRT
Energy Production and Consumption Summary

Constituent	Baseline	Alternative	Comments
Interplant Pumping: Jones Island WRF to South Shore WRF	116-hp	117-hp	
Interplant Pumping: South Shore WRF to Jones Island WRF	165-hp	153hp	Less WAS to Jones Island WRF
Total interplant pumping energy, kWh/yr @ 8,760 hr/yr	1,818,550	1,741,930	
Jones Island WRF LL influent pumping	245-hp	245-hp	
Jones Island WRF HL influent pumping	390-hp	390-hp	
Total influent pumping energy, kWh/yr @ 8,760 hr/yr	4,102,970	4,4102,970	
Change in aeration power, kW Jones Island WRF South Shore WRF	 N/A N/A	 (34) (7)	 Step feed increased aeration efficiency while increasing the SRT decreased efficiency.
Total change in aeration energy, kWh/yr @ 8,760 hr/yr	None	(352,160)	
Net energy, kWh/yr	15,807,709	15,724,391	
Energy reduction, kWh/yr	N/A	(83,315)	

EXHIBIT 10-2
Annual Estimated O&M Costs for Alternative 10

Parameter	Value	Comment
Aeration Air Savings	-$6,000	(83,315) kWh/yr @ $0.07/kWh
Solids processing	-$139,000	2.4 dry ton per day decrease in sludge cake[a]
Net O&M	-$145,000	

[a] $3/dry ton in thickening polymer; $6/dry ton in dewatering polymer; $150/dry ton for gas to dry based on 0.8 MMBtu/hr per ton sludge @ 18% cake and $6/MMBtu for natural gas

Discussion and Considerations

The following discussion should be evaluated when discussing this alternative:

- The main constraint for the Jones Island WRF in this alternative is how it conflicts with the current wet weather strategy. Any changes to the strategy could allow the Jones Island WRF to provide additional savings.
- Operating at a high MLSS in wet weather is a known issue and is risky, even with step feed, as changes in MLSS due to washout are slow.

ALTERNATIVE 11

Decrease Activated Sludge SRT

Alternative Description

The Jones Island WRF operates at a fairly low SRT of 7.5 days, the South Shore WRF at an SRT of 11 days. Both facilities nitrify, and there is no permit limit for ammonia, but Veolia has an ammonia contract limit of 5 mg/L. Therefore, both facilities could basically lower their SRTs allowing effluent ammonia to increase but still remain below the ammonia permit limit. That additional WAS created by the lower SRT could be sent to the South Shore WRF anaerobic digesters to increase energy production.

The following are potential constraints on the system:

- The Jones Island WRF already operates at a fairly low SRT as a wet weather management strategy.
- The model was simulated using a 13.5°C temperature. If daily temperatures dip below this, then there could be less safety factor resulting in nitrifier washout.
- Additional anaerobic digestion volume may require new mixing systems.
- WAS generated by the South Shore WRF for digestion will require DAF thickening facilities to be brought online.
- Although the WAS mass would increase, the additional WAS would be sent to digestion, thereby affecting the WAS-to-digested sludge fraction for Milorganite®. If the digested sludge fraction sent to the dryers becomes too high (approximately > 40 percent), there will be issues with Milorganite® pellet quality and excessive dust and chaff.

MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.

Description of Modifications Required

Changing the SRT requires no modifications or capital expenditures. The wasting rate would be increased for each facility, and the additional WAS could be digested. The interplant pumping system has ample capacity for the excess sludge.

The increase in sludge to the South Shore WRF will require thickening, otherwise the digesters will quickly run out of capacity. The South Shore WRF uses dissolved air flotation for WAS thickening. Six units are available providing a firm capacity of 6,200 lb/hr. The units are not in use but could be put back into service. The decrease in SRT is estimated to generate 1.50 mgd of sludge or 3,450 lb/hr, which would require 3 units to be brought into service. If the digesters run out of capacity, even with thickening (~3.8 percent TS), then storage digesters will need to be converted to operational digesters. This will require new mixing systems. However, the new mixing systems will increase the active volume of the digesters, increasing the VSR.

The existing system has the following characteristics:

- The Jones Island WRF primary clarifiers operate with 35 percent TSS removal efficiency, whereas those at the South Shore WRF operate at 77 percent.
- The South Shore WRF SRT is allowed to decrease to 5.5 days, the Jones Island WRF SRT to 6.3 days. Both provide a 50 percent safety factor on nitrification and the ability to meet the contract ammonia limit.
- South Shore WRF dissolved air flotation WAS thickening is set to 95 percent capture, achieving 3.8 percent TS.
- South Shore WRF digester mixers are upgraded. One additional digester is brought online. New mixing achieves 90 percent active volume and provides 18.8 days' SRT.

- Jones Island WRF to South Shore WRF interplant pumping: 3 pairs of pumps with a capacity of 2,000 gpm at 420 feet TDH, each using a 400 hp motor. It was assumed the pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 413 hp.
- Jones Island WRF Equalization/Blending Tank pumping: capacity of 1,870 gpm at 138 feet TDH, each using a 100 hp motor. It was assumed that pumping efficiency is 70 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 109hp.
- South Shore WRF to Jones Island WRF interplant pumping: 3 pumps with a capacity of 1,160 gpm at 465 feet TDH, each using a 250 hp motor. It was assumed that pumping efficiency is 60 percent, motor efficiency 90 percent, and other losses 95 percent, for a power input of 265 hp.
- The Jones Island WRF uses 2 pump stations: The LL pumps pump to the HL pumps. Historical operations show that roughly 45 percent of the influent flow goes to the LL pumps and the remaining 55 percent to the HL pumps. See Alternative 2 for details.
- Jones Island WRF aeration uses 85,000 scfm blowers at 60 percent efficiency, drawing 5,140 bhp using a 5,500 hp motor. Total draw per blower is 5,244 hp, with 98 percent motor efficiency.
- South Shore WRF aeration uses 30,000 scfm blowers with 75 percent efficiency, drawing 1,451 bhp from a 1,500 hp motor. Total draw per blower is 1,481 hp, assuming a 98 percent motor efficiency.

Estimate of Energy Reduction or Recovery

Lowering the SRT would result in an additional 35 dry tons per day of WAS going to the South Shore WRF for digestion to provide 707 kW of additional power generation. The extra sludge requires an additional anaerobic digester to be brought online along with new digester mixing, but the additional active volume increases the VSR to 38 percent, allowing for total sludge production to reduce 2 percent of 2.39 dry tons per day. The resulting digested sludge quantity will exceed the 40 percent maximum digested sludge fraction to Milorganite® (required to avoid Milorganite® production issues). Operating the South Shore WRF in step-feed mode allows an increase in SRT. CHP energy production increases by nearly 19 percent. With the inclusion of DAF thickening at the South Shore WRF, the overall net energy production increases by 10.5 million kWh per year. Exhibit 11-1 provides a summary of the alternative.

Cost Estimate

The additional WAS to the digesters requires another digester to be brought online. Since that digester will require new mixing, then it was assumed the other digesters would be retrofitted with new mixers as well. The DAF thickening units at the South Shore WRF are assumed to not require upgrades. The other pumping facilities are existing and are all within their capacities. Exhibit 11-2 summarizes the capital costs.

Maintenance costs associated with changes in the interplant pumping, blowers, and influent pumping are assumed to be negligible. Additional costs for gas cleaning are assumed at $0.00115 per cubic foot of biogas generated, while additional maintenance costs for the engine generators are assumed at $0.01/kWh. Savings from sludge generated are based on reduced polymer consumption for thickening and dewatering as well as a reduction in natural gas needed for drying. DAF thickening O&M is based on energy increase. Exhibit 11-3 lists the net energy savings associated with the extra energy generation minus the pumping energy.

Discussion and Considerations

The following considerations should be evaluated when discussing this alternative:

- Running at a low SRT will make the facilities susceptible to nitrifier washout if the system is not closely monitored for pH and temperature.
- The additional WAS to the digesters results in a 42:54 WAS-to-digested sludge ratio likely resulting in increased Milorganite® dust generation and pellet formation issues.

EXHIBIT 11-1
Decrease SRT
Energy Production and Consumption Summary

Constituent	Baseline	Alternative	Comments
Operational SRT, days			
Jones Island WRF	7.5	6.3	50% safety factor for nitrification
South Shore WRF	11	5.5	
Total Flow, mgd			
Jones Island WRF	90	90	
South Shore WRF	90	90	
Primary clarifier TSS removal			
Jones Island WRF	35%	35%	
South Shore WRF	77%	77%	
MLSS, mg/L			
Jones Island WRF	2,560	2,178	
South Shore WRF	3,700	2,213	
Secondary clarifier SLR, lb/d/ft^2			
Jones Island WRF	10.4	9.2	
South Shore WRF	15.8	8.9	
Estimated biogas production, ft^3/d	1,224,000	1,454,700	18.9% increase
Estimated biogas LHV	520	550	
Estimated energy production, kW	2716	3421	
Interplant pumping: Jones Island WRF to South Shore WRF	116-hp	172-hp	
Interplant pumping: South Shore WRF to Jones Island WRF	165-hp	165-hp	
Total interplant pumping energy, kWh/yr @ 8,760 hr/yr	1,818,550	2,177,925	
Jones Island WRF LL influent pumping	245 hp	245 hp	
Jones Island WRFHL influent pumping	390 hp	390 hp	
Total influent pumping energy, kWh/yr@8,760 hr/yr	4,102,970	4,102,970	
Change in aeration power			
Jones Island WRF	N/A	(-4)	Lower MLSS allows for higher alpha. Nitrifying to only ~1 mg/L instead of < 0.2 mg/L
South Shore WRF	N/A	613	
Est. change in aeration energy, kWh/yr@8,760 hr/yr	None	(5,276,134)	
DAF thickening power	N/A	35.8-hp	Three 2 hp motors, 10 hp compressor, 16.8 hp sludge pumping
Total DAF energy, kWh/yr	N/A	231,675	
Net energy, kWh/yr	15,807,707	26,330,920	
Energy reduction, kWh/yr	N/A	10,523,214	

EXHIBIT 11-2
Estimated Capital Costs for Alternative 11

Parameter	Value	Comment
New digester mixing (large units)	$534,0000	Pumped mixing for 2 digesters
Subtotal	*$534,000*	
Total Construction Cost	$534,000	
Markups		
Contingency		
General		
Total Non-Construction Costs	$96000	
Total	**$630,000**	

EXHIBIT 11-3
Estimated O&M Costs for Alternative 11

Parameter	Value	Comment
Estimated additional chemicals for digester gas H_2S control	$96,491	~19% additional gas production
Estimated additional engine maintenance	$56,447	No additional gas production
Estimated additional DAF polymer	$39,482	$3/DT for 36 dry tons per day
Estimated DW polymer reduction	-$5,994	2.74 DT/day reduction in solids, $6/dry ton
Estimated drying reduction	-$130,853	$150/dry ton [a]
Estimated Additional O&M	$70,000	
Total additional O&M	$147,235	
Estimated additional energy generated	-$736,625	10,523,214 kWh/yr @ $0.07/kWh
Net O&M	-$463,817	

[a] $3/dry ton in thickening polymer; $6/dry ton in dewatering polymer; $150/dry ton for gas to dry based on 0.8 MMBtu/hr per ton sludge @ 18% cake and $6/MMBtu for natural gas

ALTERNATIVE 12

Increase Belt Press Feed Solids Concentration to Increase Cake Solids

Alternative Description

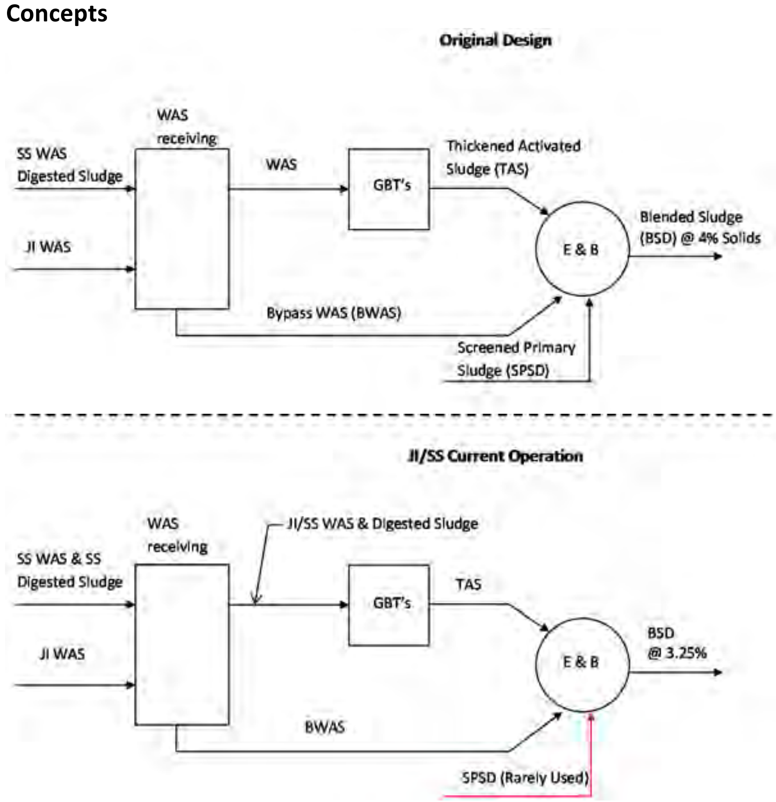
This alternative evaluates increasing the thickened waste activated sludge (TWAS) solids concentration at the Jones Island WRF, which would increase the concentration of belt press dewatered cake solids. Increasing the cake solids concentration would decrease the amount of water that the dryers must evaporate and thus decrease dryer energy use.

MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.

Description of Modifications Required

Increasing the concentration of the TWAS (which includes digested sludge from the South Shore WRF) will require modifications to the operation of the gravity belt thickeners (GBTs). Typically, higher concentrations are achieved through slower belt speeds, lower sludge feed rates, and possibly increased polymer feed. Modifications to the GBT control systems may also be required.

EXHIBIT 12-1
Jones Island WRF Solids Handling: Original and Current Design Concepts



The Jones Island WRF has four 3-meter GBTs, each typically running at 800 to 1,000 gpm. According to Veolia operations staff, each GBT can process up to 1,400 gpm. The feed sludge to the GBTs is from the equalization and blend (E&B) tanks. The E&B tanks receive WAS from the Jones Island and South Shore WRFs and digested sludge from South Shore WRF (Exhibit 12-1). The original design did not include digested sludge from the South Shore WRF, because the design intent was to land apply digested sludge. At least one new GBT will be required, but two GBTs may be desirable upon further examination of the plant operating conditions. An alternative would be to use a thickening centrifuge, as it may have a higher capacity than a GBT.

TWAS is pumped to the belt filter presses (BFPs), and the TWAS pumps would likely require modifications or replacement to pump thicker solids. The BFP feed solids average 3.2 percent, and a feed solids concentration of 5 to 6 percent is desirable to optimize cake solids concentration. A more detailed review of the actual operating conditions is required to further assess the optimum feed solids and other parameters. The blended sludge pumping system that feeds the belt presses likely needs to be modified or replaced to pump at a higher sludge concentration. According to Alan Scrivner/AES, the pumps from the E&B tank were tested on four of the belt presses and were found capable of pumping about 5 percent solids sludge. However, when the entire system was started up, the pumps were not capable of achieving adequate pressure to maintain and operate the polymer mixing valve. This was remedied by reducing the TWAS solids concentration and installing booster pumps on the fourth floor of the D&D Building. The pumping modifications required will require a more detailed evaluation if this alternative is considered further.

Veolia staff also noted the following:

- The blended sludge solids concentration fed to the BFPs had been about 2.2 percent, and it was increased to about 3.3 percent. Further increases would likely require significant system modifications.
- Higher TWAS concentrations may not be possible, especially if one GBT is out of service, because the GBTs would become hydraulically limited. Running the belt slower to achieve higher TWAS solids concentration reduces the hydraulic capacity. This further demonstrates the need for additional WAS thickening capacity.
- The TWAS pumps system lacks redundancy. Improving the level of redundancy is a 2015 CIP project.
- The addition of South Shore WRF digested sludge reduces the ability to increase the solids concentration.
- The capacity and head of the WAS receiving pumps and of the TWAS pumps may not be adequate, especially if one or more GBTs are added.

Some conditions in the Milorganite® system may limit the cake solids concentration. According to Veolia staff, some of the Milorganite® product is recycled to achieve an optimal feed solids concentration. The recycle system may not be able to be turned down to a low enough feed rate if the sludge cake is drier. If the sludge is too dry, it could result in excessive dust and chaff production. This may be an issue depending upon the final cake solids achieved.

Supplemental natural gas is required for drying because the landfill gas turbines do not provide enough waste heat. Having a drier cake would reduce the water to evaporate and the energy for drying, and may also result in operating fewer dryers and thus additional savings in O&M costs.

Estimate of Energy Reduction or Recovery

Alternative 22 evaluated the energy savings by recovering dryer exhaust heat to increasing the concentration of the feed solids to the dryers. The sludge cake solids concentration increase assumed for Alternative 22 is also used for Alternative 12. It should be noted that Alternatives 16 and 94 also address a means to increase the solids concentration fed to the dryers. All these alternatives would need to be considered together to determine the total net effect of any combination of them being implemented.

By increasing the BFP feed solids, energy used in the sludge drying process would be reduced by increasing the cake solids concentration and decreasing cake moisture. Pilot testing would be needed to confirm how much the cake solids could be increased by increasing BFP feed solids. For this analysis, it was assumed that cake solids will improve from an average of about18 to 19 percent. The reduction in moisture load to the dryers results in an energy savings of about 64,000 Dtherm per year. Veolia staff believe that it may be possible to achieve 20 percent cake solids if the BFP feed concentration could be increased to about 5 percent. If this could be done, the energy savings would about double, making the alternative even more cost-effective.

Cost Estimate

Energy savings is contingent on the moisture reduction in the sludge cake being fed to the digesters. With the assumed 1 percent improvement in cake solids, $384,000 of annual energy savings can be realized in the dryer system. Capital costs for facility modifications could include the GBT sludge feed system, at least one new GBT train, polymer feed system, and TWAS pumps. Annual O&M costs include the cost for additional polymer feed to the GBTs. It is estimated that the amount of polymer required would increase by roughly 10 percent of the amount currently used, although this could vary widely and pilot testing is recommended.

Exhibit 12-2 is the cost estimate for this alternative.

EXHIBIT 12-2
Cost Estimate for Alternative 12

Capital Costs		
GBT (New)		$180,000
Polymer feed system modifications		$30,000
WAS pump		$85,545
Installation (30% of equipment)		$92,496
Subtotal—Project Cost		*$388,041*
Markups		
Site, piping, electrical, I&C, demolition, etc.	20%	$77,608
Subtotal		*$465,649*
Contingency	25%	$116,412
Subtotal		*$582,061*
Contractor mobilization, bonds, and insurance	20%	$116,412
Subtotal		*$698,473*
Subtotal with Markups		*$698,473*
Total Construction Cost		$698,473
Non-Construction Costs		
Engineering/Administration	18%	$125,725
Subtotal—Non-Construction Costs		*$824,199*
Total Capital Cost (2014 dollars)		**$824,199**
O&M Costs (using 2014 average loads)		**Annual Cost**
Additional O&M labor (1% of new construction)		$7,000
Additional Maintenance—Parts (1% of new equipment)		$4,000
Additional polymer to GBTs		$93,000
Natural gas fuel savings		-$384,211
Total O&M Costs (2014)		**-$280,211**

ALTERNATIVE 13

Improve Plantwide HVAC Control

Jones Island WRF

Alternative Description

A Johnson Controls Metasys HVAC control system is used at the Jones Island WRF to monitor, control, and optimize the multiple area HVAC systems, including D&D, East Side Galleries, and RAS Pumping. Many of the process areas are still controlled by stand-alone hard-wired mechanical monitoring panels (MMPs). Generally, these stand-alone panels run HVAC loads based on simple relay logic regardless of any external conditions, including plant energy draw, process operations, or building occupation. It appears that some air handling units operate continuously irrespective of environmental conditions.

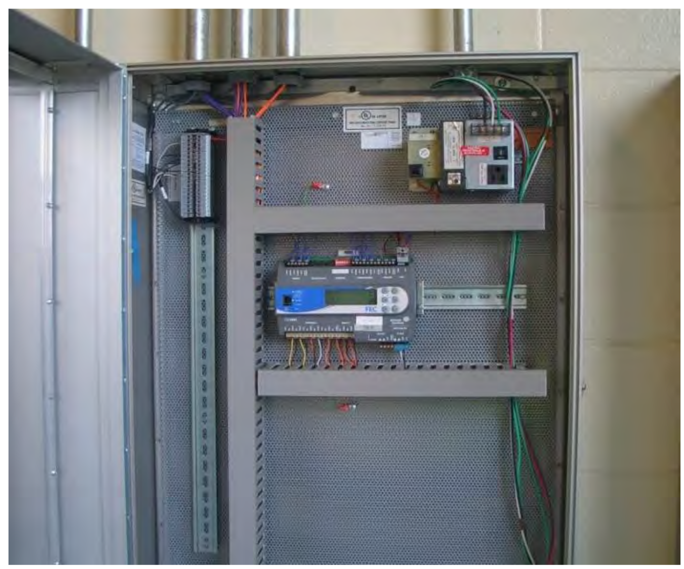
If the relay logic of MMPs is replaced with Metasys remote units that are connected in through an Ethernet network to the existing system master unit, the entire system could be programmed to optimize energy use.

Description of Modifications Required

All MMPs would need to be identified and their function, I/O, and network requirements determined. The primary Metasys processor would need to be programmed for all coordinating functions, including determining the need for the HVAC in given areas and peak energy limiting procedures.

EXHIBIT 13-1
Existing South Shore WRF Typical HVAC Technology in the Process Areas

EXHIBIT 13-2
New Proposed Technology



Estimate of Energy Reduction or Recovery

Shutting down air handling units when they are not required will save relatively small amounts of electrical energy, since the typical fan size is about 1 hp, or 0.76 kW. Larger energy savings will occur during colder weather, when the outside makeup air must be heated as it is pulled into the buildings. It was assumed that through proper algorithms and programming, about one-third of the air handling units could be shut down on average. For 40 air handling units, the annual energy savings would be about 50,000 kWh of electrical energy and natural gas savings of 3,750 MBtu. This is based upon a maintained 60-degree room temperature and average monthly ambient air temperatures from October through May.

Cost Estimate

The number of air handling units to be modified would need to be determined in a more detailed evaluation. The cost estimate in Exhibit 13-3 was prepared based on 40 existing MMPs.

EXHIBIT 13-3
Cost Estimate for Alternative 13: Jones Island WRF

Capital Costs		
Metasys modules		$400,000
Programming of system		$400,000
Installation (30% of Equipment)		$240,000
Subtotal—Project Cost		*$1,040,000*
Markups		
Site, piping, electrical, I&C, and demolition etc.	15%	$156,000
Subtotal		*$1,196,000*
Contingency	25%	$299,000
Subtotal		*$1,495,000*
Contractor mobilization/bonds/insurance	20%	$299,000
Subtotal		*$1,794,000*
Subtotal with Markups		*$1,794,000*
Total Construction Cost		$1,794,000
Non-Construction Costs		
Engineering/administration	18%	$322,920
Subtotal—Non-Construction Costs		$2,116,920
Total Capital Cost (2014 dollars)		**$2,116,920**
O&M Costs (using 2014 average loads)		**Annual Cost**
Power savings		-$3,500
Natural gas fuel savings		-$22,500-
Total O&M Costs (2014)		**-$26,000**

South Shore WRF

Alternative Description

The Honeywell HVAC control system used at the South Shore WRF monitors, controls, and optimizes the environment of the facility's office areas. The process areas are controlled by stand-alone hard-wired mechanical MMPs. The stand-alone panels generally run HVAC loads based on simple relay logic regardless of external conditions, including plant energy draw, process operations, or building occupation. Some air handling units appear to run continuously, irrespective of environmental condition. If the relay logic of all the MMPs is replaced with Honeywell remote units and networked back (by Ethernet) to the existing system master unit, the total system could be programmed for optimum energy use and operate in a coordinated fashion.

Description of Modifications Required

All MMPs would need to be identified, and their function, I/O, and network requirements determined. The primary Honeywell processor would need to be programmed for all coordinating functions, including determining the need for the HVAC in given areas and peak energy limiting procedures.

Estimate of Energy Reduction or Recovery

Shutting down air handling units when they are not required will save relatively small amounts of electrical energy since the typical fan size is about 1 hp or 0.76 kW. The larger energy savings would occur during colder months, when the outside makeup air must be heated as it is pulled into the buildings. It is assumed that though proper algorithms and programming that one-third of the air handling units can be shut down at any given time. The energy savings would be about 50,000 kWh of electrical energy and natural gas savings of 3,750 MBtu yearly. This is based upon a maintained 60° room temperature, October through May operation, and an assumed 25 air handling units.

Cost Estimate

The number of replacement unit could vary, and detailed evaluation would be required to refine the energy savings, number of units, and other factors. Exhibit 13-4 is a preliminary cost estimate assuming 25 air handling units. Although this shows that these improvements may not be cost effective, there may be other ways to improve HVAC efficiency that do not require substantial capital costs. These changes could include reviewing temperature set points, building insulation, and reductions in air changes especially those required by NFPA 820 in facilities with large HVAC energy needs such as Dewatering and Drying. However, given the large number of plant buildings and facilities, and evaluation like this is beyond the scope of this project.

EXHIBIT 13-4
Cost Estimate for Alternative 13: South Shore WRF

Capital Costs	
Programming of system/modifications	$75,000
Subtotal—Project Cost	*$75,000*
Total Capital Cost (2014 dollars)	**$75,000**
O&M Costs (using 2014 average loads)	**Annual Cost**
Power Savings	-$1,617
Natural gas fuel savings	-$14,100
Total O&M Costs (2014)	**-$15,717**

It is recommended that a detailed study of this alternative be done to verify potential costs savings.

ALTERNATIVE 14

Automate Real-Time Energy Optimization Control and Monitoring

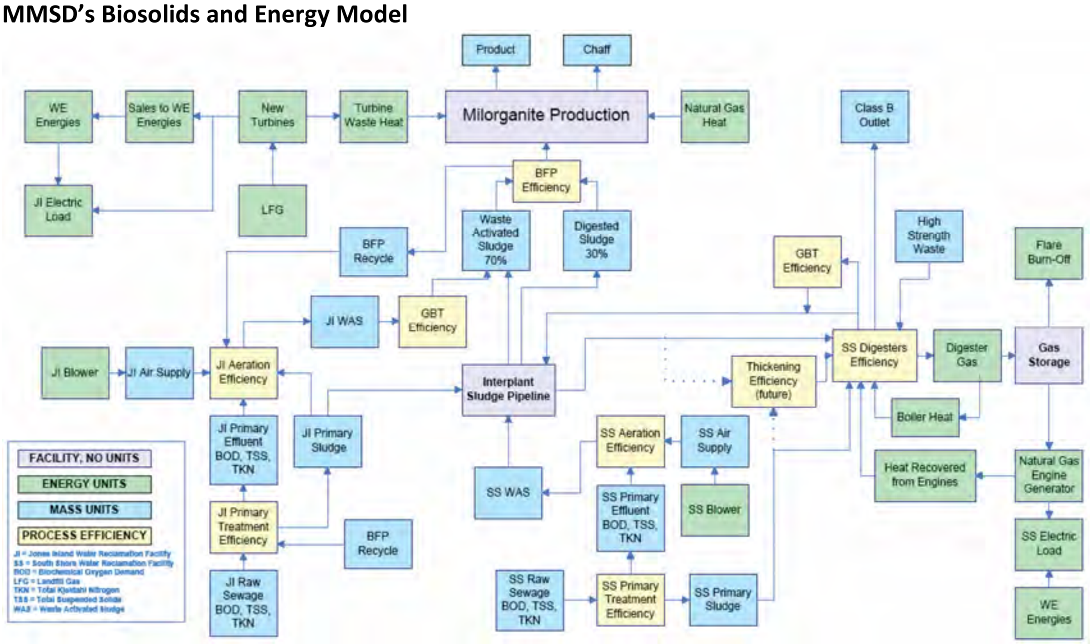
Alternative Description

Under Alternative 14, some decision processes regarding diversions between the two water reclamation facilities, solids distribution, and energy production using renewable fuels will be automated. In addition, energy users (such as process air compressors and Milorganite® production) will be displayed in real time so that operators can make process adjustments to bring energy use to within normal ranges.

Exhibit 14-1 (provided by MMSD) shows the relationship of the energy, biosolids and process units, associated with Milorganite® production, at the two water reclamation facilities and is the basis of a spreadsheet model that MMSD has used to help optimize energy and biosolids transfer. This alternative would build upon this model and a computer process model could be integrated with or used in conjunction with MMSD's model.

EXHIBIT 14-1

MMSD's Biosolids and Energy Model



Energy consumption would be reduced under Alternative 14 through the mechanisms listed below, among others:

- Minimization of pumping
- Minimization of sludge drying
- Maximization of digester gas production

Optimization of activated sludge control including SRT, number of basins on-line and other parameters

- Optimization of sludge transfers between treatment plants
- Optimization of sludge blends to maintain Milorganite® nutrient values, energy requirements, and pellet quality
- Optimization of blower energy to meet permit requirements.

Description of Modifications Required

The project would require only a small capital expenditure to install instrumentation where needed (such as the potential for nitrate analyzers in the aeration basins). The main effort would be in building the energy optimization model to reflect the actual conditions at the plant. Models that would be used include, among others, the following:

- BioWin or other similar wastewater treatment process models
- The MMSD biosolids energy spreadsheet model
- The South Shore WRF gas energy spreadsheet (developed with the installation of the new engine-generators)
- The Jones Island WRF landfill gas spreadsheet (developed with the installation of the landfill gas turbines)

With these different models, real-time energy usage, and costs, flow and biosolids information could be input so that decisions can be made regarding the following:

- **Generation of electricity versus purchase of electricity—**This would include generation using the Jones Island WRF turbines and the South Shore WRF engines. It would consider the cost of natural gas, purchased electrical power including demand charges, landfill gas, and the value of waste heat for drying Milorganite®, providing building heat, and other variables.
- **Split of influent flow between the South Shore and Jones Island WRFs—**Roughly one-third of the collection system is dedicated to the Jones Island WRF and one-third to the South Shore WRF. The remaining one-third can be directed to either plant. The flow split could be optimized to minimize pumping and treatment costs, and optimize digester gas production, drying costs, and other costs.
- **Transfer of sludges between plants—**the transfer of WAS, primary sludge, and digested sludge between plants could be optimized considering digester gas production, power generation, pumping costs, and other treatment costs.

A key to effectively implementing this alternative will be the use of real time power monitoring of individual processes. The District has identified processes where power monitoring will be installed and has purchased several power monitors that will be installed in the near future.

The effectiveness of a real-time model is difficult to determine until some effort is made to conceptually develop the model to begin to assess its potential to optimize processes for energy. Therefore, some effort should be expended conceptually developing the model before implementing. Even if the energy reductions achieved by a model are modest, it likely would be found that the model would be cost-effective given the District's high energy use and the relatively low cost of the model development.

Estimate of Energy Reduction or Recovery

Energy reduction cannot be estimated accurately without additional engineering effort, but it is reasonable to assume that the annual energy savings could be between 1 and 5 percent. The total energy use is 1,800,000 Dtherm per year (Technical Memorandum 2, Energy Baseline, Table 7). A 1 percent energy reduction equates to 18,000 Dtherm per year, and 5 percent reduction to 90,000 Dtherm.

Cost Estimate

Exhibit 14-2 presents the estimated costs for the project for both 1 percent reduction in total energy use (18,000 Dtherm per year) and 5 percent (90,000 Dtherm per hear). It can be seen that the potential energy savings are large in comparison to the implementation costs. It is recommended that preliminary engineering be done before implementation to better estimate the energy savings and implementation costs.

EXHIBIT 14-2
Cost Estimate for Alternative 14

		Energy Reduction	
		1%	**5%**
Capital Costs			
Instrumentation allowance		$200,000	$200,000
Installation (30% of equipment)		$60,000	$60,000
Subtotal—Project Cost		*$260,000*	*$260,000*
Markups			
Site, piping, electrical, I&C, demolition, etc.	20%	$52,000	$52,000
Subtotal		*$312,000*	*$312,000*
Contingency	25%	$78,000	$78,000
Subtotal		*$390,000*	*$390,000*
Contractor mobilization, bonds, and insurance	20%	$78,000	$78,000
Subtotal		*$468,000*	*$468,000*
Total Construction Cost		$468,000	$468,000
Non-Construction Costs			
Engineering/administration		$500,000	$500,000
Subtotal—Non-Construction Costs		*$968,000*	*$968,000*
Total Capital Cost (2014 dollars)		**$968,000**	**$968,000**
O&M Costs (using 2014 average loads)		**Annual Cost**	**Annual Cost**
Additional O&M labor		$4,500	$4,500
Additional maintenance—Parts		$3,000	$3,000
Total Energy Savings		-$108,000	-$540,000
Total O&M (2014)		**-$100,500**	**-$532,500**

ALTERNATIVE 15

Improve Primary Clarifier Operations/Removal Efficiency

Primary clarifier performance may not be optimal because of current standard operating procedures, clarifier inlet configuration, or other physical issues or limitations. The aeration tanks at the two WRFs use a significant amount of energy, and improved primary clarifier performance can result in increased BOD removal, which decreases organic loading to the secondary system, thereby reducing the aeration system oxygen demand and energy.

The South Shore WRF digests primary sludge and has engine/generators that use digester gas to make electricity and capture heat for digester and building heating. Increasing TSS removal will increase the mass of primary sludge sent to the South Shore WRF for digestion. All South Shore WRF primary sludge and most Jones Island WRF primary sludge is digested. The increase in primary solids to digestion will increase digester gas production and thereby reduce the energy demand through more electricity and heat energy production from the engine/generators. However, there is a limit to how much sludge can be digested because of impacts to the Milorganite® process that must be considered. Two alternatives to improve primary clarifier performance at the Jones Island WRF were considered. Because primary clarifier TSS removal at the South Shore WRF is high (roughly 80 percent), no improvement options were developed for the South Shore WRF primary clarifiers.

This alternative will be further evaluated in the 2050 Facilities Plan.

Jones Island WRF: Optimize Primary Treatment

Practice at the Jones Island WRF is to operate one primary clarifier for every 47 mgd of influent flow. Exhibit 15-1 summarizes the plant influent flow distribution from 2007 through 2013, with median flows per bracket and resulting surface overflow rates (SORs) at the median flow rate. The plant influent flow is less than 100 mgd more than 75 percent of the time, and less than 147 mgd 90 percent of the time. Under these conditions, the standard operating procedure is to operate two or three primary clarifiers. One method to optimize primary clarifier performance is to continuously operate seven primary clarifiers (assume one out of service) to reduce the SOR and thus maximize TSS removal. Exhibit 15-1 shows that the SOR for the first three flow brackets can be substantially reduced with seven primary clarifiers in service.

EXHIBIT 15-1

Jones Island WRF Influent Flow Distribution and Surface Overflow Rates

Flow Bracket (mgd)	Percentage of Days in Flow Bracket[a]	Median Bracket Flow (mgd)	Primary Clarifiers in Service @ 50 mgd/Clarifier	Surface Overflow Rate at Median Flow[b] (gal/ft^2-d)	Surface Overflow Rate with 7 Primary Clarifiers in Service (gal/ft^2-d)
< 100	78	73	2	1,815	520
101–147	12	117	3	1,940	830
147–189	5	166	4	2,070	1,185
189–236	2	211	5	2,095	1,495
236–289	2	255	6	2,115	1,810
>289	1	313	7	2,225	2,225

[a] Data set from January 1, 2007, through December 2, 2013.

[b] SOR based upon number of primary clarifiers identified for each flow bracket.

This analysis evaluates the potential benefits of continuously operating seven primary clarifiers. To simplify the analysis, it is assumed primary clarifier TSS removal performance can be improved at flows less than 147 mgd or 90 percent of the time. Plant influent data from January 1, 2007, through March 31, 2010, show that influent TSS concentrations averaged 220 mg/L and BOD concentrations 260 mg/L at flows less than 147 mgd, and 230 mg/L TSS and 270 mg/L BOD at flows less than 100 mgd. Data from May 1 through September 6, 2008, show an average primary clarifier TSS removal of 55 percent and BOD removal of 22 percent when flows are less than 147 mgd. Applying the 2008 primary clarifier TSS and BOD removal rates to the 2007 to 2010 data indicates the primary effluent TSS should be roughly 100 mg/L and BOD 205 mg/L when flows are less than 147 mgd. The estimated PE TSS and BOD values of 100 and 205 mg/L are lower than the PE TSS and $CBOD_5$ of 130 and 230 mg/L measured during a 10-day wastewater characterization in March 2010, when flows were less than 100 mgd. Full-scale testing and review of more current data are recommended to verify the current primary clarifier performance and predicted primary clarifier performance with seven clarifiers in service.

Description of Modifications Required

Modifications required for this alternative consist of changing the standard operating procedure. No physical changes to the Jones Island WRF primary clarifiers and pumping of the South Shore WRF digesters are assumed.

Estimate of Energy Reduction or Recovery

Primary effluent consists of two TSS components: settleable solids with particle settling velocities less than the SOR, and settleable solids not removed as a result of clarifier inefficiencies and nonsettleable solids that will pass through a primary clarifier. Plant influent nonsettleable TSS from 10 WWTPs evaluated under WERF Report 00-CTS-02, *Determine the Effect of Individual Wastewater Characteristics and Variances on Primary Clarifier Performance* (2006) averaged 24 percent of the influent TSS. Assuming the Jones Island WRF influent nonsettleable solids fraction is 24 percent or 53 mg/L, there is potential to capture additional TSS by reducing the primary clarifier SOR. Hydraulic inefficiencies will prevent capture of all settleable solids. This analysis assumes PE TSS is reduced an additional 30 mg/L (68 percent TSS removal) with an associated reduction in particulate BOD of 13 mg/L (27 percent BOD removal) when operating 7 primary clarifiers at flows less than 150 mgd. The potential TSS and BOD removal rates are typical of primary clarifiers treating municipal wastewater and should be field verified.

The average plant influent flow is 83 mgd when considering all flows less than 147 mgd. Assuming 30 mg/L of additional TSS removal, a primary sludge VSS:TSS ratio of 75 percent as measured in the 2010 wastewater characterization, and an operating factor of 90 percent, the annual load of Jones Island WRF primary sludge VSS to the South Shore WRF will increase by 14,000 lb VSS/d with a concurrent reduction in Jones Island WRF WAS load of 12,000 lb TSS/d.

The BioWin simulator developed under the Jones Island WRF Capacity and Aeration Projects was used to estimate aeration airflow savings. The airflow savings were estimated using steady-state simulations with flow proportional distributed to 9 and 18 aeration tanks in service on the west and east sides. Operating with seven primary clarifiers is estimated to reduce the process aeration airflow by 3,400 scfm/d (90 percent weighted basis) when maintaining dissolved oxygen at 2 mg/L. However, when bioreactor mixing and minimum airflow per diffuser requirements are considered, the average aeration airflow reduction is estimated at 2,200 scfm (90 percent weighted basis). The minimum airflow requirement may require further investigation to determine if modifications to the diffuser densities are required to achieve the low air flows.

Exhibit 15-2 summarizes the power, energy, and solids processing savings associated with this alternative. Note that increasing the amount of primary sludge will increase the amount of digested sludge, and if the portion of the solids fed to the dryers exceeds about 40 percent, issues with excessive dust and chaff production arise. According to Veolia, a portion of the JI primary sludge is sent to JI secondary treatment to generate waste activated sludge. With this diversion of primary sludge, it is expected that digested sludge sent to Milorganite® production would not exceed the 40 percent limit, even with improved primary clarifier removal efficiency. However, there must be consideration for Milorganite® production and quality when improving primary clarification. If all primary sludge was sent to digestion, the digested sludge limit to Milorganite® production would likely be exceeded. That issue would have to be addressed more closely should this alternative be considered for implementation.

Cost Estimate

Exhibit 15-3 summarizes a conceptual order of magnitude savings for this alternative.

EXHIBIT 15-2
Summary of Primary Treatment Operations/Removal Efficiency Improvements Reductions at the Jones Island WRF

Item	Units	Optimize Primary Treatment	Primary Clarifier Inlet Baffling
Primary Sludge Digestion			
Additional loading	lb VSS/d	14,000	9,200
Digester VSS destruction	Percent	60	60
Additional VSS destroyed	lb VSS/d destroyed	8,400	5,520
Digester gas production	ft^3/lb VSS destroyed	15	15
Additional digester gas production	ft^3/d	126,000	82,800
Digester gas energy	Btu/ft^3	560	560
Additional digester gas energy	MMBtu/yr	25,700	16,900
Power conversion efficiency	percent	33.5%	33.5%
Power production reduction	kWh/yr	2,530,000	1,660,000
Thermal conversion efficiency	percent	42%	42%
Thermal production reduction	MMBtu/yr	10,800	7,100
Aeration Savings			
Reduction in aeration airflow	scfm/d	2,200	1,600
Aeration energy	kW/scfm	0.03	0.03
Annual aeration savings	kWh/yr	580,000	420,000
Solids Processing Savings			
Additional digested solids	lb TSS/d	10,300	6,780
WAS reduction	lb TSS/d	12,000	7,800
Overall reduction in solids	lb TSS/d	1,700	1,020

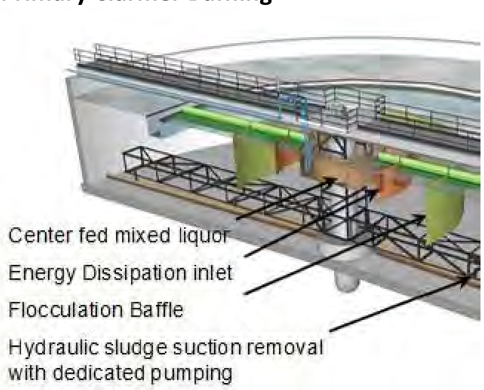
EXHIBIT 15-3
Order of Magnitude Costs for Primary Treatment Operations/Removal Efficiency Improvements at Jones Island

Item	Unit Cost	Optimize Primary Treatment	Primary Clarifier Inlet Baffling
Capital Costs	—		
Baffles	—	—	$680,000
Contingency	25 percent	—	$170,000
Subtotal	—	—	*$850,000*
Contractor mobilization, bonds, and insurance	20 percent	—	$170,000
Total Construction Cost	—	—	$1,020,000
Engineering/administration	18 percent	—	$200,000
Total Capital Costs	—	—	**$1,220,000**
O&M Savings			
Natural gas fuel	$6/MBtu	$65,000	$40,000
Cogeneration from digester gas	$0.07/kWh	$175,000	$115,000
Aeration	$0.07/kWh	$40,000	$30,000
Biosolids processing	$160/DT	$48,000	$28,800
Total O&M Savings	—	**$328,000**	**$213,800**

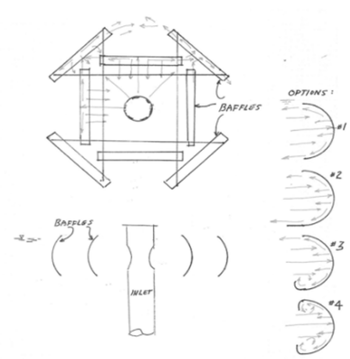
Jones Island WRF: Primary Clarifier Inlet Baffling

One method being considered to optimize the primary clarifiers is to add inlet baffling to promote flocculation and improve tank hydraulics. Exhibit 15-4 shows different conceptual designs. Limited, if any, data are available comparing primary clarifier performance with and without inlet/flocculation baffles. Flocculating center wells in secondary clarifiers are proven to enhance particle formation and to improve tank hydraulic conditions to optimize TSS removal.

EXHIBIT 15-4
Primary Clarifier Baffling



Traditional Flocculating Center Well



Concave Flocculating Energy Dissipating (by Bill Boyle)

Description of Modifications Required

This alternative requires that each primary clarifier be retrofitted with an inlet flocculating baffle. This analysis assumes the clarifier mechanisms are in good structural conditions and can support the additional weight of the inlet baffles.

Estimate of Energy Reduction or Recovery

WERF Report 00-CTS-02, *Determine the Effect of Individual Wastewater Characteristics and Variances on Primary Clarifier Performance* (2006) notes that the total TSS removal inefficiencies in primary clarifiers due to flocculation and hydraulic deficiencies at 10 WWTPs ranged from 0 mg/L to 32 mg/L, with median flocculation and hydraulic inefficiencies of 20 mg/L. This analysis assumes addition of inlet/flocculation baffling improves primary clarifier TSS removal by 15 mg/L (62 percent TSS removal) with a corresponding reduction in PE BOD estimated of 7 mg/L.

The average plant influent flow during 2007–2013 was 98 mgd. Assuming 15 mg/L of additional TSS removal and a primary sludge VSS:TSS ratio of 75 percent as measured in the 2010 wastewater characterization, the annual primary sludge VSS load from the Jones Island WRF to the South Shore WRF will increase by 9,200 pounds VSS/d.

The Jones Island WRF BioWin simulator was used to estimate aeration airflow savings. The airflow savings were again estimated using steady-state simulations with flow proportionally distributed to 9 and 18 aeration tanks in service on the west and east sides. Retrofitting the tanks with inlet baffles and using the current primary clarifier standard operating procedure is estimated to reduce the process aeration airflow by an average of 2,400 scfm when maintaining dissolved oxygen at 2 mg/L. However, when bioreactor mixing and minimum airflow per diffuser requirements are considered, the average aeration airflow reduction is estimated to be 1,600 scfm. The minimum airflow requirements and associated limitation due to diffuser patterns require further evaluation.

Exhibit 15-2 summarizes the power, energy, and solids processing savings associated with this alternative.

Cost Estimate

Exhibit 15-3 summarizes a conceptual order of magnitude costs and savings for this alternative.

ALTERNATIVE 16

Heat Sludge and Polymer Solution to Improve Cake Solids

Alternative Description

The Jones Island WRF has several sources of heat that may be available for use in heating either the thickened sludge or the polymer used for dewatering, or both. Heating the sludge and polymer has been shown at some other plants to increase the solids content of dewatered cake which would reduce the energy required for drying Milorganite®.

The energy required to heat the sludge or polymer could be obtained from the dryer exhaust. Doing that is described in Alternative No. 22. The new landfill gas turbines have a cooling water system for the gas compressors and for the turbine lube oil. They are designed to use river water for cooling the water in the cooling system loop. This amount of heat available from that source was estimated in Alternative 94.

The other potential heat source would be heat recovered from the plant effluent as described in Alternative 31. That system would have the capability of providing heat nearly year around but the plant effluent location is a substantial distance from the D&D Building.

Description of Modifications Required

Two heat exchangers would be located on the 4th floor (El. 53.0). One heat exchanger would be a plate-and-frame type for heating polymer solution and would be located near the north side where the polymer headers rise up from the basement level. The second heat exchanger would be a spiral type heat exchanger for heating blended sludge and would be located near the south side close to the blended sludge booster pumps.

There are two redundant polymer header loops (polymer not used in the dewatering process is returned to the polymer feed pump discharge). The heat exchanger would be located on one of the headers and that header would then become a primary header. Valves can be provided to allow the other header to use the heat exchanger.

There are also two redundant blended sludge loops. The flow is alternated frequently and so one heat exchanger will be provided but the sludge piping would be configured so that the heat exchanger can serve either loop. New piping would be required to carry the heated water from the plant effluent area or from the Turbine Building to the D&D building. Heat exchangers and pumps would likely be required to transfer the heat from any of the sources to the sludge or to the polymer. Because the current polymer storage tanks are not insulated, it would appear to be most advantageous to heat the sludge or diluted polymer as it is fed to the belt presses. System controls and SCADA instrumentation and monitoring would also be required.

Estimate of Energy Reduction or Recovery

Either non-potable or potable water can be used for producing and aging polymer solutions. Warm water is desirable as it helps reduce dry polymer required to produce polymer solutions when compared with achieving the same level of effectiveness using colder water. The heat required to generate warm water to produce polymer solutions is approximately 0.0036 MMBtu/hr, depending on which source water is used.

Generally, preheating the sludge would have an effect similar to that of preheating the polymer dilution water, but the reduction of polymer probably would not be as great as using the dilution water, because the higher temperature polymer aging would not be experienced.

Preheating the sludge could also result in better dewaterability as the increase in the temperature of the trapped water in the sludge subsequently decreases the water viscosity. A lower water viscosity could enable the trapped water to escape more easily, thereby achieving a dryer dewatered product. Heating the sludge at these temperatures would potentially increase cake solids by 1 to 2 percent, resulting in less energy required to dry the dewatered cake—an energy decrease of about 5 percent. However, the results experienced at other plants have varied widely with some plants seeing virtually no increase in solids.

Therefore bench and/or pilot testing would be recommended before proceeding with implementation of this alternative. Exhibit 16-1 summarizes the potential estimated polymer reduction.

EXHIBIT 16-1
Estimated Polymer Use Reduction

Description	Parameter
Current polymer consumption[a]	146.2 lb/ton
Revised polymer consumption at 10 percent reduction	132 lb/ton
Dewatered solids generation[a]	31,500 tons/yr
Potential polymer savings	230 tons/yr
Estimated water flow requirement [b]	359 gpm
Raw water temperature	45°F (potable water); 60°F (plant service water)
Temperature of water before use to produce polymer solutions	80°F
Heat required to raise the temperature of raw water	6.3 MBH (potable water); 3.6 MBH (plant service water)
Estimated polymer savings	1,981.01 lb/day

[a] 2008–2009 average.

[b] Calculated using polymer consumption, specific gravity of 1.035, 40% active, 1% mix/dilution.

[c] Assuming $0.10/lb for polymer and O&M for heat exchanger is 2.7% of equipment cost.

Cost Estimate

The estimated capital cost for this project is $1,400,000, including installation of new heat exchangers and piping.

Energy savings is contingent on the moisture reduction in the sludge cake being fed to the digesters. With the assumed 1 percent improvement in cake solids, roughly $380,000 of annual energy savings could be realized in the dryer system. Again, pilot testing would be recommended before implementing this alternative.

In addition to energy savings, the heated polymer can result in a reduction in polymer use, by about 10 percent, resulting in an additional savings of $72,000 in operations costs.

The cost estimate for this alternative is summarized in Exhibit 16-2.

EXHIBIT 16-2
Cost Estimate for Alternative 16

Capital Costs		
Heat exchanger		$100,000
Heat exchanger—plate and frame		$100,000
8-inch stainless steel insulated piping		$125,000
10-inch stainless steel insulated piping		$250,000
Installation (30% of equipment)		$97,500
Subtotal—Project Cost		*$672,500*
Markups		
Site, piping, electrical, I&C, demolition, etc.	20%	$134,500
Subtotal		*$807,000*
Contingency	25%	$201,750
Subtotal		*$1,008,750*
Contractor mobilization, bonds, insurance	20%	$201,750
Subtotal		*$1,210,500*
Subtotal with Markups		*$1,210,500*
Total Construction Cost		$1,210,500
Non-Construction Costs		
Engineering/Administration	18%	$217,890
Subtotal—Non-Construction Costs		*$1,428,390*
Total Capital Cost (2014 dollars)		**$1,428,390**
O&M Costs (using 2014 average loads)		**Annual Cost**
Additional O&M labor (2% of new construction)		$24,000
Additional maintenance—parts (1% of new equipment)		$7,000
Natural gas fuel savings		-$384,211
Total O&M (2014)		**-$-353,211**

ALTERNATIVE 17

Use Waste Heat to Heat Biological Process at Jones Island WRF

Alternative Description

The turbines at the Jones Island WRF require water for cooling. The warm turbine cooling water could be discharged into the aeration basins to provide heat to increase the wastewater temperature, accelerate the biological kinetics, and potentially reduce oxygen demand and aeration blower energy.

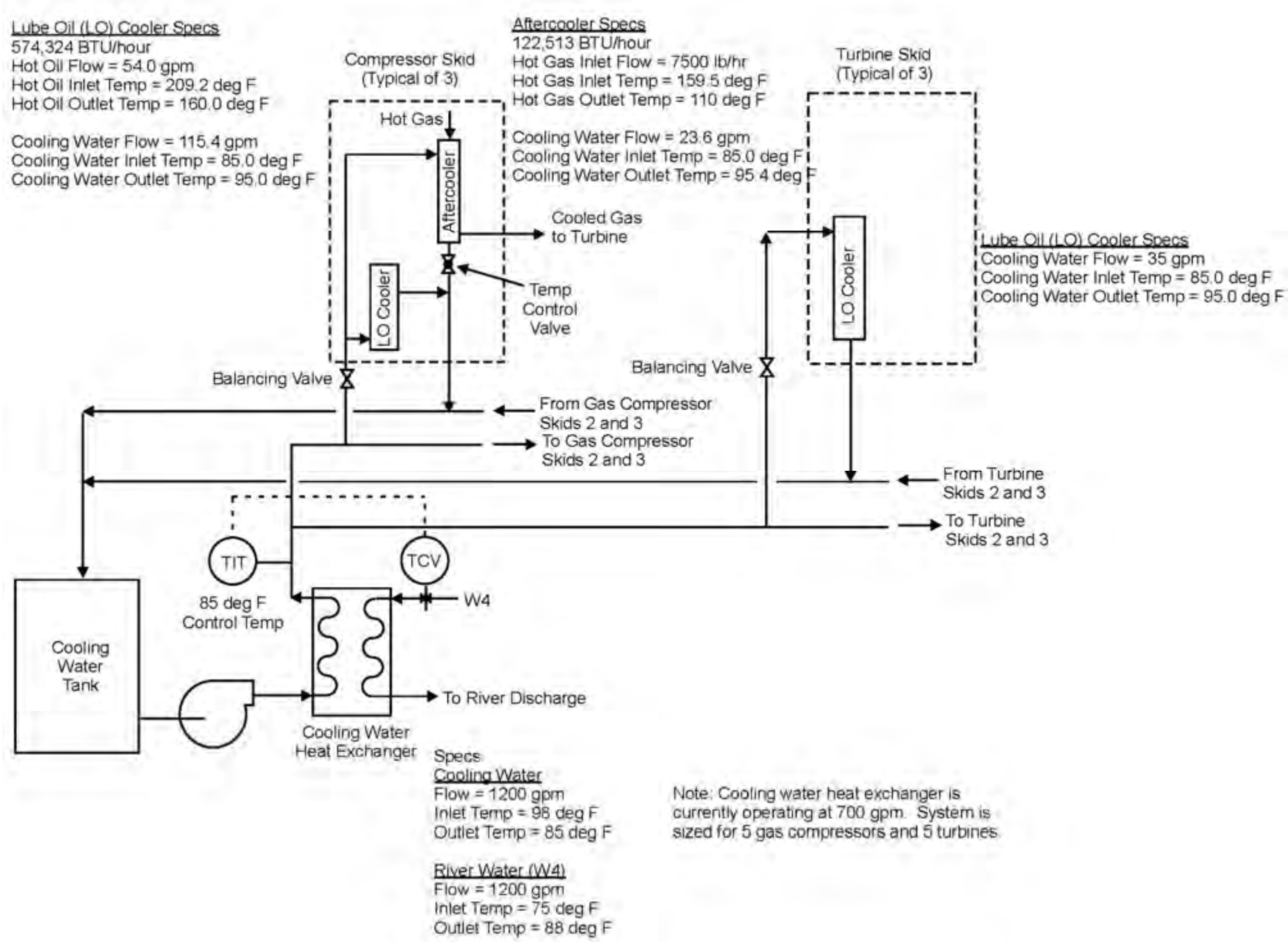
This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

The hot turbine cooling water is readily available and could be discharged with some piping modifications to the plant drain system, which eventually discharges to the aeration basins. Alternatively the cooling water could be discharged directly to the aeration to reduce heat loss, but the capital costs to do that would be higher. The total turbine cooling water is estimated at 1,200 gpm at 98 degrees F with 5 turbines operating. Currently only 2 or 3 turbines are operated, and the typical cooling water flow is estimated to be 720 gpm at 98 degrees F. The turbine cooling water configuration is shown in Exhibit 17-1.

EXHIBIT 17-1

Turbine Cooling Water Configuration



Estimate of Energy Reduction or Recovery

Adding turbine cooling water flow to the aeration basins would provide little change in the wastewater temperature. With an influent flow of 90 mgd at 56 degrees F, addition of cooling water will increase the water temperature by an only 0.3 degree F. Kinetic rates use an Arrhenius coefficient (theta) to adjust for temperature. For nitrification, the WERF maximum growth rate for nitrifiers at 20 degrees C is 0.9/day with an Arrhenius coefficient of 1.072, and the maximum growth rate for nitrifiers equates to 0.5728/day. If the temperature is raised by 0.3°F using the cooling water, the maximum growth rate increases to 0.5776/day, a 0.84 percent increase. A computer model process simulation showed a 0.18 percent decrease in WAS generation (237 lb/day) and a negligible decrease in aeration.

Cost Estimate

Additional heat is readily available and does not require major capital costs to divert it to the biological process. The decrease in energy is insignificant.

Discussion and Considerations

Although there is no energy savings to justify this alternative, should larger, warmer sources of water to heat the process be found the following should be considered:

- Some cooling water may contain antiscalants. Be wary, as these could cause nitrifier inhibition.

ALTERNATIVE 18

Install High-Efficiency Plant Lighting

Alternative Description

Plant lighting is primarily high-pressure sodium (HPS) and fluorescent, and most is not considered high efficiency by today's standards. It was noted during the walk-though that many lights were on in unmanned process areas of the plant, and lights were also on in areas where natural lighting was sufficient for pass though and more detailed tasks.

MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.

Description of Modifications Required

The modifications that would be required are the replacement of existing fixtures with light-emitting diode (LED)–based lighting in all process areas and on the required outdoor lighting. Substantial progress has been made in the replacement program for nonprocess areas. Process areas would be mainly LED-based high bay lighting in areas like Dewatering and Drying, where lighting is required to operate the process. LED-based lighting with photocell and motion sensors is suited to areas like the aeration galleries. In areas with a high level of natural lighting, the photocell would override the motion sensors during the day, but a night walkthrough would activate LED luminaires. Lights with only motion sensors would be used in areas like primary treatment and the tunnels, where there is no real natural lighting. Outdoor lighting should be replaced with LED wall packs.

Some care will need to be taken in areas that are humid or have large temperature variations so that lights are UL Damp Location rated. Outdoor lighting would need a UL Wet Location rating.

Estimate of Energy Reduction or Recovery

Because of the numerous lights at the Jones Island WRF, energy reduction is calculated in terms of 100 lights for the major categories of lights used: fluorescent, high bay, and wall pack.

Dual-bulb fluorescent lights (T8 bulbs) generally draw 64 watts plus about 15 percent for ballast losses, giving total energy usage of about 74 watts each. The LED replacement uses 59 watts each. Per 100 replacements, the savings would be 1,500 watts. Based on an estimate that with the motion and light sensors only 10 percent of the lights will need to be on at any one time, the saving would increase to 6,810 watts. Savings over a year would equal 6,810 watts/1,000 watts/kW × 8,760 hr/yr × $.07/kWh, equaling $4,176 per year/100 fixtures, or about $41.76 per fixture/year.

A 400-watt HPS high-bay luminaire consuming 460 watts can be replaced with an LED rated at 213 watts. Per 100 replacements, the difference would be 24,700 watts. It is estimated that with the addition of motion sensors and photocell controls, only 50 percent of the lights will need to be on at any given time. (This takes into account the process necessity of lighting at D&D.) The power saving with the motion detectors and photocells increases to 35,350 watts per 100 fixtures. Savings over a year would equal 35,350 watts/1,000 watts/kW × 8,760 hr/yr × $.07/kWh, equaling $21,700 per year per 100 replaced fixtures.

Most lighting at the Jones Island WRF consists of the high-bay and fluorescent fixtures, but there are other types in smaller numbers. A 250-watt wall pack consuming 288 watts, can be replaced with an LED unit that consumes 70 watts. For 100 replacements the difference would be 21,800 watts, without new controls. It is estimated that with motion sensors and photocell controls, only 30 percent of the lights will need to be on at any given time. The power savings with motion sensors and photocells increases to 26,700 watts per 100 fixtures. Savings over a year would equal 26,700 watts/1,000 watts/kW × 8,760 hr/yr × $.07/kWh, equaling $16,370 per year per 100 replaced fixtures.

A secondary advantage to LED lighting is the reduced maintenance associated with bulb replacement. In accordance with Illuminating Engineering Society publication LM-80-08, *Measurement of Lumen Maintenance* *of LED Light Sources*, set the criteria for determining the loss of light in an LED due to age. An LED luminaire is most often considered to be beyond its design life, or burned out, when the lumen output is reduced to 70 percent of its initial value. Depending upon the manufacture and model, the LM70 of a fixture ranges from 50,000 to 100,000 hours. Compare this to a typical life of 5,000 hours for an incandescent bulb, 10,000 to 15,000 hours for fluorescent bulbs, and 30,000 hours for high-intensity discharge (HID) bulbs. An LED "night light" on an average of 12 hours per night with a 100,000-hour LM70 will reach 70 percent lumen output in 22.8 years.

LED fixtures have an advantage, or disadvantage depending upon your point of view. HID and fluorescent bulbs fail catastrophically when they are at the end of their useful life. It is obvious when these bulbs need to be replaced. LEDs simply grow dimmer and dimmer. The LED array in the fixture eventually will need to be replaced. Replacement of HID/fluorescent fixtures should be done on by group (floor, building, process area), so the LM_{70} of the group of fixtures can be tracked for future replacement as a group.

It was agreed that a detailed evaluation of this alternative was beyond the scope of the Energy Plan project and that a future more detailed evaluation would likely be undertaken by District staff. In any future, more detailed evaluation, the following should be considered:

- Impacts of NFPA 820 guidelines including the need for lighting fixtures that are suitable for classified areas.
- Costs of modifications to conduits that power lighting fixtures that may be needed to comply with codes or other requirements.
- A detailed count of the number and type of fixtures that could be replaced at all District facilities.

Cost Estimate

The cost estimate is based on replacing 100 bulbs in each category described above. It is also based on $540 for an equal to a standard dual bulb fluorescent, $500 for an LED replacement of a 400 watt HPS fixture, $480 for an LED replacement of an HPS wall pack, and $400 for a LED replacement of an outdoor light. The cost of maintenance will be reduced because of the longer life of the replacement bulbs. Exhibit 18-1 presents the cost estimate for lighting replacement.

EXHIBIT 18-1
Cost Estimate for Alternative 18

Capital Costs		
Fluorescent replacement (100)		$54,000
High bay replacement (100)		$50,000
Wall pack replacement (100)		$48,000
Subtotal—Project Cost		*$152,000*
Markups		
Site, piping, electrical, I&C, demolition, etc.	20%	$30,400
Subtotal		*$182,400*
Contingency	25%	$45,600
Subtotal		*$228,000*
Contractor mobilization, bonds, and insurance	20%	$45,600
Subtotal		*$273,600*
Subtotal with Markups		$273,600

EXHIBIT 18-1
Cost Estimate for Alternative 18

Total Construction Cost		$273,600
Non-Construction Costs		
Engineering/administration	18%	$49,248
Subtotal—Non-Construction Costs		$322,848
Total Capital Cost (2014 dollars)		**$322,848**
O&M Costs (using 2014 average loads)		**Annual Cost**
Power savings		-$36,670
Additional maintenance—parts (Lower than Existing)		-$15,000
Total O&M Costs (2014)		**-$51,670**

ALTERNATIVE 19

Maximize Digestion of FOG and High-Strength Wastes at South Shore WRF

Alternative Description

This alternative evaluates the potential to expand the co-digestion program at the South Shore WRF by increasing high-strength waste (HSW) volumes and adding fats, oils and greases (FOG). MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District. Further evaluation will be completed as part of the 2050 Facilities Plan.

The South Shore WRF has 12 circular tanks that serve as either anaerobic digesters or digested sludge storage tanks. Six of the tanks (No. 6 and 8–12) are equipped with mixing systems and are operated as digesters. Six others (No. 1–5 and 7) do not have mixing and gas collection systems and are used only to store digested sludge. Under normal operating conditions, most of the primary sludge from the Jones Island WRF and all primary sludge from the South Shore WRF are sent to the anaerobic digesters. At times up to 25 percent of the South Shore WRF WAS also is sent to digestion. Stored digested sludge is pumped to the Jones Island WRF and blended with South Shore WRF and Jones Island WRF WAS for Milorganite® production.

Based on previous evaluations of the anaerobic digestion process, the mixing systems of four operating anaerobic digesters are in poor condition, and two digesters recently had new, more effective mixing systems installed. Poor mixing or the lack of mixing altogether results in volatile solids reductions (VSr) and digester gas yields that are below average. VSr is a measure of the quantity of digested solids converted to digester gas. The digester gas yield is the amount of digester gas produced per mass of volatile solids destroyed. Below average VSr and digester gas yields often requires operating the digesters at an extended solids retention time (SRT) to sufficiently stabilize sludge solids. SRT is a digester sizing criterion. For a completely mixed, once-through system, SRT is equal to the mass of solids in the digester divided by the mass of solids removed each day. It is directly related to specific growth rate of anaerobic bacteria and to the extent of anaerobic catabolic reactions that occur in an anaerobic digester. The South Shore WRF digesters are intended to be completely-mixed, once-through reactors, but poor mixing in some digesters results in short circuiting and reduces the active digester volume. This requires them to be operated at a longer SRT. This could be reduced considerably with complete and efficient mixing of the digesters. Typical SRT for conventional high-rate mesophilic anaerobic digestion (CHR-MAD) varies from 15 to 20 days.

The District is in the process of performing a comparative evaluation of two mixing systems—a pump and nozzle system versus a linear motion mixer—in two of the operating digesters (No. 10 and 12). Improved mixing will increase the VSr, resulting in a greater digester gas yield and increased active digester capacity. Increasing active digester capacity provides greater total capacity for digestion and additional capacity for receiving trucked-in FOG and HSW. This process of digesting municipal solids along with FOG and HSW is known as co-digestion. Co-digestion can significantly increase digester gas (and energy) production. The District has evaluated co-digestion in depth in conjunction with Marquette University and currently co-digests primarily aircraft deicing fluid from General Mitchell International Airport during cold weather months. HSWs other than aircraft deicing fluid have been accepted, but the District carefully selects which wastes to co-digest primarily because the wastes should not include large amounts of solids that could increase Milorganite® production. Increases in digester gas production have been apparent when these wastes are introduced to the anaerobic digesters, so expansion of the FOG and HSW receiving program is clearly a potential means of increasing energy production for the District.

Description of Modifications Required

The receiving station at the South Shore WRF has a 100,000-gallon HSW tank with a mixing system. According to Veolia staff, actual capacity of this tank is slightly lower because 4 feet of liquid must be maintained in the tank for the pump and nozzle mixing system to recirculate the contents of the tank. Factors that must be considered when receiving wastes at the South Shore WRF include the lack of a digester gas conditioning system, potential impacts on Milorganite® production, and the current waste receiving infrastructure. With these restrictions, the District must exclude some potentially high-energy value wastes.

In the future, the District may wish to upgrade waste receiving and handling facilities to expand the list of acceptable wastes for the co-digestion program. Because FOG wastes are often more problematic to handle than carbohydrate- or protein-rich HSWs, modifications and improvements to the receiving facilities would be expected. The modifications may involve providing waste heating and mixing to prevent FOG from solidifying. Some of the improvements below may be considered for HSW handling. Some have been partially implemented.

- A debris trap to remove rocks, grit, metal items, and other heavy debris.
- Screens and maceration to reduce the size of rags, plastics, wood, and other debris.
- Flow, volume, and weight measurement systems to document amount of material received from each truck for billing purposes.
- Influent or offloading pumps to remove the material from the trucks, if needed; below grade storage tanks may not require these pumps.
- Heating system to increase the temperature of FOG wastes and to prevent congealing in pumps and pipelines.
- Tanks for short-term storage of wastes before feeding to the anaerobic digesters. Multiple tanks are preferred to facilitate maintenance and cleaning. Total volume should consider multiple peak days associated with holidays and long holiday weekends with no waste receipts but continuous digester feeding.
- An isolation tank for received HSW or FOG of questionable quality (i.e., extreme pH, high chlorides, toxic materials, etc.).
- Mixing system to keep debris from settling and homogenize the material from different loads.
- Odor control for the storage tanks.
- Pumps with variable speed controllers to feed the digesters at a relatively low and constant loading rate.

Other considerations for receiving FOG/HSW include truck access requirements and site arrangement, a truck driver interface system, waste material sampling, decanting of the waste material, the need (or preference) to enclose the process within a building, and increased security measures.

To optimize the anaerobic digestion process, the existing mixing systems in the digesters that do not yet have improved mixing must be replaced. Results from the mixer evaluation currently underway should determine the appropriate system to be implemented in other digesters. With these improvements to the anaerobic digestion system, the digester gas produced can still be combusted in the existing IC engine generators to create electricity, and waste heat from the IC engine generators can still be collected for building or process heat. However, by receiving potentially large quantities of high-energy wastes there is increased likelihood that digester gas production rates may exceed IC engine generator feed capacities, and energy production in the form of electricity or heat could exceed plant demand. Therefore, alternative uses of this digester gas or energy—either onsite or offsite—may need to be explored. Regulatory requirements including air permitting should be investigated, but potential options include:

- Transport digester gas to the Oak Creek Water Treatment Plant located near the South Shore WRF in a pipeline.
- Sell excess electrical power back to the grid at the reduced rate (about $0.027/kWh).
- Convey excess digester gas to the Jones Island WRF to supplement natural gas used in the Milorganite® drying process.

EXHIBIT 19-1

Typical CHR-MAD Parameters for Co-digestion Substrates

Substrate	Digester Gas Yield (ft^3/lb VS destroyed)	Methane Content of Digester Gas (%)	Lower Heating Value of Digester Gas from Substrate (Btu/ft^3)	VSr (%)
FOG	19–26	62–75	620–750	70–90
Carbohydrates	11.2	60–75	600–750	50–70
Proteins	11.2	60–70	600–700	50–70
Primary solids	12–18	55–70	550–700	60–75
WAS	12–18	50–60	500–600	20–35

Adapted from WEF 2010, 2012; McCarty, 1971; Kabouris, 2008.

The District has also considered reducing the number of online, active digesters by incorporating recuperative thickening into the digestion process. Recuperative thickening is a process whereby biomass is removed from an anaerobic digester, thickened, and returned to the digester. Thickening devices can be thickening centrifuges, gravity belt thickeners, or dissolved air flotation thickeners. Recuperative thickening allows the SRT to become operationally separate from the HRT so solids and anaerobic bacteria can be retained in the system longer (i.e., longer SRT). This can increase biological activity and increase active digester capacity for a given tank volume. However, recuperative thickening can increase the complexity of the digestion process, require polymer use for thickening, increase maintenance requirements, and has associated costs. Because the South Shore WRF has existing (and excess) digester capacity and gravity belt thickeners, further comparison of recuperative thickening to traditional once-through mesophilic anaerobic digestion should be considered. Multistage digestion (e.g., acid-gas phase digestion) should also be considered. An alternative to recuperative thickening would be to pre-thicken primary sludge prior to digestion in order to increase digester capacity.

Estimate of Energy Reduction or Recovery

Digester gas production rates were estimated assuming that new mixing systems will be installed in all active digesters. Under this assumption, typical criteria for well-designed digesters can be applied. Exhibit 19-1 presents typical digester gas yield, digester gas characteristics, and VSr for various substrates. Exhibit 19-2 lists the assumed values in evaluating this alternative for the same parameters. The parameters are based on values estimated from testing of wastes done by Marquette University for the MMSD and the Green Bay Metropolitan Sewerage District and also on data from other utilities. The values in Exhibit 19-2 could be considered “average,” but it is important to note that the amount of digester gas generated from FOG and HSW varies widely depending upon the waste characteristics. It is recommended that the District continue to test potential future HSW and FOG wastes similar to what had been done with Marquette University.

EXHIBIT 19-2

Assumed CHR-MAD Parameters for Alternative 19

Substrate	Digester Gas Yield (ft^3/lb VS Destroyed)	Methane Content of Digester Gas (%)	Lower Heating Value of Digester Gas from Substrate (Btu/ft^3)	VSr (%)
Co-digestate[a]	20	65	700	90
Primary sludge	15	65	600	62
WAS	15	65	600	37

[a] Co-digestate is assumed to be a composite of FOG and HSW.

Material being co-digested typically has a much higher VSr because of higher concentrations of readily biodegradable material. CH2M HILL has observed co-digestate VSr as high as 95 percent at some facilities. Primary solids tend to be more amenable than WAS to anaerobic digestion; hence, the VSr assumed for primary sludge is higher than that for WAS. The digester gas yield for FOG can often be higher than for other HSWs, and therefore has a higher digester gas yield than primary sludge and WAS. This is because of the extent of the biochemical reactions involved and the size of individual lipid-containing molecules (fats and oils). While they do require more retention time in the digesters to biodegrade than carbohydrate- and protein-rich substrates, more digester gas production per unit weight (and thus energy) can be gained from fat- and oil-rich products. In contrast, carbohydrate- or protein-rich substrates are relatively easy to digest since they tend to be more amenable to simpler catabolic reactions. This makes FOG even more preferable than HSW on an energy yield basis. However, treatment plants are often more equipped to handle HSW with existing facilities, so HSW is often sought first.

Several scenarios were evaluated to establish estimates of digester gas production. The scenarios evaluated are described as follows:

- **No. 1 Base Scenario—**This scenario assumes current operation but with improved mixing in tanks operated as digesters. The South Shore WRF WAS would not be digested (current practice) and no co-digestate would be added. The number of tanks operated as digesters would be based on the total volume required for a 15-day SRT.
- **No. 2 Base Scenario with Co-digestion—**Same as the No. 1 base scenario, except that co-digestate is added to the active digesters. Tanks Nos. 6 and 8–12 would be used for anaerobic digestion. Digesters would operate at a 15-day SRT. At 15-day SRT, any excess digester capacity is assumed available for industrial/commercial waste co-digestion. This scenario would require installation of additional engines because power generation greatly exceeds current engine capacity and plant power demands. A use for the excess power would have to found.
- **Base Scenario with Co-digestion, Limited to 4 MW—**Same as the No. 2 base scenario, except that only enough co-digestate is added to the digesters to meet 4 MW total power production. This is roughly the average South Shore WRF plant dry weather power demand. Digesters would operate at a 15-day SRT.
- **Base Scenario with Co-digestion, Limited to 5.5 MW—**Same as the No. 2 base scenario, except that only enough co-digestate is added to the digesters to meet 5.5 MW total power production. This limitation is based on the total maximum rated capacities of the existing engine-generators at South Shore WRF. Digesters would operate at a 15-day SRT.
- **Base Scenario without Co-digestion, Limited by Milorganite® Production—**Same as the No. 1 base scenario, except that the amount of digested sludge is limited such that only 40 percent of the solids to the Milorganite® process are digested sludge. Above 40 percent, problems with pellet quality, and excessive dust/chaff occur. Tanks No. 6 and 8–12 would be used for anaerobic digestion, and digesters would operate at a 15-day SRT.

Exhibit 19-3 summarizes the digester gas and energy production for the scenarios and compares them to current operation. Digester gas and energy projections were calculated separately for WAS, primary sludge, and co-digestate. Power demands from parasitic loads (e.g., IC engine compressors) are not deducted from the total power generated. A maximum potential energy production scenario was also considered if 11 of the 12 digesters were operated as active, well-mixed digesters and co-digestate receiving was maximized, but digester gas and energy production estimates are not provided here. Refer to the *Potential Maximum Energy Production* technical memorandum for this information.

EXHIBIT 19-3

Estimated Digester Gas, Energy Production

Potential Digester Gas, Energy Production for Various Scenarios

	Unit	Current Operation (2013)	No. 1 Base Scenario	No. 2 Base Scenario with Co-digestion	Base Scenario with Co-digestion, Limited to 4 MW	Base Scenario with Co-digestion, Limited to 5.5 MW	Base Scenario without Co-digestion, Limited by Milorganite® Production
SRT	days	20–24	15	15	15	15	15
3.2-MG Digesters On-line	count	4	3	4	4	4	4
1.2-MG Digesters On-line	count	2	0	2	0	0	0
Digester gas production	ft^3/d	997,900	1,087,000	5,527,000	1,471,000	1,959,400	1,198,600
Co-digestate waste added	gpd	?	0	381,840	33,000	75,000	0
Volatile solids loading rate	lb VS/kft^3/day	—	57.4	179	67.9	81.2	67.2
VSr	%	—	62	81	66	70	58
Digester feed concentration	% dry solids	—	3.0	5.8	3.4	3.8	2.8
Digester gas yield	ft^3/lb VS destroyed	—	15.0	18.8	16.0	16.9	15.0
Energy production	MMBtu/hr	25	27.2	157	38.4	52.6	30.0
Power production (if all digester gas to engines)	MW	2.8	2.8	16.4	4.0	5.5	3.1
Engine waste heat available for digester/building heat	MMBtu/hr	10.5	10.0	57.8	14.2	19.4	11.1

Notes: Digester gas–specific energy (lower heating value, LHV) for municipal solids is 600 Btu/scf. LHV of FOG and HSW is 700 Btu/scf. Digester gas yield for municipal solids is 15 ft^3/lb VS. Digester gas yield for FOG and HSW is 20 ft^3/lb VS. Power conversion efficiency = 35.7%, thermal conversion efficiency = 36.9%; based on Caterpillar technical data sheet. Parasitic loads of IC engine compressors are not subtracted from the total power production values listed.

Exhibit 19-4 compares design parameters typically used for conventional mesophilic digestion with parameters used for mesophilic co-digestion of municipal and industrial/commercial wastes. It can be seen that for co-digestion, the SRT may be able to be reduced, gas production may increase, and the loading rates can be increased.

EXHIBIT 19-4
Comparison of Design Criteria for Conventional Digestion and Co-digestion

Parameter	Units	Conventional Mesophilic: Traditional Values	Conventional Mesophilic: Current Design Practice	Conventional Mesophilic + Co-digestate: Current Design Practice
SRT	days	15–20	15–20	> 15
Maximum volatile solids loading rate	$lb/kft^3/day$	200	200	250–300
VSr	%	40–50	40–70	40–70
Typical feed concentration	% dry solids	4–6	4–8	4 –8
Digester gas yield	ft^3/lb VS destroyed	12–15	12–18	15-20

The potential energy production rates depend heavily on how much FOG and HSW is available. Obtaining the large volume of waste to fully utilize existing digester capacity likely would be challenging, especially given the increasing competition from other publicly owned wastewater treatment plants and private digesters, such as that operated by the Forest County Potawatomi Community. It is recommended that an updated market analysis be done to determine how much waste may be available, considering competitors for these wastes, tipping fees, and other market factors. Other utilities that have implemented successful larger scale co-digestion programs have found that managing a co-digestion program requires a significant time commitment. Waste sources, quantities, and types change frequently and significant management time is required to track that as well as to administer a sampling program, collect fees, and market the District's ability to co-digest to industries and commercial sources.

Cost Estimate

The South Shore WRF already has a HSW receiving station and digester tanks. However, the mixing systems must be upgraded/installed in all tanks except for the two with the new mixing systems. The cost estimate in Exhibit 19-5 assumes retrofitting 4 of the 12 tanks with mixing systems (pilot tested mixing systems in No. 10 and 12 will be maintained), though retrofits could be conducted in stages as the co-digestate program expands. Refinement of this cost estimate may be required in the future to consider issues like parasitic loads and increased engine maintenance costs.

EXHIBIT 19-5
Cost Estimate for Alternative 16

Capital Costs		**Base Scenario with Co-digestion, Limited to 4 MW**	**Base Scenario with Co-digestion, Limited to 5.5 MW**
Mixing Equipment		**$533,500**	**$533,500**
Installation (30% of Equipment)		$160,050	$160,050
Subtotal—Project Cost		*$693,550*	*$693,550*
Markups			
Site, piping, electrical, I&C, and demolition, etc.	20%	$138,710	$138,710
Subtotal		*$832,260*	*$832,260*
Contingency	25%	$208,065	$208,065
Subtotal		*$1,040,325*	*$1,040,325*
Contractor mobilization, bonds, and insurance	20%	$208,065	$208,065

EXHIBIT 19-5
Cost Estimate for Alternative 16

Capital Costs		**Base Scenario with Co-digestion, Limited to 4 MW**	**Base Scenario with Co-digestion, Limited to 5.5 MW**
Subtotal		*$1,248,390*	*$1,248,390*
Subtotal with Markups		*$1,248,390*	*$1,248,390*
Total Construction Cost		*$1,248,390*	*$1,248,390*
Non-Construction Costs			
Engineering/Administration	18%	$224,710	$224,710
Subtotal—Non-Construction Costs		*$1,473,100*	*$1,473,100*
Total Capital Cost (2014 dollars)		**$1,473,100**	**$1,473,100**
O&M Costs (using 2014 average loads)		**Annual Cost**	**Annual Cost**
Power savings (as electricity)		-$490,560	-$1,410,360
Energy recovered (as heat)		-$163,833	-$426,405
Additional O&M labor (1% of new construction)		$12,500	$12,500
Additional maintenance—Parts (1% of new equipment)		$7,000	$7,000
Total O&M Costs (2014)		**-$634,893**	**-$1,817,265**

ALTERNATIVE 20

Solar Power Electricity Generation

Alternative Description

Alternative 20 evaluates the use of solar power. The assessment provides a brief summary of solar photovoltaic (PV) technologies and the assumptions used in the assessment, description of the solar resource, estimated generating capacity at the facility, and a cost estimate.

This alternative will be further evaluated in the 2050 Facilities Plan.

Solar Power

This assessment considers solar PV technologies that can be used to generate electricity to offset usage from We Energies. A PV system generally consists of PV modules (flat plate solar collectors consisting of a semiconducting substance that generates DC electricity in the presence of sunlight), racking system (for mounting on a rooftop or installed in the ground, tilted at an angle to optimize the amount of sunlight striking the surface of the module, or laid flat/horizontally), power conditioning equipment (to convert the DC electricity generated by the PV modules into AC electricity for use by the facilities electric loads), and grid integration equipment (to match the power quality of the electric utility). The following assumptions were used in this assessment:

- No battery systems are considered.
- The system is grid-connected only. (When the grid is down, energy from the PV system will not be delivered to the facility for safety purposes.)
- Energy generation estimates are based on a modeling tool developed by the National Renewable Energy Laboratories, PVWatts. This tool uses solar resource weather data for Milwaukee that is typical or representative of long-term averages.

Solar Resource

PV performance is largely proportional to the amount of solar radiation received, which may vary from the long-term average by ± 30 percent for monthly values and ± 10 percent for yearly values. Typical year solar resource data use a single year's worth of hourly data to represent solar radiation and meteorological data collected over a historical period of multiple years. Typical year data are appropriate for PVWatts economic analysis, because it uses an hourly simulation over a single year to predict the system's average monthly and annual output over a 25-year system life. Each typical year file contains months of data selected from different years in the data collection period. For example, data for a given site might contain 1995 data for the month of February, 2001 data for March, 1998 data for April, etc.

Typical year data based on data collected over a longer period are more representative than data developed from a shorter period.[1] The solar resource data used in this assessment are based on typical weather patterns measured at General Mitchell International Airport.

Exhibit 20-1 depicts the insolation values of the solar resource available to a flat plate collector, such as a photovoltaic panel, oriented due south at an angle from horizontal to equal to the latitude of the collector location. For the Milwaukee region, the map indicates that the amount of solar insolation available is roughly 3.5 to 4 kWh/m^2 per day.

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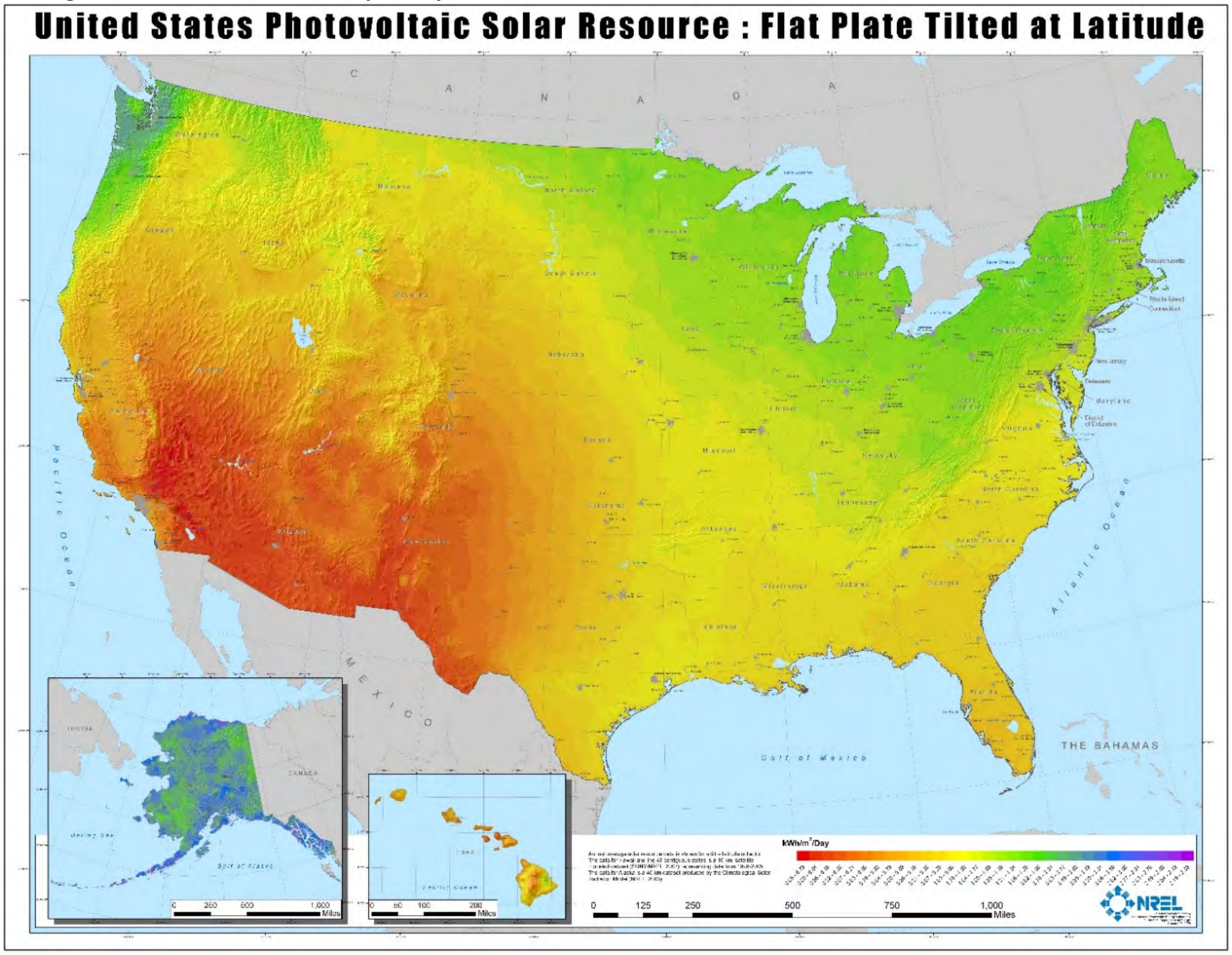
[1] PVWatts Cautions for Interpreting the Results, National Renewable Energy Laboratories http://rredc.nrel.gov/solar/calculators/pvwatts/interp.html last accessed September 26, 2014.

EXHIBIT 20-1

Average Solar Insolation kWh/m² per day



Locations Considered

Exhibit 20-2 depicts the potential areas that could be used for solar panels. The areas are numbered and color-coded as follows:

- Green—ground-mounted (areas 1 through 7)
- Blue—parking canopy (areas 8 through 11)
- Red—roof-mounted (areas 12 through 41)

Based on these areas, the total PV capacity would be about 11.5 MW_{DC}. Exhibit 20-3 summarizes each area, the method of estimation and the individual PV system capacity. For the purpose of this evaluation, it was assumed that about 5 acres of land-mounted solar panels would be installed with a total generating capacity of 1 MW. Area1 would provide space for about 5 acres of panels.

EXHIBIT 20-2
Maximum PV Power Generation: Site Locations Considered

EXHIBIT 20-3

Maximum PV Power Generation: Ground and Parking Locations Considered

EXHIBIT 20-4
Estimated PV Power Capacity per Location

Location #	Description	Capacity (kW_{DC})	Location #	Description	Capacity (kW_{DC})
Solar Site 1	Ground mounted	1,782	Solar Site 22	Roof mounted	10
Solar Site 2	Ground mounted	1,944	Solar Site 23	Roof mounted	8
Solar Site 3	Ground mounted	963	Solar Site 24	Roof mounted	4
Solar Site 4	Ground mounted	1,800	Solar Site 25	Roof mounted	4
Solar Site 5	Ground mounted	2,016	Solar Site 26	Roof mounted	8
Solar Site 6	Ground mounted	270	Solar Site 27	Roof mounted	10
Solar Site 7	Ground mounted	675	Solar Site 28	Roof mounted	52
Solar Site 8	Parking canopy	192	Solar Site 29	Roof mounted	83
Solar Site 9	Parking canopy	53	Solar Site 30	Roof mounted	60
Solar Site 10	Parking canopy	35	Solar Site 31	Roof mounted	58
Solar Site 11	Parking canopy	21	Solar Site 32	Roof mounted	53
Solar Site 12	Roof mounted	132	Solar Site 33	Roof mounted	29
Solar Site 13	Roof mounted	11	Solar Site 34	Roof mounted	32
Solar Site 14	Roof mounted	22	Solar Site 35	Roof mounted	27
Solar Site 15	Roof mounted	34	Solar Site 36	Roof mounted	21
Solar Site 16	Roof mounted	126	Solar Site 37	Roof mounted	144
Solar Site 17	Roof mounted	10	Solar Site 38	Roof mounted	35
Solar Site 18	Roof mounted	10	Solar Site 39	Roof mounted	201
Solar Site 19	Roof mounted	7	Solar Site 40	Roof mounted	192
Solar Site 20	Roof mounted	4	Solar Site 41	Roof mounted	413
Solar Site 21	Roof mounted	8		**Total Capacity**	**11,558**

Estimate of Energy Production

PVWatts was used to estimate the energy generated by a PV system. The model assumed a medium efficiency PV technology, mounted at a 25-degree tilt facing due south. Actual conditions of a PV system at MMSD may vary. However, these assumptions provide a general idea of the energy generating capacity of a PV system in the Milwaukee area. These estimates are approximate, and more detailed study is required to better estimate actual generation capacity. Based on the modeling assumptions made, the estimated annual kWh per kW_{DC} is 1,300 kWh/kW $_{DC}$. This means that on an annual average, the solar system is operating about 15 percent of its capacity, or about 1.7 MW. The reason is that power generation is decreased or eliminated at night and on cloudy days. This can be compared to wind power, which is estimated to operate at about 23 to 25 percent of its capacity. Again, these estimates are preliminary and could be refined. Exhibit 20-5 summarizes the total estimated annual energy produced at the locations in this assessment.

EXHIBIT 20-5
Estimated Net Annual Energy Production

Areas	Capacity (kW)	Annual Energy Generated (MWh per year)
Roof mounted	1,808	12,285
Parking canopy	300	390
Ground mounted	9,450	2,351
Total	**11,558**	**15,026**

Source: PV Watts, National Renewable Energy Laboratories

Cost Estimate

The estimated installed capital costs for different sized systems are shown in Exhibit 20-6.

EXHIBIT 20-6
Estimated Net Annual Energy Production and Estimated Capital Costs

OPTION	Capacity (kW_{DC})	Annual Energy Generated (MWh per year)	Estimated Capital Costs ($ Millions)
1—PV on entire site (ground-mounted and rooftops)	11,558	15,026	$31.2
2—5 MW ground mounted (25 to 30 acres)	5,000	6,500	$13.5
3—1 MW ground mounted (5 acres)	1,000	1,300	$2.7

Jones Island WRF Solar Power

Unlike the South Shore WRF, the Jones Island WRF has very limited available open land space to install turbines. There is some space available on building roofs, but several buildings have roof-mounted HVAC equipment that would limit the amount of panels that could be mounted on building roofs.

ALTERNATIVE 21

Wind Energy Generation

Alternative Description

Wind power technology is a form of renewable energy generation that uses the wind currents to spin a turbine in order to generate usable energy. The number of turbines that could be installed at the Jones Island and South Shore WRFs was evaluated. There are two major types of wind turbines: horizontal axis and vertical axis. The horizontal technology is more common and was assumed to be used.

The total installed nameplate capacity of wind turbines in the U.S. was nearly 50 gigawatts as of 2012. There are 17 wind installations in Wisconsin that generate 648 MW. Many manufacturers offer utility-scale (that is, greater than 1 MW) wind turbines for sale in the North American market. The primary considerations for selecting a wind turbine manufacturer are the size of turbine needed to meet generation requirements, cost associated with turbine construction and operation, and availability of manufacturer to provide equipment and spare parts to meet project timeline. Manufacturer offerings vary in size (such as generator rating) and configuration (such as rotor diameter, tower height, and control scheme) to best fit the wind resource characteristics of each site. Turbines rated 500 kW to 1 MW are rare, as major manufacturers have focused on larger machines in recent years. For this evaluation, 3 MW turbines were assumed.

Wind is the most mature and economically feasible of all renewable energy sources. In fact, the industry is finding that in good wind sites, wind energy can compete directly with coal and natural gas on cost of generation. The amount of electricity generated by a wind project is wind speed cubed. Thus, even an incremental increase in wind speed can dramatically change the economics of a project. For this reason, very careful resource measurement and analysis over a period of years is required to accurately determine the viability of a project.

MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.
Wind Resource

Speed

The Wind Power Prospector is a mapping and analysis tool designed by the National Renewable Energy Laboratory (NREL) to help site wind projects by providing easy access to wind resource datasets and other relevant data.[2] The data used for energy production estimates consisted of the predicted mean annual wind speeds at 80- and 100-meter heights at a spatial resolution of 2.5 kilometers and interpolated to a finer scale. The wind resource estimates were developed by AWS Truepower, LLC.

The Jones Island and South Shore WRFs are good candidates for wind power, because estimated wind speeds there are greater than 6.5 m/s at 80 meters above ground, generally considered the minimum wind speed for an economically feasible utility scale project. Exhibit 21-1 summarizes average wind speed values for 80 and 100 meters. As shown in Exhibit 21-1, wind speeds increase farther east. Thus the South Shore WRF location has incrementally better wind speeds than the Jones Island WRF. Further investigations at each site is warranted based on this preliminary data. The presence of microclimates at one site or both, too small to be modeled at the 2.5-kilometer resolution of the AWS model, could cause conditions to differ considerably from those shown on the wind map.

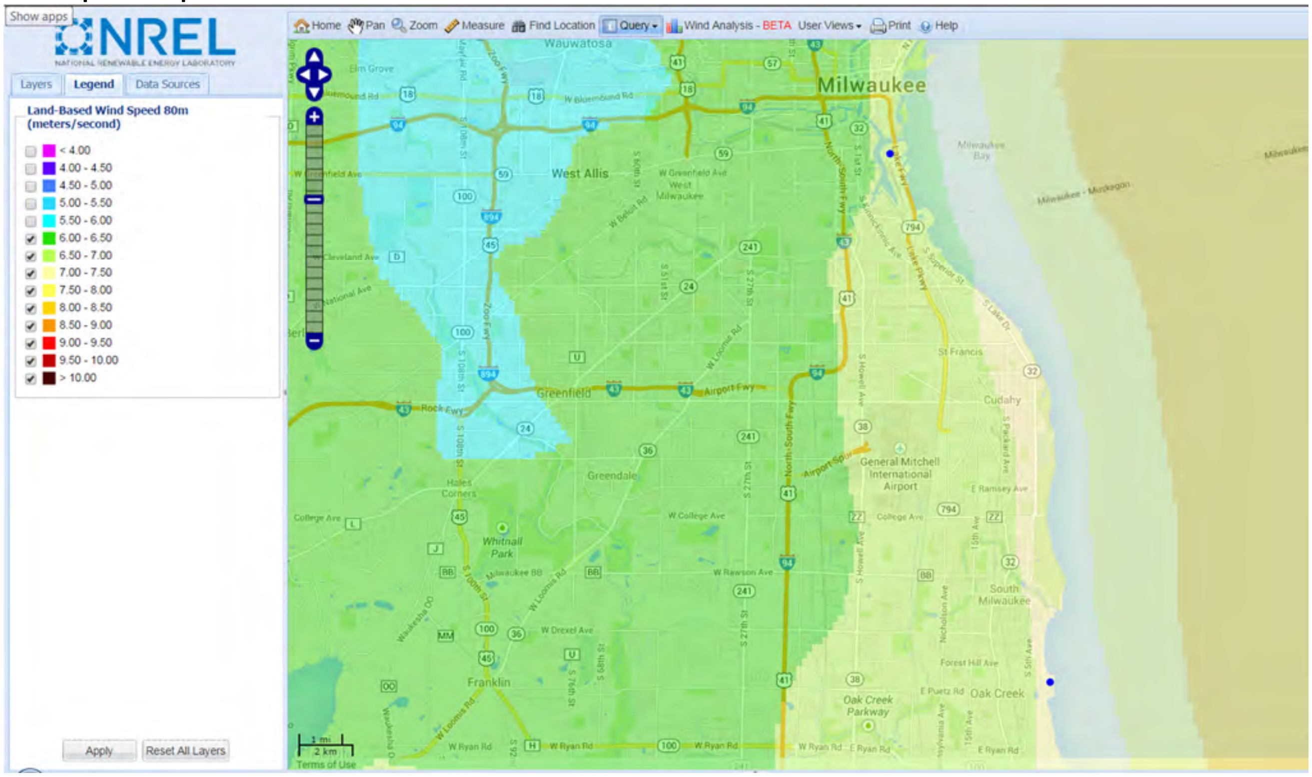
EXHIBIT 21-1
Estimated Annual Average Wind Speeds

	Jones Island WRF	South Shore WRF
Latitude	43.021951°	42.888043°
Longitude	-87.899541°	-87.848282°
NREL 80 meters	6.5–7.0 m/s	7.0–7.5 m/s
NREL 100 meters	7.0–7.5 m/s	7.0–7.5 m/s

Source: NREL Wind Power Prospector
m/s meters per second

[2] http://maps.nrel.gov/wind_prospector

EXHIBIT 21-2
Wind Speed Map



Source: NREL Wind Power Prospector.

Although wind speed generally increases with height, the range given for the South Shore WRF location is the same at both 80 and 100 meters above ground. The likelihood is that the 80-meter height would be at the bottom of the range and the 100-meter height near the top. The difference in the ranges between the Jones Island WRF and the South Shore WRF is mostly an artifact of the model and should not be construed as being vastly different.

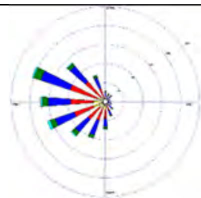
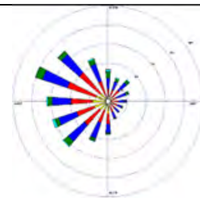
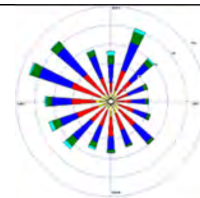
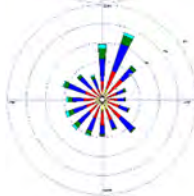
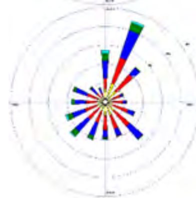
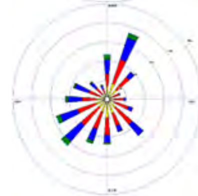
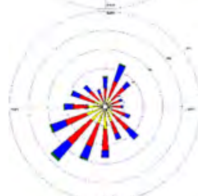
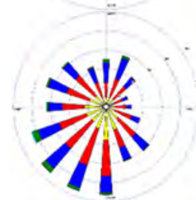
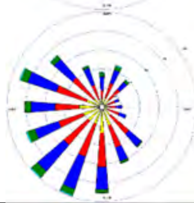
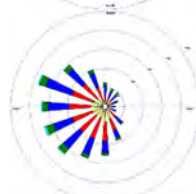
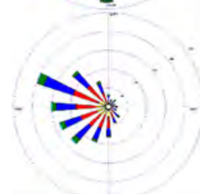
Wind Direction

The monthly wind roses from the USDA’s NRCS (National Resources Conservation Service show a multimodal wind regime not dominated by any particular direction (Exhibit 21-3). This type of regime generally requires larger spacing between machines to minimize turbulence. Typical spacing is 3 to 5 rotor diameters. Thus, for a turbine with a rotor diameter of 80 meters, spacing should be 240 to 400 meters. This spacing requirement, along with State of Wisconsin siting requirements and available space, limit the number of turbines that can be installed at the Jones Island and South Shore WRFs. Determination of the actual number of turbines that could be installed requires further, detailed analysis of wind conditions and the site.

Exhibit 21-4 lists additional monthly wind resource data for Milwaukee. Description of Siting Modifications Required

Unlike most power plants, wind generation projects are land intrusive rather than land intensive. Land use strategies associated with the development of wind generation sites include the use of “buffer zones” or setbacks to separate wind projects from potentially sensitive or incompatible land uses. Sensitive receptors include hospitals, schools, churches, public roads, public parking, residential areas, and power lines. Exhibit 21-5 summarizes of the siting guidance from Wisconsin Public Service Commission Chapter 128—Wind Energy Systems as it pertains to adequate setbacks from nonparticipating property lines, public roads, commercial buildings, public parking, power lines, and residences. The blade tip height is about 100 meters for a 1.5 MW turbine and 125 meters for a 3.0 MW turbine, meaning that turbines generally must be located about 110 to 140 meters away from property lines, rights-of-way, and so on.

EXHIBIT 21-3
Monthly Wind Rose Plots for Milwaukee

Period	Wind Roses		
January–March			
April–June			
July–September			
October–December			

Source: NRCS.

EXHIBIT 21-4
Monthly Winds at Milwaukee

Month	Average Speed	Prevailing Wind	Calm	Peak Gust	Record Gust	Year of Record Gust
January	12.5	WNW-12.8	1.3	47	SW-66	1975
February	12.3	WNW-12.4	1.8	43.7	W-67	1971
March	12.8	WNW-12.7	2	48.4	SW-77	1991
April	12.7	NNE-13.9	2.1	49.8	W-67	1979
May	11.5	NNE-13.2	2.4	47.8	SW-74	1974
June	10.4	NNE-11.3	2.2	50.1	W-76	1971
July	9.7	SW-10.8	3.2	49.2	NW-81	1984
August	9.4	SW-10.4	3.2	45.2	NW-64	1989
September	10.4	SSW-11.0	2.8	44.6	NW-62	1980
October	11.4	SSW-12.1	2.5	43.4	NW-53	1990
November	12.3	WNW-13.1	1.8	46.6	SW-56 NW-56	1988 1989
December	12.3	WNW-12.4	1.4	47.3	N-61	1979
Annual	11.4	WNW-10.9	2.2	63	NW-81	July 1984

Source: http://www.aos.wisc.edu/~sco/clim-history/stations/mke/milwind.html

Note: Elevation: 676 ft above sea level. Anemometer height: 20 ft; period of record: 1948–1990 (average winds), 1970–1993 (gusts)

EXHIBIT 21-5
Siting Criteria: Setback Distances

Setback Description	Setback Distance
Occupied community buildings	The lesser of 1,250 feet or 3.1 times the maximum blade tip height
Participating residences	1.1 times the maximum blade tip height
Nonparticipating residences	The lesser of 1,250 feet or 3.1 times the maximum blade tip height
Participating property lines	None
Nonparticipating property lines	1.1 times the maximum blade tip height
Overhead communication and electric transmission or distribution lines, not including utility service lines to individual houses or outbuildings	1.1 times the maximum blade tip height
Overhead utility service lines to individual houses or outbuildings	None
Public road right–of–way	1.1 times the maximum blade tip height

Source: Wisconsin Public Service Commission Chapter 128—Wind Energy Systems

The following areas of potential impact from a wind project that should be considered during planning:

- The human environment (visual impact, shadow flicker, sound, highways and local traffic, aviation, electromagnetic interference, and health and safety),
- Social, community, and cultural aspects (socioeconomic, recreation, cultural heritage, and archaeological and paleontological resources)
- The physical environment (soil erosion)
- The natural environment (biodiversity)
- Decommissioning and reinstatement of the site

Estimate of Wind Power Energy Production

Based on the ranges provided by the NREL Wind Prospector, a preliminary model was developed to examine the potential wind energy production at each of the sites. The net annual energy production assumes a gross to net reduction of 15 percent loss and is measured in megawatt hours per megawatt of installed nameplate capacity. The output for an 80-meter hub height turbine is roughly 3,000 MWh/MW per year at the Jones Island WRF and 3,300 MWh/MW per year at the South Shore WRF. This means that a 1 MW turbine would on an annual average produce about 0.23 to 0.25 MW of power. Exhibit 21-6 summarizes estimated wind energy production for both sites. Note that these are preliminary estimates and a more detailed evaluation would be recommended.

EXHIBIT 21-6
Estimated Net Annual Energy Production

	Jones Island WRF (MWh/MW per yr)	South Shore WRF (MWh/MW per yr)
NREL 80 minimum	2,819	3,174
NREL 80 maximum	3,174	3,502
NREL 100 minimum	3,174	3,174
NREL 100 maximum	3,502	3,502

Source: CH2M HILL Wind Energy Production Model

Wind Turbine Locations

Exhibits 21-7 and 21-8 show potential locations for wind turbines for the Jones Island and South Shore WRFs (see following pages). Exhibit 21-9 lists the estimated installed and generation capacity. These indicate the approximate, preliminary maximum number of turbines that could installed given the required turbine spacing, setback distances, and available space. A detailed study would be required to determine the actual number of turbines that could installed. The number of turbines that could be installed likely will vary from what is shown. To compare wind power to other alternatives, it was assumed that one 3 MW wind turbine would be installed at both the South Shore and Jones Island WRFs. Additional turbines could be installed and the costs would increase approximately proportionally to the number of turbines.

Some of the Jones Island WRF is constructed on fill and foundation support requirements for pole-mounted turbines must be considered in any future evaluations because it could impact the costs of the alternative.

EXHIBIT 21-7
Potential Wind Turbine Locations: Jones Island WRF

EXHIBIT 21-8
Potential Wind Turbine Locations: South Shore WRF

EXHIBIT 21-9
Wind Turbine Power Summary

	Jones Island WRF	South Shore WRF
Number of wind turbines	1	1
Nominal capacity of each wind turbine, MW	3	3
Total installed capacity, MW	3	3
Average annual power generation rate, MW	0.7	0.8
Annual estimated power generated, MWh	6,100	7,000

Cost Estimate

The cost estimate for the 3 MW wind turbine was developed based in part on historical construction cost data developed by the National Renewable Energy Laboratory (NREL). Exhibit 21-10 summarizes the cost estimates for a single 3 MW turbine at the South Shore and Jones Island WRFs. This shows that, as noted, the South Shore WRF wind turbine may be more cost effective than at the Jones Island WRF because South Shore WRF experiences higher winds. However a more detailed evaluation would be required to confirm this.

EXHIBIT 21-10
Cost Estimate for Alternative 21: 3 MW Wind Turbine

		South Shore WRF	Jones Island WRF
Capital Costs			
One 3 MW wind turbine		$3,300,000	$3,300,000
Installation (30% of equipment)		$990,000	$990,000
Subtotal—Project Cost		*$4,290,000*	*$4,290,000*
Markups			
Site, piping, electrical, I&C, demolition, etc.	20%	$858,000	$858,000
Subtotal		*$5,148,000*	*$5,148,000*
Contingency	25%	$1,287,000	$1,287,000
Subtotal		*$6,435,000*	*$6,435,000*
Contractor mobilization, bonds, and insurance	20%	$1,287,000	$1,287,000
Subtotal		*$7,722,000*	*$7,722,000*
Subtotal with markups		*$7,722,000*	*$7,722,000*
Total Construction Cost		$7,722,000	$7,722,000
Non-Construction Costs			
Engineering/administration	18%	$1,389,960	$1,389,960
Subtotal—Non-Construction Costs		*$9,111,960*	*$9,111,960*
Total Capital Cost (2014 dollars)		$9,111,960	$9,111,960
Annual O&M Costs			
Power savings		-$525,000	-$457,500
Additional O&M labor		$39,000	$39,000
Additional maintenance		$43,000	$43,000
Total O&M (2014)		**-$443,000**	**-$375,500**

ALTERNATIVE 22

Recover Heat from Dryer Exhaust

Alternative Description

The sludge dryers, located in the Dewatering and Drying (D&D) Facility, use hot gas to evaporate moisture from the dewatered sludge cake. The exhaust gas is typically about 230 degrees F as it leaves the dryer, contains a high amount of moisture and therefore a high level of energy.

This alternative involves capturing some of the heat of the dryer exhaust and then transferring the heat to the dewatering system to increase the cake solids concentration which would reduce the water to the dryer and the energy needed to dry the solids. Modifications to the dryer exhaust flow stream to recover the energy would be implemented for all 12 dryers.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

The dryer exhaust contains particulates and cyclone separators are used to remove the coarse, fibrous particulates and are followed by wet electrostatic precipitators (ESPs) used for fine particulate removal. The discharge from the cyclones first enters a quench chamber where the partially cleaned exhaust is saturated with water sprays. The quench chamber is followed by the precipitator vessel.

To capture the heat, two options were considered:

1. Providing an air to water heat exchanger on the dryer exhaust as it exits the dryer (at its highest temperature).
2. Collecting the quench chamber drain water that has been used to cool and saturate the partially cleaned dryer exhaust and recover the heat in the quench water.

The first alternative was eliminated because it was found to not be practical due to the high concentration of chaff and dust in the dryer exhaust. The second alternative was determined to be feasible and offers the advantage of being able to capture some of the latent heat of condensation.

The quench chamber drain flow from each quench chamber would be captured (see Exhibit 22-1) and piped to a heat exchanger.

All piping would be insulated to help retain heat. Roughly 300 feet of 8-inch stainless steel piping and another 500 feet of 12-inch piping would be required to convey the flow to the heat exchangers.

Approximately 100 gpm of hot water is available from each quench chamber. With an average of 7 dryers operating, there would be sufficient flow available to heat both the polymer solution and blended sludge. Two heat exchangers would be located on the 4th floor (El. 53.0). One heat exchanger would be a plate-and-frame type for heating polymer solution and would be located near the north side where the polymer headers rise up from the basement level. The second heat exchanger would be a spiral type heat exchanger for heating blended sludge and would be located near the south side close to the blended sludge booster pumps.

EXHIBIT 22-1

Quench Chamber Discharge Collection Point

Quench chamber flow collected on the discharge from each quench chamber. The piping would be insulated, and flow would be by gravity to the 4th floor, where a heat exchanger would be located.

There are two redundant polymer header loops (polymer not used in the dewatering process is returned to the polymer feed pump discharge). The heat exchanger would be located on one of the headers and that header would then become a primary header. Valves can be provided to allow the other header to use the heat exchanger.

There are also two redundant blended sludge loops. The flow is alternated frequently and so one heat exchanger will be provided but the sludge piping would be configured so that the heat exchanger can serve either loop. The spent quench chamber flow would be piped to the drain with the belt filter press filtrate water.

Note: Veolia evaluated an alternative similar to this as part of the Biosolids Bundle—Project Number 4 (April 2013). The difference was that Veolia assumed that the heat recovered would be use for building heat rather than heating polymer. Doing that would require additional capital cost and would be less energy efficient and as a result it was found in general not to be cost effective.

Estimate of Energy Reduction or Recovery

The quench chamber flow is roughly 100 gpm per ESP that is in service. When the dryer is in operation, the quench chamber discharge is roughly 125 degrees F. Some heat loss is assumed as the flow is transported to the heat exchanger and so the heat exchanger inlet is assumed to be 120 degrees F.

Energy used in the sludge drying process would be reduced by increasing the belt press cake solids (less moisture to the dryer) by using the heated polymer and heated sludge. When heat has been applied to the sludge or polymer at other facilities, some seen an increase in cake solids. Pilot testing would be required to determine how much improvement in cake solids could be achieved. For purposes of this analysis, we have assumed that cake solids will improve from an average of 18 percent to an average of 18.5 percent. This may be conservative because other plants have seen increases in solids content of up to 2 percent. The reduction in evaporative load on the dryers results in an energy savings of 33,000 Dtherm per year. If a larger improvement in cake solids were found, the energy savings would be proportionally higher.

Cost Estimate

The project is estimated to have a capital cost of $1,600,000 and could be done with minimal impact to dewatering and drying operations. Energy savings is contingent on the moisture reduction in the sludge cake. With the assumed 0.5 percent improvement in cake solids, $200,000 of annual energy savings can be realized in the dryer system. Again, if the cake solids content can be increased by more than 0.5 percent, the energy savings would increase proportionally.

In addition to energy savings, the heated polymer can result in a reduction in polymer use, by about 10 percent.

Exhibit 22-2 presents the cost estimate for this alternative.

EXHIBIT 22-2
Cost Estimate for Alternative 22

Capital Costs		
Spiral heat exchanger		$100,000
Plate and frame heat exchanger		$100,000
8-inch SST insulated piping (300 linear feet)		$125,000
12-inch SST insulated piping (500 linear feet)		$250,000
Installation (30% of equipment)		$172,500
Subtotal—Project Cost		*$747,500*
Markups		
Site, piping, electrical, I&C, demolition, etc.	20%	$149,500
Subtotal		*$897,000*
Contingency	25%	$224,250
Subtotal		*$1,121,250*
Contractor mobilization, bonds, and insurance	20%	$224,250
Subtotal		*$1,345,500*
Subtotal with Markups		*$1,345,500*
Total Construction Cost		$1,345,500
Non-Construction Costs		
Engineering/Administration	18%	$242,190
Subtotal—Non-Construction Costs		*$1,587,690*
Total Capital Cost (2014 dollars)		**$1,587,690**
O&M Costs (using 2014 average loads)		**Annual Cost**
Additional O&M Labor (1% of new construction)		$13,500
Additional Maintenance—Parts (1% of new equipment)		$7,000
Natural gas Fuel Savings		-$197,297
Total O&M (2014)		**-$176,797**

ALTERNATIVE 23

Capture More Waste Heat from Internal Combustion Engines

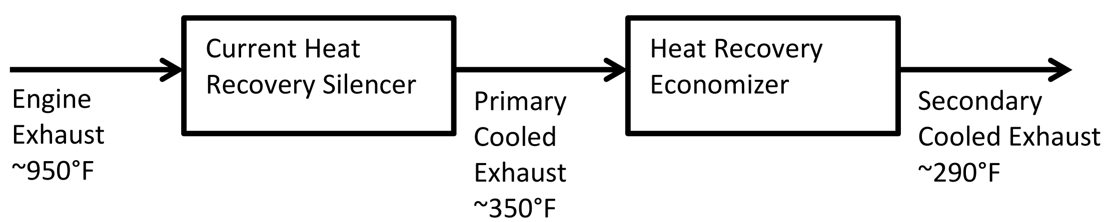
Alternative Description

The South Shore WRF spends about $77,000 a month on average purchasing natural gas to operate boilers to supplement the heat output of the digester gas–fired engine generators. The natural gas boilers operate year-round, so any improvement in engine heat recovery can be used to offset natural gas purchases. The South Shore WRF has five engine generators (four Caterpillar and one White Superior) that can operate on either natural gas or digester gas. Typically two to three engines run continuously. The engine generators convert roughly 30 to 40 percent (33.5 percent as of 2013, IC Engine Waste Heat Calculations, CH2M HILL) of the total input energy into electricity. The remaining 60 to 70 percent of the total energy input is converted into heat in the engine exhaust. According to the South Shore WRF O&M Manual, roughly 36 percent is recoverable.

The temperature is about 950°F entering the heat recovery silencer and 350°F exiting it (Appendix H of Final Design Calculations). With the installation of a heat recovery economizer, additional heat could be recovered by capturing some of the remaining heat and decreasing the exhaust temperature to ~290°F (Exhibit 23-1). Temperatures below 290°F generally are not recommended, because they will cause condensation of in the exhaust piping and heat recovery silencer, resulting in corrosion. Before this modification is considered further, it should be verified that the heat recovery system is configured to maximize heat recovery. It is also recommended that it be determined if the heat recovery units require cleaning, because a buildup of scale deposits will decrease the heat recovery capabilities of the silencer. If the system is found to be operating at maximum heat recovery potential, then further investigation of the exhaust temperature range, allowable back pressure, moisture content and sulfur concentration in the exhaust is recommended to determine if installing a heat recovery economizer is practical.

EXHIBIT 23-1

Process Flow Diagram of Additional Heat Captured



The additional recovered heat should be used to preheat the Hot Water Supply before entering the boilers. The additional heat will allow the Hot Water Supply water to increase the inlet temperature. There several ways to integrate the additional recovered heat back into the system, but with the current system in place, the project team believes preheating the boiler feed water will minimize heat loss in the system.

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

The modifications required depend on the current configuration of the exhaust piping and allowable space surrounding the engine generators. The most significant issue in the installation process will be the location of the heat recovery economizer. The heat recovery economizer ideally would be installed following the heat recovery silencer to limit heat loss. If possible, it would be ideal to connect the exhaust from the heat recovery economizer to the heat silencer exhaust line. If space does not allow that, then modifications must be made to add an exhaust stack from the heat recovery economizer.

To use the additional recovered heat most efficiently, about 100 to 200 gpm of the Hot Water Supply would be diverted into another line that would run through the new heat recovery economizers. The water would be heated and then combined with the rest of the Hot Water Supply flow before entering the boilers. Another water pump and piping would be needed to run water through the five heat recovery economizers.

Estimate of Energy Reduction or Recovery

Using the South Shore WRF final design values, it was determined that significant heat value can be recovered from the heat recovery silencer exhaust.

$$q = \dot{\text{m}} \times \text{Cp} \times \Delta\text{T}$$

q	=	heat flow rate, Btu/hr
$\dot{m}$	=	mass flow, lb/hr
Cp	=	specific heat, Btu/lb_{mass} °F
ΔT	=	the change in the fluid's temperature, as °F (or $T_{outlet} - T_{inlet}$)

Values taken from Appendix H (Final Design Calculations Process-Mechanical (J. Wills))

$\dot{m}$	=	13,598 lb/hr
Cp	=	0.0000002778 MMBtu/lb_{mass} °F
ΔT	=	57.5 °F (357.5°F – 290°F)

$$q = \frac{13{,}598\ lb}{hr} \times \frac{0.0000002778\ \text{MMBtu}}{\text{lbmass} - \text{°F}} \times 67.5\ \text{°F} \times \frac{24\ hr}{day}$$

q	=	6.12 MMBtu/day for one engine (rounded)

An engineer from Xchanger, a heat recovery manufacturer, indicated that a heat recovery economizer would be able to recovery additional heat – at most 4.8 MMBtu/day per unit. The additional heat recovery value provided by Xchanger will be used for the remaining heat calculations.

$$Required\ Heat\ at\ South\ Shore\ during\ the\ week\ at\ 60°F = 250\ MMBtu/day$$

$$Recovered\ Heat\ at\ South\ Shore\ during\ the\ week = 120\ MMBtu/day$$

$$Additional\ Heat\ Recovered\ from\ two\ Heat\ Recovery\ Economizers = 9.6\ MMBtu/day$$

$$250\ MMBtu/day - 120\ MMBtu/day = 130\ MMBtu/day\ required\ for\ heating\ at\ SS$$

$$130\ MMBtu/day - 9.6\ MMBtu/day = 120.4\ MMBtu/day\ required\ for\ heating\ at\ SS$$

The South Shore WRF typically runs two to three engine generators continuously; therefore, an additional 9.6 MMBtu/day could be captured as usable heat when two engine generators are in operation. The WRF typically recovers 120 MMBtu/day during the week and 140MMBtu/day on the weekend (Exhibit 23-2). If heat recovery economizers are installed and the additional heat captured is integrated back into the South Shore WRF heating system, then the natural gas boiler loads would decrease by about 9.6 MMBtu/day.

Cost Estimate

Exhibit 23-3 is a conceptual cost estimate. To reduce costs, further investigation could be done to determine fewer than the assumed five heat recovery economizers could be used. The Engine Generator Building might have to be modified to accommodate all five units and the additional water piping. The heat recovery silencer exhaust piping would have to be retrofitted to allow for the installation of the economizers. The cost contingency included reflects these unknowns.

$$9.6 MMBtu/day \times 365\ days = 3{,}500\ MMBtus$$

$$3{,}500\ MMBtus \times \frac{\$6}{MMBtus} = \$21{,}000\ in\ savings$$

EXHIBIT 23-2
South Shore WRF Heating Requirements

Ambient Air Temperature, °F	Heat Required, (MMBtu/day)	Heat Recovered (MMBtu/day)		Natural Gas Boiler Load (MMBtu/day)	
		Weekday	**Weekend**	**Weekday**	**Weekend**
90	184	120	140	64	44
80	196			76	56
70	209			89	69
60	250			130	110
50	296			176	156
40	341			221	201
30	387			267	247
20	432			312	292
10	478			358	338
0	523			403	383
-10	569			449	429

Note: Values taken from MMSD SSWRF Energy Management Tools

EXHIBIT 23-3
Cost Estimate for Alternative 23

Capital Costs		
5 Secondary Heat Recovery Units (quote: Xchanger)		$100,000
Additional Piping		$200,000
Building (New or Rehab)		$50,000
Installation (30% of Equipment)		$90,000
Subtotal—Project Cost		*$440,000*
Markups		
Site, Piping, Electrical, I&C, Demolition, etc.	20%	$88,000
Subtotal		*$528,000*
Contingency	40%	$211,200
Subtotal		*$739,200*
Contractor mobilization, bonds, and insurance	20%	$147,840
Subtotal		*$887,040*
Subtotal with Markups		*$887,040*
Total Construction Cost		$887,040
Non-Construction Costs		
Engineering/administration	18%	$159,667
Subtotal—Non-Construction Costs		*$1,046,707*
Total Capital Cost (2014 dollars)		**$1,046,707**
O&M Costs (using 2014 average loads)		**Annual Cost**
Additional O&M labor (1% of new construction)		$9,000
Additional maintenance—Parts (1% of new equipment)		$4,000
Natural gas fuel savings		-$21,000
Total O&M (2014)		**-$8,000**

ALTERNATIVE 24

Implement Jones Island WRF Aeration Control Using Dissolved Oxygen and Ammonia/Nitrate Probes

Alternative Description

The dissolved oxygen (DO) residual in an aeration basin is the excess oxygen that the microbiology did not use in oxidation. A DO residual is maintained to ensure there is sufficient oxygen for the microbiology. It is commonly suggested that a DO residual of 2 mg/L be maintained in aeration basins, but many installations have shown that complete treatment can occur with DO residuals much less than 2 mg/L. Those installations are able to operate at low DO levels by using a DO control system. A typical DO control system can reduce aeration rates, in most cases by 20 to 30 percent.

A relatively new variation of the DO control system incorporates ammonia (NH_3) measurements to allow for a variable DO set point. An NH_3 probe is located within the aeration basin and is generally associated with a DO probe. The operator selects an NH_3 set point with a range (dead band). The measured NH_3 within the basin is transferred to an NH_3 controller that determines whether the DO set point requires adjustment to meet the NH_3 set point. In recent studies, addition of NH_3 to the DO control system has resulted in aeration savings of 5 to 20 percent. MMSD and Veolia staff are evaluating this concept. The purpose of the alternative here is to document potential savings based on CH2M HILL's experience at other plants.

The following should be considered and evaluated before proceeding with implementation:

- Because of the wet weather strategy of idling several basins and the given diffuser grid density, nearly all the aeration basins operate at or near their minimum airflow rate. Therefore for the DO/NH_3 control system to be effective, it must be completed in conjunction with a project to decrease diffuser density or change in wet weather strategy that would allowing a lower airflow rate.

Description of Modifications Required

Every DO control system generally has the following components:

- DO measurement probe in the Aeration Basin
- DO controller
- Air mass flowmeter
- Actuating valve
- Air header pressure measurement
- Air compressor

A DO control system works with the operator setting a desired DO set point. The DO meter measures the DO in the basin at the location of the meter. The measured DO is sent to the DO controller, which determines if more or less air is needed to meet the set point. If a change is required, the DO controller sends a signal to the actuating valve to open or close the valve allowing more or less air into the basin. This causes an increase or decrease in pressure within the air header. This change in pressure will result in the blowers ramping up or down (or the blowers turning on or off) to reach the pressure set point. An algorithm in the DO controller within a dead band ensures that the system is not constantly searching for the set point and that a minimum airflow rate is maintained for mixing. Other variations include using a "most open valve" strategy to change the blower pressure set point to maintain a target valve "most open," thereby reducing blower header pressure losses.

For this system, it is expected that 3 DO probes would be located in each aeration basin: one in the first 25 percent, one in the middle of the basin, and one in the final 25 percent. The DO control system would either use the front, the middle, the rear, or the average of the measurements (any combination) for the DO control system. The ammonia probes would be co-located with the middle and final DO probes.

The following assumptions were used for evaluating this alternative:

- The primary clarifiers operate with 35 percent TSS removal efficiency.
- SRT is 7.5 days.
- The diffuser grids can operate at airflow rates lower than those at which they currently do.
- The blowers are capable of turndown to the simulated airflow rates.
- DO levels are tapered such that the highest DO is in the front and the lowest in the back. Minimum DO levels are set to 0.5 mg/L.
- The minimum mixing requirement is set to 0.09 scfm/ft^2. The airflow rate in each zone is not allowed to drop below this value.
- Baseline airflow rates are for process aeration only and do not include the estimated 40,000 scfm for channel aeration. The total airflow rates include the minimum air for the two west and two east idling basins.
- DO/NH_3 control allowed the effluent ammonia to rise up to about 1 mg/L.
- Jones Island WRF aeration uses 85,000 scfm blowers at 60 percent efficiency, drawing 5,140 bhp using a 5,500 hp motor. Total draw per blower is 5,244 hp at 98 percent motor efficiency.

Estimate of Energy Reduction

Lowering the DO has a substantial impact on airflow rates and energy consumption. Baseline models used an average DO of 3.5 mg/L across all basins. The simulated model used a tapered pattern with a DO of 1.5 mg/L in the front and 1.0 mg/L in the rear of the basin. This provided enough nitrification to produce an effluent NH_4 of 0.8 mg/L. Controlling the DO and NH_3 allowed aeration rates to be reduced from 74,500 scfm to 53,060 scfm, a reduction of nearly 30 percent. The decrease in air use would result in an estimated 985 kW blower power reduction. Even more energy savings could be realized if a more efficient blower were used.

Exhibit 24-1 provides a summary of the alternative.

EXHIBIT 24-1
Install DO and Ammonia Control at Jones Island WRF
Energy Production and Consumption Summary

Parameter	Baseline	Alternative	Comments
SRT, days	7.5	7.5	
Total flow, mgd	90	90	
Primary clarifier TSS removal	35%	35%	
MLSS, mg/L	2,560	2,178	
Estimated aeration rate, scfm			
Idle basins	8,600	8,600	
Process air	74,500	53,060	
Total	83,100	61,660	
Estimated aeration power, kW	3,822	2,837	985 kW savings
Aeration energy savings, kWh/yr @ 8,760 hr/yr	N/A	-8,540,510	

Cost Estimate

Installation of DO/NH_3 control at the Jones Island WRF would require new DO and NH_3 probes, motorized actuators, and air mass meters. It was assumed that this all would be new equipment. Again it is noted that Veolia and MMSD evaluated a similar project. Exhibit 24-2 estimates the conceptual cost for a system based on CH2M HILL's experience.

EXHIBIT 24-2
Cost Estimate for DO and Ammonia Control System for Jones Island WRF

Description	Parameter
Total number of aeration basins	32
Number of drop legs per aeration basin	3
Number of DO probes per basin	3
Total number of DO probes	96
Number of NH_3 probes per basin	2
Total number of NH_3 probes	64
Number of air mass meters and actuators per basin	3
Total number air mass meters and actuators	96
Total estimated construction cost (equipment, installation, programming/simulation)	$4,239,000
Total estimated non-construction cost	$763,000
Total estimated capital cost	$5,002,000

Exhibit 24-3 lists the estimated O&M savings for the installation of the DO/NH_3 control system. Given the large number of probes installed, it was assumed that one new full-time employee would be responsible for maintaining the system (probe cleaning, calibration, etc.).

EXHIBIT 24-3
Estimated O&M Costs

Parameter	Value	Comment
Estimated O&M	$86,400	1 full-time equivalent at $30/hr plus miscellaneous parts
Estimated energy savings	-$597,840	8,540,500 kWh/yr@ $0.07/kWh
Net O&M savings	-$511,440	

Discussion and Considerations

- To realize any of the savings presented, the following projects would need to be conducted:
- Wet Weather Strategy Modification—The current strategy requires that nearly all basins be online and available for potential wet weather events, even though all the basins are not needed for dry weather flows. Having all the basins online at a low MLSS is basically why all the basins are operated at the minimum airflow rate. If a new wet weather strategy could be implemented, this could allow basins to be taken offline and allow for a DO/NH_3 control system to realize savings
- Diffuser Grid Upgrade—The basins use porous plate diffusers that provide full floor coverage. Energy savings could only be realized if diffusers were evaluated and reconfigured to provide a tapered air flow pattern from the basin front to back. There has been some discussion about plugging some existing

plates with an epoxy coating to manipulate diffuser density. This would be a cost-effective way to accomplish this if found to be feasible.

Note: This alternative was partially implemented in 2014 and following the completion of the evaluation of this alternative, and data became available regarding the preliminary results of the implementation. A D.O. probe is installed in every other aeration basin and plant staff have been able to lower the air supply to the aeration basins to approximately 59,000 cfm. The greatest obstacle to optimizing air flows and corresponding energy usage for the JIWRF is diffuser configurations. The District is beginning to evaluate the diffuser configuration to determine the desired changes to optimize air flows. It is believed that an additional reduction of 10,000 to 15,000 cfm is possible with reconfiguration of diffusers. The projected corresponding energy reduction shown in Exhibit 4 of 970 kW likely is lower – perhaps 300 KW because the new blower is more efficient than the older blowers (~ 27 kW/1000 cf of air supplied based on recent testing).

ALTERNATIVE 25

Implement South Shore WRF Aeration Control Using Dissolved Oxygen and Ammonia/Nitrate Probes

Alternative Description

The dissolved oxygen (DO) residual in an aeration basin is the excess oxygen that the microbiology did not use in oxidation. A DO residual is maintained to ensure there is sufficient oxygen for the microbiology. It is commonly suggested that a DO residual of 2 mg/L be maintained in aeration basins, but many installations have shown that complete treatment can occur with DO residuals much less than 2 mg/L. Those installations are able to operate at low DO levels by using a DO control system. A typical DO control system can reduce aeration rates, in most cases by 20 to 30 percent.

A relatively new variation of the DO control system incorporates ammonia (NH_3) measurements to allow for a variable DO set point. An NH_3 probe is located within the aeration basin and is generally associated with a DO probe. The operator selects an NH_3 set point with a range (dead band). The measured NH_3 within the basin is transferred to an NH_3 controller that determines whether the DO set point requires adjustment to meet the NH_3 set point. In recent studies, addition of NH_3 to the DO control system has resulted in aeration between 5 and 20 percent. MMSD and Veolia staff are evaluating this concept. The purpose of the alternative here is to document potential saving based on CH2M HILL's experience at other plants.

The following should considered and evaluated before proceeding with implementation:

- Roughly half the basins at the South Shore WRF use membrane fine bubble diffuser grids. The others use porous plate diffuser grids. Both systems provide full floor coverage of the basin. At the end of the basin, where minimum treatment and air is required, the minimum required diffuser air-flux may provide excessive, unneeded air.
- The process air compressors are 30,000 scfm units equipped with 1,500 hp motors. It would be expected that one of these units be capable of turning down by 40 percent to 18,000 scfm. Therefore, aeration savings that result in aeration rates below the minimum turndown may not be realized without modifying the blower system.

Note: Veolia/MMSD has begun to implement this alternative but with fewer probes than assumed in the consultant team's evaluation.

Description of Modifications Required

Every DO control system generally has the following components:

- DO measurement probe in the Aeration Basin
- DO controller
- Air mass flowmeter
- Actuating valve
- Air header pressure measurement
- Air compressor

A DO control system works with the operator setting a desired DO set point. The DO meter measures the DO in the basin, at the location of the meter. The measured DO is sent to the DO controller, which determines if more or less air is needed to meet the set point. If a change is required, the DO controller sends a signal to the actuating valve to open or close the valve allowing more or less air into the basin. This causes an increase or decrease in pressure within the air header. This change in pressure will result in the blowers ramping up or down (or the blowers turning on or off) to reach the pressure set point. An algorithm in the DO controller within a dead band ensures that the system is not constantly searching for the set point and that a minimum air flow rate is maintained for mixing. Other variations include using a "most open valve" strategy to change the blower pressure set point to maintain a target valve "most open," thereby reducing blower header pressure losses.

For this system, it is expected that 3 DO probes would be located in each aeration basin: one located in the first 25 percent, one in the middle of the basin, and one in the final 25 percent. The DO control system would either use the front, the middle, the rear, or the average of the measurements (any combination) for the DO control system. The ammonia probes would be co-located with the middle and final DO probes.

The following assumptions were used for evaluating this alternative:

- The primary clarifiers operate with 77 percent TSS removal efficiency.
- SRT can be reduced to 9 days.
- The diffuser grids are assumed to be capable of operating at lower airflow rates
- The blowers are capable of turndown to the simulated airflow rates
- DO levels are tapered such that the highest DO is in the front and the lowest in the back. Minimum DO levels are set to 0.5 mg/L.
- Minimum mixing requirement is set to 0.09 scfm/ft2. Airflow rates are not allowed to drop below this value in each zone.
- DO/NH_3 control allows the effluent ammonia to rise to about 1 mg/L.
- South Shore WRF aeration uses 30,000 scfm blowers at 75 percent efficiency, drawing 1,451 bhp using a 1,500 hp motor. Total draw per blower is 1,481 hp at 98 percent motor efficiency.

Estimate of Energy Reduction or Recovery

Lowering the DO has a substantial effect on airflow rates and energy consumption. Baseline process computer models used an average DO of 3.3 mg/L across all basins. The simulated model used a tapered pattern with a DO of 1 mg/L in the front and 0.5 mg/L in the rear of the basin. This provided enough nitrification to produce an effluent NH_4 of 0.6 mg/L. Controlling the DO and NH_3 allowed aeration rates to reduce from about 93,300 scfm to 49,160 scfm, a reduction of nearly 47 percent. This reduction results in a 1.62 MW power reduction. This assumes fully optimized control through use of multiple probes in each basin and a well-tuned control loop. The cost effectiveness of installing multiple probes could be evaluated in the future. In addition, in 2014 BOD and ammonia loads have increased which could impact the evaluation. Exhibit 25-1 is a summary of the alternative.

EXHIBIT 25-1
Install DO and Ammonia Control at the South Shore WRF
Energy Production and Consumption Summary

Parameter	Baseline	Alternative	Comments
SRT, days	11	9	
Total flow, mgd	90	90	
Primary clarifier TSS removal	77 percent	77 percent	
MLSS, mg/L	3,700	3,150	
Estimated aeration rate, scfm	93,300	49,160	
Estimated aeration power, kW	3,433	1,809	1.624 MW reduction
Aeration energy savings, kWh/yr @ 8,760 hr/yr	N/A	(14,079,300)	

Cost Estimate

Installation of the DO/NH_3 control at SSWRF would require new DO and NH_3 probes, motorized actuators, and air mass meters. It was assumed that this would all be new equipment. Exhibit 25-2 provides a summary of the capital costs.

EXHIBIT 25-2
DO and Ammonia Control System for South Shore WRF

Description	Parameter
Total number of Aeration Basins	28
Number of drop legs per Aeration Basin	4
Number of DO probes per basin	3
Total number of DO probes	84
Number of NH_3 probes per basin	2
Total number of NH_3 probes	56
Number of air mass meters and actuators per basin	4
Total number air mass meters and actuators	84
Total estimated construction cost (equipment, installation, programming/simulation)	$3,729,000
Total Estimated Non-Construction Cost	$671,200
Total Estimated Capital Cost	$4,400,200

The estimated O&M savings for the installation of the DO/NH_3 control system is provided in Exhibit 25-3. Given the sheer number of probes installed, it is assumed that 1 new full time employee would be responsible for the maintenance of the system (probe cleaning, calibration, etc.)

EXHIBIT 25-3
Estimated O&M Costs

Parameter	Value	Comment
O&M	$83,400	1 full-time equivalent at $30/hr plus miscellaneous parts
Energy savings	-$985,550	14,079,300 kWh/yr@ $0.07/kWh
Net O&M	-$902,150	

Discussion and Considerations

To realize any of the savings above, the following project would need to be implemented:

- Diffuser Grid Evaluation—Roughly half the basins use porous plate or membrane diffusers that provide full floor coverage. Energy savings could be realized only if a diffuser evaluation were conducted the system were modified to provide a tapered aeration pattern from front to back.

As previously noted, this alternative has been begun to be implemented by Veolia/MMSD and it has been noted that the energy reduction is projected to be less than that shown in Exhibit 25-3. However significantly fewer probes are being used than is recommended in Exhibit 25-2 which will result in a more coarse control of aeration. This evaluation assumes fully optimized control through use of multiple probes in each basin and a well-tuned control loop. The cost effectiveness of installing multiple probes could be evaluated in the future. In addition, in 2014 BOD and ammonia loads have increased which could impact the evaluation.

ALTERNATIVE 26

Install Turbine Waste Heat Landfill Gas Dryer Burners, Duct Burners or Air Heaters

Description of Alternative

The quantity of landfill gas used in the Jones Island WRF solar turbines may increase over time as more landfill gas becomes available, and then exceed the capacity of the three solar turbine generators. The new Powerhouse has space to add two more solar turbines. In early 2013, the District performed a planning-level study to evaluate how to use additional landfill gas. The recommendations stated that the District should continue to evaluate two alternatives: (1) additional landfill gas turbine-generators or (2) using landfill gas to produce dryer heat using dryer burners, waste heat duct burners, or air heaters using duct burners. The study used information from two previous efforts regarding landfill gas dryer burners and duct burners.

In 2009, the District performed engineering, developed plans and specifications, and sought bids for the replacement of the natural gas dryer burner system with a system capable of burning landfill gas. The District rejected all bids, because costs were significantly higher than budgeted and lower natural gas prices forced a reevaluation of the project. In 2011, the District studied the feasibility of using duct burners to use landfill gas for sludge drying. The District recently contracted with CH2M HILL and others (under a contract separate from the Energy Plan) to evaluate and obtain final recommendations regarding how to use additional landfill gas. Consultants will evaluate duct burners, air heaters using duct burners, and conversion of the natural gas dryer burners into new dual fuel burner systems, allowing use of either natural gas or landfill gas. A separate consultant will use the output of this evaluation to make a final recommendation in terms of quantities of additional landfill gas, pricing, and what infrastructure to pursue, such as additional turbines, duct burner, or dryer burners.

The studies have only recently begun. The results of these evaluations should incorporated into the Energy Plan when completed.

ALTERNATIVE 29

Implement South Shore WRF Renewable Energy Powered UV Disinfection for 100 mgd Base Flow

Alternative Description

At the South Shore WRF, wastewater effluent undergoes sodium hypochlorite disinfection and sodium bisulfite dechlorination before it is discharged to Lake Michigan. Per District staff, annual chemical costs are roughly $500,000. The intent of this alternative is to evaluate the potential to use a 100-mgd capacity UV disinfection system in place of the chemical system and power the UV system with renewable energy. Based on data from January 2006 through April 2008, annual average influent flow (including wet weather events) is about 110 mgd. Excluding wet weather events, influent dry weather flow typically varies from 70 mgd to 90 mgd. A 100-mgd UV disinfection system would be capable of treating most dry weather flows, and sodium hypochlorite and sodium bisulfite could be used for disinfection when flows are higher.

Based on other alternative evaluations, there are three sources that could generate renewable electricity to power a 100-mgd UV disinfection system:

- Alternative 19—Maximize South Shore WRF FOG and High-Strength Waste Digestion
- Alternative 20—Solar Power Electricity Generation
- Alternative 21—Wind Energy Generation

This alternative will be further evaluated in the 2050 Facilities Plan.

Description of Modifications Required

This alternative would require the installation of a 100-mgd UV disinfection facility at the South Shore WRF and for the sodium hypochlorite and sodium bisulfite chemical systems that would be used during higher flows.

The renewable energy systems that would provide the power for UV are described in those alternative evaluations.

Estimate of Energy Reduction or Recovery

Using the *Chlorine Gas Decision Tool for Water and Wastewater Utilities* (March 2006) offered by the Department of Homeland Security and National Association of Clean Water Agencies, a 100-mgd UV disinfection facility has an estimated electrical demand of 960 kW.

The digester gas–powered engines likely would provide the most promising source of consistent, internally generated renewable electrical energy. With the addition of improved mixing and expansion of the co-digestion program, the available energy is substantial. From the Alternative 19 evaluation, power production under current conditions (without co-digestion) is about 2.8 MW and the average South Shore WRF power demand is nominally 4 MW, meaning under current conditions there is not excess renewable power. With co-digestion maximized using active digester volumes, this power production potential increases significantly, perhaps to as high as 16.4 MW. However there is a significant uncertainty as to whether that required volume of co-digested waste and FOG could be obtained. The 100-mgd UV disinfection system requires only about 1 MW, so energy from even a modest co-digestion program should be able to supply all the power for the UV system.

The cost of power generated by co-digestion would likely be slightly higher than the cost of the additional O&M costs of engine operation which ranges from $0.01 to $0.02 per kwh. This cost would be lower than other power source costs including purchasing off-peak power which is about $0.05 per kwh.

The five IC engines can produce a maximum of 5.5 MW. Demand at the South Shore WRF is about 4 MW, meaning that about 1.5 MW would be available with all IC engines operating. With storage available onsite, plant operators may be able to address fluctuations in digester gas production or balance UV disinfection power demand.

The results from the Alternative 20 evaluation indicate that 5 acres of PV panels located at the South Shore WRF would have a rated capacity of about 1,800 kW_{DC}. On annual average, a solar PV system in Milwaukee operates at an estimated 15 percent of its rated capacity. This is due to the reduced or eliminated power generation on cloudy days or at nighttime hours. Accounting for non-generating times, the rated capacity is equivalent to 270 kW_{DC} of delivered power. The delivered power from 5 acres of solar PV panels is insufficient to meet the power demand (~1 MW) of a 100-mgd UV disinfection facility. Roughly 18 acres of solar PV panels would be required to meet the UV disinfection facility power demand.

Similar to solar power generation, wind power is subject to variability from fluctuating environmental conditions. Power production at the South Shore WRF from wind is roughly 25 percent the rated capacity of the wind turbine. Therefore, with three 3-MW turbines installed at the South Shore WRF, the average annual power generation rate is about 2.3 MW. On an annual average basis, 3 turbines could supply enough electrical energy for a 100-mgd UV disinfection facility. Because wind energy production is variable, power supply solely from wind to the UV disinfection facility would also be variable. More detailed design may determine that fewer than three turbines could be constructed, in which case, the power generation will decrease.

Because many of the required facilities exist, electricity generation from anaerobic digestion/co-digestion would be the most cost-effective source of internally-generated renewable energy for a 100-mgd UV disinfection facility. However, if wind or solar power is implemented, either could generate excess power that could be used to power the UV system.

Cost Estimate

Exhibit 29-1 is a cost comparison of the costs of powering a UV disinfection system using energy generated from anaerobic digestion/co-digestion digester gas and the cost of purchasing chemicals for disinfection.

EXHIBIT 29-1
Cost Comparison of Renewable Energy UV Disinfection to Chemical Disinfection
Estimated Costs for a 100-mgd UV Disinfection System versus Sodium Hypochlorite/Sodium Bisulfite Addition

	UV Disinfection with Co-digestion as Power Source	Sodium Hypochlorite Disinfection with Sodium Bisulfite Dechlorination
Annual O&M cost (power, other)	$244,000	$500,000
Annual net reduction in disinfection O&M costs	$256,000	N/A
Capital cost	$8,850,000	N/A
Simple Payback	35	N/A

The price of purchased electricity varies but is typically about $0.07/kWh. Electricity generated by the digester gas engines would cost at most about $0.02/kWh, which is equal to the cost of engine O&M—again making it the lowest cost power. If additional engines had to be purchased, this power generation cost would increase to account for amortization of new engines. If the District were able to collect tipping fees for co-digested waste, the cost to generate power would decrease. The annual costs for UV disinfection are less than those for chlorination/dechlorination, but the capital cost of a UV system results in a long payback. There are however non-monetary benefits for UV including no formation of disinfection by-products, no chemical hazards and potentially more effective disinfection at higher UV doses.

ALTERNATIVE 31

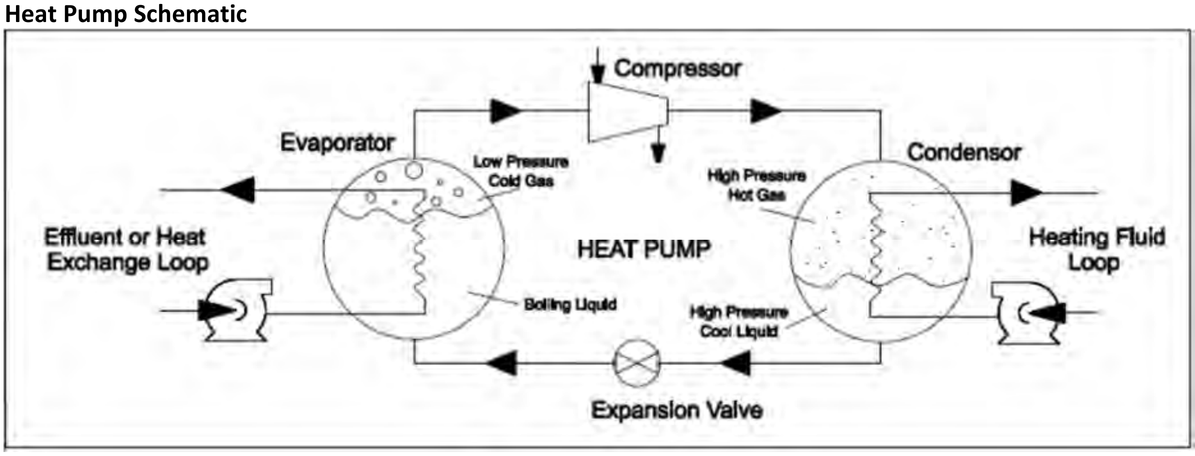
Large-Scale Effluent Heat Recovery Using Heat Pumps

Alternative Description

Alternative 31 evaluates recovering heat from the plant effluent using heat pumps. Treated final effluent from a wastewater treatment plant offers a convenient and reliable source of heat at a relatively high temperature (compared to surface or ground waters). The heat pump withdrawal would take the water from the effluent channel after the chlorine contact tank and heat a circulating water loop. The heated water can then be used in another part of the treatment plant through the plant's heat loop. Effluent temperatures at the Jones Island and South Shore WRFs are above 50 degrees Fahrenheit throughout the year, presenting adequate temperatures for heat pump operation. Exhibit 31-1 shows a schematic of a water-to-water heat pump.

Hot water heating system temperatures often operate between 160 and 199 degrees to provide adequate temperatures for process heating. One issue with integrating effluent heat pumps into an existing plant heating system is that the temperature of the hot water produced is limited to a value of about 110 degrees greater than the effluent water temperature. In addition, the efficiency of the process decreases as the hot water temperature set point is increased. If the plant heating system is designed and operated at 190 degrees, some heating system components might not have sufficient heat transfer area or flow capacity with lower temperature water on very cold days.

EXHIBIT 31-1
Heat Pump Schematic



Description of Modifications Required

The heat pump would be installed at the final effluent conduit. One example water source heat pump model, which is suitable for producing 170-degree heated water, is capable of recovering 1.7 million Btu/hr of thermal energy. This heat pump was chosen because of its ability to heat water to 170 degrees and to handle the flow from the final effluent. If the plant requires more heat, two or more heat pumps can be placed in parallel to get the desired heat output.

A water pump to circulate the water taken from the final effluent conduit will be needed, along with insulated pipe to convey the hot water to a connection to the existing hot water system connection or another desired location.

Estimate of Energy Reduction or Recovery

The thermal energy recovered from the heat pumps can either be placed back into the plant's existing heat loop to help reduce heating cost during the winter months or the hot water from the heat pump could be used for other uses such as heating the sludge or polymer dilution water to increase cake solids as described in Alternative 16.

Exhibit 31-1 summarizes the potential energy that could be recovered from the treated effluent. The actual energy recovered will vary depending on the system design and configuration. There is much more heat in the effluent than could ever be used in the plant and the system size could be increased to cover all plant heating needs.

EXHIBIT 31-2
Potential Energy Recovery from the Jones Island and South Shore WRFs Effluent Using Heat Pumps

Average flow rate: Jones Island WRF and South Shore WRF, mgd	97
Hot water produced temperature, °F	170
Coefficient of performance, COP	2.3
Effluent temperature, °F	50.6 to 67
Thermal energy output, MMBtu/hr	1.77
Operating power, kW	222
Effluent flow rate, gpm	424

Note: Data are for a multistack model #MS105AN

Cost Estimate

This alternative is estimated to have a capital cost of roughly $905,000 for the example heat pump size described in Exhibit 31-3.

The heat generated by the heat pump may not be needed when buildings do not require heat. However, a chiller air conditioning system could be installed to use the energy. Exhibit 31-3 compares the cost to generate heat for the effluent heat pump system to other available sources of energy. In addition to the electrical cost to run the heat pump, there is a small energy requirement to pump the final effluent through the heat pump. This does not include the cost of capital to install the heat pump system and if that were included it would make the cost of generating heat with the heat pump higher. This shows that at current natural gas prices, a heat pump system would be more costly than heat generated by a natural gas boiler. As natural gas prices rise due to inflation, the gap between the cost to generate energy using a heat pump system and natural gas would narrow. Exhibit 31-4 is the complete cost estimate.

EXHIBIT 31-3
Comparison of Effluent Heat Pump System to Other Purchased Energy Sources
Cost to produce 1,000,000 Btu

Energy Source	Equipment	Efficiency or COP	Heat Value	Cost of Source[a]	Cost per MMBtu
Fuel oil	Boiler	80%	140,000 Btu/gal	$3.09/gal	$27.59
Natural gas	Boiler	78%	100,000 Btu/therm	$0.60/therm	$7.69
Electric	Water source heat pump	2.3	3413 Btu/kW	$0.07 kWh	$8.91

[a] Approximate MMSD cost to purchase.

EXHIBIT 31-4
Cost Estimate for Alternative 31

Capital Costs		
Heat pumps		$200,000
Water pumps	2	$60,000
10-inch ductile iron pipe (300 ft)		$47,670
12-inch ductile iron pipe (100 ft)		$20,010
Installation (30% of equipment)		$98,304
Subtotal—Project Cost		$425,984
Markups		
Site, piping, electrical, I&C, demolition, etc.	20%	$85,197
Subtotal		$511,181
Contingency	25%	$127,795
Subtotal		$638,976
Contractor mobilization, bonds, and insurance	20%	$127,795
Subtotal		$766,771
Subtotal with markups		$766,771
Total Construction Cost		$766,771
Non-Construction Costs		
Engineering/administration	18%	$138,019
Subtotal—Non-Construction Costs		$904,790
Total Capital Cost (2014 dollars)		**$904,790**
O&M Costs (using 2014 average loads)		**Annual Cost**
Power cost		-$36,986
Additional O&M Labor (1% of new construction)		$7,500
Additional maintenance—parts (1% of new equipment)		$4,000
Natural gas fuel savings		-$77,110
Total O&M Costs (2014)		**-$28,624**

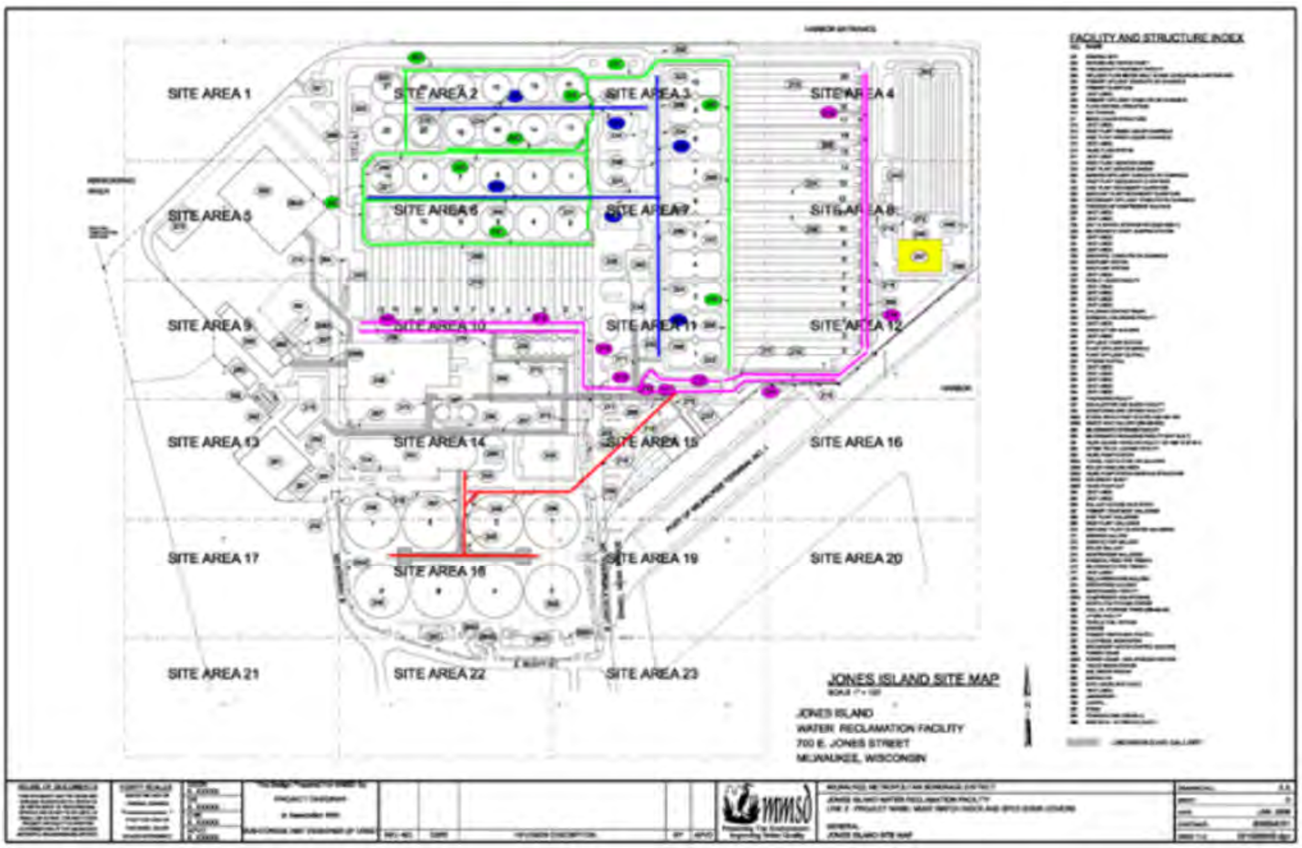
ALTERNATIVE 34

Change Channel Mixing to Large Bubble Mixers

Alternative Description

Channel aeration accounts for 20,000 scfm or just over 15 percent of the average total air used daily at the Jones Island WRF (Exhibit 34-1). In the past, it appears that the channels used about 40,000 scfm and recent reductions are estimated to have resulted in the current use of about 20,000 scfm. However, that should be verified. Reducing or eliminating that air usage could achieve a significant reduction in power. One method would be to install a large bubble mixing system, such as the Enviro-Mix BioMix system. The system uses compressor air to form large bubbles in a series of floor diffusers. The system is operated sequentially to create a desired mixing pattern. A recent study at the F. Wayne Hill Water Resources Facility showed a 60 percent reduction in mixing power compared to mechanical mixing using submersible mixers.

EXHIBIT 34-1
Channel Aeration at Jones Island WRF



One potential constraint on the system is that the existing process air compressors are quite large (118,000 scfm units equipped with 1,500 hp motors). Aeration accounts for roughly 75,000 scfm of the air. Removing channel aeration airflows will push the blower to near its minimum turndown and savings could diminish.

Description of Modifications Required

Large bubble mixing systems mix liquids by firing short bursts of compressed air through engineered nozzles affixed to the floor of a tank. This compressed air is fired intermittently in fractional second durations to mix the tank. The relatively small surface area, the large gas volumes, and their rapid upward velocity enable large bubble systems to transfer an insignificant amount of oxygen to the wastewater while still providing efficient anaerobic/anoxic mixing. The systems include the following equipment (see Exhibit 34-2):

- 304SS large bubble nozzles affixed to the channel floor
- SCH5 304SS Air Piping
- Electrically actuated valves and corresponding manifold
- Rotary-screw air compressor
- Air-pressure receiver/tank

Exhibit 34-3 lists the characteristics of this alternative.

EXHIBIT 34-2
Large Bubble Mixing System (courtesy of Enviro-Mix)

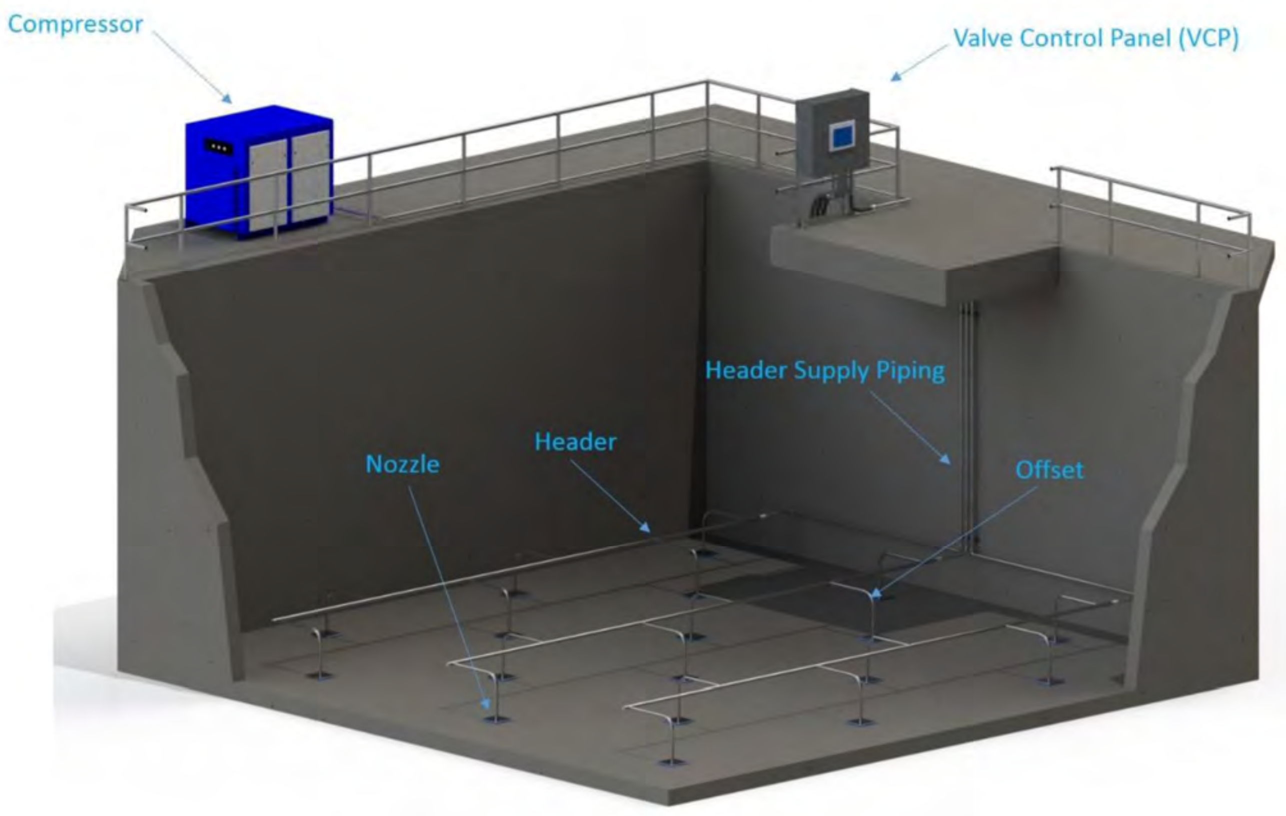


EXHIBIT 34-3
Estimated Channel Mixing System Criteria for the Jones Island WRF

Description	Parameter
Existing channel aeration	20,000 scfm[a]
Estimated power used for channel aeration	920 kW[b]
Aeration Basin Influent Channels (Structures 209, 210, 213, and 214)	
Estimated Total Channel Length, ft	5,263
209/210	827
213	2,456
214	1,980
Diameter of Headers Pipe, inches	2
Large Bubble Headers per Channel	
209/210	11
213	33
214	27
Length of individual headers, ft	75
Number of large bubble nozzles per header	12
Estimated total number of nozzles	852
209/210	132
213	396
214	324
Number of large bubble compressors	1 duty, 1 standby
Compressor horsepower, each	100
Compressor type	Rotary screw
Aeration Basin Effluent Channels (Structure 220)	
Estimated total channel length, ft	7,620
Diameter of headers pipe, inches	2
Large bubble headers per channel	100
Length of individual headers, ft	75
Number of large bubble nozzles per header	12
Estimated total number of nozzles	1,200
Number of large bubble compressors	1 duty, 1 standby
Compressor horsepower, each	150
Compressor type	Rotary screw

[a] Jones Island Water Reclamation Facility Capacity Analysis Report (CH2MHILL, 2011)
[b] Assumes 8.5 psig, 60 percent efficient blower, 98 percent efficient motor

Estimate of Energy Reduction or Recovery

A large bubble mixing system significantly reduces the amount of energy required for channel mixing. The existing system uses about 20,000 scfm, equating to 920 kW. The large bubble mixing system is estimated to use 179 kW, representing an 80 percent decrease in energy usage worth 6.49 million kWh/year. Exhibit 34-4 is a summary of the alternative.

EXHIBIT 34-4
Install Large Bubble Mixing
Energy Production and Consumption Summary

Constituent	Baseline	Alternative	Comments
Estimated channel aeration rate, scfm	20,000	N/A	
Estimated aeration power, kW	920	179	831 kW savings
Aeration Energy Savings, kWh/yr @ 8,760 hr/yr	N/A	-7,275,180	

Cost Estimate

The large bubble channel mixing system is a package system provided by the manufacturer. Installation will require the removal of the existing system and the installation of the new system. Exhibit 34-5 provides the capital cost estimate. Exhibit 34-6 provides the estimated O&M savings for the installation of the new channel mixing system.

EXHIBIT 34-5
Large Bubble Channel Mixing System for Jones Island WRF

Description	Parameter
Aeration Basin Influent Channel Large Bubble Mixing System	$1,300,000
Aeration Basin Effluent Channel Large Bubble Mixing System	$1,800,000
Total Estimated Construction Cost (demolition of existing grids, installation, markups)	$7,073,000
Total Estimated Non-Construction Cost	$1,273,000
Total Estimated Capital Cost	**$8,346,000**

EXHIBIT 34-6
Estimated O&M Costs

Parameter	Value	Comment
Estimated O&M	$34,900	Compressor maintenance per the MFR, plus 1 hr/day labor @ $30/hr
Estimated energy savings	-$ 509,263	7,275,180 kWh/yr@ $0.07/kWh
Net O&M	**-$474,363**	

Discussion and Considerations

The following consideration should be evaluated if this alternative were selected for further evaluation:

- If this option is combined with any other aeration reduction options (such as DO control), then a blower evaluation will need to be conducted, to determine if aeration rates fall within the range of the blower capacity.

Note: After the evaluation of this alternative was completed, additional data and information became available. The December 2014 estimated channel air flow is approximately 30,000 cfm. This was determined from existing channel air flow measuring stations and was validated by comparing the value to the total air supplied minus the sum of the air flows to the 32 aeration basins, which now totals approximately 59,000 cfm. The actual difference was 37,000 cfm. It is not known how much leakage may exist in the air supply piping. Major leaks have been corrected, but smaller unquantified leaks still exist. The District is trying to quantify the volume of these air leaks. With the existing diffuser configuration, the projected minimum channel air supply is 20,000 cfm, which can be achieved by adjusting the newly installed butterfly valves. The *required energy to deliver 20,000 cfm with the new blower is approximately 520 kW. The energy requirement for a large bubble mixing system is 179 kW; therefore, the projected savings is approximately 340 kW – less than shown in Exhibit 34-4.*

ALTERNATIVE 36

Increase Use of Waste Heat from Internal Combustion Engines

This alternative was combined with Alternative 23. See Alternative 23 for evaluation of increasing the South Shore WRF engine waste heat capture.

ALTERNATIVE 41

Install Variable Frequency Drives for Pumps, Fans, and Other Equipment

Alternative Description

Variable frequency drives (VFDs) are used to control the speed of alternating current (AC) motors and can be used to best match motor output and energy needs to process needs. VFDs also have several advantages over standard across the line motor starters to be discussed herein. Motor inrush current is limited to 150 percent of full load current, whereas across the line motor starting draws up to six times full load current. The VFD can be programmed to accelerate the motor slowly, thus reducing the starting stress on the mechanical systems. The lower motor starting current will allow more motors to be placed on a bus, as less capacity in that switchgear needs to be reserved to accommodate full load current. In addition, because VFDs convert the AC power to DC and then back to AC, the input power to the VFD is near unity power factor. Energy savings will be achieved because of the power factor improvements. Energy savings also can be obtained if VFDs are used for flow or pressure control in place of flow control valves, because flow control valves require additional head pressure.

MMSD has already proceeded with evaluating this alternative. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.

Description of Modifications Required

The use of VFDs for motor-driven loads could be required for all future projects that require flows and process parameters to be varied. For small loads, the system could be equipped with VFDs that provide precise speed control and that can also be used to gather usage data, such as total energy used. Existing motor starters could be replaced with VFDs for the same reasons. It is recommended that VFDs be placed on pumps to control flow rates rather than relying on control valves for this purpose. This change would reduce energy costs by roughly 30 percent.

Estimate of Energy Reduction or Recovery and Cost Estimate

The total power draw of all motors at the South Shore and Jones Island WRFs is greater than 15,000 hp, and there are many pump and fan motors that could become VFD controlled. An estimate of the potential power savings of installing VFDs on all these motors is beyond the scope of this project. However, an example can be used to illustrate the potential cost-effectiveness of a typical VFD.

If flow is controlled by installing a VFD on a 200 hp pump motor rather than controlling flow with a throttling valve in a pressure or flow control application, about 30 percent or 60 hp could be saved. However, the savings can vary depending on several factors, and the 30 percent is likely conservative. Assuming the pump or fan runs year-round, 12 hours per day, the savings would be:

$$60 \text{ hp} \times 746 \text{ watts/hp}/1{,}000 \text{ watts/kW} \times 4{,}380 \text{ hr/yr} \times \$0.075/\text{kWh} = \sim \$14{,}700 \text{ per year}$$

The installed cost of a typical 200 hp VFD is perhaps $150/hp or $30,000. In this example, the simple payback would be about 2 years which, compared to other alternatives, would be highly cost-effective.

Because of advances in semiconductor technology over the last several decades, VFDs no longer cost four to five times as much as across the line motor starters. The cost to provide VFDs is now about twice the cost of across the line starters, with costs varying from $150 to $500 per hp installed. Cost per horsepower decreases as horsepower increases.

For the purpose of comparing the overall potential of this alternative to others, if say a total pump/fan load of 2 MW could have VFDs added, the load could be reduced by 0.6 MW and the capital cost of the VFDs would be perhaps $540,000 (assuming $200/hp). A more detailed evaluation is required, but this estimate allows an order-of-magnitude comparison with other alternatives. Any future more detailed evaluation should include:

- A complete inventory of which existing motors have VFDs.
- The age and type of the VFDs
- A determination of where VFDs may be cost effective including an evaluation of variations of process electrical demands, system efficiencies, etc.
- For those systems where installing VFDs appears to be feasible, a detailed cost estimate should be done including obtaining equipment quotes.

ALTERNATIVE 44

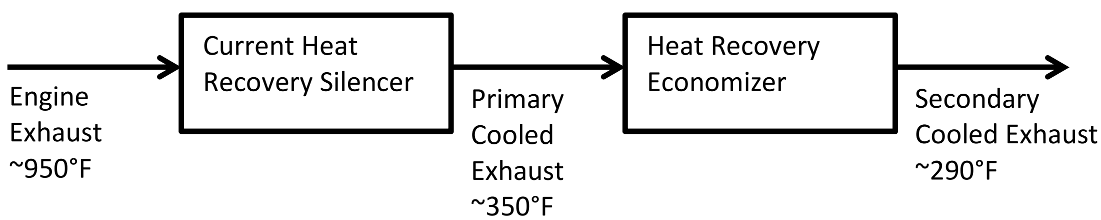
Send Excess Heat to Nearby Industries, Commercial Buildings, and Residences

Alternative Description

The South Shore WRF spends about $77,000 a month on average purchasing natural gas to operate boilers to supplement the heat output of the biogas-fired engine generators. The heat can be used to heat the digesters and for building heating. The natural gas boilers operate year-round, so any improvement in engine heat recovery can be used to offset natural gas purchases. There are five engine generators (four Caterpillar and one White Superior), that can operate on either natural gas or digester gas. Typically two to three engines operate continuously. Roughly 30 to 40 percent of the total input energy is converted into electricity by the engine generators. The remaining 60 to 70 percent of the energy input is converted into heat in the engine exhaust. According to the South Shore WRF O&M Manual, roughly 36 percent is recoverable.

Heat is captured from the engine jacket water, lube oil, and engine exhaust by the Heating Water Supply (HWS) and Cooling Water Supply (CWS). The captured heat is used to heat the digesters, and in winter it is also used to heat buildings. Additional heat can be recovered from the exhaust leaving the heat recovery silencers. The temperature entering the engine heat recovery silencer is ~950°F; it exits at about 350°F. With the installation of a heat recovery economizer, additional heat can be recovered by capturing some of the remaining heat and decreasing the exhaust temperature to 290°F. (Exhibit 44-1). Temperatures below 290°F are generally not recommended, because they can cause acid gas condensation to form in the exhaust piping and heat recovery silencer, resulting in corrosion. If this alternative is implemented, the existing heat recovery units should be inspected to see if cleaning is required, because scale deposits will decrease the heat recovery.

EXHIBIT 44-1
Process Flow Diagram of Additional Heat Captured



The additional heat recovered by the economizer would be used to preheat the water in the HWS before it enters the boilers, which would decrease the amount of natural gas needed for the boilers. If plant biogas production is increased by increasing industrial/commercial waste co-digestion or other means, then additional electricity and heat would be generated. The additional heat and energy could result in the South Shore WRF having more energy than the plant requires and that excess heat that could be sent to a nearby industry.

When looking for nearby industries, ideally the South Shore WRF would like to a find an industry that requires heat continuously. The industry must be relatively close to the South Shore WRF to avoid significant heat loss or substantial conveyance piping construction costs. Potential users of the energy are shown in Exhibit 44-2. Further investigation would be required to determine if sending energy to these users is feasible. However, the Oak Creek Drinking Water Treatment uses hot water for building heating, CH2M HILL is currently designing an expansion of their plant and Oak Creek staff have indicated that they would be willing to discuss using energy (digester gas or hot water) with MMSD.

Description of Modifications Required

For this example, it was assumed that only the excess heat that could be captured by the economizers would be sent to nearby industries. As noted, if digester gas quantities increase in the future, there could be substantial excess digester gas or engine heat that could be transported to nearby industries. This scenario is considered in Alternative 19.

Ideally, the heat recovery economizers would be installed immediately after the heat recovery silencers to limit heat loss. If the existing layout allows, it would be ideal to connect the exhaust from the heat recovery economizer to the heat silencer exhaust line. If space does not allow, then modifications will have to be made to add an exhaust stack from the heat recovery economizer. A new water line pipeline will have to be buried and insulated to minimize heat loss. The water line will make a loop from the nearby industry to the heat recovery economizers. Pumps, expansion tanks, and other equipment will have to be purchased in order to effectively and efficiently transport heat offsite.

EXHIBIT 44-2

Potential Users of Heat and Power near the South Shore WRP

Photo taken from Google Maps.

1. Mid-America Steel Drum Company; 2. International Production Specialists; 3. Cooper Industries; 4. South Milwaukee Wastewater Treatment Plant; 5. Everbrite; and 6. Oak Creek Drinking Water Treatment Plant.

Estimate of Energy Reduction or Recovery

The amount of additional heat captured from the economizers is shown in the calculations below. The mass flow rate, specific heat and ΔT values used to calculate the recoverable heat were taken from the South Shore WRF final design report.

$$q = \dot{m} \times \mathrm{Cp} \times \Delta\mathrm{T}$$

q = heat flow rate, Btu/hr
$\dot{m}$ = mass flow, lb/hr
Cp = specific heat, Btu /$\mathrm{lb_{mass}}$ - °F
ΔT = the change in the fluid's temperature, as °F (or $T_{outlet} - T_{inlet}$)

$\dot{m}$ = 13,598 lb/hr
Cp = 0.0000002778 MMBtu /$\mathrm{lb_{mass}}$ - °F
ΔT = 57.5 °F (357.5°F - 290°F)

$$q = \frac{13{,}598\ lb}{hr} \times \frac{0.0000002778\ \mathrm{MMBtu}}{\mathrm{lb_{mass}} - {}^\circ\mathrm{F}} \times 67.5\ {}^\circ\mathrm{F} \times \frac{24\ hr}{day}$$

q = 6.12 MMBtu/day for one engine

Xchanger—a Minnesota based Heat Recovery Manufacturer—indicated that a heat recovery economizer would be able to recover a maximum amount of 4.8 MMBtu/day per unit.

$$Required\ Heat\ at\ South\ Shore\ during\ the\ week\ at\ 60°F = 250\ MMBtu/day$$

$$Recovered\ Heat\ at\ South\ Shore\ during\ the\ week = 120\ MMBtu/day$$

$$Additional\ Heat\ Recovered\ from\ 2\ Heat\ Recovery\ Economizers = 9.6\ MMBtu/day$$

$$250\ MMBtu/day - 120\ MMBtu/day = 130\ MMBtu/day\ required\ for\ heating$$

$$130\ MMBtu/day - 9.6\ MMBtu/day = 120.4\ MMBtu/day\ required\ for\ heating$$

Typically, the South Shore WRF runs two to three engine generators continuously; therefore, an additional 9.6 MMBtu/day could be captured as usable heat when two engine generators are in operation. The South Shore WRF typically recovers 120 MMBtu/day during the week and 140 MMBtu/day on the weekend (Exhibit 44-3) If heat recovery economizers are installed and the additional heat captured is integrated back into the South Shore WRF HWS, then the natural gas boiler loads (South Shore WRF heat demand) would potentially be 9.6 MMBtu/day less.

EXHIBIT 44-3
South Shore WRF Heating Requirements

Ambient Air Temperature, °F	Heat Required, (MMBtu/day)	Heat Recovered (MMBtu/day)		Natural Gas Boiler Load (MMBtu/day)	
		Weekday	Weekend	Weekday	Weekend
90	184	120	140	64	44
80	196			76	56
70	209			89	69
60	250			130	110
50	296			176	156
40	341			221	201
30	387			267	247
20	432			312	292
10	478			358	338
0	523			403	383
-10	569			449	429

Note: Values taken from MMSD SSWRF Energy Management Tools

Cost Estimate

Exhibit 44-4 is the cost estimate for Alternative 44. It can be seen that the capital cost for a pipeline to transport the heat is high. Conveyance of excess heat will constitute most of the cost for the alternative. Rather than transport the additional captured heat from the economizer offsite, the heat could be used at the South Shore WRF. It can be seen that using heat onsite is much more cost-effective than transporting heat offsite. However, if a future expanded co-digestion program or other means of digester gas production were implemented, excess heat may be available, and then offsite usage would become more cost-effective.

EXHIBIT 44-4
Cost Estimate for Alternative 44

	Captured Heat to Nearby Industry		Use Heat Onsite	
Capital Costs				
Secondary heat recovery units		$100,000		$100,000
Trenching and piping		$2,100,000		—
Expansion tank		$5,000		$5,000
Additional pumps		$10,000		$10,000
Building (new or rehab)		$100,000		—
Installation (30% of equipment)		$693,000		$33,000
Subtotal—Project Cost		*$3,008,000*		*$148,000*
Markups				
Site, piping, electrical, I&C, demolition, etc.	20%	$601,600	20%	$29,600
Subtotal		*$3,609,600*		*$177,600*
Contingency	25%	$902,400	25%	$44,400
Subtotal		*$4,512,000*		$222,000
Contractor mobilization, bonds, and insurance	20%	$902,400	20%	$44,400
Subtotal		*$5,414,400*		*$266,400*
Subtotal with Markups		*$5,414,400*		*$266,400*
Total Construction Cost		$5,414,400		$266,400
Non-Construction Costs				
Engineering/Administration	18%	$974,592	18%	$47,952
Subtotal—Non-Construction Costs		*$6,388,992*		*$314,352*
Total Capital Cost (2014 dollars)		**$6,388,992**		**$314,352**
O&M Costs (using 2014 average loads)		**Annual Cost**		**Annual Cost**
Additional O&M labor (2% of new construction)		$108,000		$5,000
Additional maintenance—Parts (1% of new equipment)		$30,000		$1,000
Natural gas fuel savings		-$21,000		-$21,000
Total O&M Costs (2014)		**$117,000**		**-$15,000**

ALTERNATIVE 64

Install High-Efficiency Motors for Pumps, Fans, and Other Equipment at Jones Island WRF

Alternative Description

Most of MMSD's electrical energy use is for motor-driven loads associated with pumping, process, and HVAC. Premium efficiency motor standards have been updated, and the use of premium efficiency motors can reduce energy consumption by 1 to 2.5 percent compared to standard motors and by 0.5 percent compared to what were up until recently were considered "high efficiency" motors. The Energy Independence and Security Act of 2007 (EISA), which took effect in 2010, essentially requires NEMA premium efficiency motors.

MMSD has already proceeded with evaluating this alternative in areas of need or of high priority. It was included in the Energy Plan in an effort to comprehensively summarize energy producing or energy conserving options available to the District.

Description of Modifications Required

Replacing older, relatively efficient yet functional motors are functional may not be cost-effective in some cases, because the new motor cost would be high compared the relatively small reduction in energy. However, procedures should be implemented that ensure that all motors for new and replacement equipment be specified to be premium efficiency. The District likely rewinds some failed motors instead of replacing them, because the cost is lower in some cases, especially for larger motors. Before motors are rewound, an evaluation should be done that compares energy savings and new versus rewound motors.

Estimate of Energy Reduction and Cost

The District's facilities have many motors with a total connected load of likely greater than 15,000 hp. An evaluation of replacing all of the District's motors is beyond the scope of this project. However, two examples of the potential energy savings are shown below.

Example 1
Replace one 200 hp, 20- to 30-year-old motor with premium efficiency motor
Energy reduction: ~1.2 percent or about 2.4 hp
Energy cost savings: ~$1,200 per year @ $0.075/kWh with continuous motor operation
Installed cost of motor: ~$15,000
Simple payback: ~12.5 years

Example 2
Replace one 20 hp, 20- to 30-year-old motor with premium efficiency motor
Energy reduction: ~2 percent or about 0.4 hp
Energy cost savings: ~$200 per year @ $0.075/kWh with continuous motor operation
Installed cost of motor: ~ $1,500
Simple payback: ~7.5 years

For the purpose of comparison to other alternatives, it was assumed that the simple payback would average about 10 years, and that multiple motors with a total power draw of 2,700 hp would be replaced at a cost of about $200,000. A detailed evaluation of the many motors at the plant is beyond the scope of this project, but this simple exercise is useful to illustrate the relative, order-of-magnitude cost-effectiveness potential of this alternative.

ALTERNATIVE 73

Increase Natural Light in Buildings

Alternative Description

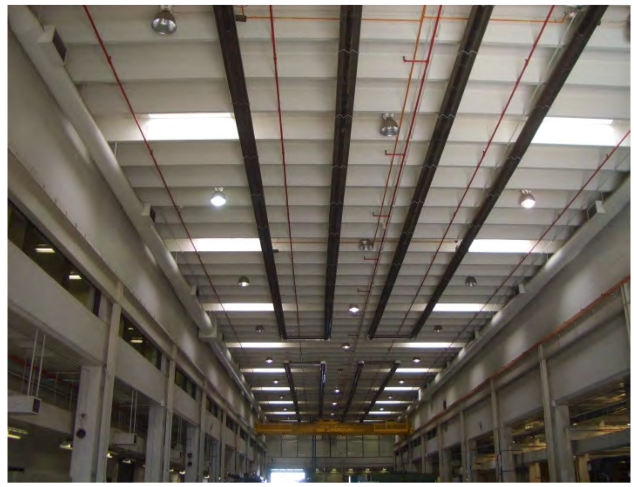
Natural lighting has been shown to have significant potential for energy savings. A walk-through of the Jones Island WRF showed that the plant already makes extensive use of windows and skylights for natural lighting.

Description of Modifications Required

Jones Island WRF

In many cases, the natural lighting alone at the Jones Island and South Shore WRFs is sufficient for walking traffic, but the overhead lights are still turned on. A prime example is the aeration tank galleries, which has numerous windows. Methods to reduce lighting energy in these areas are addressed in Alternative 18.

Natural light at South Shore WRF.



Natural light used at Jones Island WRF Maintenance Building.

Some areas that had a lack of natural lighting have building structural issues that would make additional windows or skylights difficult and expensive to install. Another issue regarding adding more skylights in the process areas is that the ceilings are high there, making natural lighting much less effective.

Cost Estimates

Natural lighting could be increased in several areas of the plant but for the reasons noted above, which could be cost-prohibitive. The cost of adding more natural lighting is highly dependent upon several variables and would vary depending on the building area. See Alternative 18 for a discussion of costs to reduce lighting energy.

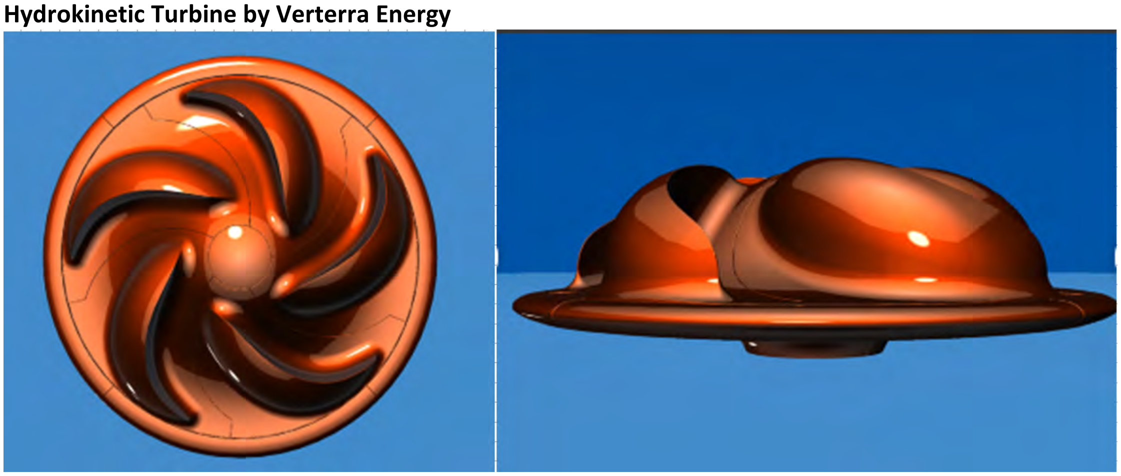
ALTERNATIVE 78

Large-Scale Hydrokinetic Turbines/Micro-Hydropower

Alternative Description

This alternative involves recovery of the hydraulic energy captured from plant effluent flow by means of a hydrokinetic turbine. A hydrokinetic turbine has a rotating element or runner that is attached to a power generator. The assembly typically is either in a floating arrangement, anchored to the floor of an effluent channel (see Exhibit 78-1), or contained in a pipe. The hydroturbine is operated by the flow from the treated effluent water before it is discharged to Lake Michigan. The effluent would be diverted from the outfall pipeline to pass through a turbine-generator unit before flowing into the lake. An in-pipe turbine, which has been used in potable water systems, could also be used.

EXHIBIT 78-1
Hydrokinetic Turbine by Verterra Energy



Description of Modifications Required

The hydrokinetic turbine would be operated roughly 7 months of the year. The remainder of the year, the effluent head would not be enough to justify operating the turbine because of high lake levels. Piping at least 72 inches in diameter and about 40 feet long would be installed parallel to the effluent channel to house the turbine. Effluent would bypass the turbine when it is not operational or during periods of high lake levels. Isolation valves could operate automatically based on lake level. If this alternative were to be refined further, other locations for capturing hydro energy could be evaluated.

EXHIBIT 78-2
Hydrokinetic Turbine and Bypass Piping

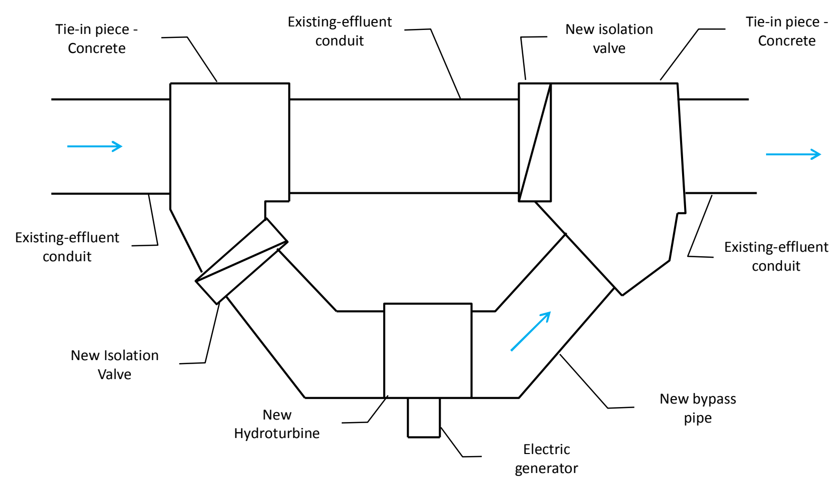


Exhibit 78-2 shows the possible location of the hydrokinetic turbine and the bypass piping.

Estimate of Energy Reduction or Recovery

Exhibit 78-3 shows the amount of electrical energy that could be produced by the hydroturbine, based on the available head between effluent water level and the Lake Michigan surface elevation. The estimate is based on the water level of Lake Michigan and the effluent flow in a typical year. The power output would vary, but average about 13 kW.

EXHIBIT 78-3
Hydrokinetic Energy Recovery

Available Head (ft)	Hours per year	Plant Flow (cfs)	Power Output (kW)	Electric Output (kWh)	Electric Value (kWh)	Electric Value
2.00	8.76	123.78	14.68	129	$0.09	$12
1.99	867.24	124.81	14.72	12,770	$0.09	$1,149
1.95	876	173.80	20.06	17,571	$0.09	$1,581
1.94	876	143.12	16.49	14,444	$0.09	$1,300
1.86	876	99.02	10.90	9,548	$0.09	$859
1.60	876	202.68	19.18	16,804	$0.09	$1,512
1.59	876	123.00	11.57	10,134	$0.09	$912
1.35	701	107.53	8.62	6,046	$0.11	$665
1.33	701	130.74	10.33	7,242	$0.11	$797
1.16	701	153.17	10.50	7,360	$0.11	$810
1.13	701	129.19	8.68	6,082	$0.11	$669
1.07	701	115.27	7.31	5,123	$0.11	$564
	8,761			113,251		$10,830

Cost Estimate

Exhibit 78-4 presents the estimated cost to implement the alternative.

EXHIBIT 78-4
Cost Estimate for Alternative 78

Capital Costs		
Hydrokinetic turbine		$250,000
Generator		$10,000
Concrete work		$200,000
72-inch reinforced concrete pipe	40 ft	$12,840
72-inch 45° bend	2 each	$15,000
Isolation valve	1 each	$25,000
Temporary bypass		$250,000
Electrical conduit, cables, etc.		$200,000
Installation (30% of equipment)		$141,852
Subtotal—Project Cost		*$1,104,692*
Markups		
Site, piping, electrical, I&C, demolition, etc.	23%	$254,079
Subtotal		*$1,358,771*
Contingency	25%	$339,693
Subtotal		*$1,698,464*
Contractor mobilization, bonds, and insurance	20%	$339,693
Subtotal		*$2,038,157*
Subtotal with Markups		*$2,038,157*
Total Construction Cost		$2,038,157
Non-Construction Costs		
Engineering/administration	18%	$366,868
Subtotal—Non-Construction Costs		*$2,405,025*
Total Capital Cost (2014 dollars)		**$2,405,025**
O&M Costs (using 2014 average loads)		**Annual Cost**
Power savings		-$10,830
Additional O&M labor (1% of new construction)		$20,500
Additional maintenance—Parts (1% of new equipment)		$11,000
Total O&M (2014)		**$20,670**

Alternative Variation—Utilize Head between South Shore WRF Grit Chambers and Primary Clarifiers

A variation of this alternative would be to install a turbine or bank of turbines to capture energy from the head drop between the grit chambers and primary clarifiers at the South Shore WRF. Under average flow conditions, the head drop is about 4.4 ft. Assuming an average annual flow of 90 mgd and full time operation of the turbines, the annual power savings would be about $20,700 at a rate of $0.07/KWH. The capital cost of installation and annual O&M cost for the turbine facility would be at least as high at that estimated in Exhibit 78-4 for a facility to recovery energy from the effluent line. With an energy savings of $20,700, there would be a net additional O&M cost for the turbine installation.

ALTERNATIVE 94

Recover Heat from Turbine Cooling Water

This alternative is evaluated under Alternative No. 17.

ALTERNATIVE 95

Increase Jones Island WRF Turbine Landfill Gas Volume

The Jones Island WRF landfill gas turbines provide renewable energy in the form of electrical power and waste heat that is used to dry Milorganite® and provide building heat. There are three turbines each nominally rated at 4.8 MW. Landfill gas is transported in a pipeline from a landfill operated by Advanced Disposal and the volume of landfill gas produced is less than originally anticipated. Improvements are being made that will likely increase the volume of gas. Exhibit 95-1 shows a scenario where all of the Jones Island WRF power would be supplied by the landfill gas turbines and where there would additional, excess landfill gas available to use in the dryers. This would be about a 250 percent increase in available landfill compared to what was available in 2014. The scenario also assumes that the Jones Island average power demand is reduced from the historical approximate 10.5 MW level to 7.8 MW. It is important to note that compared to the baseline when the GE natural gas turbines were operating, the amount of waste heat available from the landfill gas turbines is significantly less because the Solar landfill gas turbines are more efficient.

EXHIBIT 95-1
Turbine Landfill Gas and Power Generation: Jones Island WRF

Landfill Gas Available (MMBtu)		Turbine Power from LFG (MW)	LFG Used in Turbines (MMBTU/HR)	LFG used in dryers (MMBtu/hr)
Per Year	Per Hour			
1,020,000	117	7.8	76	41

Alternatives Evaluated in TM 3

Note: These costs and energy values may vary from Exhibit 5 of the Energy Plan. Alternatives were further refined after TM 3 was finalized.

					Annual Values (Year 1)		Annual Costs (Year 1)					
Alt No.	Alternative Name	Capital Cost	Capital Cost Per Annual Energy Reduction ($/MMBtu)	Energy / Fossil Fuel Reduction: Power (MW)	Non-energy O&M	Energy / Fossil Fuel Reduction: Heat (MMBtu)	Energy Savings	Net Energy and Non-Energy O&M Savings (*Note 1*)	Annual Payment on 20 Yr SRF Loan	Net Annual O&M / Energy Savings Less SRF Loan Payment	Simple Payback (yr)	Include in Plan? (Yes/No)
19a	Maximize South Shore Digestion: No. 1 Base Scenario (Optimized Digestion; No Co-digestate)	$1,473,100	$20	1.00	$107,100	42,048	$865,488	$758,388	$95,839	$662,549	2	No
19b	Maximize South Shore Digestion: HSW Accepted to Meet 4 MW Power Production	$1,473,100	$10	2.20	$212,220	78,840	$1,822,080	$1,609,860	$95,839	$1,514,021	1	Yes
95	Increase Jones Island Turbine Landfill Gas Volume (2018 Contracted Advanced Disposal)	$0	$0	5.50	$529,980	204,108	$1,790,211	$1,260,231	$0	$1,260,231	0	Yes
25	Implement South Shore Aeration Control Using DO and Ammonia/Nitrate Probes	$4,400,000	$92	1.61	$83,400	0	$985,600	$902,200	$286,262	$615,938	5	Yes
34	Change Channel Mixing to Large Bubble Mixers	$8,346,000	$168	1.66	$34,900	0	$1,018,700	$983,800	$542,987	$440,813	8	Yes
15a	Improve Primary Clarifier Operations/Removal Efficiency: Optimize Primary Treatment at Jones Island	$0	$0	0.35	$183,960	18,833	$328,000	$144,040	$0	$144,040	0	Yes
41	Install Variable Frequency Drives for Pumps, Fans, and Other Equipment	$540,000	$30	0.60	$5,400	0	$367,920	$362,520	$35,132	$327,388	1	Yes
11	Decrease Activated Sludge SRT	$0	$0	0.60	$0	21,809	$867,478	$867,478	$0	$867,478	0	Yes
12	Increase Belt Press Feed Solids Concentration to Increase Cake Solids	$851,300	$13	0.00	$104,000	64,033	$384,200	$280,200	$55,385	$224,815	3	Yes
16	Heat Sludge and Polymer Solution to Improve Cake Solids	$1,428,000	$22	0.00	$31,000	64,035	$384,211	$353,211	$92,905	$260,306	4	No
2	Optimize Influent Flow Split Between Plants	$0	$0	0.52	$94,200	0	$317,420	$223,220	$0	$223,220	0	Yes
15b	Improve Primary Clarifier Operations/Removal Efficiency: Primary Clarifier Inlet Baffling at South Shore	$1,220,000	$66	0.24	$0	11,467	$213,800	$213,800	$79,373	$134,427	6	Yes
24	Implement Jones Island Aeration Control Using DO and Ammonia/Nitrate Probes	$5,002,000	$172	0.97	$86,400	0	$597,800	$511,400	$325,428	$185,972	10	Yes
1	Optimize Biosolids Transfer between Plants for Energy Generation and Use	$0	$0	0.42	$78,200	0	$258,000	$179,800	$0	$179,800	0	No
8	Modify/Optimize Activated Sludge Process for Energy	$0	$0	0.22	$0	0	$135,395	$135,395	$0	$135,395	0	Yes
9b	Optimize Waste Heat Pressure Control With Dryer Control Modifications	$1,656,700	$44	0.00	$0	37,600	$225,600	$225,600	$107,784	$117,816	7	Yes
9a	Optimize Waste Heat Pressure Control With Waste Heat Boiler Damper	$27,600	$1	0.00	$0	18,667	$112,000	$112,000	$1,796	$110,204	0	Yes
10	Increase SRT to Reduce Solids Processing Energy	$0	$0	0.01	$0	23,214	$145,284	$145,284	$0	$145,284	0	No
22	Recover Heat from Dryer Exhaust	$1,588,000	$48	0.00	$20,500	32,883	$197,300	$176,800	$103,315	$73,485	9	Yes
6	Optimize Pumping Energy Using PLC Logic (RAS/WAS Pumps)	$20,000	$22	0.03	$200	0	$18,400	$18,200	$1,301	$16,899	1	Yes
5b	Decrease Number of Idle Aeration Basins Online at South Shore	$0	$0	0.12	$16,000	0	$75,071	$59,071	$0	$59,071	0	Yes
14	Automate Real-Time Energy Optimization Control and Monitoring (One Percent Energy Reduction)	$968,000	$53	0.14	$7,500	14,000	$108,000	$100,500	$62,978	$37,522	10	Yes
18	Install High-Efficiency Plant Lighting	$322,800	N/A	0.06	-$15,000	0	$36,670	$51,670	$21,001	$30,669	6	Yes
44b	Send Excess Heat to Nearby Industries, Commercial Buildings, and Residences: Use Heat Onsite	$314,400	$90	0.00	$6,000	3,500	$21,000	$15,000	$20,455	($5,455)	21	No
4	Bypass Jones Island High-Level Screw Pumps	$407,780	$1,195	0.01	$2,000	0	$7,000	$5,000	$26,530	($21,530)	82	No
31	Large-Scale Effluent Heat Recovery Using Heat Pumps	$905,000	$70	0.00	$48,468	12,852	$77,110	$28,642	$58,879	($30,237)	32	No
23	Capture More Waste Heat from Internal Combustion Engines	$1,047,000	$299	0.00	$13,000	3,500	$21,000	$8,000	$68,117	($60,117)	131	No
13b	Improve Plantwide HVAC Control at South Shore	$1,380,600	$568	0.00	$0	2,350	$15,700	$15,700	$89,821	($74,121)	88	No
20	Solar Power Electricity Generation (1-MW Capacity, 5 Acres)	$2,700,000	$609	0.15	$27,000	0	$91,000	$64,000	$175,661	($111,661)	42	No
13a	Improve Plantwide HVAC Control at Jones Island	$2,116,900	$540	0.01	$0	3,750	$26,000	$26,000	$137,725	($111,725)	81	No
29	Implement South Shore Renewable Energy Powered UV Disinfection for 100 mgd Base Flow	$8,850,000	N/A	0.00	-$256,000	0	$0	$256,000	$575,777	($319,777)	35	No
21	Wind Energy Generation (One, 3-MW Turbine at SS and JI)	$18,224,000	$381	1.60	$164,000	0	$982,500	$818,500	$1,185,645	($367,145)	22	No
5a	Decrease Number of Idle Aeration Basins Online at Jones Island	$6,889,500	$1,883	0.12	$16,000	0	$75,071	$59,071	$448,228	($389,157)	117	No
3	Purchase More Green Energy from We Energies	$0	N/A	0.00	$0	0	$0	$0	$0	$0	NO PAYBACK	No
17	Use Waste Heat to Heat Biological Process at Jones Island	$0	N/A	0.00	$0	0	$0	$0	$0	$0	NO PAYBACK	No
78	Large-Scale Hydrokinetic Turbines/Micro-Hydropower	$2,405,000	$4,556	0.02	$31,500	0	$10,830	-$20,670	$156,468	($177,138)	NO PAYBACK	No
44a	Send Excess Heat to Nearby Industries, Commercial Buildings, and Residences: Captured Heat to Nearby Industry	$6,389,000	$1,825	0.00	$138,000	3,500	$21,000	-$117,000	$415,665	($532,665)	NO PAYBACK	No
64	Install High-Efficiency Motors for Pumps, Fans, and Other Equipment	$200,000	$166	0.04	$2,000	0	$24,693	$22,693	$13,012	$9,681	9	No
7	Use CEPT to Reduce Aeration Energy and Increase Primary Sludge/Digester Gas	$45,800,000	$612	1.44	$5,982,000	31,667	$1,075,000	-$4,907,000	$2,979,728	($7,886,728)	NO PAYBACK	No
94	Recover Heat from Turbine Cooling Water. *Evaluated under Alternative 17.*											No
73	Increase Natural Light in Buildings. *Not evaluated; see text.*											No
26	Install Turbine Waste Heat Landfill Gas Duct Burners. *Awaiting results of CH2M HILL study.*											No
36	Increase Use of Waste Heat from Internal Combustion Engines. *Combined with Alternative 23.*											No

2014 Estimated Greenhouse Gas Emission Reduction for Landfill Gas Turbines

PREPARED FOR: Karen Sands/Milwaukee Metropolitan Sewerage District

COPY TO: Steve Graziano/CH2M HILL

PREPARED BY: Erin Laude/CH2M HILL

REVIEWED BY: Bill Desing/CH2M HILL

DATE: October 2, 2014

PROJECT NUMBER: MMSD Contract M030721P01; MMSD File Code: P6150

Greenhouse Gas Emissions

As part of the MMSD Energy Plan Project, MMSD requested that CH2M HILL estimate the reduction in greenhouse gas emissions due to the operation of the new Jones Island landfill gas turbines. This memorandum describes the assumptions used to estimate the greenhouse gas emission reduction for 2014. Three scenarios were evaluated as follows:

1) Baseline: GE turbines on natural gas

2) Operating Solar turbines with 55% of 2014 contracted amount of landfill gas

3) Operating Solar turbines with 100% of 2014 contracted amount of landfill gas

The emissions generated by scenarios 2 and 3 were both compared to the baseline emission to calculated the greenhouse gas emission reduction.

The energy consumption is based on operating the turbines to produce 10.25 MW of electricity and operating the dryers using all available waste heat from the turbines to dry 155 dry tons per day of solids (the 2013 actual dried solids). Assumptions for each scenario are summarized in Table 1.

TABLE 1
Jones Island 2014 Projected Energy Consumption
Energy Plan

	Baseline	55% Landfill Gas	100% Landfill Gas
Electricity Generated (MMBtu/yr) [a]	306,363	306,363	306,363
Turbine Efficiency [b]	18.5%	34.0%	34.0%
Energy required to generate electricity (MMBtu/yr)	1,653,800	901,069	901,069
Landfill gas available (MMBtu/yr)	0	379,722	690,404
Natural gas necessary to make up difference (MMBtu/yr)	1,653,800	521,347	210,665
Total waste heat generated (Energy required – electricity generated)	1,347,437	594,706	594,706
Waste heat lost (%5 stack, 3% mechanical)	107,795	47,576	47,576
Waste heat available (total waste heat – waste heat loss)	1,239,642	547,129	547,129
Dryer Heat Required (MMBtu/yr) [c]	1,033,434	1,033,434	1,033,434
Additional dryer heat necessary, NG (MMBtu/yr)	0	486,305	486,305

[a] 1 kWh = 3412.3 BTU

[b] GE Turbine Efficiency based on GE turbine heat rate curve provided by Lee Lundberg, Veolia Water. Solar turbine efficiency based on 2014 Solar test runs at Jones Island provided by Alan Scrivner.

[c] Dryer heat required based on dryer waste heat needs of 83.9 MMBTU/hr for 110 dry tons provided by Alan Scrivner.

Table 2 summarize the nonbiogenic[1] greenhouse gas emission reduction in terms of the total carbon dioxide equivalent (CO_{2e}) metric tons per year due to energy consumption for generating electricity and drying solids.

TABLE 2
Jones Island 2014 Projected Greenhouse Gas Emissions Savings
Energy Plan

Emission Sources/Fuel Type	Energy Use (MMBTU/yr)[a]	Reportable CO_{2e} Emissions (metric tons/yr) [b,c,d]	CO_{2e} Emission Reduction (metric tons/yr)
Baseline - Operating GE turbines on natural gas. Waste heat from turbines meets 100% of heat needed for dryers.			
Rotary Sludge Dryers, Natural Gas	0	0	
GE Turbines, Natural Gas	1,653,800	87,837	
Total Energy/Emissions	**1,653,800**	**87,837**	
Condition 1 – Operating Solar turbines, using 55% of contracted amount of landfill gas, remainder is natural gas. Waste heat produced from turbines does not meet 100% of heat needed for dryers, additional natural gas is purchased to dry the solids.			
Rotary Sludge Dryers, Natural Gas	486,305	25,829	
Solar Turbines, Natural Gas	521,347	27,690	
Solar Turbines, Landfill Gas	379,722	100	
Total Energy/Emissions/Savings over Baseline	**1,387,374**	**53,618**	**34,219**
Condition 2 - Solar turbines only, using 100% of contracted amount of landfill gas, remainder is natural gas. Waste heat produced from turbines does not meet 100% of heat needed for dryers, additional natural gas is purchased to dry the solids.			
Rotary Sludge Dryers, Natural Gas	486,305	25,829	
Solar Turbines, Natural Gas	210,665	11,189	
Solar Turbines, Landfill Gas	690,404	181	
Total Energy/Emissions/Savings over Baseline	**1,387,374**	**37,199**	**50,638**

[a] Calculated based on 10.25 MW hours of electricity produced annually and 155 dry tons per day of solids processed through the dryers.

[b] Emission factors for natural gas and landfill gas are based on the EPA Mandatory Reporting Rule (Nov 29, 2013).

[c] CO_2 equivalents are calculated by multiplying the global warming potential (GWP) by the CO_2 emissions. The GWP for CO_2 is 1, N_2O is 310 and CH_4 is 21.

[d] Total reportable CO_{2e} emissions exclude CO_2 but include CH_4 and N_2O from landfill gas combustion.

[1] Per USEPA reporting rules, nonbiogenic greenhouse gas emissions exclude CO_2 emissions but include CH_4 and N_2O emissions released from burning biomass, such as digester gas and landfill gas.

Potential Maximum Energy Production

PREPARED FOR:	Karen Sands/MMSD	
PREPARED BY:	Steve Graziano/CH2M HILL	Jaya Jackson/CH2M HILL Bill Desing/CH2M HILL
DATE:	October 6, 2014	
MMSD CONTRACT	M03072P01 (File Code: P6150)	

Introduction and Purpose

As part of the Energy Plan project, CH2M HILL was asked to add to the scope of work a task to estimate the approximate maximum amount of renewable energy that could be produced by the District's two wastewater reclamation facilities. This memorandum summarizes the results of that task. The following are the primary assumptions used in the estimate:

- All the energy readily recoverable from both the biosolids and the liquid wastewater will be "extracted" into a usable form of energy, either electrical power or heat.
- Only equipment and processes that have been proven at other wastewater plants will be used. Technologies still in the developmental stage will not.
- A significant capital investment would be required. (Costs were not estimated as part of this scope.)
- Much of the land space at the water reclamation plants will be used to install wind or solar power. Land space at other MMSD-owned properties, such as collection system pump stations, will not be used.

Summary of Improvements

The following are improvements assumed to be made to maximize renewable energy production:

- Wind turbines will be installed at South Shore and Jones Island.
- Solar panels will be installed at South Shore and Jones Island.
- Nearly the entire capacity of the existing South Shore digesters will be used to co-digest municipal and industrial/commercial wastes to generate electrical power and waste heat in engines.
- Heat will be recovered from the effluent at both Jones Island and South Shore using a large scale system.
- The maximum projected future landfill gas volume produced from the Advanced Disposal and Waste Management landfills will be used to generate electrical power and waste heat from gas turbines at Jones Island.

The following describes the energy sources, assumptions, and results.

Wind Power

Wind power technology is a form of renewable energy generation that uses the wind currents to spin a turbine in order to generate usable energy. The number of turbines that could be installed at Jones Island and South Shore was evaluated. There are two major types of wind turbines: horizontal axis and vertical axis. The horizontal technology is more common and was assumed to be used.

The total installed nameplate capacity of wind turbines in the U.S. was nearly 50 gigawatts as of 2012. There are 17 wind installations in Wisconsin that generate 648 MW. Many manufacturers offer utility-scale (that is, greater than 1 MW) wind turbines for sale in the North American market. The primary considerations for selecting a wind turbine manufacturer are the size of turbine needed to meet generation requirements, cost associated with turbine construction and operation, and availability of manufacturer to provide equipment and spare parts to meet project timeline. Manufacturer offerings vary in size (such as generator rating) and configuration (such as rotor diameter, tower height, and control scheme) to best fit the wind resource characteristics of each site. Turbines rated 500 kW to 1 MW are rare, as major manufacturers have focused on larger machines in recent years. For the maximum renewable energy evaluation, 3 MW turbines were assumed. The wind alternative evaluated in Technical Memorandum 3 provides cost estimates and additional information regarding wind power.

Wind is the most mature and economically feasible of all renewable energy sources. In fact, the industry is finding that in good wind sites, wind energy can compete directly with coal and natural gas on cost of generation. The amount of electricity generated by a wind project is wind speed cubed. Thus, even an incremental increase in wind speed can dramatically change the economics of a project. For this reason, very careful resource measurement and analysis over a period of years is required to accurately determine the viability of a project.

Wind Resource

Speed. The Wind Power Prospector is a mapping and analysis tool designed by the National Renewable Energy Laboratory (NREL) to help site wind projects by providing easy access to wind resource datasets and other relevant data.[1] The data used for energy production estimates consisted of the predicted mean annual wind speeds at 80- and 100-meter heights at a spatial resolution of 2.5 kilometers and interpolated to a finer scale. The wind resource estimates were developed by AWS Truepower, LLC.

The Jones Island and South Shore facilities are good candidates for wind power, because their estimated wind speeds are greater than 6.5 m/s at 80 meters above ground, generally considered the minimum wind speed for an economically feasible utility scale project. Table 1 summarizes average wind speed values for 80 and 100 meters. As shown in the wind speed map in Figure 1, wind speeds increase farther east. Thus the South Shore location has incrementally better wind speeds than Jones Island. Further investigations at each site is warranted based on this preliminary data. The presence of microclimates at one site or both, too small to be modeled at the 2.5-kilometer resolution of the AWS model, could cause conditions to differ considerably from those shown on the wind map.

TABLE 1
Estimated Annual Average Wind Speeds

	Jones Island	South Shore
Latitude	43.021951°	42.888043°
Longitude	-87.899541°	-87.848282°
NREL 80 meters	6.5–7.0 m/s	7.0–7.5 m/s
NREL 100 meters	7.0–7.5 m/s	7.0–7.5 m/s

Source: NREL Wind Power Prospector
m/s meters per second

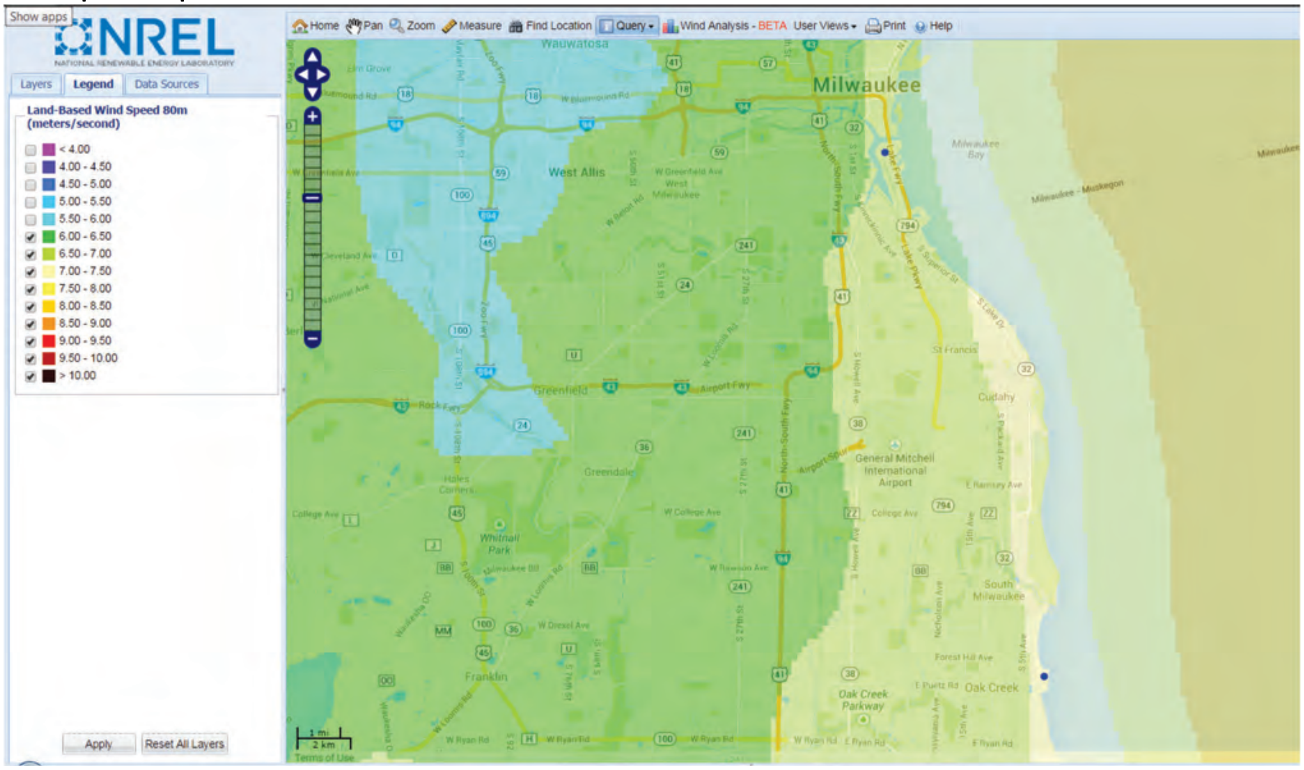
Although wind speed generally increases with height, the range given for the South Shore location is the same at both 80 and 100 meters above ground. The likelihood is that the 80-meter height would be at the bottom of the range and the 100-meter height near the top. The difference in the ranges between Jones Island and South Shore is mostly an artifact of the model and should not be construed as being vastly different.

Wind Direction. The monthly wind roses from the USDA's NRCS (National Resources Conservation Service show a multimodal wind regime not dominated by any particular direction (Figure 2). This type of regime generally requires larger spacing between machines to minimize turbulence. Typical spacing is 3 to 5 rotor diameters. Thus, for a turbine with a rotor diameter of 80 meters, spacing should be 240 to 400 meters. This spacing requirement, along with State of Wisconsin siting requirements and available space, limit the number of turbines that can be installed at Jones Island and South Shore. Determination of the actual number of turbines that could be installed requires further, detailed analysis of wind conditions and the site.

Table 2 lists additional monthly wind resource data for Milwaukee.

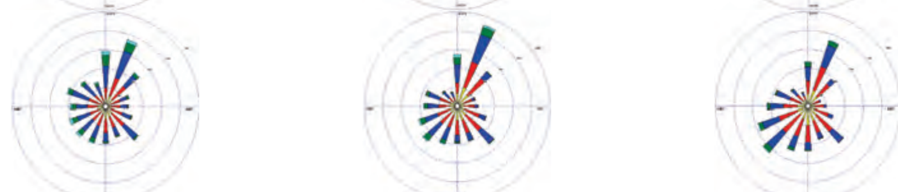
[1] http://maps.nrel.gov/wind_prospector

FIGURE 1
Wind Speed Map



Source: NREL Wind Power Prospector.

FIGURE 2
Monthly Wind Rose Plots for Milwaukee

Period	Wind Roses
January–March	
April–June	
July–September	
October–December	

From USDA's NRCS.

TABLE 2
Monthly Winds at Milwaukee

Month	Average Speed	Prevailing Wind	Calm	Peak Gust	Record Gust	Year of Record Gust
January	12.5	WNW-12.8	1.3	47	SW-66	1975
February	12.3	WNW-12.4	1.8	43.7	W-67	1971
March	12.8	WNW-12.7	2	48.4	SW-77	1991
April	12.7	NNE-13.9	2.1	49.8	W-67	1979
May	11.5	NNE-13.2	2.4	47.8	SW-74	1974
June	10.4	NNE-11.3	2.2	50.1	W-76	1971
July	9.7	SW-10.8	3.2	49.2	NW-81	1984
August	9.4	SW-10.4	3.2	45.2	NW-64	1989
September	10.4	SSW-11.0	2.8	44.6	NW-62	1980
October	11.4	SSW-12.1	2.5	43.4	NW-53	1990
November	12.3	WNW-13.1	1.8	46.6	SW-56 NW-56	1988 1989
December	12.3	WNW-12.4	1.4	47.3	N-61	1979
Annual	**11.4**	**WNW-10.9**	**2.2**	**63**	**NW-81**	**July 1984**

Source: http://www.aos.wisc.edu/~sco/clim-history/stations/mke/milwind.html

Note: Elevation: 676 ft above sea level. Anemometer height: 20 ft; period of record: 1948–1990 (average winds), 1970–1993 (gusts)

Description of Siting Modifications Required

Unlike most power plants, wind generation projects are land intrusive rather than land intensive. Land use strategies associated with the development of wind generation sites include the use of "buffer zones" or setbacks to separate wind projects from potentially sensitive or incompatible land uses. Sensitive receptors include hospitals, schools, churches, public roads, public parking, residential areas, and power lines. Table 3 summarizes of the siting guidance from Wisconsin Public Service Commission Chapter 128—Wind Energy Systems as it pertains to adequate setbacks from nonparticipating property lines, public roads, commercial buildings, public parking, power lines, and residences. The blade tip height is about 100 meters for a 1.5 MW turbine and 125 meters for a 3.0 MW turbine, meaning that turbines generally must be located about 110 to 140 meters away from property lines, rights-of-way, and so on.

The following areas of potential impact from a wind project that should be considered during planning:

- The human environment (visual impact, shadow flicker, sound, highways and local traffic, aviation, electromagnetic interference, and health and safety),
- Social, community, and cultural aspects (socioeconomic, recreation, cultural heritage, and archaeological and paleontological resources)
- The physical environment (soil erosion)
- The natural environment (biodiversity)
- Decommissioning and reinstatement of the site

TABLE 3
Siting Criteria: Setback Distances

Setback Description	Setback Distance
Occupied community buildings	The lesser of 1,250 feet or 3.1 times the maximum blade tip height
Participating residences	1.1 times the maximum blade tip height
Nonparticipating residences	The lesser of 1,250 feet or 3.1 times the maximum blade tip height
Participating property lines	None
Nonparticipating property lines	1.1 times the maximum blade tip height
Overhead communication and electric transmission or distribution lines, not including utility service lines to individual houses or outbuildings	1.1 times the maximum blade tip height
Overhead utility service lines to individual houses or outbuildings	None
Public road right–of–way	1.1 times the maximum blade tip height

Source: Wisconsin Public Service Commission Chapter 128—Wind Energy Systems

Estimate of Wind Power Energy Production

Based on the ranges provided by the NREL Wind Prospector, a preliminary model was developed to examine the potential wind energy production at each of the sites. The net annual energy production assumes a gross to net reduction of 15 percent loss and is measured in megawatt hours per megawatt of installed nameplate capacity. The output for an 80-meter hub height turbine is roughly 3,000 MWh/MW per year at Jones Island and 3,300 MWh/MW per year at South Shore. This means that a 1 MW turbine would on an annual average produce about 0.23 to 0.25 MW of power. Table 4 summarizes estimated wind energy production for both sites.

TABLE 4
Estimated Net Annual Energy Production

	Jones Island (MWh/MW per yr)	South Shore (MWh/MW per yr)
NREL 80 minimum	2,819	3,174
NREL 80 maximum	3,174	3,502
NREL 100 minimum	3,174	3,174
NREL 100 maximum	3,502	3,502

Source: CH2M HILL Wind Energy Production Model

Wind Turbine Locations

Figures 3 and 4 show potential locations for wind turbines for Jones Island and South Shore (see following pages). Table 5 lists the estimated installed and generation capacity. These indicate the approximate, preliminary maximum number of turbines that could installed given the required turbine spacing, setback distances, and available space.
A detailed study would be required to determine the actual number of turbines that could installed. The number of turbines that could be installed likely will vary from what is shown.

TABLE 5
Wind Turbine Power Summary

	Jones Island	South Shore
Number of wind turbines	3	3
Nominal capacity of each wind turbine, MW	3	3
Total installed capacity, MW	9	9
Average annual power generation rate, MW	2.1	2.3
Annual estimated power generated, MWh	18,400	20,100

FIGURE 3
Potential Wind Turbine Locations: South Shore

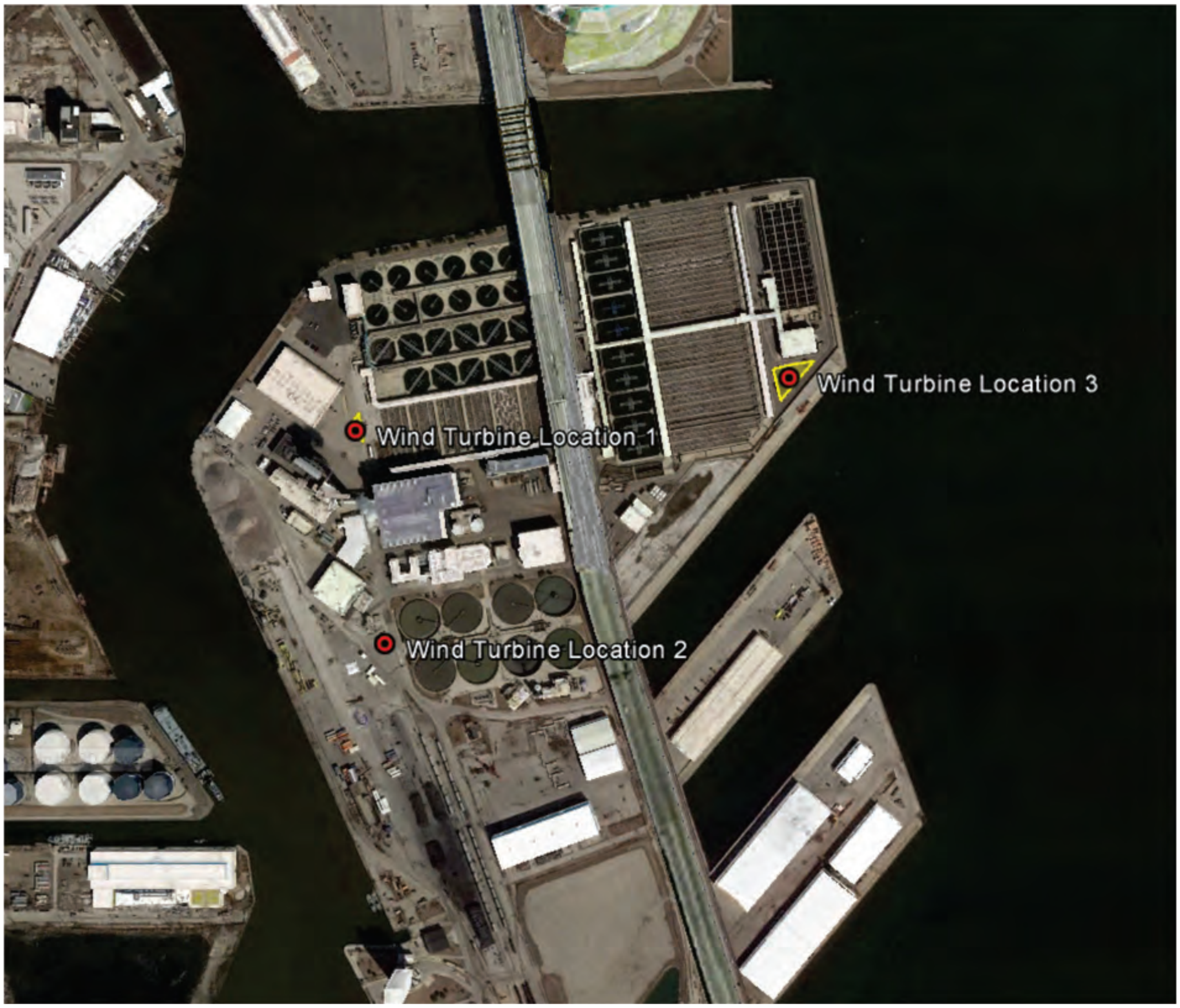
Solar Power

An evaluation was done to estimate energy generation from solar photovoltaic (PV) power systems. It was assumed that solar panels will be installed on virtually all available open land areas, parking lots, and rooftops. This evaluation summarizes solar PV technologies and the assumptions used in the assessment, and describes the solar resource and the estimated generating capacity at the facility. Technical Memorandum 3 will contain additional detail and cost estimates.

This assessment considers solar PV technologies that can be used to generate electricity to offset usage from We Energies. A PV system generally consists of PV modules (flat plate solar collectors consisting of a semiconducting substance that generates DC electricity in the presence of sunlight), racking system (for mounting on a rooftop or installed in the ground, tilted at an angle to optimize the amount of sunlight striking the surface of the module, or laid flat/horizontally), power conditioning equipment (to convert the DC electricity generated by the PV modules into AC electricity for use by the facilities electric loads), and grid integration equipment (to match the power quality of the electric utility). The following assumptions were used in this assessment:

- No battery systems are considered.
- The system is grid-connected only. (When the grid is down, energy from the PV system will not be delivered to the facility for safety purposes.)

FIGURE 4
Potential Wind Turbine Locations: Jones Island



- Energy generation estimates are based on a modeling tool developed by the National Renewable Energy Laboratories, PVWatts. This tool uses solar resource weather data for Milwaukee that is typical or representative of long-term averages.

Solar Resource

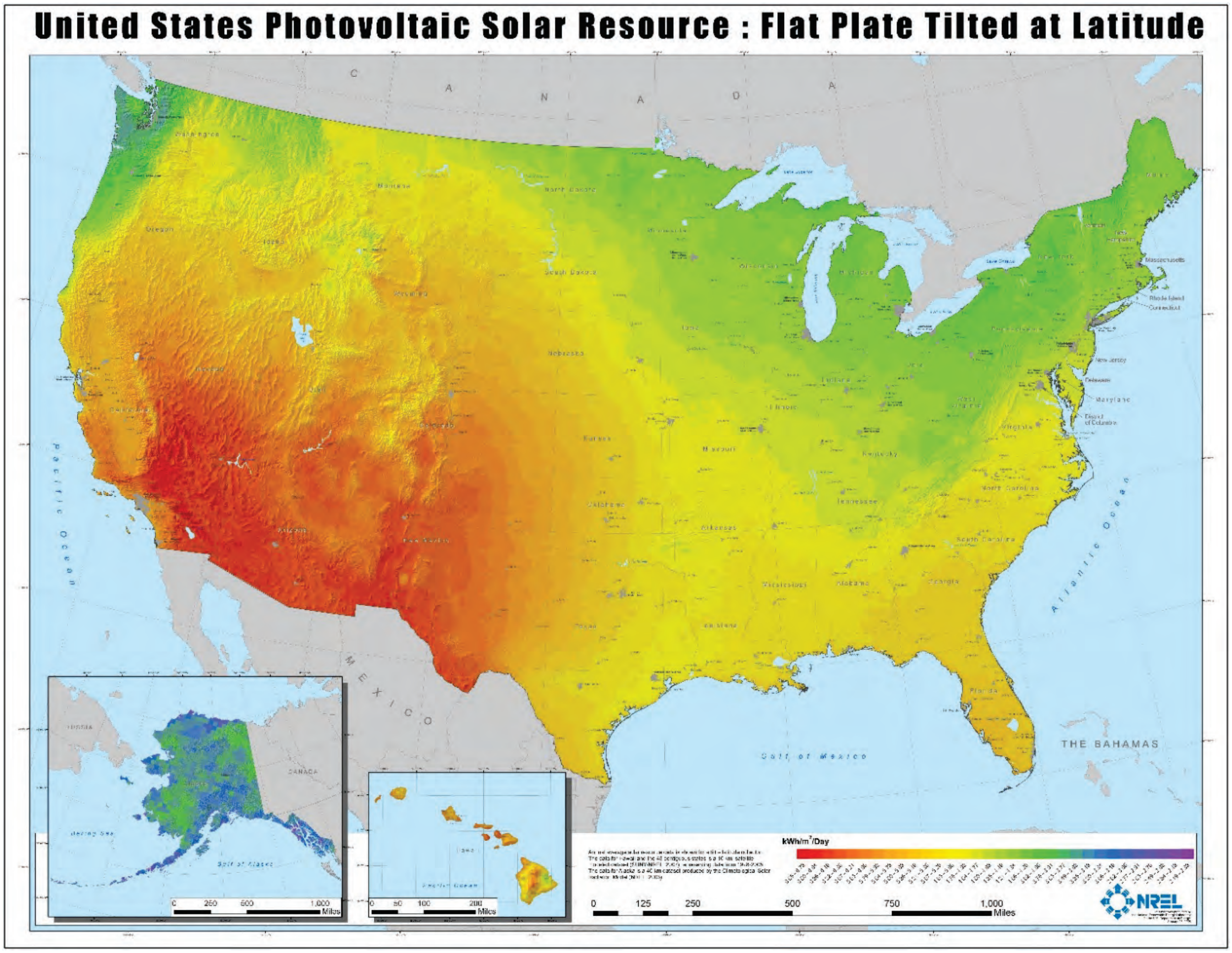
PV performance is largely proportional to the amount of solar radiation received, which may vary from the long-term average by ± 30 percent for monthly values and ± 10 percent for yearly values. Typical year solar resource data use a single year's worth of hourly data to represent solar radiation and meteorological data collected over a historical period of multiple years. Typical year data are appropriate for PVWatts economic analysis, because it uses an hourly simulation over a single year to predict the system's average monthly and annual output over a 25-year system life. Each typical year file contains months of data selected from different years in the data collection period. For example, data for a given site might contain 1995 data for the month of February, 2001 data for March, 1998 data for April, etc.

Typical year data based on data collected over a longer period are more representative than data developed from a shorter period.[2] The solar resource data used in this assessment are based on typical weather patterns measured at General Mitchell International Airport.

[2] PVWatts Cautions for Interpreting the Results, National Renewable Energy Laboratories http://rredc.nrel.gov/solar/calculators/pvwatts/interp.html last accessed September 26, 2014.

Figure 5 depicts the insolation values of the solar resource available to a flat plate collector, such as a photovoltaic panel, oriented due south at an angle from horizontal to equal to the latitude of the collector location. For the Milwaukee region, the map indicates that the amount of solar insolation available is roughly 3.5 to 4 kWh/m^2 per day.

FIGURE 5
Average Solar Insolation kWh/m^2 per day



Locations Considered

Figure 6 depicts the areas included in determining the maximum generating capacity. The areas are numbered and color-coded as follows:

- Green—ground-mounted (areas 1 through 7)
- Blue—parking canopy (areas 8 through 11)
- Red—roof-mounted (areas 12 through 41)

Based on these assumptions and methodology, the maximum PV capacity at the MMSD is 11.5 MW_{DC}. Table 7 summarizes each area, the method of estimation and the individual PV system capacity.

FIGURE 6

Maximum PV Power Generation: Site Locations Considered

FIGURE 7
Maximum PV Power Generation: Ground and Parking Locations Considered

TABLE 7
Estimated PV Power Capacity per Location

Location #	Description	Capacity (kW_{DC})	Location #	Description	Capacity (kW_{DC})
Solar Site 1	Ground mounted	1,782	Solar Site 22	Roof mounted	10
Solar Site 2	Ground mounted	1,944	Solar Site 23	Roof mounted	8
Solar Site 3	Ground mounted	963	Solar Site 24	Roof mounted	4
Solar Site 4	Ground mounted	1,800	Solar Site 25	Roof mounted	4
Solar Site 5	Ground mounted	2,016	Solar Site 26	Roof mounted	8
Solar Site 6	Ground mounted	270	Solar Site 27	Roof mounted	10
Solar Site 7	Ground mounted	675	Solar Site 28	Roof mounted	52
Solar Site 8	Parking canopy	192	Solar Site 29	Roof mounted	83
Solar Site 9	Parking canopy	53	Solar Site 30	Roof mounted	60
Solar Site 10	Parking canopy	35	Solar Site 31	Roof mounted	58
Solar Site 11	Parking canopy	21	Solar Site 32	Roof mounted	53
Solar Site 12	Roof mounted	132	Solar Site 33	Roof mounted	29
Solar Site 13	Roof mounted	11	Solar Site 34	Roof mounted	32
Solar Site 14	Roof mounted	22	Solar Site 35	Roof mounted	27
Solar Site 15	Roof mounted	34	Solar Site 36	Roof mounted	21
Solar Site 16	Roof mounted	126	Solar Site 37	Roof mounted	144
Solar Site 17	Roof mounted	10	Solar Site 38	Roof mounted	35
Solar Site 18	Roof mounted	10	Solar Site 39	Roof mounted	201
Solar Site 19	Roof mounted	7	Solar Site 40	Roof mounted	192
Solar Site 20	Roof mounted	4	Solar Site 41	Roof mounted	413
Solar Site 21	Roof mounted	8		**Total Capacity**	**11,558**

Estimate of Energy Production

PVWatts was used to estimate the energy generated by a PV system. The model assumed a medium efficiency PV technology, mounted at a 25-degree tilt facing due south. Actual conditions of a PV system at MMSD may vary. However, these assumptions provide a general idea of the energy generating capacity of a PV system in Milwaukee. These estimates are approximate, and more detailed study is required to better estimate actual generation capacity. Based on the modeling assumptions made, the estimated annual kWh per kW_{DC} is 1,300 kWh/kW_{DC}. This means that on an annual average, the solar system is operating about 15 percent of its capacity, or about 1.7 MW. The reason is that power generation is decreased or eliminated at night and on cloudy days. This can be compared to wind power, which is estimated to operate at about 23 to 25 percent of its capacity. Again, these estimates are preliminary and could be refined. Table 8 summarizes the total estimated annual energy produced at the locations in this assessment.

TABLE 8
Estimated Net Annual Energy Production

Areas	Capacity (kW)	Annual Energy Generated (MWh per year)
Roof mounted	1,808	12,285
Parking canopy	300	390
Ground mounted	9,450	2,351
Total	**11,558**	**15,026**

Source: PV Watts, National Renewable Energy Laboratories

Jones Island Solar Power

Unlike South Shore, Jones Island has very limited available open land space to install turbines. There is some space available on building roofs but several of the building have roof mounted HVAC equipment which would limit the amount of panels that could be mounted on building roofs. Because of the limited potential for installing solar power at Jones Island, a detailed evaluation of solar power was not done but a rough estimate showed that about 0.2 MW (annual average generation rate) of solar could be installed at Jones Island.

Maximize Digester Gas Production

South Shore has nearly doubled the required digester volume required for current average biosolids loadings. If all the capacity could be used, digester gas production could be increased significantly. Increasing digester gas production would allow more power and heat to be produced by the engines. To maximize the digestion and energy production, the following was assumed:

- All Jones Island and South Shore primary sludge will be digested, as is currently done.
- The primary clarifiers at each plant would be operated to produce a thicker primary sludge, allowing greater capacity in the digesters.
- Some South Shore waste activated sludge (25 percent) will be thickened and digested, then pumped to Jones Island. Thickening the waste activated sludge to 5 percent solids also would allow for greater capacity in the digesters.
- The mass of digested sludge sent for dewatering and drying at Jones Island was not limited. Veolia staff have stated that problems with Milorganite production, such as excessive dust, are encountered when the percentage of digested sludge exceeds 40 percent. However, it was assumed that the drying system would be modified to address this limitation.
- New mixing systems will be installed in all digesters to minimize the required solids retention time and to maximize gas production.
- 7.7 MG of digester volume will be required for digestion of Jones Island and South Shore sludge given the above conditions.
- One digester (1.2 MG) will be used to store thickened sludge, rather than multiple digesters as now used.
- Industrial/commercial waste will be co-digested with Jones Island and South Shore sludges. The amount of digester gas produced from the waste was based on typical values estimated from testing of wastes done by Marquette University for MMSD and the Green Bay Metropolitan Sewerage District, and also on data from other utilities. The amount of digester gas generated from industrial/commercial wastes varies widely depending upon the waste characteristics. In addition, obtaining this large volume of waste likely would be challenging, especially given the increasing competition from other publicly owned wastewater treatment plants and private digesters, such as those operated by the Forest County Potawatomi Community.

Table 9 lists the quantities of wastes digested. Table 10 summarizes the amount of energy generated from the waste volumes given in Table 9. Of the energy generated shown in Table 10, most of the energy—greater than about 85 percent—is produced from the industrial/co-digested waste.

TABLE 9
Quantities of Wastes Digested at South Shore

Waste Stream	Quantity
Jones Island primary sludge (DTPD)	76,800
South Shore primary sludge (DTPD)	112,800
South Shore waste activated sludge (DTPD)	24,600
Industrial/commercial waste (gallons/day)	785,300

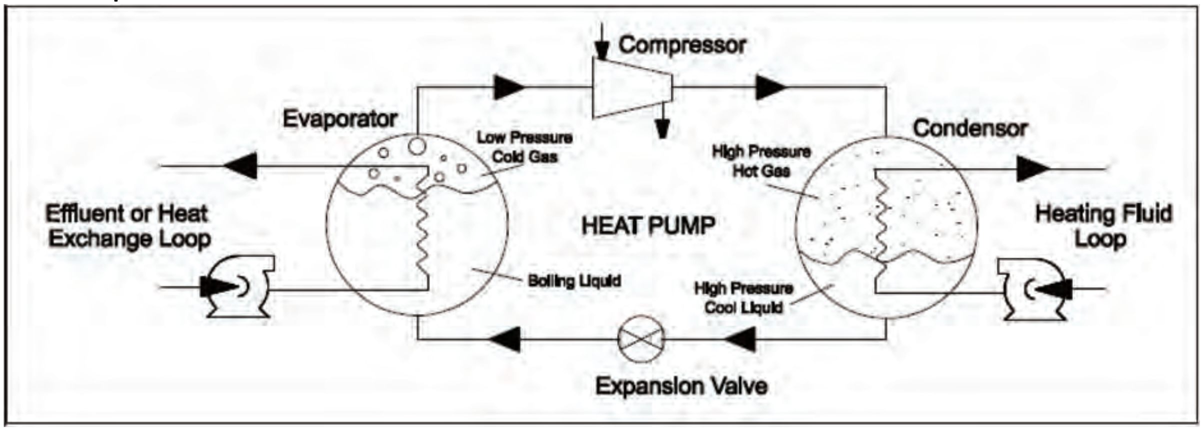
TABLE 10
Energy Generated by Co-digestion of Jones Island and South Shore Sludges with Industrial/Commercial Wastes

Annual average power generation rate	39 MW
Annual average heat generation rate	143 MMBtu/hr

Effluent Heat Recovery

There are three basic techniques or methods in use for active extraction of heat from the treatment plant effluent. The basic premise behind all of these techniques is a heat pump to transfer the heat from the incoming source fluid to the high quality heated fluid for use in treatment plant processes. Figure 8 shows how the heat pump cycle works.

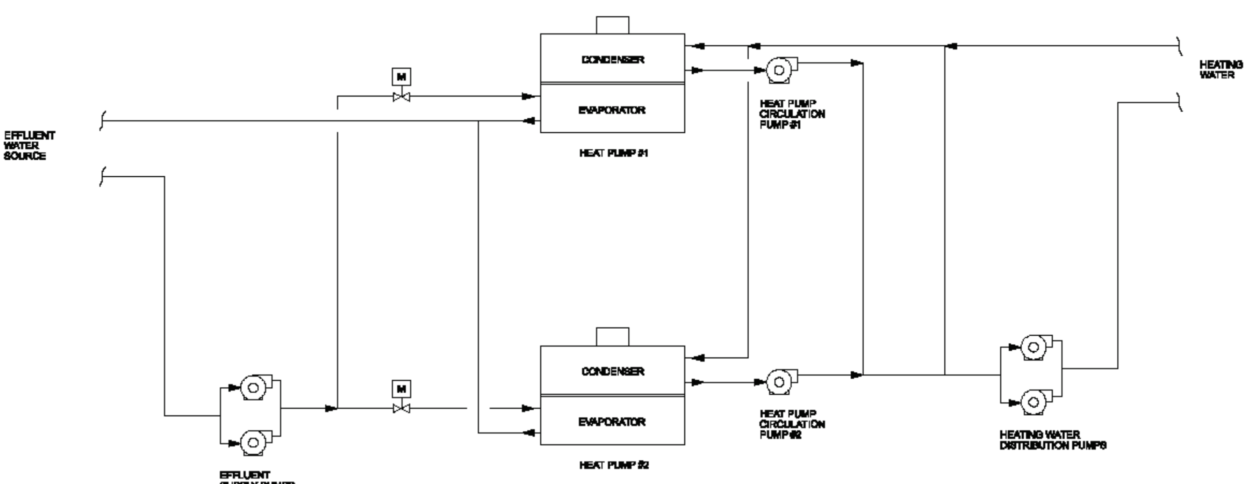
FIGURE 8
Heat Pump Schematic



This technique uses the heat directly from the effluent stream. The warmer effluent is pumped to the heat pump evaporator, where the heat is transferred to boiling refrigerant at a low pressure. The cooled effluent is returned to the plant. The refrigerant vapor from the evaporator is compressed in the heat pump compressor to a high pressure. The heat of compression increases the temperature of the gas. The high pressure, high temperature gas enters the heat pump condenser. Heat is transferred from the high pressure, high temperature gas to the heating fluid. The heat transfer causes the refrigerant to condense back to a liquid. The high temperature liquid is flashed to a lower pressure through an expansion valve. The resulting change in pressure causes the liquid refrigerant to boil. This removes heat from the liquid, lowering its temperature. The low temperature boiling liquid can now remove heat from the effluent source. This technique is the most efficient.

Figure 9 shows more specifically how an effluent heat recovery system might be configured for MMSD's plants. The amount of energy that could be recovered from the 200 mgd of effluent is very large—many times more than the plants require. The amount of energy that can be recovered as useful energy will depend in large part

FIGURE 9
Conceptual Effluent Heat Recovery System



on the energy input to the heat pump and ancillary equipment. The coefficient of performance (COP) of a heat pump is a ratio of heating or cooling provided to electrical energy consumed. Higher COPs equate to lower operating costs. The COP may exceed 1, because it is a ratio of energy output to loss that differs from thermal efficiency, which is the ratio of output to input energy. The COP is highly dependent on operating conditions, especially absolute temperature and relative temperature between sink and system.

Table 11 shows an example of the potential energy that could be recovered from the effluent in the form of hot water. The actual energy recovered will vary depending on the system design criteria and configuration. A more detailed evaluation of effluent heat recovery including cost estimates will be provided in Technical Memorandum 3.

TABLE 11
Example Energy Recovery from Effluent at South Shore and Jones Island: Hot Water

Average flow rate: Jones Island and South Shore (mgd)	180
Hot water produced temperature (degrees F)	150 to 160
COP	1.5 to 2.3 with average of 2.0
Effluent temperature (degrees F)	50 to 68 with average of 60
Total energy output (MMBTU/HR)	1,300
Heat pump/ancillary equipment energy input (MMBtu/hr)	430
Net energy output (MMBtu/hr)	870

It can be seen that the potential energy that could be recovered from the effluent is great compared to other plant energy uses. For comparison, two Solar turbines produce about 40 MMBtu/hr of waste heat. Recovering that much energy from the effluent would require a large capital expenditure that would likely show the concept was more costly than other energy recovery options. But if excess electrical energy were generated through increased co-digestion, for example, the excess power could be used to power the heat pumps, making effluent heat recovery much more cost-effective.

Landfill Gas Turbines

The Jones Island landfill gas turbines provide renewable energy in the form of electrical power and waste heat that used to dry Milorganite and provide building heat. There are three 4.8 MW turbines. If the landfill gas from the Advanced Disposal landfill were increased in the future to its potential and if additional landfill gas were obtained from the Waste Management landfill, the amount of landfill gas available would increase significantly from current landfill gas volumes.

TABLE 12
Potential Power Generation with Maximum Estimated Landfill Gas from Advanced Disposal and Waste Management landfills

Landfill gas, MMBtu/yr	1,518,000
Landfill gas, MMBtu/hr	173
Total turbine power output, MW	19.4
Total turbine power output, MMBtu/hr	66.2
Useful waste heat produced by turbines, MMBtu/hr	80.9
Number of new 4.8 MW turbines needed (no redundancy)	1

Table 12 shows the estimated power and waste heat production if the landfill gas volumes were increased. An additional new turbine would need to be installed. The amount of power that could be generated then would be almost double the typical, nominal 10 MW Jones Island demand. The amount of waste heat generated may be enough to dry all the biosolids depending upon biosolids loadings and other factors.

Summary

Table 13 summarizes the estimated maximum renewable energy that could be generated at South Shore and Jones Island.

TABLE 13
Estimated Maximum Renewable Energy: All Facilities and Sources

Renewable Energy Source	Installed Capacity (MW)	Average Annual Generation Rate (MW)	Average Annual Generation Rate (MMBtu/hr)
Wind turbines: South Shore	9	2.3	7.8
Wind turbines: Jones Island	9	2.1	7.2
Solar: South Shore	11.6	1.7	5.8
Solar: Jones Island	1.4	0.2	0.7
Landfill gas turbines: electrical power	19	19	65
Landfill gas turbines: waste heat	NA	24	81
Effluent heat recovery: South Shore and Jones Island	NA	381	1,300
Co-digestion electrical power from engines: South Shore	NA	40	136
Co-digestion waste heat from engines: South Shore	NA	42	143
Total		**469**	**1,600**

The potential exists to generate much more renewable energy than could be used at the treatment plants. For comparison, the current energy use for all MMSD facilities is about 200 MMBtu/hr and the estimated maximum renewable energy generation rate is 8 times that amount. Assuming an average household electrical energy use of 1.2 KW, the maximum estimated energy generated shown in Table 13 would provide equivalent to power for more than 390,000 households (not accounting for generation, transmission losses and conversion of heat to electrical power).

The excess electrical energy could be sold to We Energies or to other industries near the plants. Heat generated in the form of hot water or hot thermal oil could be used for building heat or air conditioning, with the remainder sold to nearby industries. One potential use near South Shore is the Oak Creek Drinking Water Treatment Plant, which has potential need for about 2 MW of electrical power and could use hot water for building heat. At the Oak Creek plant, natural gas is used in a 1 MW backup generator, and a second 1 MW generator may be installed in the future. Those generators could be converted to operate on digester gas or power could be sent to the Oak Creek plant.

Complete List of Alternatives Considered for Screening

Note: Some alternative names and concepts were changed as the alternatives were evaluated and refined.

Alt No.	Category	Option Description	Comments	Source	JIWRF	SSWRF	Conveyance, including ISS	HQ / Ancillary Facilities	Appropriate for 2035 Vision (not 2050 Plan)	Significant Energy Reduction Potential (>~500KW, 670 hp, 1.7 MMBTU/HR or ~1% of District energy)[a]	Implementable w/o Construction Capital Expenditure	Implementable For Low Capital Cost (<~$1 to $5M) or Minimal Process Impacts	Strategic Value	Screening Score
					Applicable Facilities				Screening Criteria with Weights					
									20	30	25	15	10	100
1	Process Modifications	Optimize Biosolids Transfer between Plants	Consider both PS and WAS pumping energy versus digester gas production. Impacts on Milorganite quality and minimum contracted production must be evaluated carefully.	Energy Plan Workshop No. 2	X	X	X		Yes	Yes	Yes	No	Yes	4.3
2	Process Modifications	Optimize Influent Flow Split between Plants	Split influent flow to optimize energy use. Build on District integrated model. About 1/3 of flow can be directed to either plant using automated gates. Increased detention time could cause odors. Bill Krill estimates liquid treatment cost is about 25 percent less at SS so directing more flow to SS could be effective.	Energy Plan Workshop No. 2	X	X	X		Yes	Yes	Yes	No	Yes	4.3
3	Process Modifications	Purchase More Green Energy	Already being done for HQ (at a higher cost). We Energies is in the process of changing MMSD rate structure which could impact this.	Energy Plan Workshop No. 2	X	X	X	X	Yes	Yes	Yes	No	Yes	4.3
4	Process Modifications	Bypass Jones Island High-Level Screw Pumps	Bypass high level screw pumps at JIWRF Preliminary Treatment to avoid pumping energy. Has been used in past, but not for many years.	Bill Farmer project list	X				Yes	Yes	Yes	No	No	3.8
6	Facility Optimization	Optimize Pumping Energy Using PLC Logic	PLC logic installed to select optimum number of pumps to run and speed of each pump to minimize energy. May only apply to RAS/WAS pumps. Determine if applicable to other pumps.	Energy Plan Workshop No. 2	X	X	X		Yes	Yes	Yes	No	No	3.8
9	Facility Optimization	Optimize Waste Heat Pressure Control	Began during startup of JIWRF LFG turbines. Some WH must be vented to allow WH pressure control. Installation of solar turbines has significantly decreased WH vented compared to GE turbines but there may still be opportunity to reduce vented WH further.	Energy Plan Workshop No. 2	X				Yes	Yes	Yes	No	No	3.8
12	Process Modification	Increase Belt Press Feed Solids Concentration to Increase Cake Solids	Thickened sludge pumps may need modification. Initial testing at JIWRF had problems with high solids on BFP (~5%). BFPs 9-12 can be used for piloting. Currently operating at about 3.2 % solids to BFPs. Not clear if problems related to pumping or process issues.	Energy Plan Workshop No. 2	X				Yes	Yes	Yes	No	No	3.8
14	Facility Optimization	Automate Real-Time Energy Optimization Control and Monitoring	Primarily applies to JIWRF turbine/dryers and SSWRF engine systems.	Energy Plan Workshop No. 2	X	X			Yes	Yes	Yes	No	No	3.8
16	Process Modification	Heat Sludge and Polymer Solution to Improve Cake Solids	Pilot testing may be required as effectiveness can vary from plant to plant. A "what-if" could simply be done to estimate energy savings per percent increase in cake solids. Bench testing could be a cost-effective way to address.	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	Yes	3.8
19	Non-Process Facility Optimization	Maximize South Shore FOG and High-Strength Waste Digestion	MMSD working with Marquette University has already thoroughly evaluated HSW issues but it appears that FOG digestion was not evaluated in detail. Alternative will evaluate what the likely range of digester gas production would be if all digester excess capacity were used to digest FOG and HSW. Assume existing system can accommodate FOG. If excess digester gas can be produced, evaluate constructing a pipeline to the Oak Creek Water Plant for use in their existing 1 MW natural gas engine generator.	Veolia/MMSD project list		X			Yes	Yes	No	Yes	Yes	3.8
20	Energy Generation Improvements	Solar Power Electricity Generation	Implemented on small scale already by the District, but could implement on larger scale. Scale depends on land available. Assumes 1 MW and 5 acres at SSWRF. Per Bill Farmer, if this alternative makes the final cut, it is suggested that CH2M HILL evaluate the use of solar power for a 100 MGD UV disinfection system (see Alternative No. 29).	Energy Plan Workshop No. 2	X	X	X	X	Yes	Yes	No	Yes	Yes	3.8
21	Energy Generation Improvements	Wind Energy Generation	Scale could vary widely. Assumes 1 MW turbine. Urbain Boudjou has already evaluated wind power at various MMSD facilities, but only for small scale.	Energy Plan Workshop No. 2	X	X	X	X	Yes	Yes	No	Yes	Yes	3.8
22	Process Modifications	Recover Heat from Dryer Exhaust	Recover heat (or power?) in exhaust vapor that has been evaporated from biosolids. A challenge may be that each dryer has a separate exhaust duct and its own dedicated air pollution control system which could require separate heat recovery but there may be a common duct where a single system could be used.	Veolia/MMSD project list	X				Yes	Yes	No	Yes	Yes	3.8
23	Equipment Improvements	Capture More Waste Heat from IC Engines	Engine jacket heat is currently captured but there is likely excess waste heat in the summer when building heat not needed. Evaluate in conjunction with alternative number 36.	Energy Plan Workshop No. 2		X			Yes	Yes	No	Yes	Yes	3.8
29	Energy Generation Improvements	Implement South Shore Renewable Energy Powered UV Disinfection for 100 mgd Base Flow	A solar array could possibly be located on 5 acres of vacant land on NW corner of SSWRF. Cost savings would be gained by potentially eliminating about $500k per year of chemical costs. Related to Alternative No. 20.	Bill Farmer project list		X			Yes	Yes	No	Yes	Yes	3.8
31	Non-Process Facility Optimization	Large-Scale Effluent Heat Recovery Using Heat Pumps		Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	Yes	3.8
78	Energy Generation Improvements	Large-Scale Hydrokinetic Turbines/Micro-Hydropower	7 feet of head available and could produces in range of 0.1 to 1 MW.	Bill Farmer project list	X	X	X		Yes	Yes	No	Yes	Yes	3.8
94		Recover Heat from Turbine Cooling Water	Need to address thermal water quality permitting regulations.	Workshop No. 3	X				Yes	Yes	No	Yes	Yes	3.8
13	Non-Process Facility Optimization	Improved Control of Plant-wide HVAC Control	Consultant team will provide very high level evaluation to determine rough potential, order of magnitude savings. District could do a future detailed study.	Bill Farmer project list	X	X			Yes	Yes	Yes	No	No	3.8
18	Equipment Improvements	Install High-Efficiency Plant Lighting	Consultant team will provide very high level evaluation to determine rough potential, order of magnitude savings. District could do a future detailed study.	Bill Farmer project list	X	X	X	X	Yes	Yes	No	Yes	Yes	3.8
41	Equipment Improvements	Install Variable Frequency Drives for Pumps, Fans, and Other Equipment		Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	No	3.3
64	Equipment Improvements	Install High-Efficiency Motors for Pumps, Fans, and Other Equipment	There may already be several high efficiency motors installed.	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	No	No	2.5
73	Non-Process Facility Optimization	Increase Natural Light in Buildings		Energy Plan Workshop No. 2	X	X	X	X	Yes	No	No	Yes	Yes	2.3
7	Process Modifications	Use CEPT to Reduce Aeration Energy and Increase Primary Sludge/Digester Gas	CEPT can already be done at SSWRF, but is not operating for a few reasons: (1) they are limiting chemical use, (2) they must maintain the phosphorus balance, and (3) nutrient removal is an issue. Has been tested by United Water and others at JIWRF (polymer only). Per Bill Farmer, this evaluation would need to compare energy gains made in improving PC TSS removal efficiency against net change in operating costs. PC TSS removal efficiencies are already good during dry weather because of low SOR. It is questionable whether analysis of this project would be a good Energy Plan expenditure. If analysis of this option would proceed, it should not include the use of ferric chloride.	Energy Plan Workshop No. 2	X	X			Yes	Yes	Yes	No	No	3.8
8	Process Modification	Modify/Optimize Activated Sludge Process for Energy	Consider changes to sludge age, RAS flows, etc. JIWRF originally designed to operate at a much lower sludge age. ***Consultant team will use BioWin model to evaluate.***	Energy Plan Workshop No. 2	X	X			Yes	Yes	Yes	No	No	3.8
10	Process Modification	Increase SRT to Reduce Solids Processing Energy	Bill Farmer questions whether this would be a good Energy Plan expenditure. This would require **Veolia** involvement in order for it to be meaningful, otherwise it will be an academic exercise. ***Consultant team proposes to use BioWin model to evaluate.***	Energy Plan Workshop No. 2	X	X			Yes	Yes	Yes	No	No	3.8

Complete List of Alternatives Considered for Screening

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									Screening Criteria with Weights					
					Applicable Facilities				20	30	25	15	10	100
Alt No.	Category	Option Description	Comments	Source	JIWRF	SSWRF	Conveyance, including ISS	HQ / Ancillary Facilities	Appropriate for 2035 Vision (not 2050 Plan)	Significant Energy Reduction Potential (>~500KW, 670 hp, 1.7 MMBTU/HR or ~1% of District energy)[a]	Implementable w/o Construction Capital Expenditure	Implementable For Low Capital Cost (<~$1 to $5M) or Minimal Process Impacts	Strategic Value	Screening Score
11	Process Modification	Decrease Activated Sludge SRT	Increased volume of solids may be beneficial for energy production through anaerobic digestion at SSWRF. **Consultant team will use BioWin model to evaluate.**	Energy Plan Workshop No. 2	X	X			Yes	Yes	Yes	No	No	3.8
15	Process Modifications	Improve Primary Clarifier Operations/Removal Efficiency	Optimize primary treatment (without chemically enhanced primary treatment) at both JIWRF and SSWRF. Bill Boyle is applying for an energy grant to evaluate improving primary clarifier sludge removal efficiency to generate more primary sludge and send less organic load to aeration system. This may need to be a physical improvement, not chemical; so nutrient balance is not adversely affected in the biological treatment process. Likely need to model to verify potential issue. Bill Farmer sees this alternative to be essentially the same as Alternative No. 7: Chemically enhanced primary treatment (CEPT) to reduce aeration energy and increase primary sludge/digester gas. ***Consultant team could provide review and documentation of past work and ongoing work including BioWin models if used.***	Bill Farmer project list	X	X			Yes	Yes	No	Yes	Yes	3.8
17	Process Modification	Use Waste Heat to Heat Biological Process at Jones Island	Waste heat from hot water system (engines?) at SSWRF already discharged to aeration tanks. Per Bill Farmer, if waste IC engine heat can already be discharged to the aeration basins, why would it be necessary to do this evaluation? <CH2M HILL: This may still be feasible at JIWRF.> ***Consultant team to use BioWin model to evaluate.***	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	Yes	3.8
5	Process Modifications	Decrease Number of Idle Aeration Basins Online	Per Bill Farmer, MMSD and Veolia are already evaluating the idling of aeration basins. ***Consultant team could provide review and documentation of past work and ongoing work including BioWin models if model used.***	Bill Farmer project list	X	X			Yes	Yes	Yes	No	No	3.8
24	Equipment Improvements	Implement Jones Island Aeration Control Using DO and Ammonia/Nitrate Probes	Pilot testing at JIWRF to determine the feasibility of implementing basin idling and the method to implement basin idling (using W-3 water, mixed liquor or a hybrid of both) has been recommended. Includes use of ammonia and DO probes. Per Bill Farmer, this project is already being done by MMSD and Veolia.	Veolia/MMSD project list	X				Yes	Yes	No	Yes	Yes	3.8
25	Equipment Improvements	Implement South Shore Aeration Control Using DO and Ammonia/Nitrate Probes	Pilot testing at SSWRF to determine site-specific experience for idling one or two aeration basins has been recommended. Includes use of ammonia probes. Per Bill Farmer, this project is already being done by MMSD and Veolia.	Veolia/MMSD project list		X			Yes	Yes	No	Yes	Yes	3.8
26	Equipment Improvements	Install Turbine Waste Heat Landfill Gas Duct Burners	Per Bill Farmer and Bill Krill, this project is already being done. CH2M HILL is investigating this under the Turbine Project.	Energy Plan Workshop No. 2	X				Yes	Yes	No	Yes	Yes	3.8
34	Equipment Improvements	Change Channel Mixing to Large Bubble Mixers	CH2M HILL rough evaluation showed this to be cost effective.	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	No	3.3
36	Facility Optimization	Increase Use of Waste Heat from Internal Combustion Engines	Assumes can be accomplished by operational or control changes. Evaluate in conjunction with alternative 23.	Energy Plan Workshop No. 2		X			Yes	Yes	No	Yes	No	3.3
44	Energy Generation Improvements	Send Excess Heat to Nearby Industries, Commercial Buildings, and Residences	Example: Excess SSWRF engine heat transported off-site during summer when there are no building heating needs. Some buildings at JIWRF can be converted from natural gas heat to hot water. Related to Alternatives No. 23 and 36.	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	No	Yes	3.0
27	Equipment Improvements	Install air heater to use landfill gas	This is for dryer inlet air. <CH2M HILL: Was looked at previously and determined not to be cost-effective - therefore drop>	Energy Plan Workshop No. 2	X				Yes	Yes	No	Yes	Yes	3.8
30	Non-Process Facility Optimization	Influent heat recovery using heat pumps (large-scale)	Solids in influent may not be compatible with heat exchangers. <CH2M HILL: Effluent heat recovery more appropriate; therefore this was dropped.)	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	Yes	3.8
33	Equipment Improvements	Recuperative Sludge Thickening at SSWRF - Biosolids Bundle Project #1	Withdrawal of a portion of the digested biosolids from each digester, pumping to one or more of the existing GBTs for thickening, and then return the thickened biosolids back to the digester feed line to increase SRT in digesters, reduce solids volume, increase digester gas, reduce polymer costs, etc.	Veolia/MMSD project list		X			Yes	Yes	No	Yes	No	3.3
42	Equipment Improvements	Install high efficiency blower	MMSD and Veolia have implemented and are further evaluating this energy saving opportunity with the aeration systems at JIWRF and SSWRF. Per Bill Krill, this has been evaluated as part of the aeration upgrade project for both plants.	Bill Farmer project list	X	X			Yes	Yes	No	Yes	No	3.3
43	Equipment Improvements	Replace SSWRF existing diffusers with more efficient diffusers to increase oxygen transfer efficiency and better match aeration demands	Refer to CH2M HILL TM "Potential Energy and Greenhouse Gas Reduction Strategies at the Jones Island and South Shore Water Reclamation Facilities". Per Bill Krill, this has also been evaluated as part of the aeration upgrade project. Per Bill Farmer, the panel diffusers were not replaced, but they were tested by Dave Redmon and determined to be nearly as efficient as membrane diffusers, plus membrane diffusers make it more difficult to clean the aeration basins. This was completed for both plants, which already have fine bubble diffusers. (CH2M: But SS does not have panel diffusers?)	Energy Plan Workshop No. 3		X			Yes	Yes	No	Yes	No	3.3
35	Equipment Improvements	Increase WH boiler efficiency	Methods to accomplish?	Energy Plan Workshop No. 2	X	X			Yes	Yes	No	Yes	No	3.3
37	Facility Optimization	D&D process energy optimization	May need to further define before evaluation.	Energy Plan Workshop No. 2	X				Yes	Yes	No	Yes	No	3.3
38	Facility Optimization	Evaluate potential ventilation energy savings in D&D building	This needs to balanced against required ventilation requirements at JIWRF. Need to consider NFPA 820 which may require minimum, high air flows. But NFPA may not be a strict requirement in all cases.	Bill Farmer project list	X				Yes	Yes	No	Yes	No	3.3
39	Equipment Improvements	Replace JIWRF panel diffusers with membrane diffusers to increase oxygen transfer efficiency and better match aeration demands	CH2M HILL rough evaluation showed this to be cost effective. District evaluation showed this to not be cost effective? Per Bill Krill, this has been evaluated as part of the aeration upgrade project. Per Bill Farmer, the panel diffusers were not replaced, but they were tested by Dave Redmon and determined to be nearly as efficient as membrane diffusers, plus membrane diffusers make it more difficult to clean the aeration basins.	Energy Plan Workshop No. 2	X				Yes	Yes	No	Yes	No	3.3
45	Process Modifications	Anaerobic sludge pretreatment and conditioning methods	e.g., thermal hydrolysis, cell lysis, electrical pulse, etc.	Energy Plan Workshop No. 2		X			Yes	Yes	No	No	Yes	3.0
46	New Process Facilities	Ostara/ANITA™Mox - Biosolids Bundle Project #3	Sidestream nutrient removal/recovery options to reduce ammonia- and/or ammonia- and phosphorus-rich side stream and additional nitrogen and phosphorus loading on the SSWRF biological treatment system.	Veolia/MMSD project list		X			Yes	Yes	No	No	Yes	3.0
32	Energy Generation Improvements	Thermal energy generation/recovery in collection system (large-scale)	Evaluated by Arcadis.	Energy Plan Workshop No. 2			X		No	Yes	No	Yes	Yes	2.8

Complete List of Alternatives Considered for Screening

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Alt No.	Category	Option Description	Comments	Source	Applicable Facilities: JIWRF	SSWRF	Conveyance, including ISS	HQ / Ancillary Facilities	Screening Criteria with Weights: Appropriate for 2035 Vision (not 2050 Plan)	Significant Energy Reduction Potential (>~500KW, 670 hp, 1.7 MMBTU/HR or ~1% of District energy)[a]	Implementable w/o Construction Capital Expenditure	Implementable For Low Capital Cost (<~$1 to $5M) or Minimal Process Impacts	Strategic Value	Screening Score
									20	30	25	15	10	100
61	Equipment Improvements	Reconfigure diffuser densities	MMSD and Veolia have implemented and are further evaluating this energy saving opportunity with the aeration system at JIWRF. Per Bill Krill, this has been done as part of the aeration upgrade project. Per Bill Farmer, there is a future capital project to evaluate diffuser configuration, but this has to be done in concert with basin idling, bio-P and other operational changes that may occur. Therefore Bill Farmer does not recommend evaluating this as part of the Energy Plan.	Bill Farmer project list	X	X			Yes	Yes	No	No	No	2.5
62	Equipment Improvements	Pump base influent flow with higher efficiency pump	Use more efficient pump than JIWRF screw pumps to pump dry weather flow?	Bill Farmer project list	X				Yes	Yes	No	No	No	2.5
63	Equipment Improvements	Install more efficient lift station pumps		Energy Plan Workshop No. 2			X		Yes	Yes	No	No	No	2.5
66	Process Modification	Optimize biogas use by having 3rd shift powerhouse operator	Per Bill Krill, this initiative has been approved and will be implemented.	Energy Plan Workshop No. 2		X			Yes	No	Yes	No	No	2.3
67	Process Modifications	Energy savings with improved RAS pumping rates and control	Refers to RAS pumping rates and control at JIWRF. <Duplicate of Alternative No. 6.>	Bill Farmer project list	X				Yes	No	Yes	No	No	2.3
69	Equipment Improvements	JIWRF fuel gas compression system energy improvements	Under present controls the fuel gas compression system uses the full 400 hp regardless of fuel gas requirement. Look at control modifications and possibly using existing GE gas compressors to supply compressed gas to the Solar turbines. Per Bill Krill, this alternative already exists. A mechanical slide gate is used to control power use. The compressors do not use 400 hp, but horsepower use is proportional to the CFM of gas.	Energy Plan Workshop No. 2	X				Yes	No	Yes	No	No	2.3
65	Process Modifications	Energy tariff/demand-side management		Energy Plan Workshop No. 2	X	X	X		Yes	No	Yes	No	No	2.3
68	Non-Process Facility Optimization	HVAC control at major remote sites	Refers to the Conveyance System. Must balance energy savings with freezing and ventilation. NFPA 820 issues?	Bill Farmer project list			X		Yes	No	Yes	No	No	2.3
72	Equipment Improvements	General energy/water conservation measures	Need to further define this alternative.	Energy Plan Workshop No. 2	X	X	X	X	Yes	No	No	Yes	Yes	2.3
74	Non-Process Equipment Improvements	Alternative fuel fleet vehicles (i.e., NG, DG, solar, electricity)		Energy Plan Workshop No. 2		X			Yes	No	No	Yes	Yes	2.3
93	[a] Actual energy reduction has not been evalua	Modify CISCO network switches	Jack Knight could help address this.	Workshop No. 3	X	X	X	X	Yes	No	Yes	No	No	2.3
70	Equipment Improvements	Improved digester mixing for greater biogas generation	Testing two mixing technologies on two of the large digesters at SSWRF. Per Bill Krill, this project is already underway.	Energy Plan Workshop No. 2		X			Yes	No	No	Yes	Yes	2.3
71	Energy Generation Improvements	Solar power at flow measuring stations or lighting at other low wattage facilities	Refers to the Conveyance System.	Bill Farmer project list			X	X	Yes	No	No	Yes	Yes	2.3
47	Energy Generation Improvements	Algae bioreactor for biofuel production (large-scale)		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
48	New Process Facilities	Change in anaerobic digestion operation (i.e., from mesophilic to thermophilic or acid-gas)	Evaluate potential increased biogas generation at higher loadings/lower SRT for SSWRF.	Energy Plan Workshop No. 2		X			No	Yes	No	No	Yes	2.0
49	Facility Optimization	Consolidate process facilities		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
50	New Process Facilities	Low energy ammonia removal (e.g., ANAMMOX) - mainstream at SSWRF and JIWRF	Major capital investment required. Few if any proven installations.	Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
51	New Process Facilities	Algae bioreactor for P removal		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
52	New Process Facilities	Microbial fuel cells		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
53	New Process Facilities	Anaerobic secondary treatment	Replace existing aerobic treatment with anaerobic treatment from a reduced energy use perspective.	Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
54	New Process Facilities	Solar drying		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
55	New Process Facilities	Composting (incl. numerous composting technologies)		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
56	New Process Facilities	Geothermal energy (large-scale)		Energy Plan Workshop No. 2	X	X		X	No	Yes	No	No	Yes	2.0
57	New Process Facilities	Geothermal energy from Lake Michigan or river coupled with heat pumps (large-scale)		Energy Plan Workshop No. 2	X	X	X	X	No	Yes	No	No	Yes	2.0
58	New Process Facilities	Hydroelectric energy from Lake Michigan wave action (large-scale)		Energy Plan Workshop No. 2	X	X	X	X	No	Yes	No	No	Yes	2.0
59	Energy Generation Improvements	Drying gasification to produce synthetic gas (syngas)		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	Yes	2.0
60	Energy Generation Improvements	Pyrolysis of excess Milorganite for heat energy recovery and create biochar	Per Bill Krill, this is currently a Marquette University research project.	Energy Plan Workshop No. 2	X				No	Yes	No	No	Yes	2.0
86	Equipment Improvements	Repair aeration header leaks	Per Bill Krill, it is believed that all large leaks have been fixed. Per Bill Farmer, Veolia has fixed large leaks in the JIWRF air header. Bill Farmer is not aware of any leaks in the SSWRF header.	Energy Plan Workshop No. 2	X	X			Yes	No	No	Yes	No	1.8
87	Process Modifications	Optimize non-process aeration uses	Optimize non-process aeration uses at JIWRF. Per Bill Krill, this has been looked at in concert with Alternative No. 39. Bill Farmer recommends that the JIWRF aerated channels be looked at as part of the Energy Plan (see Alternative No. 34).	Energy Plan Workshop No. 2	X	X			Yes	No	No	Yes	No	1.8
81	Equipment Improvements	Install new air flow control valves on aerated channels	MMSD and Veolia have implemented and are evaluating at JIWRF and SSWRF.<Not clear how energy savings achieved??>	Bill Farmer project list	X	X			Yes	No	No	Yes	No	1.8
80	Process Modifications	Sidestream storage for dewatering or other treatment at convenient time		Energy Plan Workshop No. 2	X	X			Yes	No	No	Yes	No	1.8
83	Equipment Improvements	75 hp air compressor replacement on SSWRF blend tanks	In-kind replacement? Status?	Energy Plan Workshop No. 2		X			Yes	No	No	Yes	No	1.8
84	Equipment Improvements	Address landfill gas air pipe leaks and pressure losses		Energy Plan Workshop No. 2	X				Yes	No	No	Yes	No	1.8
88	Energy Generation Improvements	Low energy ammonia removal (e.g., ANAMMOX) - sidestream at SSWRF	CH2M HILL did preliminary analysis in Energy Footprint Project.	Energy Plan Workshop No. 2		X			Yes	No	No	No	Yes	1.5
89	Energy Generation Improvements	Recover hydropower in collection system (large-scale)		Energy Plan Workshop No. 2			X		Yes	No	No	No	Yes	1.5
90	Energy Generation Improvements	Solar hot water generation		Energy Plan Workshop No. 2	X	X		X	Yes	No	No	No	Yes	1.5
75	Equipment Improvements	Install new JIWRF Milorganite dryers that use less energy	Evaluate for potential energy savings (as opposed to optimizing current operation).	Energy Plan Workshop No. 2	X				No	Yes	No	No	No	1.5
76	New Process Facilities	Dry weather load equalization		Energy Plan Workshop No. 2	X	X			No	Yes	No	No	No	1.5
77	Process Modification	Consolidate or downsize non-process/administrative facilities	Downsize facilities, thereby downsizing energy use (e.g., transition to "virtual office"). United Water closed down the SSWRF administration building and then Veolia re-opened it. There could be data that could be utilized.	Energy Plan Workshop No. 2				X	No	No	Yes	No	No	1.3
79	Energy Generation Improvements	Hydroelectric energy from river flow (large-scale)		Energy Plan Workshop No. 2	X	X	X	X	No	No	No	Yes	Yes	1.3

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									20	30	25	15	10	100
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91	Equipment Improvements	Install more efficient effluent pumps	Effluent pumps used infrequently, therefore energy savings low? Confirm effluent pumps are used infrequently.	Energy Plan Workshop No. 2	X	X			Yes	No	No	No	No	1.0
82	Equipment Improvements	Use smaller pumps for dewatering ISS between rain events and diversions	Refers to Conveyance System.	Bill Farmer project list			X		No	No	No	Yes	No	0.8
85	Energy Generation Improvements	Alternative method of powering effluent pumps	Evaluate power use for SSWRF effluent pumps, which have a demand of approximately 600 kW when pumping 300 MGD. Typically, the effluent pumps are not used during high plant flows unless lake level is high. Effluent pumps may be needed to achieve high flow rates. Existing on-site power generation may not be sufficient to power the effluent pumps, along with plant's base demand. Using purchased power would result in a large demand charge. <Ideas to address??>	Bill Farmer project list		X			No	No	No	Yes	No	0.8
92	Process Modification	Throttle back influent gates	Refers to influent gates at SSWRF. The gates are typically throttled back to limit the flow coming to SSWRF, forcing more to JIWRF. If something is placed there to capture energy, it could impact future wet weather treatment plans at SSWRF. There have been discussions of putting in high rate wet weather treatment at SSWRF and then letting flow go there by gravity (~540 mgd?) during a rain event.	Energy Plan Workshop No. 2		X			No	No	No	Yes	No	0.0

[a] Actual energy reduction has not been evaluated in detail. Criterion is approximate maximum potential and used for screening only.

Color-Coded Key

Consultant to evaluate life-cycle costs and cost-effectiveness.

Consultant to provide very high level evaluation to determine rough, potential order-of-magnitude savings. District could do a detailed study in the future.

Consultant to use existing BioWin models to evaluate potential process operational changes.

Consultant to review past MMDS/Veolia work and to document and incorporate into Energy Plan.

Consensus to evaluate even though scored lower.

To be evaluated in the 2050 Facility Plan Project.