This document is released for the purpose of information exchange review and planning only under the authority of Tracy Anne Clinton, September 2017, State of California, PE No. 48199 and Elizabeth Abigail Charbonnet, September 2017, State of California, PE No. 84612

City of Oxnard

Public Works Integrated Master Plan

WASTEWATER

PROJECT MEMORANDUM 3.7.1 TRADITIONAL OXNARD WASTEWATER TREATMENT PLANT ALTERNATIVES - UPGRADE IN PLACE

REVISED FINAL DRAFT
September 2017

Engineers...Working Wonders With Water™

2700 YGNACIO VALLEY ROAD • SUITE 300 • WALNUT CREEK, CALIFORNIA 94598 • (925) 932-1710 • FAX (925) 930-0208

PREFACE

The analysis and evaluations contained in these Project Memorandum (PM) are based on data and information available at the time of the original date of publication, December 2015. After development of the December 2015 Final Draft PMs, the City continued to move forward on two concurrent aspects: 1) advancing the facilities planning for the water, wastewater, recycled water, and stormwater facilities; and 2) developing Updated Cost of Service (COS) Studies (Carollo, 2017) for the wastewater/collection system and the water/distribution system. The updated 2017 COS studies contain the most recent near-term Capital Improvement Projects (CIP). **The complete updated CIP based on the near-term and long-term projects is contained in the Brief History and Overview of the City of Oxnard Public Works Department's Integrated Planning Efforts: May 2014 – August 2017 section.**

At the time of this Revised PWIMP, minor edits were also incorporated into the PMs. Minor edits included items such as table title changes and updating reports that were completed after the December 2015 original publication date.

City of Oxnard

Public Works Integrated Master Plan

WASTEWATER

PROJECT MEMORANDUM 3.7.1
TRADITIONAL OXNARD WASTEWATER TREATMENT PLANT ALTERNATIVES - UPGRADE IN PLACE

TABLE OF CONTENTS

Page

LIST OF TABLES

LIST OF FIGURES

TRADITIONAL OXNARD WASTEWATER TREATMENT PLANT ALTERNATIVES - UPGRADE IN PLACE

1.0 INTRODUCTION

The purpose of this Project Memorandum (PM) is to develop the list of projects to be included in the wastewater Capital Improvement Program (CIP) of the Public Works Integrated Master Plan (PWIMP) with associated project cost, timing, and drivers. The CIP is an estimate of the City of Oxnard’s (City's) capital expenses over the next 25 years to address limitations, rehabilitation needs, and recommended improvements to the wastewater treatment plant. The CIP is intended to assist the City in planning future budgets and making financial decisions.

1.1 PMs Used for Reference

The recommendations outlined in this PM include recommendations from the following other PMs:

- PM 1.1 – Overall – Master Planning Process Overview.
- PM 1.4 – Overall – Basis of Costs.
- PM 3.2 – Wastewater System – Flow and Load Projections.
- PM 3.4 – Wastewater System – Treatment Plant Performance and Capacity.
- PM 3.5 – Wastewater System – Condition Assessment.
- PM 3.6 – Wastewater System – Seismic Assessment.
- PM 3.8 – Wastewater System – Arc Flash Assessment.
- PM 3.9 – Wastewater System – Cathodic Protection Assessment.
- PM 3.10 – Wastewater System – SCADA Assessment.
- PM 3.11 – Wastewater System – Flow Monitoring.
- PM 4.3 – Recycled Water System – AWPF/OWTP Outfall Regulatory Considerations.

1.2 Other Reports Used for Reference

In developing the wastewater Scenarios, recommendations from other reports were incorporated to ensure a well-rounded and holistic look at the wastewater treatment plant system. The following reports are used in this PWIMP analysis:

- “Water and Wastewater Process Optimization and Mechanical Audit Report DRAFT” (The Energy Network - Process Optimization, 2014). - Appendix A.

- "Mechanical Audit Report" (The Energy Network - Mechanical Audit, 2014). - Appendix B.
- "Oxnard Wastewater Treatment Plant Energy Evaluation Report" (Carollo, 2013). - Appendix C.
- "Preliminary Identification of Immediate Needs for the Oxnard Wastewater Treatment Plant and Collection System Sewers and Lift Stations" (KEH, 2014). - Appendix D.
- "Energy Action Plan: A component of the Oxnard Climate Action and Adaptation Plan" (Oxnard Planning Division, 2013).

2.0 WASTEWATER TREATMENT GOALS

In considering improvements to the Oxnard Wastewater Treatment Plant (OWTP), a number of goals were established to aid in scenario development. The five main goals are as follows:

- Goal 1: Provide a compliant, reliable, resilient, and flexible system.
- Goal 2: Manage assets effectively (economic sustainability).
- Goal 3: Mitigate and adapt to potential impacts of climate change.
- Goal 4: Protect and enhance environmental and resource sustainability.
- Goal 5: Investigate green and grey infrastructure with an emphasis on energy efficiency.

3.0 DEVELOPMENT OF WASTEWATER TREATMENT PLANT SCENARIOS

Three scenarios were developed for consideration by the City of Oxnard (City). These three scenarios all address plant reliability concerns and future capacity needs. The scenarios differ in their area of focus. Scenario 1 focuses simply on plant reliability, Scenario 2 focuses on energy efficiency, and Scenario 3 focuses on resource recovery. It is important to recognize that these scenarios are not mutually exclusive. Instead, these scenarios are compatible with one another and additive to provide for increasing levels of treatment. A detailed discussion of these three scenarios and their associated projects can be found in the sections below.

3.1 Scenario 1: Baseline

Scenario 1 includes all projects needed to meet existing and anticipated future level of treatment requirements. Projects to optimize operations and maintenance are included in this scenario as are projects that adopt newer technologies in place of aging equipment. Because of the OWTP's age and state of repair, the majority of OWTP projects recommended in this master plan are related to repair and replacement required for continued plant operation. Because of this, this baseline scenario includes a majority of the proposed projects. All of these rehabilitation and replacement driven projects are required to achieve wastewater treatment goal number one and will require a substantial near-term investment. All proposed improvements to the OWTP under Scenario 1 are discussed below by process area.

3.1.1 Headworks

The proposed headworks improvement projects include improvements to odor containment and ventilation facilities, below cover coating repairs of influent structures, a new seal water system for the influent pumps, fiberglass covers for the headworks structures, minor modifications for seismic reliability at the grit screenings building, concrete repairs, and small equipment replacement. In addition, a new non-hazardous liquid (septage) receiving station and screen wall are also recommended. All of these projects provide greater reliability to help maintain a fully NPDES permit compliant plant, and do not increase plant capacity.

The odor control project will enclose the influent screens and horizontal screenings conveyors with RFP or aluminum covers and provide ventilation. These improvements produce an air quality benefit. Coating repair should include coating the influent sewer vortex structure, influent junction structure, influent screen channels, grit chamber bypass channels, and influent pump station wet well.

Small equipment at the headworks will be replaced as each item reaches the end of its remaining useful life. Equipment will be replaced with more energy efficient models, thus decreasing power usage, an environmental benefit. A list of small equipment in need of replacement and their economic remaining useful life (EcRUL) can be found in Table 1.

3.1.2 Primary Treatment

Based on the condition assessment and seismic evaluation done at the OWTP, it has been determined that the primary clarifiers are in poor condition and in some cases past their EcRUL. Due to this assessment, as a conservative approach in this PWIMP, it was assumed that all four clarifiers are in need of replacement.

In addition to rebuilding both the primary clarifiers and the associated primary clarifier building, it is recommended that an influent splitter box be added for better flow control. Also, with the construction of new primary clarifiers the City should continue to incorporate Chemically Enhanced Primary Treatment (CEPT) for better nutrient removal and allowance for cathodic protection. While it is assumed that the primary clarifiers will be replaced in full, budget was allocated to replace the existing primary clarifier equipment to maintain reliable service during the construction of new primary clarifiers. The recommendation to replace the primary clarifiers will increase the reliability of the OWTP and the safety of plant operators.

Table 1	Small Equipment at the Headworks Public Works Integrated Master Plan City of Oxnard
Item	**EcRUL (years)**
Bar Screens	6 to 8
Flowmeter	4
Grit Blowers	8
Grit Pumps	8
Grit Separator/Classifiers	8
Hypo Chemical Feed Pump (Sodium Hypo Pump 2)	4
Influent Check Valves	14
Influent Pumps	8
Odor Control Ductworks & Vessels	8
Screening Compactors	6
Sodium Hydroxide Pumps	3
Sodium Hydroxide Storage Tank	9
Sodium Hypochlorite Pump	3
Sodium Hypochlorite Storage Tank	9
Standby Generator	8
VFDs	6

3.1.3 Secondary Treatment

This section outlines the recommendations of this PWIMP for OWTP's secondary treatment processes.

3.1.4 Biotowers and Interstage Pumping

Based on the condition assessment and seismic evaluation done at the OWTP, it has been determined that the biotowers are in poor condition and past their EcRUL. Due to this assessment, this PWIMP recommends that the biotowers be demolished. Since it is recommended that the biotowers be removed from the process stream, no associated equipment has been budgeted for replacement in this PWIMP.

While it is recommended that the biotowers be removed, the interstage pump station is still necessary. This PWIMP recommends that the interstage pump station be re-configured when the biotowers are demolished. The existing pumps are nearing the end of their EcRUL and the current pump station location is not optimal for future plant operation. When the pump station is replaced, the pumps should be replaced with more energy efficient models and a location should be determined to minimize pumping head from primary to secondary treatment. This reconfiguration will potentially decrease power usage, an environmental benefit. When the facility is reconfigured, it is also recommended that a water quality early warning system be constructed. This facility would alert downstream recycled water users to any changes in water quality leaving the OWTP. None of the recommended changes to the biotowers or interstage pumping will increase the capacity of the plant. The proposed modifications will only increase operator safety and plant reliability.

3.1.5 Activated Sludge Tanks

The activated sludge tanks (ASTs) were constructed during the 1988 improvement project, and as of 2015, they are 27 years old. Based on their condition, this PWIMP recommends that the City invest in concrete repair of these structures. Additionally, based on the age of their construction and their existing condition they are in need of a seismic retrofit. A seismic assessment was performed on these structures and it was found that the AST walls are under reinforced and present shear failure. Concrete testing determined that shotcrete reinforcing is needed for seismic safety.

In addition to structural repairs, equipment associated with the ASTs are also in need of replacement. It is recommended that the diffusers and blowers be replaced, as they are nearing the end of their EcRUL. Additionally, as is recommended in the “Water and Wastewater Process Optimization and Mechanical Audit Report DRAFT” (Appendix A) at least three (3) of the six (6) blowers should be replaced with high efficiency turbo blowers to reduce energy usage (The Energy Network - Process Optimization, 2014). With this blower change, an upgrade to the supervisory control and data acquisition (SCADA) system to accommodate better control of the new aeration blowers and the aeration process is also recommended.

When the biotowers are removed, the ASTs will see an increase in loading. Because of this, it is recommended that baffle walls be added to facilitate better BOD removal in the ASTs. Additionally, it is recommended that the ASTs be run in a step-feed configuration, something these facilities are already set up to do. These minor alterations will allow the ASTs to treat higher loadings without expanding their footprint.

3.1.6 Secondary Sedimentation Tanks

The Secondary Sedimentation Tanks (SSTs) were also constructed in 1988. Like the ASTs, the SSTs are also in need of concrete repair. However, based on concrete testing, these structures are in fair condition seismically and are not in need of a retrofit. It is recommended that instead, the SSTs be re-painted.

Much of the SST equipment is nearing the end of its EcRUL. Table 2 lists the small equipment items associated with the SSTs as well as their EcRUL. In addition to this small equipment, the RAS pumps and collectors, skimmers, and drives also need to be replaced. This equipment has nearly reached or passed its EcRUL.

Table 2 Small Equipment at the SSTs Public Works Integrated Master Plan City of Oxnard	
Item	**EcRUL (years)**
RAS Pump Galley Ventilation Fans	6
Secondary Sed. Sludge Magnetic Flow Meters	3
VFDs	4
WAS Pumps	2

In order to optimize the secondary treatment process, the following process changes are recommended. These changes do not alter the plant's capacity, but instead improve performance. The first improvement is a modification to the SST inlet to more equally partition flow between each SST. The second improvement is the addition of a mixed liquor (ML) wasting station to automatically control the solids residence time (SRT) in the secondary system.

3.1.7 Membrane Bioreactor

As the Advanced Water Purification Facility (AWPF) is expanded, it will draw a larger percentage of OWTP effluent from the outfall and replace this flow with reverse osmosis (RO) concentrate. As discussed in PM 4.3, this will cause a concentration effect in the outfall and prevent the OWTP from complying with the technical-based effluent limits of its National Pollutant Discharge Elimination System (NPDES) permit. To address this, this PWIMP recommends the City take a three-pronged approach. It is recommended that the City:

- Pursue a change in the point of compliance for secondary treatment with the regulatory board (LARWQCB).
- Pursue a mass loading effluent limit with the regulatory board (LARWQCB).
- Add membrane bioreactors (MBRs) when the AWPF is expanded in Phase 2.

Recommendations 1 and 2 are both regulatory policy approaches and should be pursued first. However, in the event the policy changes are unachievable, then the engineering solution will require MBR due to the footprint constraints at the OWTP. The addition of MBRs is recommended as a "placeholder" technology to replace the SSTs and would treat all OWTP flow. Details of this recommendation can be found in PM 4.3. In addition to MBRs, a Ultraviolet/Advanced Oxidation Process (UV/AOP) is recommended as an additional step for flows sent to the AWPF. Details on this recommendation can be found in Section 3.1.9.1.

3.1.8 Flow Equalization

Like the ASTs and the SSTs, the flow equalization basins were constructed in 1988 and have similar condition and seismic concerns as the ASTs. Based on their condition, this

PWIMP recommends that the City invest in concrete repair of these structures. Additionally, based on concrete testing, shotcrete reinforcing is needed for seismic safety.

The EcRULs of small equipment at the equalization basins are shown in Table 3. The replacement of this equipment is included in Scenario 1.

Table 3 Small Equipment at the Equalization Basins
Public Works Integrated Master Plan
City of Oxnard

Item	EcRUL (years)
3WHP Facilities Pumps	2
Flow Equalization Gates & Drives	6
Flow Equalization Pumps	6

Additionally, in the “Water and Wastewater Process Optimization and Mechanical Audit Report DRAFT” The Energy Network recommends modifying the SCADA system control of the utility water system, which draws water from secondary effluent. It is recommended that the system pressure be reduced from 90 PSI to 60 PSI during the night when high-pressure water is not necessary. The cost of this modification is included in the CIP and it is expected that this cost will ultimately be offset by resulting energy savings.

3.1.9 <u>Disinfection</u>

To keep the tanks functional and safe, this PWIMP recommends that the City invest in concrete repairs and a new interior coating. Additionally, a small equipment replacement cost has been incorporated to keep the facilities operational. The small equipment included is listed in Table 4.

Table 4 Small Equipment at the Chlorine Contact Tank
Public Works Integrated Master Plan
City of Oxnard

Item	EcRUL (years)
Hypo Pumps	3
Hypo Tanks	9
Chlorine Contact Gates, Supports & Operators	2

3.1.9.1 UV/AOP (Future)

As discussed in Section 3.1.7, the expansion of the AWPF will cause concentration effects in the OWTP outfall that need to be addressed. One recommendation to address this is the addition of MBR in place of the existing SSTs when the AWPF is expanded. Oxnard will be one of the first facilities to reuse a significant percentage of their wastewater flow in their AWPF. One concern with this high reuse percentage is that the concentrate will raise disinfection issues. Thus as a placeholder technology in this PWIMP, UV/AOP treatment is recommended to address the potential pathogen and toxics concern. UV/AOP treatment would be needed for all OWTP effluent sent to the AWPF. A detailed discussion of this recommendation can be found in PM 4.3.

3.1.10 Effluent Pumping

The effluent pump station was installed prior to 1975 and the structure was evaluated for Immediate Occupancy during the seismic analysis. Based on this assessment, the effluent pump station building was found to be in need of replacement. Furthermore, the associated effluent pump station equipment is nearing the end of its EcRUL. In light of this, it is recommended that the entire effluent pumping station facility be replaced. These effluent pump station changes do not alter plant capacity; instead, they provide reliability for downstream users and safety for plant operators.

3.1.11 Ocean Outfall

The existing outfall was constructed around 1963, and as of 2015, the outfall is 52 years old. A pipe dive inspection was conducted in 2013 and found that the outfall was in good condition. They did not find any leaks, erosion, holes, or cracks in the line, nor did they find any port obstructions. Because of the outfall's good condition, it is recommended that the City conduct an inspection every five years and allocate funds for minor repairs after each such inspection.

3.1.12 Sludge Thickening

This section outlines the major recommendations for baseline improvements to the sludge thickening operations at the OWTP.

3.1.12.1 Gravity Thickeners

The gravity thickeners were built prior to 1964 and are in poor condition. While record drawings were not available to seismically evaluate the structures, it was assumed that because the gravity thickeners are over 50 years old, they are not seismically sound. Due to their age and poor condition, and because the majority of the equipment associated with the gravity thickeners are reaching the end of their EcRUL, it is recommended that this facility be abandoned and that the City switch to co-thickening in the Dissolved Air Flotation Thickeners (DAFTs) or thickening in the new primary clarifiers. The gravity thickeners should not only be abandoned, they should be demolished because they are taking up valuable space in the center of the treatment plant. In addition, the associated blower building and odor reduction tower, which are nearing or have passed their EcRUL, should also be demolished.

3.1.12.2 Dissolved Air Flotation Thickeners

The DAFTs are currently located to the west of the existing digesters. DAFT No. 1 has an EcRUL of only 5 years while DAFT No. 2 has a EcRUL of 15 years. If the OWTP were to switch to co-thickening in the DAFTs, additional DAFT units would be required. At their existing location, there is not space for these additional DAFT units. Additionally, the location of the existing DAFTs is the logical location for additional digesters. Because of the lack of space for additional units at their current location, their obstruction of new digester facilities, and because DAFT No. 1 is reaching the end of its EcRUL this PWIMP recommends relocating all DAFT units in the near future. Because it is recommended that the DAFTs be relocated, the replacement of existing equipment is not recommended in this master plan. Since additional DAFT units are required for co-thickening and for handling the additional solids produced with the removal of the biotower and not for additional plant capacity needs, the proposed modifications do not increase the capacity of the OWTP.

When the DAFTs are relocated, larger thickened waste activated sludge (TWAS) pumps should be added to accommodate the additional co-thickened primary sludge.

3.1.13 Digestion

It is recommended that all digesters be replaced with larger equal-sized digesters within the planning period. Digester Nos. 1 and 2 were constructed in 1975 and are thus 40 years old. Digester No. 3 was constructed in 1988 and is thus 27 years old. Digester No. 2 is currently not in service because its cover is in need of replacement. Additionally, the majority of equipment associated with the digesters is nearing the end of their EcRUL. Equipment and structures associated with digestion have EcRULs ranging from -20 years to 9 years. The condition assessment done as part of this PWIMP determined that Digester No. 2 is past its EcRUL and Digester Nos. 1 and 3 have EcRULs of only 5 years. This PWIMP recommends that before the digesters are replaced, concrete testing be performed to better assess their seismic reliability. While initial assessment indicated no seismic deficiencies, the condition of the pre-stressing bars is unknown and there may be other defects that are hard to quantify without concrete testing. Concrete testing was not done as part of this PWIMP because currently a digester cannot be taken off-line. The digester control building was assessed and it does not meet seismic code. The replacement of this building is recommended.

Replacement is also recommended for all three digesters instead of rehabilitation in part because, with the current digester configuration, there is no room for digester expansion in the future. Additionally, all three digesters are nearing the end of their EcRUL so replacement in the near future makes sense. For these reasons, this PWIMP recommends replacing the digesters with slightly larger digesters and locating them further west, starting where the DAFTs are currently located. This allows space for a future Digester No. 4 if needed beyond the planning horizon of this master plan. In order to stage this digester transition, the cover on Digester No. 2 should be replaced so it can be put back in service temporarily while concrete testing is conducted and while Digester No. 1 is moved. No other equipment replacement is included in this master plan since the digesters will be replaced in full.

3.1.14 Sludge Dewatering

It is recommended that the Solids Processing Building be relocated to the central portion of the plant in order to concentrate unsightly and odorous operations away from property boundaries. This move also allows the OWTP the option of adding a Fats, Oil, and Grease (FOG) receiving station near the digester campus of the plant. When the Solids Processing Building is moved, it is recommended that the existing belt filter presses (BFPs) be replaced as they are past their EcRUL. For the purposes of this PWIMP it was assumed that the BFPs would be replaced with centrifuges or screw presses to allow for a conservative cost estimation. Also, as solids loads increase, an additional dewatering unit would allow more operator flexibility so that the dewatering units will not need to run continuously. While it is recommended that the dewatering facilities be replaced, funds for equipment replacement have been reserved to ensure reliability during transition to a new facility.

Additionally, to decouple dewatered sludge hauling from sludge dewatering, it is recommended that digested sludge silos be added. This addition will allow operators to run the dewatering units without having to haul the sludge at the same time.

3.1.15 Cogeneration

This PWIMP recommends that the existing cogeneration building be rebuilt because it was found to be nonconforming for the Immediate Occupancy performance level during a seismic review. When this building is rebuilt, it is recommended that the associated cogeneration equipment be replaced. Following the recommendations of the “Oxnard Wastewater Treatment Plant Energy Evaluation Report,” it is recommended that the existing cogeneration units be replaced with two 850-kW generators (Carollo, 2013).

It is recommended that a complete overhaul of the existing facilities wait until after projects that are more critical have been completed. As an interim solution, this PWIMP recommends that the cogeneration building roof be rehabilitated in the near future. This recommendation is consistent with the “Preliminary Identification of Immediate Needs for the Oxnard Wastewater Treatment Plant and Collection System Sewers and Lift Stations” report (KEH, 2014) (Appendix D). A complete facility rebuild would then occur once other more critical projects, such as primary clarifier replacement, have been completed.

3.1.16 Electrical Equipment

It is recommended that the City implement a major re-electrification project at the OWTP. The majority of the existing electrical equipment was found to be in poor condition and in need of replacement. All of the motor control centers (MCCs) throughout the plant are within minus eight (-8) to eight (8) years of their EcRUL. Table 5 lists all the plant MCCs and their EcRUL. Furthermore, many of the programmable logic controllers (PLCs) and local control panels (LCPs) need to be replaced as well. A list of all electrical equipment and their EcRUL is shown in Table 6.

Table 5 Plant-Wide MCCs
Public Works Integrated Master Plan
City of Oxnard

Item	EcRUL (year)
MCC-DP4A, MCC-EDPID, MCC- DP2A, MCC- EBPIB, MCC - DP3C, MCC -DP3D, MCC-DP2B, MCC-DPIA, MCC-DPIB, MCC-EDPIA	-8
MCC-DP2C, MCC-EDPIC, MCC-GF, MCC-DP4, MCC-DP4B, MCC-GB, MCC-GC, MCC-GD, MCC- DP2D, MCC-DP3A, MCC-EDPIE, MCC-HG, MCC-DP3B	2
MCC-SH, MCC-NA, MCC-NC, MCC-ND, MCC-NE, MCC-NF, MCC-HC, MCC-NG, MCC-GA	6
MCC- HW	8

Table 6 Small Electrical Equipment
Public Works Integrated Master Plan
City of Oxnard

Item	EcRUL (year)
Electrical - Main Electrical Building	
Older Transformers	2
Older Transformer 2	2
Switchboard MA-MB	6
Switchgear 1	6
Switchgear 2	2
Switchgear HW	6
Transformer A	10
Transformer B	10
Electrical - North Area Electrical Building	
Switchboard-NB	8
Switchgear	6
Switchboards Large	12
Transformer TC	6
Transformer TD	8
VFDs (13)	6
General - Effluent Electrical Building	
Gym Switchgear	-8

Another major electrical concern at the OWTP is the lack of emergency power. There is only one power feed to the plant. While the generators have adequate capacity, these cannot be brought on line quickly enough to serve as emergency power. In the event of power loss, influent is directed to a primary clarifier. This allows for a half hour detention time until power can be brought online. Reserving clarifier capacity for emergency use, however, means that many maintenance and rehabilitation activities cannot be conducted routinely. This PWIMP recommends replacing the generators.

This PWIMP also recommends conducting an electrical vault repair predesign study, which is consistent with KEH's findings (KEH, 2014). This study would look at the need to repair corroded concrete surfaces and replace corroded conduits, wires, and junction boxes. SCADA improvements are also recommended. A detailed discussion of these recommendations can be found in PM 3.10, *Wastewater - SCADA Assessment.*

3.1.17 Non Process Buildings

The non-process buildings were assessed during both the condition and the seismic analysis. The results of these two assessments are summarized in Table 7.

Table 7 Non Process Building Recommendations
Public Works Integrated Master Plan
City of Oxnard

Building	Seismic Deficiency	Condition Assessment EcRUL (year)
Replacement Recommended		
Main Switchgear Building	Replace	-20
Butler Storage Building - West	Replace	5
Operations Center Building	Replace	-20
Administration Building(1)	Structure is Adequate, Retrofit Non Structural Components(2)	15
Vacuum Filter Building	Replace	-20
Eastern Trunk Pump Station	Not Evaluated	5
Butler Storage Buildings - East	Replace	5
Effluent Electrical Building(3)	Replace	5
Rehabilitation Recommended		
Collection System Maintenance Building	Retrofit Structural and Non Structural Components(2)	5
Chemical Handling Facilities Building	Retrofit Structural and Non Structural Components(2)	5
Maintenance Building	Retrofit Structural and Non Structural Components(2)	15
North Area Electrical Building	Retrofit Non Structural Components(2)	20

Table 7	Non Process Building Recommendations Public Works Integrated Master Plan City of Oxnard

Notes:
(1) It is recommended that the Operations Center be replaced and co-located with the existing Administration Building, either as an addition or as a new combined structure. This frees space in the central corridor of the OWTP and concentrates non-process facilities at the perimeter.
(2) Details of the recommended retrofits can be found in the Seismic Assessment of OWTP Structures – Tier 2 Evaluation.
(3) It is recommended that the Effluent Electrical Building be replaced as part of the major electrical upgrade recommended. Additionally, this building is currently located at one of the lowest elevations at the plant most at risk for sea level rise.

3.1.18 Other Facility Recommendations

This section tabulates all the miscellaneous plant improvement recommendations of this PWIMP. On a plant-wide basis, it is recommended that budget be allocated for a plant re-paving project once the initial set of construction projects is complete. Additionally, this PWIMP recommends that budget be allocated for a plant-wide cathodic protection project and yearly cathodic protection maintenance. This recommendation is consistent with the “Asset Corrosion Assessment and CP Evaluation Survey” done by JDH Corrosion Consultants (PM 3.9) as part of this PWIMP. It is also recommended that the City invest in a new Computerized Maintenance Management System (CMMS). The existing system is old and outdated and does not communicate with all of the different departments. An upgrade will allow for more uniformity and the ability to share data between departments. Finally, as recommended in the “Mechanical Audit Report,” various heat pumps and AC condensing units should be replaced with more efficient models (The Energy Network - Mechanical Audit, 2014).

In addition to these plant-wide improvements, it is recommended that the City allocate funds for the potential future need for a seawall. As shown in Figure 1, it is anticipated that the 100-year storm sea level could rise as much as seven (7) feet by 2040. Based on these high end projections, Table 8 shows the year when each major unit process could be flooded. This PWIMP recommends that the need for a sea wall be re-evaluated and potentially implemented as soon as 2034.

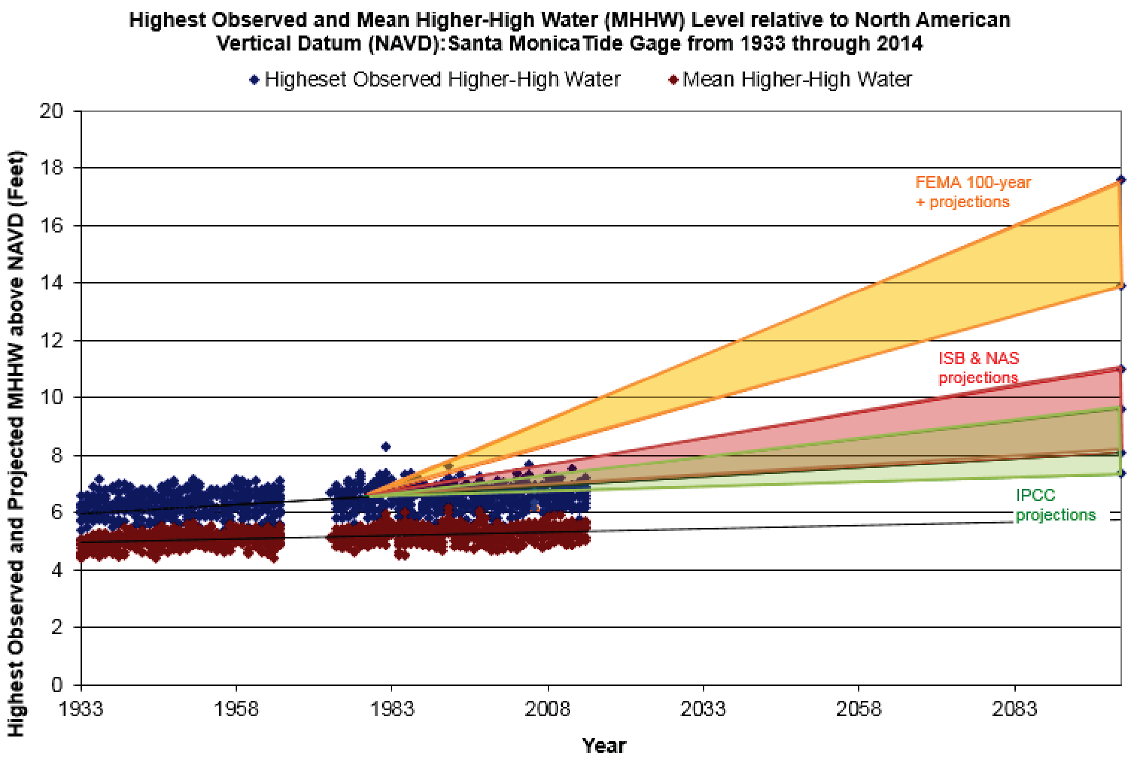


Figure 1 Projected Sea Level Rise

Table 8 Flood Level Projections for Major Unit Processes
Public Works Integrated Master Plan
City of Oxnard

Unit Process	Lowest Flood Elevation (ft)	Year of Flooding[1,2]	Notes
WAS Pumps	4.8	1958	Replacing Facility
Main Electrical Building	9.8	2014	Replacing and Moving Facility
Plant Control Center	10.3	2020	Replacing and Moving Facility
Gravity Thickeners	10.4	2021	Abandoning Facility
Interstage Pump Station	10.5	2021	Replacing and Moving Facility
Flow Equalization Basins	10.7	2023	
Primary Treatment Pumps	10.8	2025	Replacing Facility
Solids Processing/Dewatering	11.3	2030	Replacing and Moving Facility
Aerated Activated Sludge	12.0	2038	
North Area Electrical Building	12.2	2041	
Collection System Maintenance	12.3	2041	
Administration Building	12.6	2044	Replacing Facility
DAF Tanks	12.6	2045	Replacing and Moving Facility
Digesters	12.9	2048	Replacing and Moving Facility
Effluent Pump Station	12.9	2048	Replacing and Moving Facility
Sedimentation Basins	13.7	2057	

Table 8 Flood Level Projections for Major Unit Processes Public Works Integrated Master Plan City of Oxnard			
Unit Process	**Lowest Flood Elevation (ft)**	**Year of Flooding(1,2)**	**Notes**
Headworks	15.3	2075	
Disinfection Facilities	17.5	2099	
Primary Tanks	19.5	2121	Replacing Facility
RAS Pumps	27.1	2205	Replacing Facility

Note:
(1) Year of flooding based off of FEMA 100 Year+ Projections (Santa Monica Tide Levels 1933 to 2014).
(2) See Figure 7 in PM 3.1 for a graphical interpretation of this data.

3.2 Scenario 2: Energy Efficiency

While the baseline scenario, Scenario 1, focuses on repairs and additions necessary to keep the plant operational and in compliance with their existing NPDES permit, Scenario 2 focuses on projects that promote energy efficiency at the OWTP. This scenario includes all projects discussed under Scenario 1. However, Scenario 2 also includes projects to reduce energy use at the OWTP. These additional projects are discussed in the sections below.

3.2.1 FOG Receiving Station

The first project recommended as part of Scenario 2 is a Fats, Oil, and Grease (FOG) receiving station. This receiving station would allow for flexibility in FOG addition timing thus preventing slug loading which can cause digester upsets. This also allows for the addition of FOG when energy costs are high. Two alternatives for a FOG receiving station were recommended in the “Oxnard Wastewater Treatment Plant Energy Evaluation Report” (Carollo, 2013). The first alternative would double the current FOG addition. The second alternative would increase FOG addition to the digester capacity limit. For the purpose of this PWIMP, alternative two was chosen because it had the larger potential for energy savings. Adding a FOG receiving station by 2020 is also recommended as part of Oxnard’s Energy Action Plan (Oxnard Planning Division, 2013).

3.2.2 Solar or Alternative Energy Facility

The second project recommended as part of Scenario 2 is the addition of solar cells as recommended in the “Oxnard Wastewater Treatment Plant Energy Evaluation Report” (Carollo, 2013) (Appendix C). For this PWIMP, it was assumed that solar photovoltaic cells would be added to the rooftops and carports recommended in the Energy Evaluation Report (Carollo, 2013). This addition would increase the amount of energy produced onsite and thus help the OWTP achieve energy self-sufficiency.

3.3 Scenario 3: Resource Recovery

Scenario 3 focuses on projects that maximize water reuse and nutrient mining. This scenario includes all projects discussed under Scenario 1 and Scenario 2. However, Scenario 3's focus is to protect and enhance resource sustainability. The additional projects included in Scenario 3 are discussed in the sections that follow.

3.3.1 Phosphorous Recovery

The first project recommended as part of Scenario 3 in this PWIMP is the addition of a phosphorous recovery facility. This facility would harvest phosphorous from the dewatering centrate and create marketable fertilizer pellets. An example of such a process is shown in Figure 2.

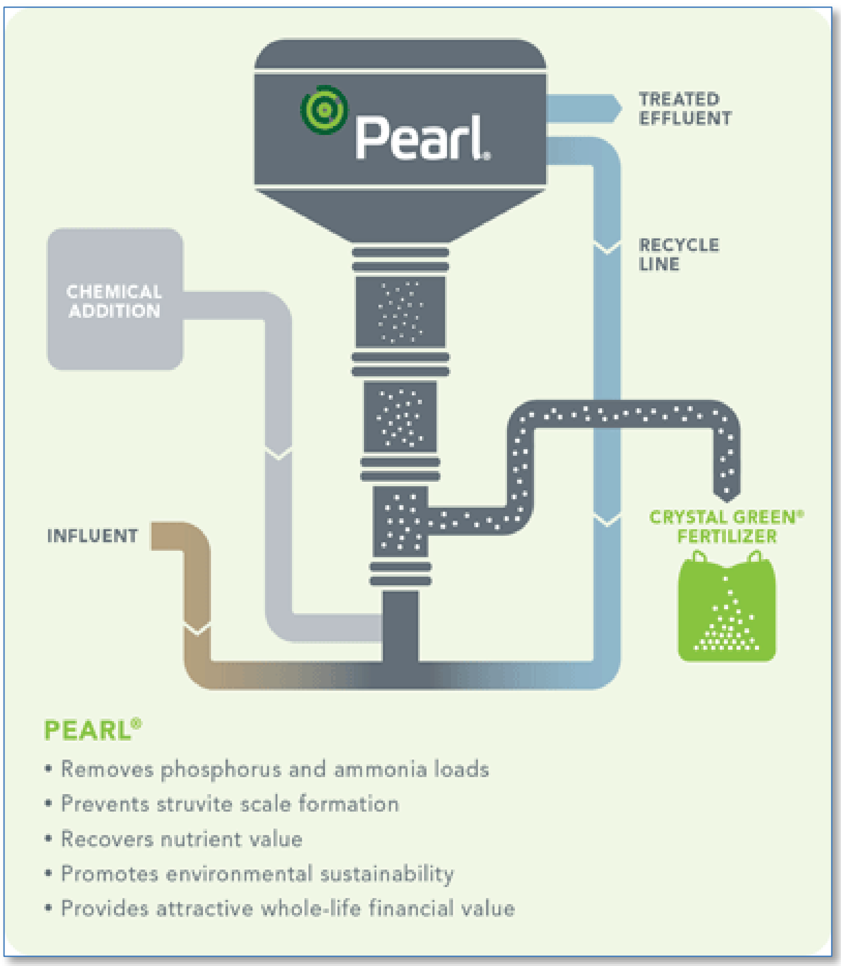


Figure 2 Phosphorous Recovery Schematic *Source: Ostara Nutrient Recovery Technologies*

3.3.2 Sludge Post Processing

The second project recommended as part of Scenario 3 is the addition of a sludge post processing facility. The purpose of this facility would be to decrease the amount of sludge hauled to a landfill. This reduction not only enhances onsite reuse of waste materials, but it is also more favorable from a regulatory standpoint. As discussed in PM 3.1 Section 2, sending sludge to a landfill facility will likely become increasingly difficult throughout California. It is thus prudent to plan for alternative sludge disposal methods.

4.0 SCENARIO EVALUATION

4.1 Economic Analysis

A cost estimate of the three main scenarios was developed for facilities needed through the planning period (2040). The costs were developed using factors outlined in PM 1.4, Basis of Cost as well as cost information from past projects and estimates. The economic comparison of the three scenarios considered is shown in Table 9.

Table 9 Comparison of Scenario Costs(1)
Public Works Integrated Master Plan
City of Oxnard

Cost ($ M)	Scenario 1	Scenario 2	Scenario 3
Headworks	$14.9	$14.9	$14.9
Primary Treatment	$20.9	$20.9	$20.9
Secondary Treatment	$100.3	$100.3	$100.3
Disinfection/Effluent Pumping/Outfall	$24.5	$24.5	$24.5
Sludge Thickening	$13.4	$13.4	$13.4
Digestion	$34.4	$34.4	$34.4
Dewatering and Sludge Post Processing	$27.6	$27.6	$88.1
Cogeneration/FOG	$13.8	$16.5	$16.5
Electrical	$18.3	$18.3	$18.3
Non-Process Buildings	$25.1	$25.1	$25.1
Other	$33.6	$34.8	$38.3
Total Construction Cost	**$327**	**$331**	**$395**
Total Project Cost(2)	**$405**	**$410**	**$489**
Annual Costs ($ M / yr)	$20.3	$20.5	$24.5
Annualized Project Cost(3)	$33	$33	$39
Total O&M(4)	$5.0	$5.4	$6.5
Total Annual Cost	$37.5	$38.3	$45.8

Table 9	Comparison of Scenario Costs(1) Public Works Integrated Master Plan City of Oxnard

Notes:
(1) Costs derived using the methodology outlined in PM 1.4, Basis of Cost.
(2) Project costs include project cost factor (as outlined in PM 1.4, Basis of Cost).
(3) Annualized at 5% over 20 years.
(4) O&M costs include only additional O&M costs from new capital improvement projects.

4.2 Non-Economic Considerations

In addition to the economic analysis, non-economic considerations were summarized that relate to the goals and objectives for the PWIMP, as noted in Section 2.0. That summary is included in Table 10. Using those considerations, a combined comparison was done to determine if there was dramatic difference in the scenarios. The comparison, highlighted in Table 10, showed a slight advantage to Scenario 2 and 3 due to moderate to high goal achievement. Based upon this assessment and the lower cost of Scenario 2 compared to Scenario 3, the City agreed to move forward with Scenario 2: Energy Efficiency.

4.2.1 Energy Analysis

In addition to the overall comparison shown in Table 10, a specific energy comparison was developed to further assess the three scenarios. This comparison draws in large part from the following documents:

- "Energy Action Plan: A component of the Oxnard Climate Action and Adaptation Plan" (Oxnard Planning Division, 2013).
- "Oxnard Wastewater Treatment Plant Energy Evaluation Report" (Carollo, 2013).
- "Water and Wastewater Process Optimization and Mechanical Audit Report DRAFT" (The Energy Network, 2014).
- "Mechanical Audit Report" (The Energy Network, 2014).

This section summarizes the findings of the documents listed above and explains how they are applicable to the OWTP scenario evaluation. In general, there is the potential for energy savings from both large recommended capital improvement projects, and smaller equipment replacement projects. All of the smaller equipment replacement projects are recommended for all three scenarios, and thus while important, do not differentiate one scenario from another. The recommended small equipment projects are as follows:

- Replace the Admin Building 10-ton rooftop split system outdoor heat pump unit.
- Replace the Maintenance Building 4-ton rooftop single package heat pump unit.

Table 10 Non-Economic Consideration of Water Supply Alternatives
Public Works Integrated Master Plan
City of Oxnard

	Scenario 1 - Baseline	Scenario 2 - Energy Efficiency	Scenario 3 - Resource Recovery
Goal 1: Compliant, reliable, flexible system	Moderate	High	High
Goal 2: Economic sustainability	Moderate	High	Moderate
Goal 3: Mitigate/adapt to climate change	Moderate	Moderate	Moderate
Goal 4: Resource sustainability	Low	Moderate	High
Goal 5: Energy efficiency	Low	High	High
Benefits	• Lower overall cost • Focuses on rehabilitating the existing plant as the highest priority • Provides a seawall to protect against potential sea level rise from climate change	• Moderate cost • More flexible system to address potential future changes in the cost of energy • Provides a seawall to protect against potential sea level rise from climate change	• More flexible in sludge handling and resource recovery • More flexible system to address potential future changes in the cost of energy • Provides a seawall to protect against potential sea level rise from climate change
Drawbacks	• Does not directly address goal 4 or goal 5 • Less able to adapt to potential future increases in the cost of energy • Does little to take advantage of resources produced onsite	• Does not focus on recovering nutrients and sludge onsite	• High Cost

- Replace the Maintenance Building 5-ton rooftop single package gas/electric unit.
- Replace the Operations Center 4-ton and two 3-ton rooftop single package heat pumps.
- Replace the Effluent Electrical Room 3-ton rooftop split system outdoor heat pump unit.
- Replace the North Area Electrical Building 7.5-ton rooftop single package heat pump unit.
- Replace the storage building server room 5-ton split system AC condensing unit.
- Replace the new headworks 3-ton rooftop single package AC.

See The Energy Network's "Mechanical Audit Report" for more information on these recommendations. Combined, these changes could decrease energy use at the plant by 27,075 kWhs.

There is also the potential for some of the recommended larger capital improvement projects to produce energy savings. These projects and their potential energy savings are shown in Table 11.

Table 11 Potential Energy Savings
Public Works Integrated Master Plan
City of Oxnard

Recommendation	Potential Relative Energy Savings		
	Scenario 1	Scenario 2	Scenario 3
Biotower Removal and Interstage Pump Reconfiguration	Included in All Scenarios	Included in All Scenarios	Included in All Scenarios
AST Blower Replacement	Included in All Scenarios	Included in All Scenarios	Included in All Scenarios
Cogen Replacement	Included in All Scenarios	Included in All Scenarios	Included in All Scenarios
FOG Receiving Station	NA	+	+
Solar or Alternative Energy Facility	NA	+	+
Incineration	NA	NA	+
Total Potential Energy Savings:	+	++	+++

Note:
(1) Only projects that could produce energy savings are included in this analysis.

As shown in this table, both Scenario 2 and 3 achieve greater potential energy savings than Scenario 1. Furthermore, both Scenario 2 and 3 are consistent with Oxnard's Energy Action Plan.

As discussed in PM 1.1, one of Oxnard's goals, as stated in the Energy Action Plan, is to reduce City-wide energy usage by 10 percent. The Energy Action Plan outlines specific ways to help achieve this goal, and one of these recommendations is directly applicable to the OWTP. Goal G-14: Increase on-site electricity generation at City wastewater treatment and materials recovery facility is directly addressed in Scenario 2 and 3 with the addition of a FOG receiving station to increase FOG sent to the digesters. This project will subsequently increase the amount of energy the cogeneration facilities can recover. Given the greater potential for energy savings and the alignment with Oxnard's Energy Action Plan goals, Scenario 2 is recommended.

5.0 RECOMMENDED PROJECTS

After discussion with the City, the team recommends proceeding with Scenario 2. This section summarizes the estimated funding requirements for all within the fence-line OWTP projects in Scenario 2 through the year 2040. This information is used as the basis for the financial analysis portion of the PWIMP to determine the financial impact of the project to the City and its rate payers.

There are four main drivers for the projects included within the CIP: 1) Rehabilitation and Replacement (R&R), 2) Small Equipment Replacement, 3) Performance, and 3) Resource Sustainability. These drivers are noted next to each project along with their anticipated start year and length of project completion. The projects are categorized in phases which loosely also follows timing of the projects: 1) Phase 1A and B – Immediate needs; 2) Phase 2 – Near-Term Needs; and 3) Phase 3 – Long-Term Needs.

Each of the drivers is described in more detail below.

5.1 Rehabilitation and Replacement (R&R)

Several analysis conducted as part of the PWIMP have assessed the condition of the City's existing wastewater system assets. In general, R&R is the main driver for the majority of the recommended projects at the OWTP. The following PMs address the existing OWTP asset assessments that were made:

- PM 3.5 - Wastewater Condition Assessment - Assessed the R&R needs of and developed priorities for the wastewater lift stations and all mechanical and electrical equipment as well as all structures at the OWTP.

- PM 3.6 - Seismic Assessment - Assessed the seismic safety hazard of all buildings and all water retaining structures at the OWTP.

- PM 3.8 - Arc Flash Assessment - Included a Short Circuit Study, Protective Device Coordination Study and an Arc Flash Study of the OWTP facilities.

- PM 3.9 - Cathodic Protection - Assessed the cathodic protection needs of the wastewater system and developed a list of recommended projects to address deficiencies.

5.2 Small Equipment Replacement

Small equipment replacement budgets have been included for all unit processes. These budgets were developed as part of the condition assessment analysis conducted in PM 3.5, Wastewater Condition Assessment. All existing small equipment at the OWTP was assigned a remaining useful life as well as a replacement cost. Small equipment for each unit process was then grouped by expected replacement year into five year increments and their expected replacement costs were summed. The allocated costs in Table 10 reflect this analysis.

5.3 Performance

Performance projects include projects that will help optimize current OWTP plant operations. These projects with either make the plant easier to run for plant operators or they will help optimize the treatment ability of the plant.

5.4 Resource Sustainability

Resource sustainability is the main driver for the projects that aim to recover resources on site and decrease waste sent offsite. Such projects include onsite energy generation, onsite nutrient recovery, and onsite sludge reduction.

5.5 Cost, Phase and Schedule Summary

The Recommended Wastewater project costs presented in Table 12 are based on the preliminary layouts, sizing and configuration. Project costs are estimated based on unit costs developed from estimating guides, equipment manufacturer's information, unit prices, and construction costs of similar facilities and other locations. A more detailed discussion of the basis of costs is included in PM 1.4, Basis of Cost.

The costs and timing presented in this PM represent Carollo's best professional judgment of the capital expenditure needs of the City and of the timing needed to maintain a reliable and compliant system that can meet current and future wastewater generation needs. Timing was set to align with the seven master plan drivers, namely: R&R, regulatory requirements, economic benefit, performance benefit, growth, resource sustainability, and policy decisions. Timing is also based on input from City staff and the condition assessments performed.

Table 12 Recommended Projects, Cost Estimates, and Phasing for Within Fence-Line Wastewater System – Upgrade in Place[7]
Public Works Integrated Master Plan
City of Oxnard

Project Name	Driver	Start Year	Years to Implement	Un-escalated Project Cost ($)
Phase 1A Projects:				
Biotower Removal				
Demolish Biotowers	R&R	2016	1	$770,000[1]
Add Baffle Walls in ASTs	R&R	2016	1	$380,000
Reconfigure Interstage Pumping (and replace pumps)	R&R	2016	2	$15,020,000
Primary Clarifier Replacement				
Demolish and Rebuild Primary Clarifiers	R&R	2016	6	$18,600,000
Rebuild Primary Clarifier Building/ Pump Sludge Pump Station	R&R	2016	6	$2,893,000
Add CEPT including Mixing Facilities	Performance	2016	2	$1,470,000[2]
Add Influent Splitter Box	Performance	2016	2	$1,450,000
Demolish Butler Storage Building - West	R&R	2016	1	$49,000
New Butler Storage Building - West	R&R	2021	1	$954,000
Small Equipment Replacement - Primary Clarifier	R&R	2016	1	$469,000
Electrical Upgrade: MCC, Electrical Buildings, CMMS, and Emergency Generator Replacement				
New Main Switchgear Building	R&R	2017	3	$926,000
New Effluent Electrical Building	R&R	2017	3	$1,158,000
Electrical Vault Repair Pre-Design Study	R&R	2016	2	$27,000[3]
Replace Standby Generators	R&R	2016	3	$2,543,000
Replace Plant MCCs	R&R	2016	5	$5,430,000

Table 12 Recommended Projects, Cost Estimates, and Phasing for Within Fence-Line Wastewater System – Upgrade in Place[7]
Public Works Integrated Master Plan
City of Oxnard

Project Name	Driver	Start Year	Years to Implement	Un-escalated Project Cost ($)
Plant-wide SCADA System Upgrade	R&R	2016	5	$10,816,000
Small Equipment Replacement - Electrical 1	Small Equipment Replacement	2016	2	$275,000
Small Equipment Replacement - Electrical 2	Small Equipment Replacement	2020	2	$626,000
Small Equipment Replacement - Electrical 3	Small Equipment Replacement	2023	2	$653,000
CMMS	R&R	2016	3	$250,000
BFP Rehab and Non Hazardous Liquid Receiving Station				
BFP Rehab	R&R	2016	1	$2,280,000[2]
Construct a Non Hazardous Liquid Receiving Station[8]	Performance	2016	2	$2,564,000
Phase 1B Projects:				
Plant-wide Cathodic Protection	R&R	2016	2	$1,430,000[4]
Solids Campus Upgrade: Gravity Thickener Demo, Dewatering Move and Upgrade, and DAFT Move and Expansion				
Install Cover on Digester 2	R&R	2016	1	$2,260,000[3]
Demolish Gravity Thickeners and Blower Building	R&R	2017	1	$583,000
Demolish Odor Reduction Tower	R&R	2017	1	$100,000
Demolish Operations Center and Vac Filter Bld	R&R	2017	1	$448,000
Move Dewatering Facility and add New Centrifuges	Performance	2016	3	$23,370,000
Add Dewatering Capacity	Performance	2016	3	$2,160,000
New Operations Center Building co-located with new Administration Building	R&R	2016	4	$20,940,000
Add Sludge Silos	Performance	2018	3	$6,370,000

Table 12 Recommended Projects, Cost Estimates, and Phasing for Within Fence-Line Wastewater System – Upgrade in Place[7] Public Works Integrated Master Plan City of Oxnard				
Project Name	**Driver**	**Start Year**	**Years to Implement**	**Un-escalated Project Cost ($)**
Demolish DAFTs and Rebuild (2) at New Solids Campus	Performance	2018	3	$8,590,000
Build additional 2 DAFTs at New Solids Campus	Performance	2018	3	$7,350,000
Add TWAS Sludge Pumping Capacity	Performance	2018	3	$40,000
Building Upgrades for Seismic Safety and Plant Paving Resurfacing				
Rehab Cogen Building Roof	R&R	2017	2	$120,000[3]
New Storage Building ("Vacuum Filter Building")	R&R	2017	3	$4,406,000
Rehab Collection System Maintenance Building	R&R	2019	2	$1,399,000
Rehab Chemical Handling Facilities Building	R&R	2019	2	$746,000
Rehab Maintenance Building	R&R	2019	2	$279,000
Rehab North Area Electrical Building	R&R	2019	2	$448,000
Rehab Grit Screening Building - Seismic Retrofit	R&R	2019	2	$1,866,000
New Eastern Trunk Pump Station	R&R	2019	2	$1,003,000
New Butler Storage Buildings - east	R&R	2022	2	$1,158,000
Small Equipment Replacement - General Building 1	Small Equipment Replacement	2016	2	$190,000
Small Equipment Replacement - General Building 2	Small Equipment Replacement	2023	2	$89,000
Plant Paving Resurfacing	Small Equipment Replacement	2022	3	$410,000[5]
Headworks Odor Control, Concrete and Coating Repair, and RPF Cover Replacement				
Headworks Odor Control with Screen Walls, Concrete Repair, and RPF Cover Replacement	R&R	2016	3	$4,640,000[2,3]
Below Cover Coating Repairs	R&R	2016	4	$1,310,000[3]

Table 12 Recommended Projects, Cost Estimates, and Phasing for Within Fence-Line Wastewater System – Upgrade in Place(7)
Public Works Integrated Master Plan
City of Oxnard

Project Name	Driver	Start Year	Years to Implement	Un-escalated Project Cost ($)
Secondary Treatment Concrete Rehab, Equipment Replacement, and Process Optimization				
Concrete Repair and Seismic Retrofit - EQ Basin	R&R	2016	3	$2,596,000
Concrete Repair and Seismic Retrofit - ASTs	R&R	2016	11	$8,121,000
Concrete Repair and Re-painting - SSTs	R&R	2016	11	$5,719,000
Modify SST Inlet	Performance	2016	3	$160,000
New ML Wasting Station	Performance	2016	3	$2,640,000
Replace Collectors, Skimmers, and Drives (Secondary Sedimentation Tanks)	R&R	2016	3	$9,925,000
RAS Pump Modifications	Performance	2016	3	$1,120,000
Replace Blowers	R&R	2016	3	$2,585,000
Diffuser Replacement	R&R	2016	3	$3,120,000(1)
Small Equipment Replacement - secondary 1	Small Equipment Replacement	2016	3	$610,000
Small Equipment Replacement - secondary 2	Small Equipment Replacement	2020	3	$62,000
Small Equipment Replacement - wet weather storage 2	Small Equipment Replacement	2020	3	$527,000
Disinfection and Effluent Pumping Equipment Replacement				
New Effluent Pumping Station Building	R&R	2017	4	$1,234,000
New Effluent Pump Station	R&R	2017	4	$13,838,000(2)
Water Quality Early Warning System	Performance	2017	4	$330,000(2)
			PHASE 1 TOTAL:	**$213,895,000**

Table 12 Recommended Projects, Cost Estimates, and Phasing for Within Fence-Line Wastewater System – Upgrade in Place[(7)]
Public Works Integrated Master Plan
City of Oxnard

Project Name	Driver	Start Year	Years to Implement	Un-escalated Project Cost ($)
Phase 2 Projects:				
Headworks Equipment Replacement and Building Rehab				
Small Equipment Replacement - Headworks 1	Small Equipment Replacement	2019	2	$383,000
Small Equipment Replacement - Headworks 2	Small Equipment Replacement	2023	3	$6,306,000
Small Equipment Replacement - Headworks 3	Small Equipment Replacement	2028	2	$149,000
Rehab Headworks Building	R&R	2032	3	$ 3,858,000
Digester Campus Rebuild of Digesters and Digester Control Building				
New Digester 1	R&R	2019	3	$12,950,000
New Digester 2	R&R	2020	3	$12,950,000
New Digester 3	R&R	2021	3	$12,950,000
New Digester Control Building	R&R	2019	5	$1,543,000
Cogen Building and Equipment Replacement, New FOG Receiving Station				
New Cogen Building	R&R	2022	3	$4,630,000
Small Equipment Replacement - Cogen	Small Equipment Replacement	2022	3	$2,233,000
Replace Cogen Engines	R&R	2022	3	$10,140,000[(6)]
Add a FOG Receiving Station	Resource Sustainability	2019	2	$3,390,000[(6)]
Disinfection Equipment Replacement				
Coating Replacement on Chlorine Contact Tanks	R&R	2026	2	$1,359,000
Small Equipment Replacement 1	Small Equipment Replacement	2024	3	$403,000
			PHASE 2 TOTAL:	**$73,244,000**

Table 12 Recommended Projects, Cost Estimates, and Phasing for Within Fence-Line Wastewater System – Upgrade in Place[7] Public Works Integrated Master Plan City of Oxnard				
Project Name	**Driver**	**Start Year**	**Years to Implement**	**Un-escalated Project Cost ($)**
Phase 3 Projects:				
MBR	Resource Sustainability	2019	2	$71,000,000
Add UV/AOP after MBR	Resource Sustainability	2019	2	$13,200,000
Solar or Alternative Energy Facility	Resource Sustainability	2021	10	$1,540,000[6]
Seawall	Resource Sustainability	2033	5	$37,260,000
	PHASE 3 TOTAL:			**$123,000,000**

Notes:

(1) From 2014 report by MKN Associates.
(2) From AECOM's estimates.
(3) From KEH's 2014 Immediate Needs Report.
(4) From PM 3.8 Cathodic Protection Assessment.
(5) From City's 2013 CIP.
(6) From the 2013 Energy Evaluation Report by Carollo.
(7) Project costs, schedules, and phasing are based on data and information available at the time of the original date of preparation – December 2015. The updated CIP is contained in the Brief History section of the PMs, the Summary Report, and the Executive Summary.
(8) The Waste Receiving Station should be located near the OWTP Headworks (i.e., the head of the plant). Based on this, the City may need to use the land currently leased to the Port Hueneme Water Agency.

While the costs developed in this PM match the costs analyzed as part of the Cost of Service Study, the timing presented may differ. The Cost of Service Study will balance not only the CIP projects identified but also the rates and rate payer affordability based on a yearly balance and also the integrated costs for the different City funds and enterprises.

The Overall Project Costs for the Recommended Wastewater Projects are summarized in Table 13.

Based on capacity and reliability needs, a preferred project schedule for Scenario 2 was developed to phase the recommended project components over a 25-year period. The schedule presented in this section was developed based on the technical aspects of the projects to minimize risk and allow for future flexibility. Both design and construction durations are shown. Because the majority of the projects are R&R and many of them could ideally start now, consideration was given to constructability at the space-limited plant and precedence was shown for critical projects. It is possible that the actual timing of these projects will change when looking at all of the City's facilities holistically instead of just focusing on the within-fence line OWTP projects.

Table 13 Overall Project Costs by Phase for within Fence-Line Wastewater System – Upgrade in Place(1)
Public Works Integrated Master Plan
City of Oxnard

Phase	Un-escalated Project Cost
1A	$70,000,000
1B	$144,300,000
2	$73,200,000
3	$123,000,000
Total	**$410,500,000**

Notes:
(1) Project costs, schedules, and phasing are based on data and information available at the time of the original date of preparation – December 2015. The updated CIP is contained in the Brief History section of the PMs, the Summary Report, and the Executive Summary.

The 25-year CIP runs through FY 2039/40. During this period, the majority of the CIP is focused on rehabilitation and replacement of the existing system. Over the next 25 years, the City's CIP will accomplish:

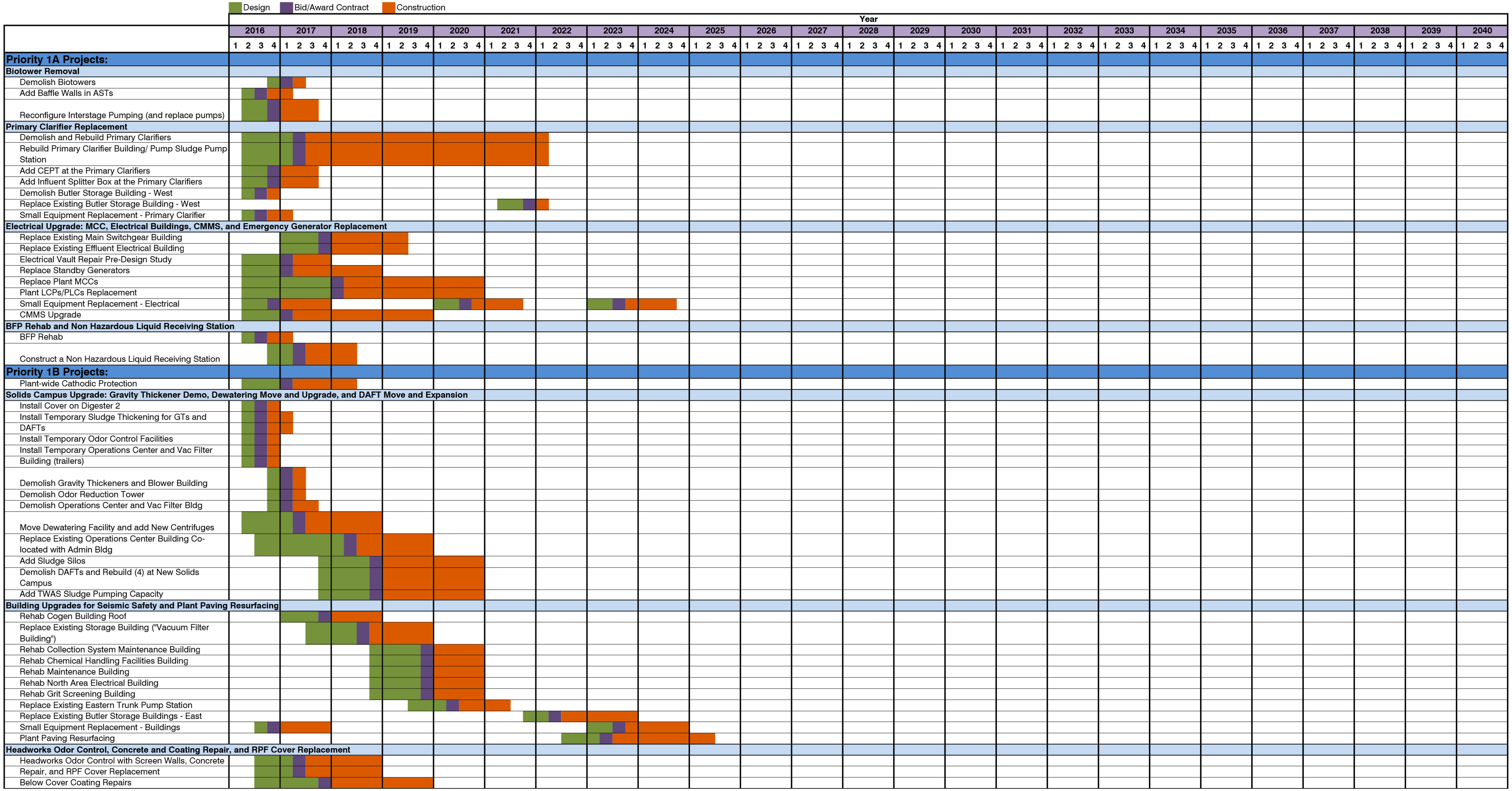
- Removal of the Biotowers.
- Replacement of the Primary Clarifiers.
- A major re-electrification of the plant to increase reliability.

- A solids campus upgrade to increase the reliability of sludge thickening, digestion, and dewatering.
- Building upgrades to meet current seismic code.
- Headworks upgrades to control odors.
- Secondary treatment rehab to address seismic and aging equipment concerns.
- A replacement of the effluent pumping equipment.
- A replacement of the cogeneration facilities.
- Potential process changes to promote resource recovery and energy self-sufficiency.

Figures 3A and 3B show the Recommended Wastewater Project schedule for Scenario 2. Scenario 2 totals approximately $416 million in 2014 dollars. Recommended expenditures are heavily weighted towards the first 10 years of the program, totaling $373 million. Due to the front-loaded nature of the Recommended Projects, implementation of these projects will be the most significant driver of the City's financial plan.

Figures 3C through 3H show the 2015 – 2020 year-by-year implementation projects, respectively. Figures 3I through 3K show the 2025, 2030, and 2035 implementation projects, respectively.

Oxnard - Wastewater CIP Schedule



RECOMMENDED WASTEWATER CIP SCHEDULE (Part 1)

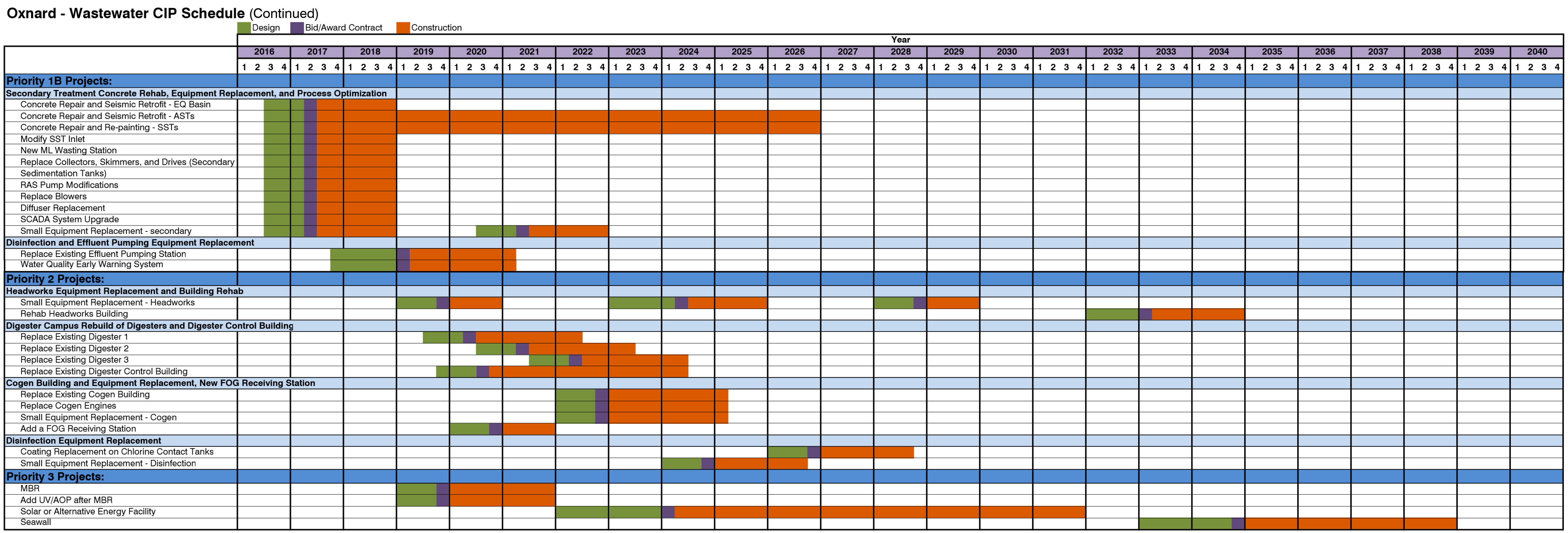
FIGURE 3A

CITY OF OXNARD

PM NO. 3.7.1 WASTEWATER

PUBLIC WORKS INTEGRATED MASTER PLAN

ox1015f1-9587(PM3-7-1FIG3A).ai



RECOMMENDED WASTEWATER CIP SCHEDULE (Part 2)

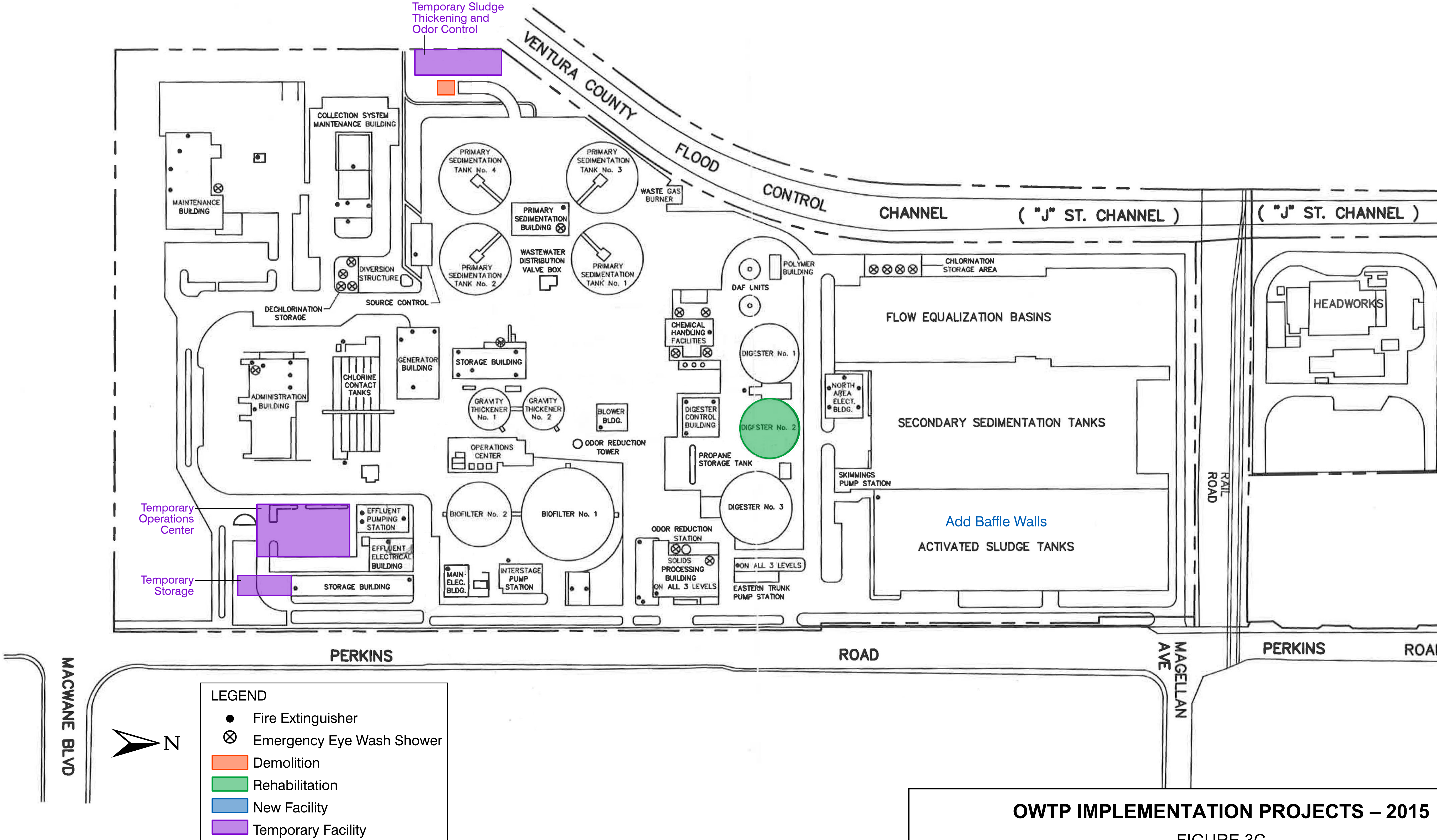
FIGURE 3B

CITY OF OXNARD

PM NO. 3.7.1 WASTEWATER

PUBLIC WORKS INTEGRATED MASTER PLAN

ox1015f2-9587(PM3-7-1FIG3B).ai

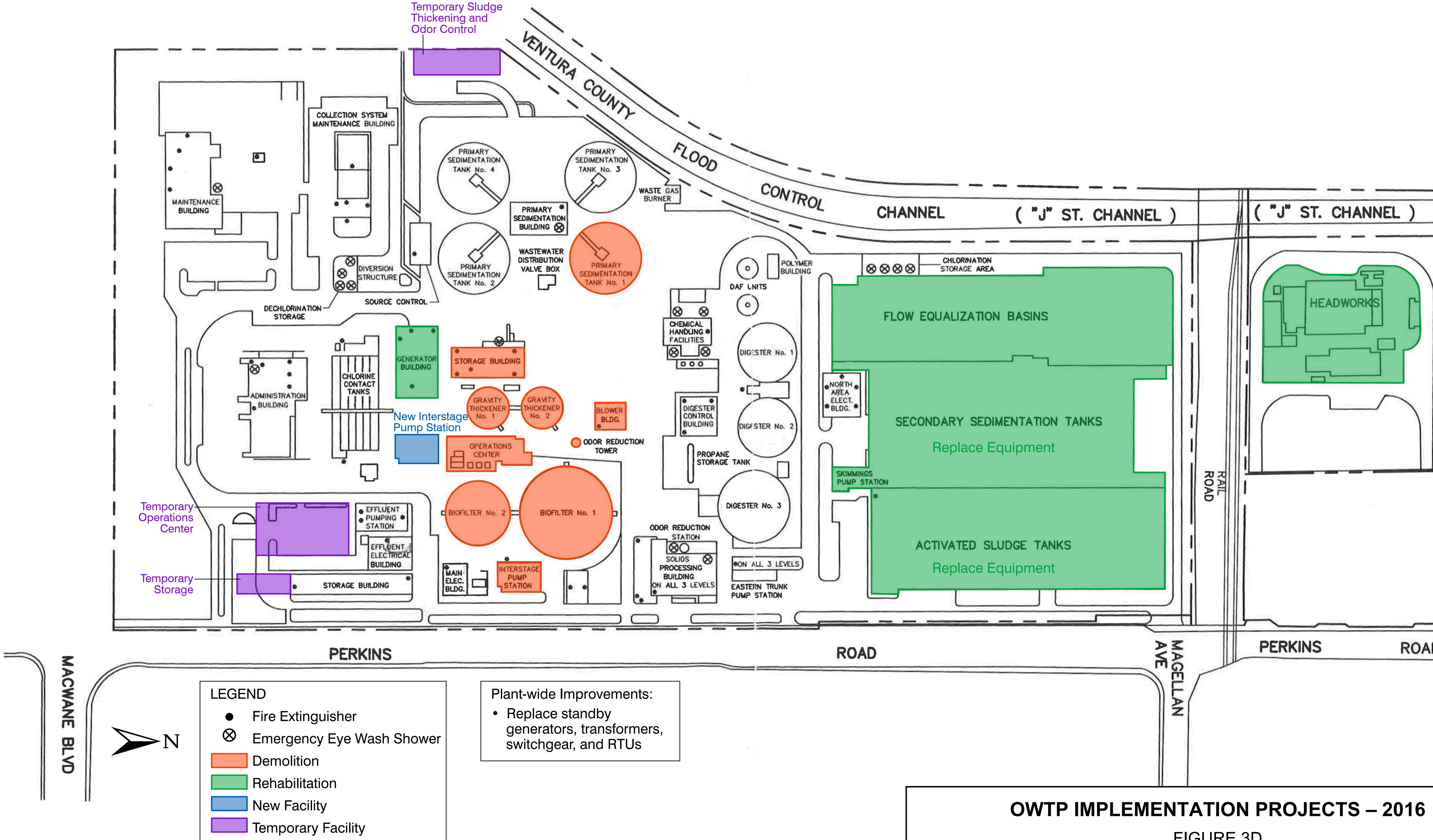


OWTP IMPLEMENTATION PROJECTS – 2015

FIGURE 3C

CITY OF OXNARD
PM NO. 3.7.1 WASTEWATER
PUBLIC WORKS INTEGRATED MASTER PLAN

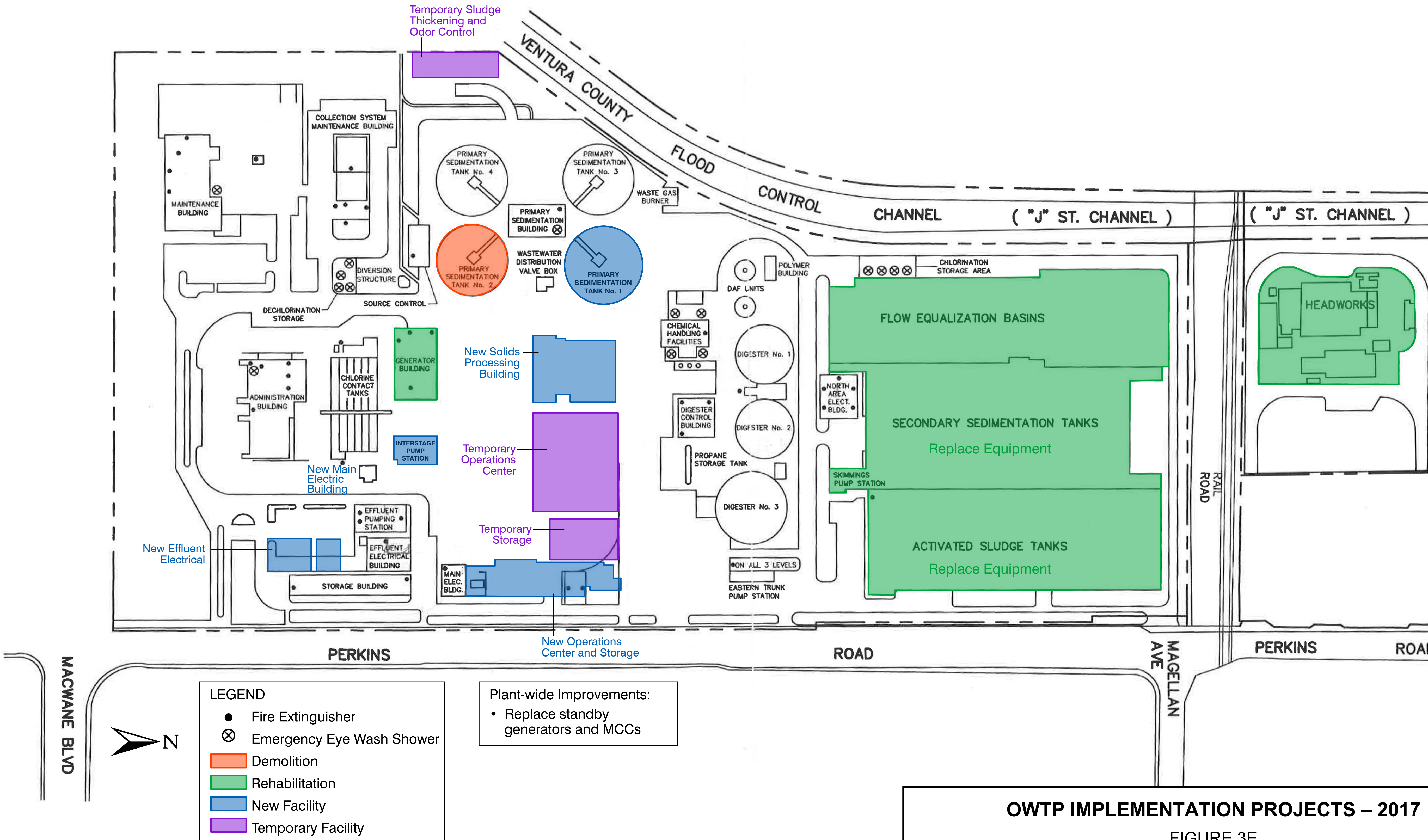
ox0115f10-9587(PM3-7-1FIG3C).ai



OWTP IMPLEMENTATION PROJECTS – 2016

FIGURE 3D

CITY OF OXNARD
PM NO. 3.7.1 WASTEWATER
PUBLIC WORKS INTEGRATED MASTER PLAN

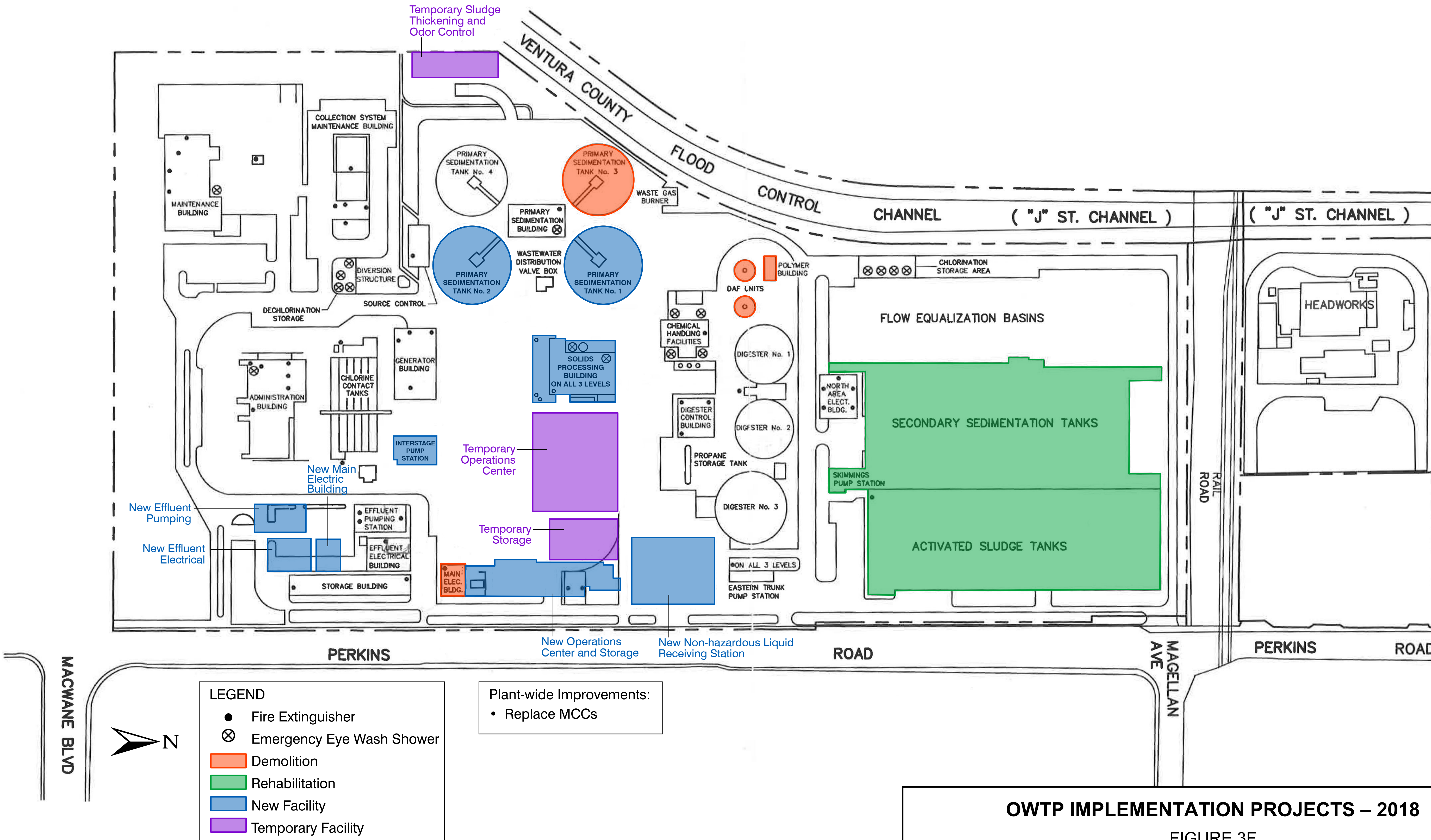


OWTP IMPLEMENTATION PROJECTS – 2017

FIGURE 3E

CITY OF OXNARD
PM NO. 3.7.1 WASTEWATER
PUBLIC WORKS INTEGRATED MASTER PLAN

ox0115f12-9587(PM3-7-1FIG3E).ai



OWTP IMPLEMENTATION PROJECTS – 2018

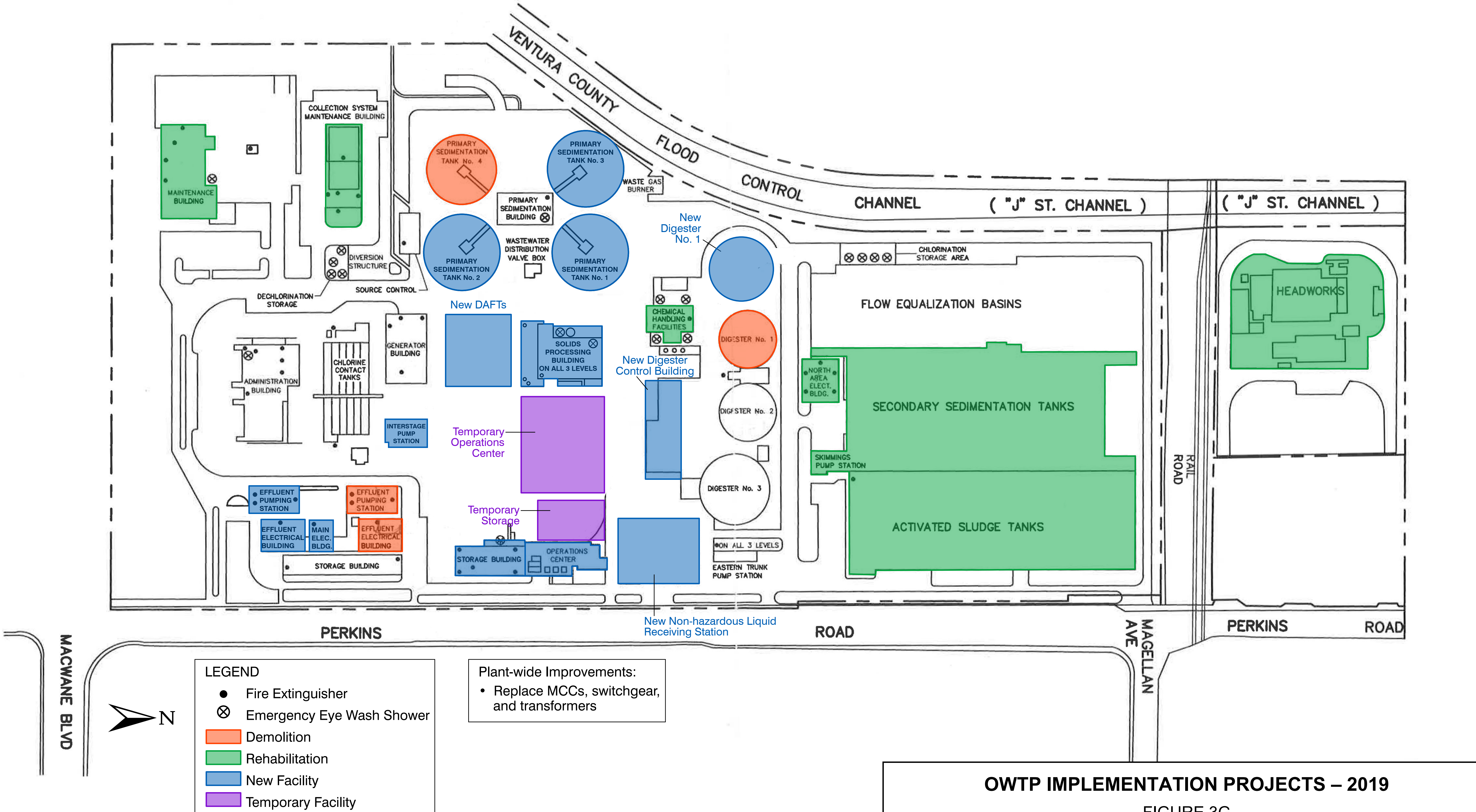
FIGURE 3F

CITY OF OXNARD

PM NO. 3.7.1 WASTEWATER

PUBLIC WORKS INTEGRATED MASTER PLAN

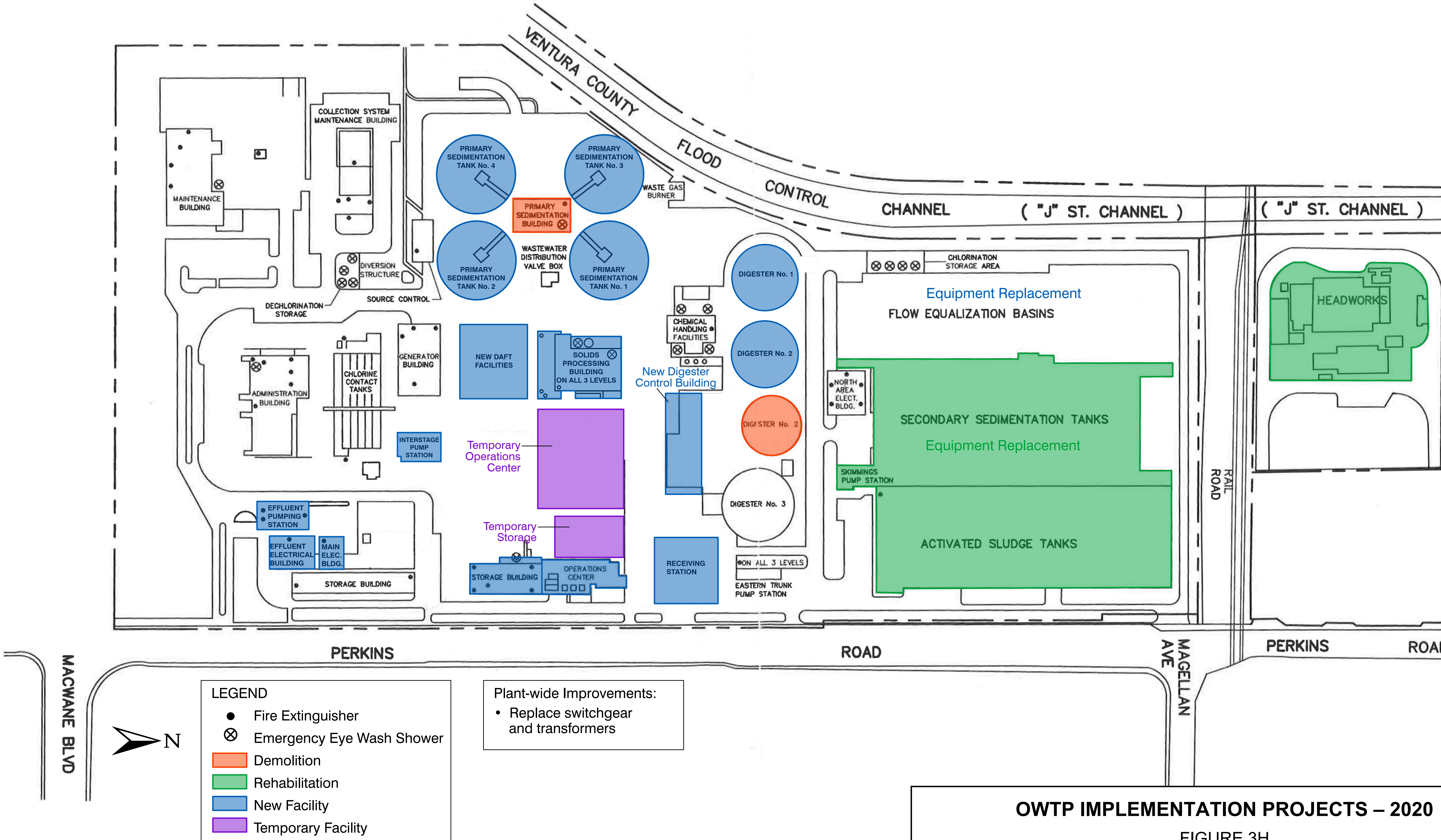
ox0115f13-9587(PM3-7-1FIG3F).ai



OWTP IMPLEMENTATION PROJECTS – 2019

FIGURE 3G

CITY OF OXNARD
PM NO. 3.7.1 WASTEWATER
PUBLIC WORKS INTEGRATED MASTER PLAN



OWTP IMPLEMENTATION PROJECTS – 2020

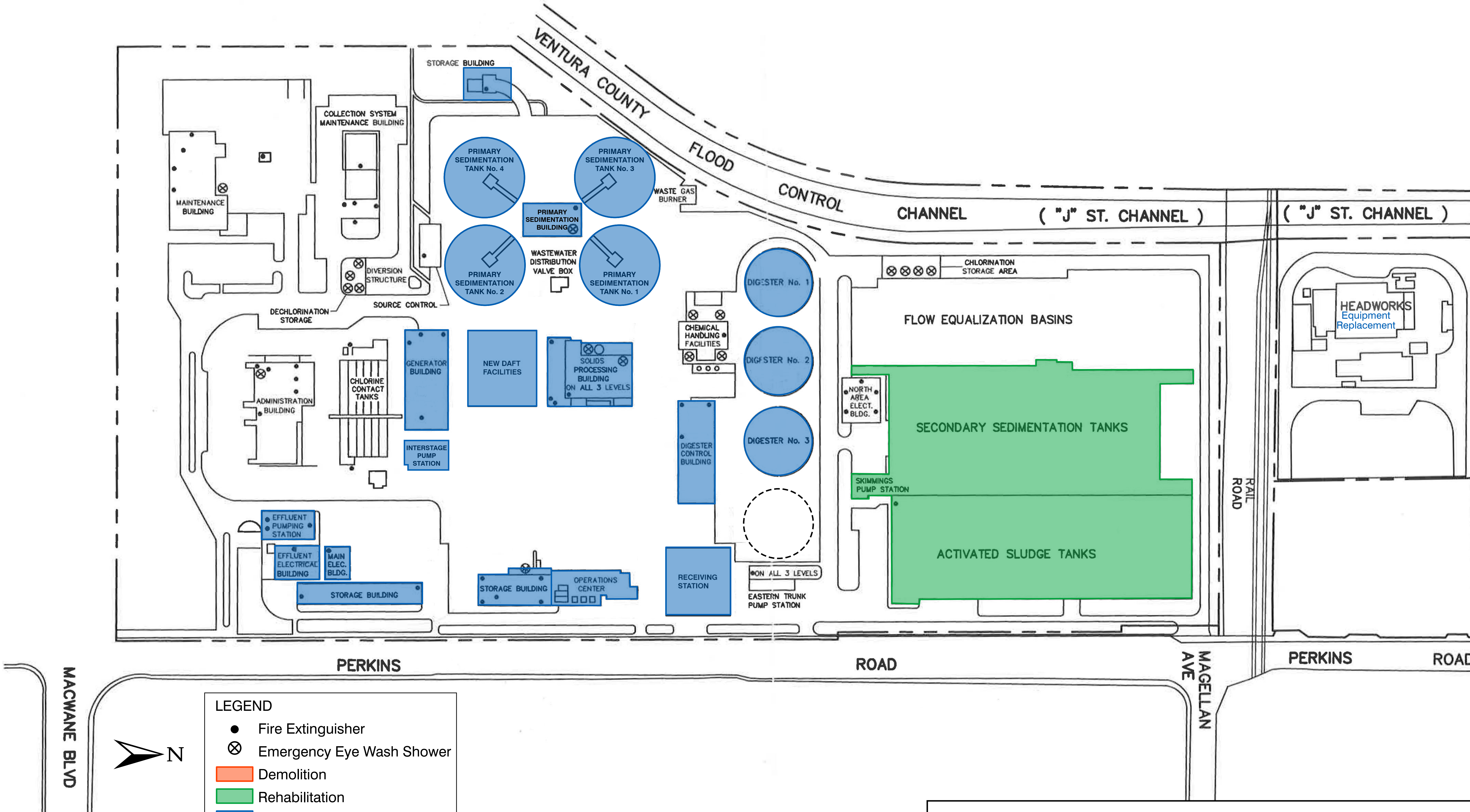
FIGURE 3H

CITY OF OXNARD

PM NO. 3.7.1 WASTEWATER

PUBLIC WORKS INTEGRATED MASTER PLAN

ox0115f15-9587(PM3-7-1FIG3H).ai



OWTP IMPLEMENTATION PROJECTS – 2025

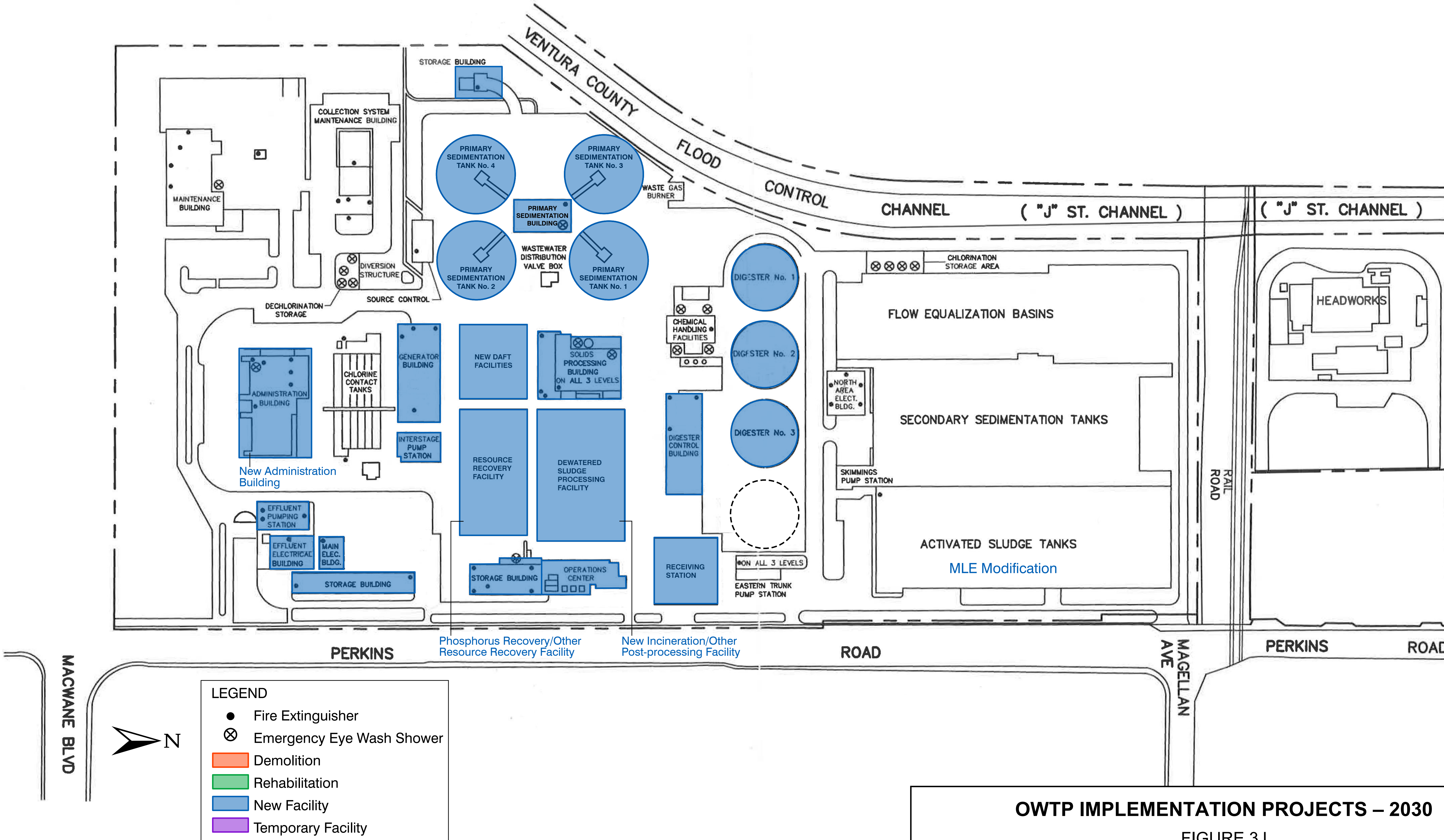
FIGURE 3I

CITY OF OXNARD
PM NO. 3.7.1 WASTEWATER
PUBLIC WORKS INTEGRATED MASTER PLAN

OXNARD CALIFORNIA
carollo Engineers...Working Wonders With Water®

carollo

ox0115f16-9587(PM3-7-1FIG3I).ai

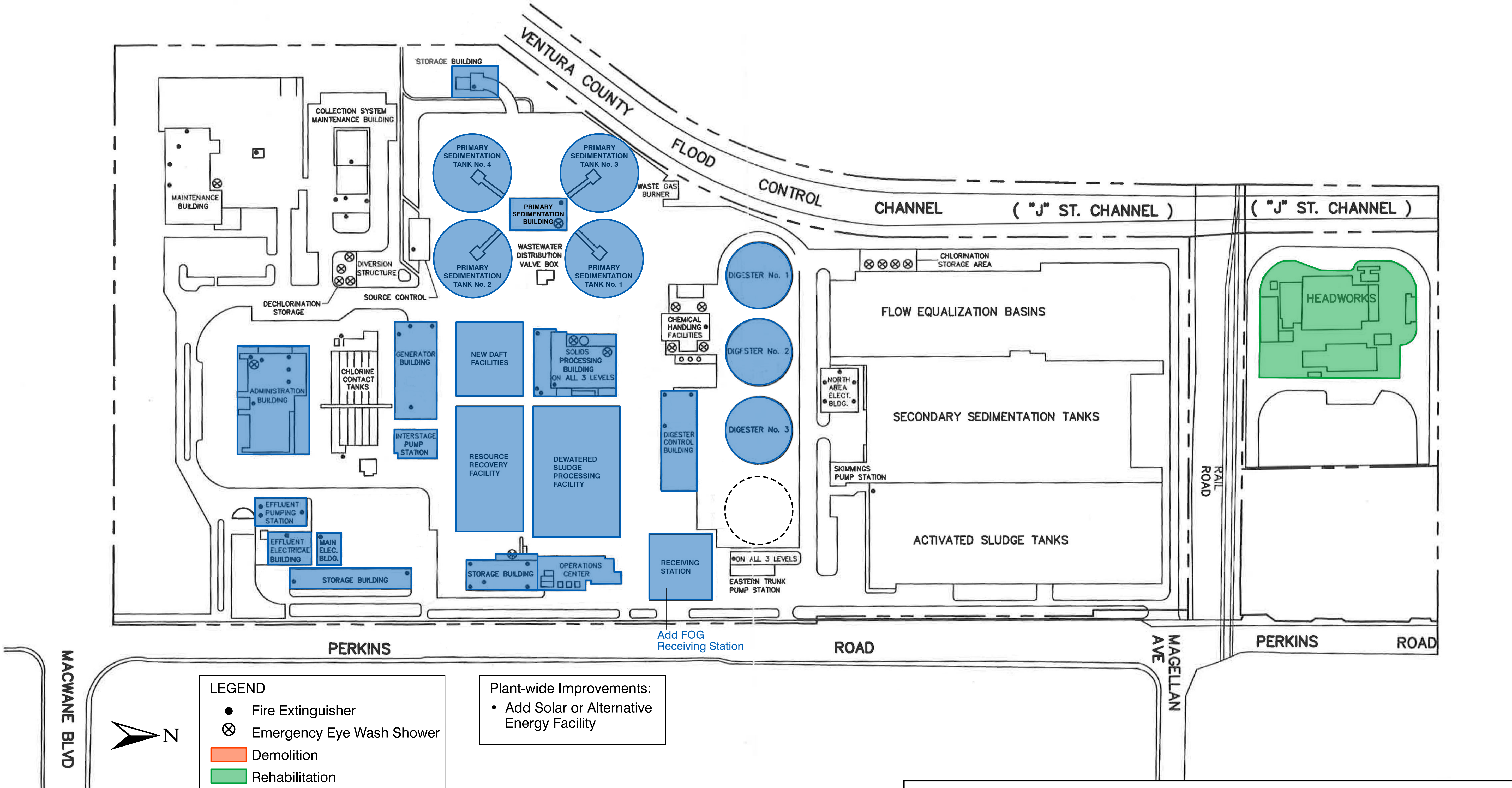


OWTP IMPLEMENTATION PROJECTS – 2030

FIGURE 3J

CITY OF OXNARD
PM NO. 3.7.1 WASTEWATER
PUBLIC WORKS INTEGRATED MASTER PLAN

ox0115f17-9587(PM3-7-1FIG3J).ai



OWTP IMPLEMENTATION PROJECTS – 2035

FIGURE 3K

CITY OF OXNARD

PM NO. 3.7.1 WASTEWATER

PUBLIC WORKS INTEGRATED MASTER PLAN

ox0115f18-9587(PM3-7-1FIG3K).ai

APPENDIX A - WATER AND WASTEWATER PROCESS OPTIMIZATION AND MECHANICAL AUDIT REPORT DRAFT

\

Water and Wastewater Process Optimization and Mechanical Audit Report
DRAFT

Prepared for

City of Oxnard
City of Oxnard Wastewater Treatment Plant
A24CPO1

Prepared by

The Energy Network

Audit Performed by

QuEST, Inc.

November 11, 2014

This page intentionally left blank

Table of Contents

1. Executive Summary

The Energy Network is pleased with the opportunity to provide this Engineering Audit Report to the City of Oxnard (City) that presents energy efficiency opportunities at the City of Oxnard Wastewater Treatment Plant (OWTP). The Energy Network, administered by Los Angeles County, was created by the California Public Utilities Commission to help eligible public agencies in Southern California harness their collective action, save energy, reduce operating costs and protect precious resources. To expand public agency participation in utility energy efficiency programs, The Energy Network is offering a range of energy efficiency services to assist public agencies with accelerating energy retrofits.

This report describes a package of recommended energy efficiency measures for the operational processes, electrical, and mechanical equipment at OTWP estimated to reduce total annual energy usage by 3,659,807 kWh 36% reduction of total energy provided by SCE, yielding estimated cost reduction of $361,461[1].

The Energy Network's engineering consultant, QuEST has performed a process and mechanical energy audit of OWTP. The facility has capacity to treat up to 31.7 million gallons per day (MGD) of wastewater at a secondary level, although the facility is currently operating at about 20 MGD.

Plant Overview

The City of Oxnard (City) Wastewater Treatment Plant (OWTP) is located at 6001 South Perkins Road. The OWTP provides secondary wastewater treatment. It has a nominal average day dry weather flow (ADWF) of 20 million gallons per day (mgd) with a design capacity of 31.7 (mgd). The OWTP includes the following major treatment facilities:

- Preliminary treatment (Headworks) including mechanically cleaned bar screens, aerated grit removal, and influent pumping.
- Primary sedimentation
- Biofilters (shown as Fixed Film Reactor in Figure No. 1)
- Inter-process pumping
- Fine-bubble activated sludge
- Secondary sedimentation
- Secondary effluent equalization
- Chlorination and dechlorination
- Effluent pumping and ocean outfall
- Emergency standby power generators
- Anaerobic digestion
- Solids processing facilities
- Onsite cogeneration facilities

1

The Public Works Department (Public Works) staff continually manages the treatment facilities assets to assure that they meet required performance standards, are cost-effective, and maximize water reuse and other benefits to the community.

1.1. Energy Efficiency Measures

The following energy efficiency measures (EEMs) were developed in consultation with site staff and the TEN consulting team. A total of six measures were developed with two measures being a variation of the bio-filter removal. The recommended measures are as follows:

- EEM # 1 Replace 2 Grit Pumps
- EEM # 2 Replace Primary Sludge Pumps
- *EEM #3 - Remove Bio-filters and Replace 3 Aeration Blowers (EEM #3A includes the addition of Chemically Enhanced Primary Sedimentation)*
- *EEM #4 - Turn off Bio-filters and Add Additional SCADA Control to Aeration System (EEM #4A includes the addition of Chemically Enhanced Primary Sedimentation)*
- EEM # 5 Modify Reclaimed Water System
- EEM # 6 Modify Digester Mixing and Heating
- EEM # 7 Replace Biofilter Interstage Pumps

A major issue exists in relationship to the disposition of the existing Bio-Filters. The structural integrity and seismic safety require a capital project. In both cases they require demolition. Reconstruction/rehabilitation will be a major added capital construction item in the long-term Master Plan. In either case, a factor outside of the energy audit is the potential for avoided cost of reconstruction/rehabilitation. The analysis performed within the energy audit indicates that there is low value in reconstructing the bio-filters and therefore serious consideration should be given to not reconstructing them. Then the question is how and when to integrate the cost of demolition.

Until that issue is addressed, the audit provides two options : 1) the bio-filters are removed now, as a discrete project, and the aeration system upgraded (EEM3), or 2) the bio-filters turned off (EEM4) and demolition and the aeration upgrades are delayed until the future as part of the long-term Master Plan, with cost integrated within the overall Master Plan schedule and financial plan. For each of these options there is the opportunity to add Chemically Enhanced Primary Sedimentation (CEPS) as a means of reducing aeration needs.

For each of the options above the most cost-effective option was assessed along with the other non-bio-filter measures to create a package of wastewater measures.

- **Option A** - defined as removal of the bio-filters and upgrading the aeration system (EEM#3) and installation of the remaining measures (EEMs #1, #2, #5, #6),
- **Option B** - defined as turning off and isolating the bio-filters with delayed demolition, and adding CEPS (EEM#4A) and installation of the remaining measures (EEMs #1, #2, #5, #6),

If Option A is implemented the total annual electricity savings is estimated at 3,659,807 kWh – approximately 36% of total electricity provided by SCE. If Option B is implemented annual electricity savings is estimated at 3,166,029 kWh – approximately 31 % of total electricity provided by SCE. The associated cost savings are estimated to be $361,461 for Option A and $294,259 for Option B.

The project savings, costs and financial analyses are summarized in Tables 1.1 through 1.6.

The Gross Project Cost, estimated at $4,274,000 and $2,777,000, for Option's A and B respectively. These costs include those borne by the agency and those covered through The Energy Network services. The projected incentives are contingent on a number of factors. The potential incentives for these projects if fully realized are estimated at $703,844 and $611,442 for Option's A and B respectively.

Total Rebate/Incentives are based on the utility incentive rates. When subtracting incentives from the Gross Project Cost, the Net Project Cost to your agency is estimated at $3,570,156 and $2,165,558 for Option's A and B respectively.

See Table 1.2 for a breakdown of the various project cost components.

Table 1.1: Recommended Mechanical Measures - Option A

			Annual Savings[1]			Cost Savings, Project Costs, and Utility			
EEM #	Facility	Energy Efficiency Measure Description	Electric Savings (kWh/yr)	Peak Savings (kW)	Gas Savings (therms/yr)	Total Annual Cost Savings[2] ($/yr)	Gross Project Costs[3] ($)	Total Incentives[4] ($)	Net Project Costs ($)
EEM-1	OWTP - Oxnard Wastewater	Replace 2 grit pumps	36,858	4.2	-	$4,479	$85,000	$23,851	$61,149
EEM-2	OWTP - Oxnard Wastewater Treatment Facility	Replace sludge pumps	65,788	7.5	-	$9,001	$202,000	$13,235	$188,765
EEM-3	OWTP - Oxnard Wastewater Treatment Facility	Remove Bio-Filter and replace blowers system	2,175,332	248.3	-	$218,579	$2,727,000	$407,051	$2,319,949
EEM-5	OWTP - Oxnard Wastewater Treatment Facility	Modify reclaimed water system	66,571	15.2	-	$5,540	$26,000	$13,597	$12,403
EEM-6	OWTP - Oxnard	Modify digestor heating and	1,315,258	150.1	-	$123,862	$1,234,000	$246,109	$987,891
		Total	3,659,807	425.3	-	$361,461	$4,274,000	$703,844	$3,570,156

Table 1.2: Financial Benefits - Option A

	Gross Project Costs ($)	Total Incentives ($)	Net Project Costs ($)	Net Present Value[5,6] (NPV)	Internal Rate of Return (IRR)	Savings-to-Investment Ratio[7] (SIR)	Return on Investment[8] (ROI)	Simple Payback[9] (years)
Project Summary	$4,274,000	$703,844	$3,570,156	$1,092,203	8.9%	1.31	9%	9.9

Table 1.3: Recommended Mechanical Measures - Option B

			Annual Savings[1]			Cost Savings, Project Costs, and Utility			
EEM #	Facility	Energy Efficiency Measure Description	Electric Savings (kWh/yr)	Peak Savings (kW)	Gas Savings (therms/yr)	Total Annual Cost Savings[2] ($/yr)	Gross Project Costs[3] ($)	Total Incentives[4] ($)	Net Project Costs ($)
EEM-1	OWTP - Oxnard Wastewater	Replace 2 grit pumps	36,858	4.2	-	$4,479	$85,000	$23,851	$61,149
EEM-2	OWTP - Oxnard Wastewater Treatment Facility	Replace sludge pumps	65,788	7.5	-	$9,000	$202,000	$13,235	$188,765
EEM-3	OWTP - Oxnard Wastewater Treatment Facility	Turn off Bio-Filter and Implement CEPS	1,681,554	191.9	-	$151,389	$1,230,000	$314,649	$915,351
EEM-5	OWTP - Oxnard Wastewater Treatment Facility	Modify reclaimed water system	66,571	15.2	-	$5,539	$26,000	$13,597	$12,403
EEM-6	OWTP - Oxnard	Modify digestor heating and	1,315,258	150.1	-	$123,850	$1,234,000	$246,109	$987,891
		Total	3,166,029	368.9	-	$294,259	$2,777,000	$611,442	$2,165,558

Table 1.4: Financial Benefits - Option B

	Gross Project Costs ($)	Total Incentives ($)	Net Project Costs ($)	Net Present Value[5,6] (NPV)	Internal Rate of Return (IRR)	Savings-to-Investment Ratio[7] (SIR)	Return on Investment[8] (ROI)	Simple Payback[9] (years)
Project Summary	$2,777,000	$611,442	$2,165,558	$766,261	10.4%	1.35	6%	7.4

1.2. Project Cost Breakdown

Table 1.5 Project Cost Breakdown Option A

Budget Component	Estimated Cost
Construction (JOC)	$3,631,000
Contingency	$643,000
Subtotal: Agency Gross Construction Costs	**$4,274,000**
SCE/SCG Incentives	$703,844
Subtotal: Agency Net Construction Costs	**$3,570,156**
Project Management	$6,740
Audit	$48,555
Design	$3,680
Construction Management Support	$5,630
M&V	$5,970
Subtotal: The Energy Network Costs	**$70,575**
TOTAL PROJECT COST	**$3,640,731**

Contingency at 17.7%

Table 1.6 Project Cost Breakdown Option B

Budget Component	Estimated Cost
Construction (JOC)	$2,455,000
Contingency	$322,000
Subtotal: Agency Gross Construction Costs	**$2,777,000**
SCE/SCG Incentives	$611,442
Subtotal: Agency Net Construction Costs	**$2,165,558**
Project Management	$6,740
Audit	$48,555
Design	$3,680
Construction Management Support	$5,630
M&V	$5,970
Subtotal: The Energy Network Costs	**$70,575**
TOTAL PROJECT COST	**$2,236,133**

2. Introduction

This section provides an overview of The Energy Network, the energy efficiency services available to participating agencies, and the Project Team that contributed to completing this report.

2.1. Program Overview

The Energy Network, administered by Los Angeles County, was created by the California Public Utilities Commission to help eligible public agencies in Southern California harness their collective action, save energy, reduce operating costs and protect precious resources.

To expand public agency participation in utility energy efficiency programs, The Energy Network is offering an unprecedented level of services. Our Turnkey Project Delivery method is aimed at minimizing strain on your agency's resources. The Network provides all of the services you need to carry out successful energy retrofit projects including project management, energy audits, retrofit design, construction management support, and expedited construction services.

Turnkey Project Delivery Services provided at no cost to your Agency include:

- Project Management
- Energy Audits
- Project Design
- Evaluating and Arranging Construction Financing
- Rebate and Incentive Process Handling
- Retrofit Construction Management Support

Construction costs net of any applicable incentives would be covered by your agency, but The Energy Network offers expedited construction procurement services specifically designed to fast track energy efficiency retrofits and reduce your costs. Pools of pre-qualified mechanical and electrical contractors in your region have already been selected and awarded indefinite quantity construction contracts by the National Joint Powers Alliance® (NJPA) through a public competitively bid process.

By becoming a member of the NJPA, participating agencies can receive on call, energy retrofit construction services and be assured they are getting high quality firms that will perform work at guaranteed prices. Becoming a member of the NJPA can be done on-line at no-cost, no obligation and no liability.

The City of Oxnard can save time and money by not going through a lengthy qualification and bidding process, and the pricing for any work is transparent, detailed and guaranteed up front. And because the construction prices are set by the unit pricing in the catalog, the risk of inflated costs for change orders is greatly reduced. The Energy Network can help arrange financing for your energy efficiency projects, including utilizing our Energy Project Master Lease Program financing designed specifically for public agency energy projects; and we can handle the entire utility rebate and incentive process on your behalf

After construction, The Energy Network can assist the City of Oxnard to realize the full energy savings potential of recommended EEMs by training your staff on the effective operation of the installed measures.

By providing unbiased expertise, project management, financing, and premium engineering services, The Energy Network addresses the common barriers that prevent many local governments and public agencies with limited resources from adopting energy saving measures. The Energy Network's services will complement and support services provided by other existing programs.

2.2. Project Team

Commissioned by Thien Ng through The Energy Network, QuEST, Inc. performed a process and mechanical energy audit of the OWTP operated by the City.

The project team consisted of:

- City of Oxnard : John Jardin, Chief Plant Operator, OWTP
- Wyatt Troxel (Consultant to TEN) who provided invaluable assistance and access to the facility areas.
- The Energy Network's Project Manager was Douglas O'Brien.
- The personnel performing this audit were Derrick Rebello, QuEST, Inc. and Gregory Harris, Herwit Engineering.

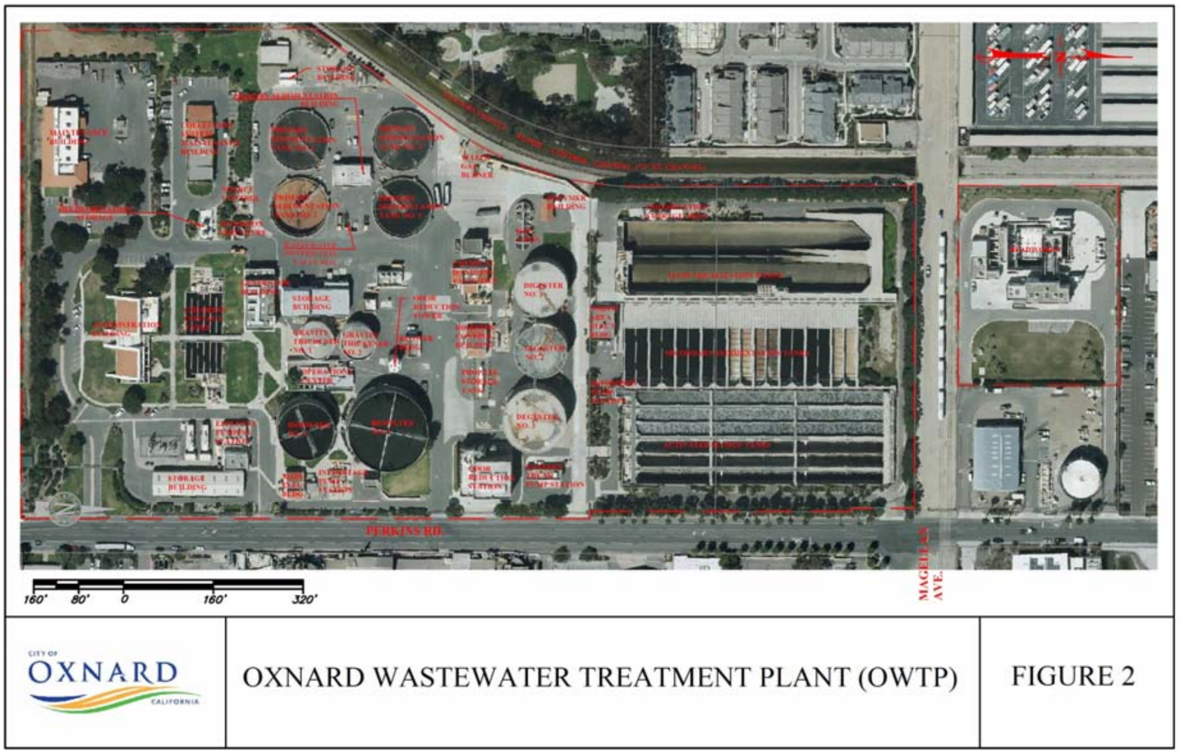
3. Facilities Information

OWTP is located at 6001 South Perkins Street Oxnard, CA. The facility is operated by the City of Oxnard. A description of the facility is provided below.

3.1. General Facility Description

The OWTP serves approximately 225,000 customers from the City of Oxnard, City of Port Hueneme and Naval Base Ventura County. The OWTP collection system, spanning more than 400 miles, brings wastewater to the plant for treatment. An aerial view of the OWTP is provided in Figures 3.2. The site includes administration buildings, illuminated outside areas for night operations, and numerous additional structures associated with plant treatment processes.

Figure 3.1 – Aerial View of OWTP

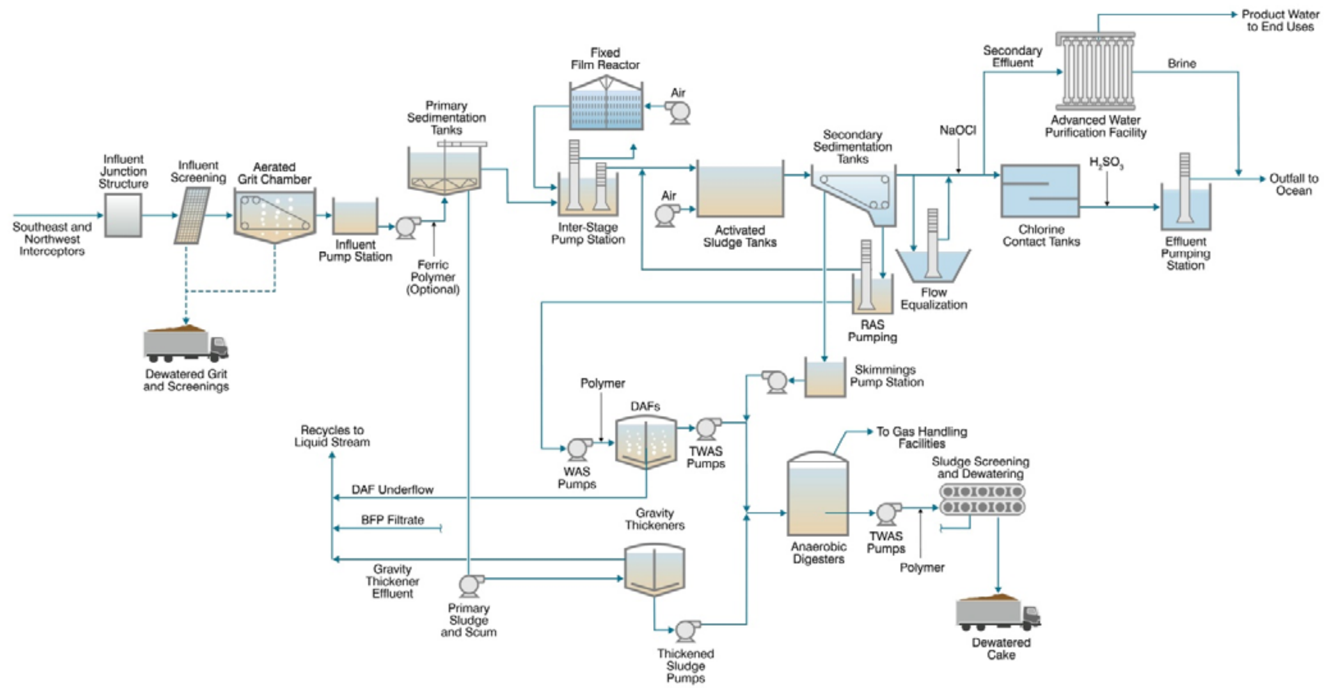


OWTP has a design capacity of 31.7 MGD, current daily flows (observed) are approximately 20 MGD.

Although the facility's operations are continuous (24 / 7 - 365 days/yr), the daytime overall operating hours of the facility when operators are present are from 8:00 AM to 5:00 PM, Monday through Friday.

A schematic of the plant operations is presented in Figure 3.2.

Figure 3.2 Oxnard Wastewater Treatment Plant Process Schematic



CITY OF OXNARD CALIFORNIA

OXNARD WASTEWATER TREATMENT PLANT PROCESS FLOW SCHEMATIC

FIGURE 1

3.2. Description of Areas Surveyed

The audit process began with a review of the entire plant's wastewater treatment processes and a discussion with plant staff to better understand their needs. A detailed review of the processes was conducted with the intent of identifying potential cost-effective energy savings measures, including the following:

- Preliminary treatment (Headworks) including mechanically cleaned bar screens, aerated grit removal, and influent pumping.
- Primary sedimentation
- Biofilters (shown as Fixed Film Reactor in Figure No. 1)
- Inter-process pumping
- Fine-bubble activated sludge
- Secondary Clarification
- Effluent Chlorine Disinfection
- Utility water system
- Anaerobic digestion
- Solids processing facilities
- Onsite cogeneration facilities

4. Historic Energy Use and Cost

During a recent 12-month period from December, 2012 through November, 2013, the facility's total electricity consumption was 10,108,710 kWh, at a cost of $762,285 and the facility's total natural gas consumption was 1,787 therms, at a cost of $1,833[2]. The total annual cost of energy at this site is approximately $764,118. Table 4.1 show the monthly breakdown of electric and gas usage and costs.

Table 4.1 Monthly Utility Usage and Cost

Month	Electricity Usage (kWh)	Demand (kW)	Electricity Costs ($)	Natural Gas (therms)	Gas Costs ($)	Total Utility Cost ($)
December-12	897,840	2,016	$53,014	139	$146	$53,160
January-13	921,564	1,728	$52,353	394	$347	$52,700
February-13	912,924	1,872	$57,185	230	$226	$57,411
March-13	799,434	1,800	$50,038	188	$181	$50,219
April-13	869,364	1,944	$54,812	118	$123	$54,935
May-13	859,158	1,944	$61,687	99	$109	$61,797
June-13	878,508	1,872	$62,331	114	$131	$62,462
July-13	762,228	2,016	$76,430	98	$116	$76,545
August-13	798,480	2,016	$84,654	97	$111	$84,765
September-13	784,152	1,872	$74,841	104	$117	$74,958
October-13	744,588	1,944	$72,071	94	$103	$72,174
November-13	880,470	1,872	$62,871	112	$123	$62,993
Total	10,108,710	22,896	$762,285	1,787	$1,833	$764,118

During a recent 12-month period from July, 2013 through June, 2014, the facility's total gas consumption related to co-generation was 187,061 therms, at a cost of $129,229. Table 4.2 show the monthly breakdown for gas usage associated with the Plant's co-generation system.

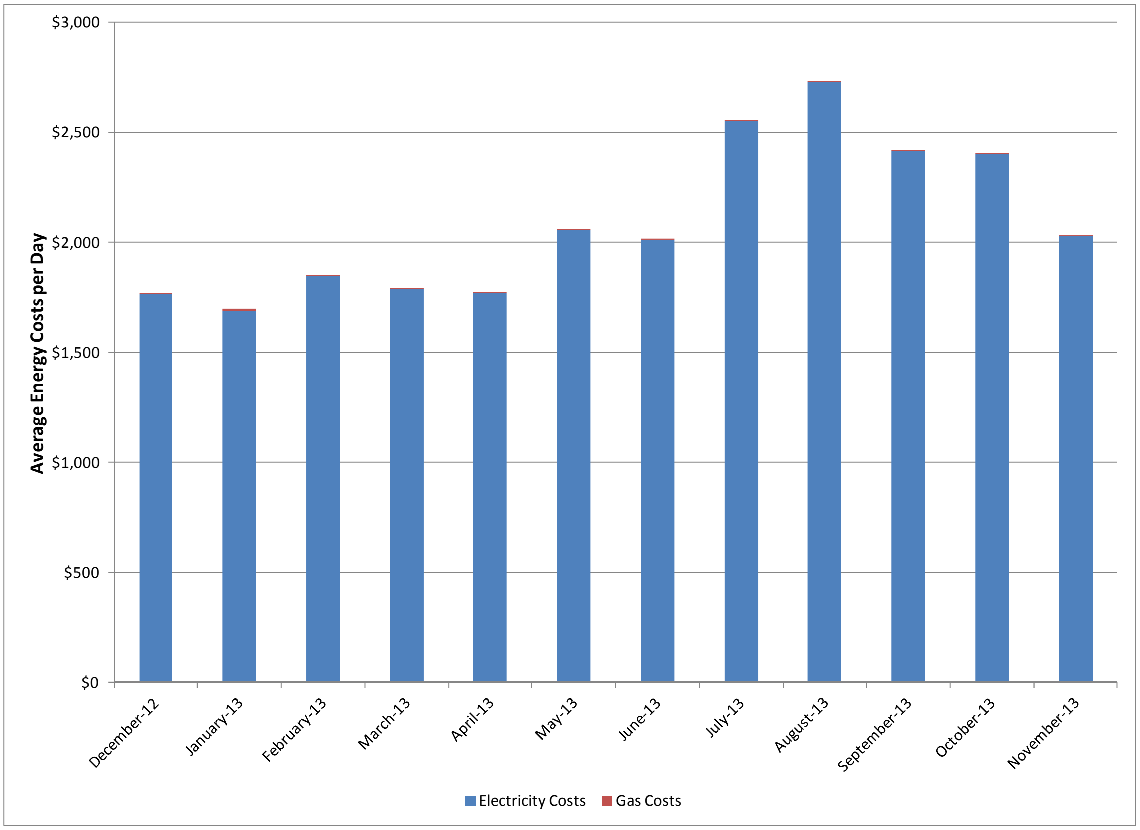
[2] This represents only the gas for general use and does not include the gas used in the co-gen system.

Table 4.2 Monthly Co-Gen Gas Usage and Cost

Month	Gas Usage (therms)	Gas Costs ($)
July-13	26,989	$17,571
August-13	26,644	$17,232
September-13	27,519	$17,893
October-13	14,947	$9,838
November-13	11,568	$7,834
December-13	12,058	$8,102
January-14	11,170	$8,214
February-14	7,811	$6,269
March-14	6,252	$5,131
April-14	11,030	$8,163
May-14	9,228	$7,049
June-14	21,845	$15,933
Total	187,061	$129,229

Figure 4.1 below depicts the total cost of energy broken down into electric and gas costs by month for the 12-month period of December, 2012 through November, 2013.

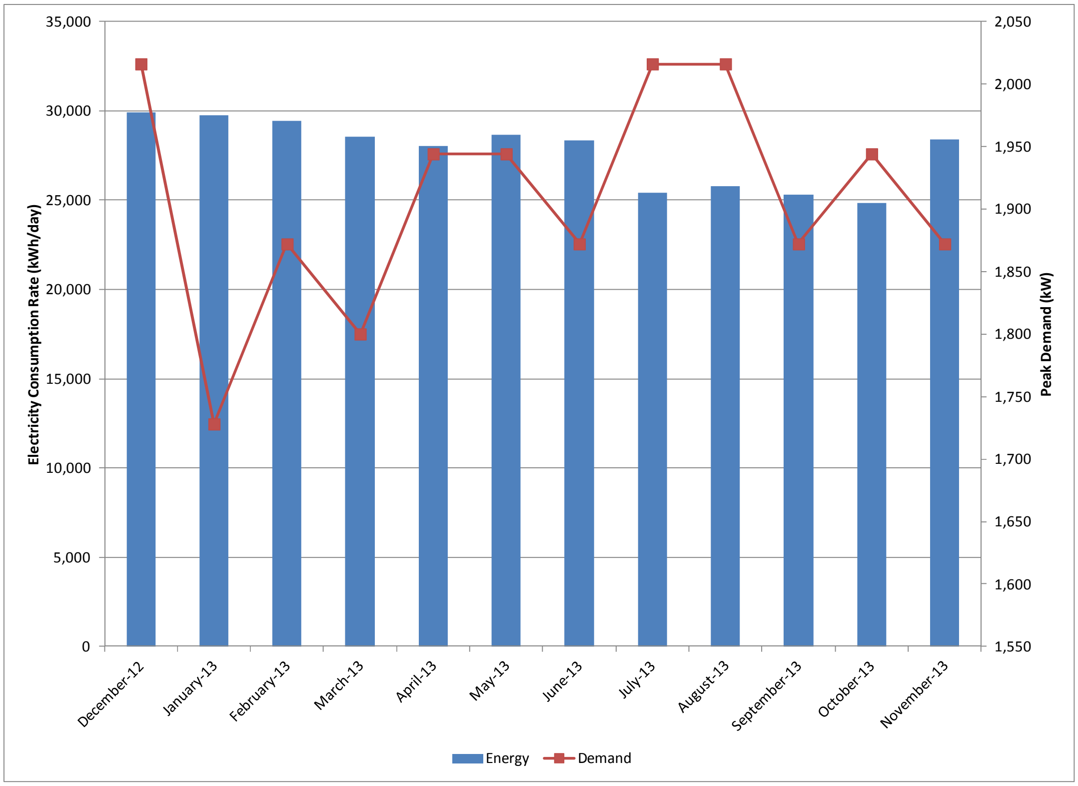
Figure 4.1: Total Monthly Energy Costs



4.1. Monthly Electricity Consumption and Demand

Figure 4.2 shows electricity consumption (kWh) and demand (kW) for 12-month period from December, 2012 through November, 2013.

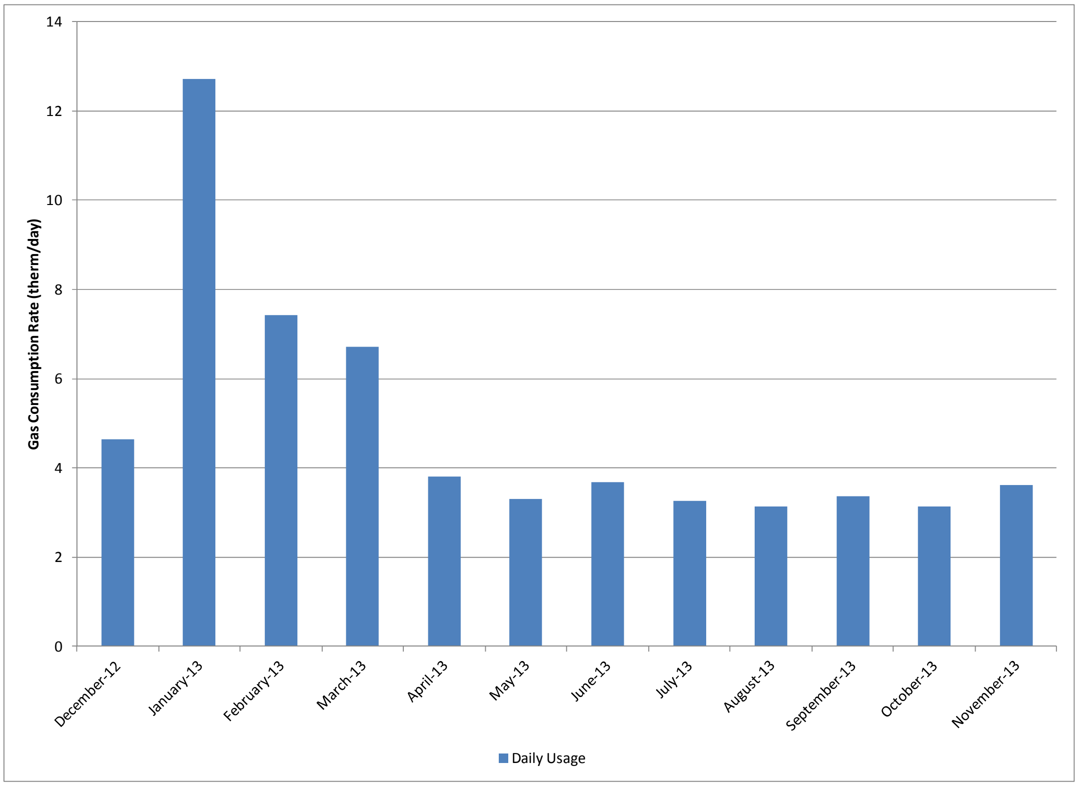
Figure 4.2: Monthly Electricity Consumption and Demand



4.2. Monthly Natural Gas Consumption

Figure 4.3 shows the total annual gas consumption history for the 12-month period from December, 2012 through November, 2013.

Figure 4.3: Monthly Natural Gas Consumption



The Oxnard WWTP uses natural gas to power its co-generation facility. Gas consumption and expenses related to the

5. Energy Efficiency Recommendations

To identify and assess the feasibility of energy efficiency and improvement opportunities, a team of engineers visited the facility and performed visual inspections of the existing equipment and site conditions. In addition the team monitored energy consumption and demand for many of the major systems and processes.

5.1. Existing Systems

At OWTP, there are several processes with significant energy demand. Section 3 above, provides a list of the plant's treatment processes. It was noted during the audit process the OWTP was interested in exploring options that would either remove the existing bio-filters (bio-towers) or at least eliminate them from the process.

5.2. Recommended Measures

This section details the recommended Energy Efficiency Measures (EEMS) of this analysis. Each measure is described in detail, including the method of analysis for estimating measure energy savings.

5.2.1. EEM # 1 Replace 2 Grit Pumps

Currently, there are eight 30 hp grit pumps that pump grit from the grit tanks to the grit dewatering unit. The grit pumps are broken up into 4 pumps for the east side and 4 pumps for the west side. The East side and west side grit tanks are alternated every 6 months with only one side in operation at a time. For each side, the existing grit pumps are operated with Pump No. 1 running 100% of the time at 24 hours per day, Pump No. 2 running 48% of the time and the remaining pumps on less than 29% of the time. The grit pumps are a torque flow style pumps equivalent to the Wemco Model C style pump. These pumps have very low efficiencies but were historically installed for their low initial capital cost and overall robustness in pumping grit and other high solids.

This measure evaluates replacing the lead pump on the east and west side with a modified torque flow pump equivalent to the Wemco Model CE pump. The Model CE pump is also designed for grit service, but is approximately twice as efficient as the Model C pump. The increased efficiency provides the opportunity to sequence the grit pumps via SCADA controls to avoid concurrent operation, thus reducing the instantaneous kW demand of the system to the load of a single pump.

Since the remaining pumps do not run full time, it is proposed under this measure to not replace them. However, given the age of the grit pumps, it may be desirable to replace all of the existing pumps with a Model CE pump under a normal capital replacement cycle.

Savings and costs are calculated under this measure for only replacing the two lead grit pumps.

Analysis EEM #1

To establish the energy baseline for this measure, the power usage of the existing pumps was monitored with power monitors from 8/5/201 through 8/27/2014. The data indicated that the lead pump runs 100% of the time (24 hrs/day) with the remaining pumps running less time. Based on this information, the total power usage for the existing condition was determined as indicated in Table 1.

To evaluate the changed conditions for this measure, the flow and pressure conditions for the existing grit pumps were used in conjunction with pump curves for the WEMCO model CE pump to determine the pump power required for a replacement pump. This power was then compared to the measured power during the monitoring period for the existing pumps to determine the net energy savings.

Table 5.1 presents the energy savings analysis for this option based on the established baseline energy usage from the monitoring period compared to the implemented measure. A total of 36,858 kWh annually can be saved by implementing this measure. In addition, 4.21 kW of power demand would be reduced by implementing this measure.

The cost to implement this measure is presented in Table 5.2. The largest cost is to purchase the new pumps and then modify the existing piping and bases to accept the new pump.

An economic summary with a simplified life cycle analysis for all 6 energy efficiency measures is presented in Table 5.20.

Table 5.1 Energy Savings Analysis for EEM#1

Existing Condition

Monitoring Period 8/5/2014 - 8/27/2014

	Total No.	Motor Size (hp)	No. In Service
GRIT Equipment			
1) Grit Pumps	8	30	4
Average Power Draw Per Pump (kW)	19.2		

	Power Used (kW)				
	Pump No. 1	Pump No. 2	Pump No. 3	Pump No. 4	Total
Average Power Demand	18.98	8.26	5.72	5.43	38.40
Pump Run Time % On	98.9%	43.8%	28.6%	28.6%	

New Condition

Monitoring Period 8/5/2014 - 8/27/2014

	Total No.	Motor Size (hp)	No. In Service
GRIT Equipment			
1) Grit Pumps	8	25	4
Average Power Draw Per Pump (kW)	14.9		

	Power Used (kW)				
	Pump No. 1	Pump No. 2	Pump No. 3	Pump No. 4	Total
Average Power Demand	14.78	8.26	5.72	5.43	34.19
Pump Run Time % On	98.9%	43.8%	28.6%	28.6%	

Existing Power Usage	38.4	kW
New Power usage	34.2	kW
Total Power Saved	4.2	kW
Pre-Installation Energy Consumption	336,367	kWh
Post-Installation Energy Consumption	299,509	kWh
Total Energy Saved	36,858	kWh
Pre-Installation Demand	38.40	kW
Post-Installation Demand	34.19	kW
Total Demand Savings	4.21	kW

Table 5.2 Costs Analysis for EEM#1

Item Description	Quantity	Unit	Unit Cost	Total Cost
Wemco Model 4 x 11- 25 hp motor	2	EA	$ 26,974	$ 53,948
Pump Installation	2	EA	$ 3,500	$ 7,000
Modify Existing Piping	2	EA	$ 2,500	$ 5,000
New Gauges and Instruments	2	EA	$ 1,500	$ 3,000
Miscellaneous Construction	0.5	EA	$ 5,000	$ 2,500
Engineering Design and Project Management	0.75	EA	$ 15,000	$ 11,250
Construction Support	0.75	EA	$ 10,000	$ 7,500
			Subtotal	$ 90,000
Contingency			20%	$ 18,000
			Total	$ 108,000

5.2.2. EEM # 2 Replace Primary Sludge Pumps

Currently, there are four 25 hp primary sludge pumps that pump primary sludge from the primary clarifiers to a gravity thickening tank. The sludge pumps are assigned one to each of four primary clarifiers. Normally three primary clarifiers are in service with one on standby. Clarifiers and pumps are rotated together in and out of service periodically. Each pump for an in service primary clarifier pumps 24 hours a day to the gravity thickener. The primary sludge pumps are torque flow style pumps equivalent to the Wemco Model C style pump. These pumps have very low efficiencies but were historically installed for their low initial capital cost, and robustness in pumping grit and high solids.

This measure evaluates replacing all four primary clarifier pumps with a screw centrifugal pump equivalent to the Wemco Model Hydrostal. The Model Hydrostal pump is also designed for high solids such as primary sludge service, but is approximately 3 to 4 times more efficient as the Model C pump.

Since the primary sludge pumps pump 24 hours per day, the primary sludge is not very thick and this service is fairly easy for the Hydrostal style pump. The increased efficiency provides the opportunity to sequence the primary sludge pumps via SCADA controls to avoid concurrent operation, thus reducing the instantaneous kW demand of the system to the load of a single pump. The pumps would likely be operated 1/3 of the time, rotating the operational function sequentially among the pumps.

Savings and costs are calculated under this measure for replacing all four of the primary sludge pumps.

Analysis EEM -2

To establish the energy baseline for this measure, the power usage of the existing pumps was monitored with power monitors from 8/5/2014 through 8/27/2014. The data indicated that 3 of the 4 pumps run 100% of the time (24 hrs/day) with the remaining pump off line when the clarifier is not in service. Based on this information, the total power usage for the existing condition was determined as indicated in Table 5.3.

To evaluate the changed condition for this measure, the flow and pressure conditions for the existing primary sludge pumps were used in conjunction with pump curves for the WEMCO model Hydrostal pump to determine the pump power required for a replacement pump. This power was then compared to the measured power during the monitoring period for the existing pumps to determine the net energy savings.

Table 5.3 presents the energy savings analysis for this option based on the established baseline energy usage from the monitoring period compared to the implemented measure. A total of 65,788 kWh annually can be saved by implementing this measure. In addition, 7.51 kW of power demand would be reduced by implementing this measure.

The cost to implement this measure is presented in Table 5.4. The largest cost is to purchase the new pumps and then modify the existing piping and bases to accept the new pump.

Table 5.3 Energy Savings Analysis for EEM#2

Existing Condition

Monitoring Period 8/5/2014 - 8/27/2014

	Total No.	Motor Size (hp)	No. In Service
Primary Clarifier Equipment			
1) Primary Sludge Pumps	4	25	3
Average Power Draw Per Pump (kW)	9.1		

	Power Used (kW)				
	Pump No. 1	Pump No. 2	Pump No. 3	Pump No. 4	Total
Average Power Demand	0.00	7.94	10.26	9.23	27.43
Pump Run Time % On	0.0%	100.0%	100.0%	100.0%	

New Condition

Monitoring Period 8/5/2014 - 8/27/2014

	Total No.	Motor Size (hp)	No. In Service
Primary Clarifier Equipment			
1) Primary Sludge Pumps	4	15	3
Average Power Draw Per Pump (kW)	6.6		

	Power Used (kW)				
	Pump No. 1	Pump No. 2	Pump No. 3	Pump No. 4	Total
Average Power Demand	0.00	6.64	6.64	6.64	19.92
Pump Run Time % On	0.0%	100.0%	100.0%	100.0%	

Existing Power Usage	27.4	kW
New Power usage	19.9	kW
Total Power Saved	7.5	kW
Pre-Installation Energy Consumption	240,287	kWh
Post-Installation Energy Consumption	174,499	kWh
Total Energy Saved	65,788	kWh
Pre-Installation Demand	27.43	kW
Post-Installation Demand	19.92	kW
Total Demand Savings	7.51	kW

Table 5.4 Costs Analysis for EEM#2

Item Description	Quantity	Unit	Unit Cost	Total Cost
Wemco Hydrostal F4K-MH 15 hp motor	4	EA	$ 28,918	$ 115,674
Pump Installation	4	EA	$ 3,500	$ 14,000
Modify Existing Piping	4	EA	$ 2,500	$ 10,000
New Gauges and Instruments	4	EA	$ 1,500	$ 6,000
Miscellaneous Construction	1	EA	$ 5,000	$ 5,000
Engineering Design and Project Management	1	EA	$ 10,000	$ 10,000
Construction Support	1	EA	$ 7,500	$ 7,500
			Subtotal	$ 168,000
Contingency			20%	$ 34,000
			Total	$ 202,000

5.2.3. Bio-filter Measures (EEM 3, 3A, 4, 4A) General Overview

Currently, the plant uses two processes in series to aerobically treat the biochemical oxygen demand (BOD) present in the wastewater leaving the primary clarifiers. The first process is a fixed film reactor called a biofilter or biotower. There are two biofilters. Biofilter No. 1 is 140 feet in diameter and Biofilter No. 2 is 100 feet in diameter. Each biofilter is approximately 26 feet tall and filled with PVC media. Water is pumped to the top of the tower with three 200 hp biofilter recirculation pumps. The water distributes onto the media and trickles down through the tower. Air is blown up through the tower in the opposite direction with four 10 hp blowers for Biofilter No. 1 and four 5 hp blower for Biofilter No. 2. Aerobic biological bacteria are grown on the media that uptake a portion of the BOD from the wastewater as the water passes over it.

The second process step is a typical activated sludge aeration basin. The aeration basin consists of 2 long serpentine basins with 3 passes each. Air is bubbled through the wastewater with fine bubble ceramic diffusers. Air is supplied to the diffusers with five 350 hp Turblex blowers. Only one basin is in service at a time with the second basin kept as a standby.

Water leaving the biofilters is pumped with three 250 hp interstage pumps to the in-service aeration basin. Water leaving the aeration basins flows to the secondary clarifiers for settling.

The physical condition and performance of the bio-filters are very poor. Inspection shows that a significant amount of wastewater pumped to the top of the biotowers is bypassing the media and falling directly down the center column. Typically, the existing bio-filters are removing less than 30% of the BOD. This is well below the desired performance level. The question is whether to replace the towers or eliminate them altogether. Eliminating them incurs overall energy savings and avoids cost of construction of new or rehabilitated towers.

In addition, the existing aeration blowers are very old and not as efficient as modern day blowers. The existing diffuser system in the activated sludge process is also very old and in need of eventual replacement. There is also very limited SCADA control of the entire process, and only one blower can be controlled automatically from SCADA with the remaining blowers controlled by hand when needed. As a result of these issues, the existing two step process runs very inefficiently.

Because the secondary process has several process steps and requires multiple pieces of equipment to operate, four options for energy efficiency measures were developed and analyzed. These measures include the following. Each of these measures is described in detail below.

- EEM #3 - Remove the biofilters and replace three of the aeration blowers
- EEM #3A - Remove the biofilters and replace three of the aeration blowers and add CEPS
- EEM #4 - Turn off the biofilters, await future demolition and add additional SCADA control for the existing blowers and aeration system.
- EEM #4A - Turn off the biofilters, await future demolition, add additional SCADA control for the existing blowers and aeration system, and add CEPS.

Chemically Enhance Primary Sedimentation

Two of the measures are the same as the original measures with the addition of chemically enhance primary sedimentation (CEPS). The concept of CEPS is to add additional chemicals to the primary clarifiers to pull additional biological load or BOD from the wastewater prior to going to the secondary process and to send that additional BOD to the anaerobic digesters where it produces energy instead of needing energy if treated in the secondary process. The concept of CEPS was evaluated previously by others in the 2014 Unit Process Evaluation and Optimization Study by Nunnley and Associates and in the 2014 Master Plan being prepared by Carollo. In both reports, it was found that the existing performance of approximately 45%-50% BOD removal in the primary clarifiers already performed at the expected levels for a chemically enhanced primary clarifier. The reason given for this was that there is so much existing ferric chloride addition occurring in the collection systems upstream of the plant for odor control reasons that this collection system chemical addition is affecting the settling in the clarifiers without any additional chemical addition at the clarifier itself.

While it is true the existing clarifier performance already meets historical design values for chemical addition, recent research has shown that adding a minor amount of polymer in addition to ferric chloride can increase typical BOD removal from 50% to 60%-65% or above. Therefore, in relation to CEPS, the energy efficiency measures that include CEPS assume the existing ferric chloride addition up stream of the facility is maintained, if not reduced, and that emulsion polymer is added directly up stream of the primary clarifiers as an additional CEPS measure.

The largest negative impact of CEPS is normally increased sludge to the digesters and the downstream dewatering and disposal facilities. A large portion of this sludge is chemical sludge that does not degrade in the digester and increases overall disposal costs. However, the largest portion of the chemical sludge is from adding ferric chloride (95% or more). In this case, the addition of ferric chloride is an existing condition at the facility. Therefore, in the energy efficiency measures, the cost impact of additional sludge production and disposal is ignored. The cost of actual polymer usage is included as an offset to the energy savings obtained. The actual type of polymer, the amount required, and the total cost of chemical is site specific and must be verified prior to implementation of any of the CEPS measure options. Plant staff has begun testing polymer addition to one of the primary clarifiers to determine this information and verify assumptions in this analysis.

For the measures that include CEPS, it is assumed that approximately 0.2 mg/l of emulsion polymer will be required at a cost of $2/lb to reliably increase the primary clarifier removal of BOD to 60%. Operation of the CEPS does not utilize any additional significant energy.

Process Modeling

To complete the analysis of each energy efficiency measure, a process model using BioWin modeling software was developed for the treatment plant. The model was calibrated against the existing performance conditions of the biofilters, aeration basins, and blowers. Alternative scenarios were then analyzed. The primary output from the model is the estimated performance of the biofilters and the air flow required to treat the wastewater entering the aeration basin under the different scenarios.

The unique character of a two step biofilter-aeration basin process not only affects the biological load entering the aeration basin, but performance of the diffused air system and its interaction with the wastewater itself. In modeling terms, the alpha factor used to determine how well the water takes up the air is affected downstream of a biofilter where the soluble BOD has been reduced versus what will occur when the biofilter is removed and highly levels of soluble BOD will enter the first stage of the aeration process. The extent to which the alpha will adjust when the biofilters are removed is unknown. For purposes of modeling alpha was adjusted to typical values seen for aeration basins without biofilters to come up with a reasonable estimate of the new airflow required once the biofilter is removed. This new estimated airflow without the biofilter is more than what would be estimated based on BOD alone without an adjustment in alpha.

In addition, the existing SCADA system has target dissolved oxygen (DO) set points that are very low for each portion of the aeration basin. The actual system almost uniformly underperforms in holding the target DO set points with real world achieved DO levels almost always below the SCADA system set points. This results in lower real existing air flows than predicted to achieve the SCADA system target DO set points. For the purposes of this analysis the existing SCADA target DO set points were utilized to determine existing and future required air flows for all BioWin models.

For the different energy efficiency measures, the existing recorded and predicted BioWin airflow estimates for the aeration basin are as follows:

- Existing recorded average air flow - 3,804 scfm
- BioWin - Existing predicted average air flow - 4,065 scfm
- BioWin - Biofilters removed, Alpha adjusted, predicted average air flow - 6,950 scfm
- BioWin - Biofilters removed, Alpha adjusted, CEPS added, predicted average air flow - 4,816 scfm

In preparing the modeling, it was noted that the existing aeration basins are run in a long serpentine pattern with all of the load sent to the entrance of aeration basin Zone 1. When the biofilter is removed, it may be more desirable to change the aeration basin operation to a step feed system or convert the serpentine basins to parallel basins. Both of these changes have process and maintenance advantages and further evaluation of these options is strongly recommended. However, for the scope of this analysis, the basins are modeled as serpentine basin and further changes are left to be considered in more detail during the final design process.

5.2.4. EEM # 3 Remove Biofilter and Replace 3 Aeration Blowers

Under this measure, the biofilters are turned off, decommissioned and ultimately removed from the plant site. In addition, three of the existing blowers are replaced with higher efficiency turbo blowers. The existing SCADA system is also replaced to accommodate full control of the new blowers and the aeration process. Proposed diffuser modifications are left as a separate capital improvements project and not considered in this measure. CEPS is not considered in this measure. The primary energy savings comes from turning off biofilter recirculation pumps and blowers and the more efficient blowers.

Analysis EEM 3

To establish the existing baseline energy usage, power monitors were installed on the biofilter equipment from 8/5/2014 to 8/27/2014. SCADA data including blower power and aeration air flow and DO levels from the plant SCADA system were collected for the same time period. Based on this data, the total power used to operate the existing secondary process was determined. During the monitoring period, this secondary process used a total of 571.7 kW on average. This is presented in Tables 5.5-5.7.

This base line energy usage measured during the monitoring period 8/5/2014-8/27/2014 was then adjusted by the influent BOD load to the facility for the month of August 2014 to the average influent BOD load conditions for the facility presented in the Carollo master plan. In this case, the average influent load during the monitoring period was 49,698 lbs/day of BOD. Per the Carollo 2014 master plan, the average annual loading for the facility is 53,167 lbs/day of BOD. The 571.7 kW was then scaled up to 600.1 kW based on the ratio of the influent BOD loading during the monitoring period and the average annual BOD loading. 600 kW was then used as the baseline power demand for the complete secondary process for all measures. This information is summarized in Tables 5.5-5.7.

To evaluate the changed condition for this measure, a process model was built using BioWin software to predict the performance of the biofilter and aeration basins in series. The model was calibrated against the current operation and then used to predict air flow requirements under the different measure options. Once new air flow requirements were developed, power usage for new high efficiency turbo blowers was calculated from blower performance curves for Neuros NX 300 turbo blowers.

For Option #3A with CEPS, the same process model was used to predict the loading to the aeration basin without the biofilter and improved BOD removal in the primary clarifier under the CEPS option. Once new air flow requirements with CEPS were developed, power usage for new high efficiency turbo blowers was calculated from blower performance curves for Neuros NX 300 turbo blowers.

Table 5 presents the energy savings analysis for this option based on the established baseline energy usage from the monitoring period compared to the implemented measure. A total of 2,175,333 kWh annually with 248 kW of demand reduction can be saved by implementing Measure #3. A total of 2,972,333 kWh annually with 339 kW of demand reduction can be saved by implementing Measure #3A.

The costs to implement these measures are presented in Table 5.8. The largest cost is to purchase the new blowers and demolition and removal of the existing biofilters. Measure #3A has an increased capital cost for the chemical addition facility and increased operations cost for the cost of the chemicals.

Table 5.5 Energy Savings Analysis (Existing Condition) for EEM#3 and 3A

Existing Condition - Measure #3 and #3A			
Monitoring Period 8/5/2014 - 8/27/2014	Total No.	Motor Size (hp)	No. In Service
Bio-Tower and Aeration Equipment			
1) Biofilter Recirculation Pumps	3	200	2
2) Biofilter Interstage Pumps	3	250	3
3) Biofilter No. 1 Blowers	4	10	4
4) Biofilter No. 2 Blowers	4	5	4
5) Aeration Blowers	5	350	1
	Power Draw (kW)		
Average Power Demand			
1) Biofilter Recirculation Pumps	212.0		
2) Biofilter Interstage Pumps	110.8		
3) Biofilter No. 1 Blowers	22.31		
4) Biofilter No. 2 Blowers	6.648		
5) Aeration Blowers	220		
Total Usage During Test Period (kW)	571.7		
Average Aeration Air Flow (SCFM)	3563		
Average Blower Pressure (psig)	7.7		
Adjust for Plant Loading During Test Period Compared to Average for the Year			
Monthly Average Influent BOD Concentration (mg/l)		295	
Monthly Average Plant Flow (mgd)		20.2	
Monthly Average BOD Loading (ppd)		49,698	
Average Influent Loadings			
Plant Flow MGD		21.03	
Pounds per Day BOD		52,167	
Total Usage During Test Period (kW)		571.7	
BOD Loading During Test Period (ppd)		49,698	
Normal Annual BOD Loading (ppd)		52,167	
Adjusted Base Line Energy Usage (kW)		**600.1**	

Table 5.6 Energy Savings Analysis (New Condition) for EEM#3 and #3A

New Condition- Measure #3 and #3A

Monitoring Period 8/5/2014 - 8/27/2014
Primary Clarifier Equipment

Monitoring Period 8/5/2014 - 8/27/2014

Bio-Tower and Aeration Equipment	Total No.	Motor Size (hp)	No. In Service
1) Biofilter Recirculation Pumps	0	0	0
2) Biofilter Interstage Pumps	3	250	2
3) Biofilter No. 1 Blowers	0	0	0
4) Biofilter No. 2 Blowers	0	0	0
5) Aeration Blowers (Existing)	2	350	0
6) Aeration Blowers (Turbo)	3	300	1

Aeration Airflow Without Biofilter	Measure #3 Without CEPS	Measure #3A With CEPS
Average Aeration Air Flow (SCFM)	6950	4816
Average Blower Pressure (psig)	8	7.9
Blower Power Draw (kW)	241	150

	Total Power (kW)	
Average Power Demand	Measure #3 Without CEPS	Measure #3A With CEPS
1) Biofilter Recirculation Pumps (kW)	0.0	0.0
2) Biofilter Interstage Pumps (kW)	110.8	110.8
3) Biofilter No. 1 Blowers (kW)	0	0.0
4) Biofilter No. 2 Blowers (kW)	0	0.0
5) Aeration Blowers (kW)	241	150
Total New Power Usage	351.8	260.8

Table 5.7 Energy Savings Analysis for EEM#3 and 3A

Energy Savings Estimate	Measure #3 Without CEPS	Measure #3A With CEPS	
Existing Power Usage (kW)	600.1	600.1	kW
New Power Usage (kW)	351.8	260.8	kW
Total Power Saved (kW)	248.3	339.3	kW
Pre-Installation Energy Consumption	5,257,123	5,257,123	kWh
Post-Installation Energy Consumption	3,081,791	2,284,631	kWh
Total Energy Saved	2,175,333	2,972,493	kWh
Pre-Installation Demand	600.13	600.13	kW
Post-Installation Demand	351.80	260.80	kW
Total Demand Savings	248.33	339.33	kW

Table 5.8 Costs Analysis for EEM#3

Item Description	Quantity	Unit	Unit Cost	Total Cost
Demolition of Existing Bio Towers	1	LS	$ 479,000	$ 479,000
Replace Activated Sludge Blowers	3	EA	$ 300,000	$ 900,000
Aeration System Electrical and SCADA	0.5	LS	$ 450,000	$ 225,000
			Subtotal	$ 1,604,000
Planning and Preliminary Engineering			10%	$ 160,000
Final Design			15%	$ 241,000
Construction Management and Admin			15%	$ 241,000
Construction Contingency			30%	$ 481,000
(All values from MKA-P&S Report March 26, 2014)			Total	$ 2,727,000

5.2.5. EEM # 3A Remove Biofilter and Replace 3 Aeration Blowers With Addition of Chemical Enhanced Primary Sedimentation

This measure is the same as Measure #3 with the addition of CEPS to the primary clarifiers. In addition to the energy savings noted under Measure #3, the CEPS reduces biological loading to the aeration basin and further reduces the energy usage of the aeration basin over Measure #3. There are increased capital and chemical costs associated with this measure.

Analysis EEM 3A

Analysis for EEM 3A is presented above in Section 5.2.4. Costs for EEM 3A are presented in Table 5.9 below. The table does not reflect avoided cost of reconstruction/rehabilitation of the Bio-towers, as reflected in other engineering analyses.

Table 5.9 Costs Analysis for EEM#3A

Item Description	Quantity	Unit	Unit Cost	Total Cost
Demolition of Existing Bio Towers	1	LS	$ 479,000	$ 479,000
Replace Activated Sludge Blowers	3	EA	$ 300,000	$ 900,000
Aeration System Electrical and SCADA	0.5	LS	$ 450,000	$ 225,000
Chemical Addition to Primaries	1	LS	$ 500,000	$ 500,000
			Subtotal	$ 2,104,000
Planning and Preliminary Engineering			10%	$ 160,000
Final Design			15%	$ 241,000
Construction Management and Admin			15%	$ 241,000
Construction Contingency			30%	$ 481,000
(All values from MKA-P&S Report March 26, 2014)			Total	$ 3,227,000

5.2.6. EEM # 4 Turn Off Biofilter and Make SCADA Improvements

Under this measure, the biofilters are simply turned off and isolated to prevent reuse. The existing SCADA system is replaced to accommodate better control of the new blowers and the aeration process. Proposed diffuser modifications are left as a separate capital improvements project and not considered in this measure. CEPS is not considered in this measure. The primary energy savings comes from turning off biofilter recirculation pumps and blowers. Total capital costs for this measure are less and the total energy savings is also less.

Analysis EEM 4

The baseline energy usage for this option is the same as for Measure #3 and #3A discussed above.

To evaluate the changed condition for this measure, a process model was built using BioWin software to predict the performance of the biofilter and aeration basins in series. The model was calibrated against the current operation and then used to predict air flow requirements under the different measure options. Once new air flow requirements were developed for the condition without the biofilters, power usage for the existing blowers was scaled up to match the new air flow based on the measured power demand per air flow ratio of 0.061746 kW/scfm measured during the monitoring period.

For Option #4A with CEPS, the same process model was used to predict the loading to the aeration basin without the biofilter and improved BOD removal in the primary clarifier under the CEPS option. Once new air flow requirements were developed for the condition without the biofilters, power usage for the existing blowers was scaled up to match the new air flow based on the measured power demand per air flow ratio of 0.061746 kW/scfm measured during the monitoring period.

Tables 5.10-5.12 present the energy savings analysis for this option based on the established baseline energy usage from the monitoring period compared to the implemented measure. A total of 537,290 kWh annually with 60 kW of demand reduction can be saved by implementing Measure #4. A total of 1,681,554 kWh annually with 192 kW of demand reduction can be saved by implementing Measure #4A. Measure #4 and #4A have less demand reduction and energy savings then Measures #3 and #3A because the existing blowers are less efficient then the high speed turbo blowers included under Measure #3 and #3A.

The costs to implement these measures are presented in Table 5.13. The largest cost is to install the SCADA improvements to better control the existing blowers and aeration system. SCADA improvements are required to operate the aeration system at increased air flows because the existing system is limited and is only capable of controlling one blower. Measure #4A has an increased capital cost for the chemical addition facility and increased operations cost for the cost of the chemicals.

Table 5.10 Energy Savings Analysis (Existing Condition) for EEM#4 and #4A

Table 5.11 Energy Savings Analysis (New Condition) for EEM#4 and #4A

Existing Condition

Monitoring Period 8/5/2014 - 8/27/2014

	Total No.	Motor Size (hp)	No. In Service
Bio-Tower and Aeration Equipment			
1) Biofilter Recirculation Pumps	3	200	3
2) Biofilter Interstage Pumps	3	250	2
3) Biofilter No. 1 Blowers	4	10	4
4) Biofilter No. 2 Blowers	4	5	4
5) Aeration Blowers	5	350	1

	Power Draw (kW)
Average Power Demand	
1) Biofilter Recirculation Pumps	212.0
2) Biofilter Interstage Pumps	110.8
3) Biofilter No. 1 Blowers	22.3
4) Biofilter No. 2 Blowers	6.6
5) Aeration Blowers	220.0
Total Usage During Test Period (kW)	571.7
Average Aeration Air Flow (SCFM)	3563
Average Blower Pressure (psig)	7.7
Existing Blower Power (kW/scfm)	0.061746

Adjust for Plant Loading During Test Period Compared to Average for the Year

Monthly Average Influent BOD Concentration (mg/l)	295
Monthly Average Plant Flow (mgd)	20.2
Monthly Average BOD Loading (ppd)	49,698
Average Influent Loadings	
Plant Flow MGD	21.03
Pounds per Day BOD	52,167
Total Usage During Test Period (kW)	571.7
BOD Loading During Test Period (ppd)	49,698
Normal Annual BOD Loading (ppd)	52,167
Adjusted Base Line Energy Usage (kW)	**600.1**

New Condition			
Monitoring Period 8/5/2014 - 8/27/2014			
Primary Clarifier Equipment			
Monitoring Period 8/5/2014 - 8/27/2014	Total No.	Motor Size (hp)	No. In Service
Bio-Tower and Aeration Equipment			
1) Biofilter Recirculation Pumps	0	0	0
2) Biofilter Interstage Pumps	3	250	2
3) Biofilter No. 1 Blowers	0	0	0
4) Biofilter No. 2 Blowers	0	0	0
5) Aeration Blowers	5	350	1
	Measure #4	Measure #4A	
Aeration Airflow Without Biofilter	Without CEPS	With CEPS	
Average Aeration Air Flow (SCFM)	6950	4816	
Average Blower Pressure (psig)	8	7.9	
Blower Power Draw (kW)	429	297	
	Total Power (kW)		
	Measure #4	Measure #4A	
Average Power Demand	Without CEPS	With CEPS	
1) Biofilter Recirculation Pumps (kW)	0.0	0.0	
2) Biofilter Interstage Pumps (kW)	110.8	110.8	
3) Biofilter No. 1 Blowers (kW)	0	0.0	
4) Biofilter No. 2 Blowers (kW)	0	0.0	
5) Aeration Blowers (kW)	429	297	
Total New Power Usage	539.9	408.2	

Table 5.12 Energy Savings Analysis for EEM#4 and #4A

Energy Savings Estimate	Measure #4 Without CEPS	Measure #4A With CEPS	
Existing Power Usage (kW)	600.1	600.1	
New Power Usage (kW)	539.9	408.2	
Total Power Saved (kW)	60.2	192.0	
Pre-Installation Energy Consumption	5,257,123	5,257,123	kWh
Post-Installation Energy Consumption	4,729,834	3,575,569	kWh
Total Energy Saved	527,290	1,681,554	kWh
Pre-Installation Demand	600.13	600.13	kW
Post-Installation Demand	539.94	408.17	kW
Total Demand Savings	60.19	191.96	kW

Table 5.13 Costs Analysis for EEM#4

Item Description	Quantity	Unit	Unit Cost	Total Cost
Aeration System Electrical and SCADA	1	LS	$ 250,000	$ 250,000
		Subtotal		$ 250,000
Final Design			10%	$ 160,000
Construction Management and Admin			10%	$ 160,000
Construction Contingency			10%	$ 160,000
		Total		$ 730,000

5.2.7. EEM # 4A Turn Off Biofilter and Make SCADA Improvements With Addition of Chemical Enhanced Primary Sedimentation

This measure is the same as Measure #4 with the addition of CEPS to the primary clarifiers. In addition to the energy savings noted under Measure #4, the CEPS reduces biological loading to the aeration basin and further reduces the energy usage of the aeration basin over Measure #4. There are increased capital and chemical costs associated with this measure.

Analysis EEM 4A

Analysis for EEM 4A is presented above in Section 5.2.6. Costs for EEM 4A are presented in Table 5.14 below.

Table 5.14 Costs Analysis for EEM#4A

J

Item Description	Quantity	Unit	Unit Cost	Total Cost
Aeration System Electrical and SCADA	1	LS	$ 250,000	$ 250,000
Chemical Addition to Primaries	1	LS	$ 500,000	$ 500,000
		Subtotal		$ 750,000
Final Design			10%	$ 160,000
Construction Management and Admin			10%	$ 160,000
Construction Contingency			10%	$ 160,000
		Total		$ 1,230,000

5.2.8. EEM # 5 Modify Utility Water System

The existing utility water pumping system pumps secondary effluent into an internal piping system for reuse of the water within the plant. The system consists of three 125 hp vertical turbine pumps with VFD control. The pumps maintain a system pressure of 90 psi at all times. This measure includes modifying the SCADA system to reduce the system pressure from 90 PSI to 60 PSI all day. The primary need for high pressure water is the dewatering operation which does not occur at night. The other users of the utility water such as seal water and spray water do not require 90 psi water. The energy savings achieved with this measure is a result of operation of the pumps at lower pressure for 12 hours a day.

Analysis EEM 5

To establish the energy baseline for this measure, the power usage of the existing pumps was monitored with power monitors from 8/5/201 through 8/27/2014. The data indicated that the lead pump runs 100% of the time (24 hrs/day) with the remaining pumps running less time. Based on this information, the total power usage for the existing condition was determined as indicated in Table 5.15.

To evaluate the changed condition for this measure, the reduced pressure condition of 60 psi for the 12 hour period from 6 pm to 6 am was used in conjunction with pump affinity laws to reduce actual measured pump power to the lower pressure condition. This lower pressure power condition was then compared to the measured power at full pressure during the monitoring period for the existing pumps to determine the net energy savings for the 12 hour period.

Table 5.15 presents the energy savings analysis for this option based on the established baseline energy usage from the monitoring period compared to the implemented measure. A total of 66,572kWh annually can be saved by implementing this measure. There is no demand savings for this measure because the pumps run full power 12 hours a day.

The cost to implement this measure is presented in Table 5.16. The largest cost is to modify the existing SCADA system to set pressure for the pumps based on a time clock.

Table 5.15 Energy Savings Analysis for EEM#5

Existing Condition			
Monitoring Period Mar-Apr 2014			
	Total No.	No. In Service	
Number of Reclaimed Water Pumps	3	3	
Pump Design Conditions/Operating Conditions			
Flow (gpm)		Variable	
Existing Pump Head (feet)		208	90 (psi)
Power Usage		Power Used	
Pump Motor Size (hp)		125	hp
Average Power Usage Total for all Pumps(kW)		33.5	kW
New Condition			
	Total No.	No. In Service	
Number of Reclaimed Water Pumps	3	3	
Pump Design Conditions/Operating Conditions			
Flow (gpm)		Variable	
New Pump Head 6 pm - 6 am (feet)		139	60 (psi)
New Pump Head 6 am - 6 pm (feet)		208	90 (psi)
Power Usage		Power Used	
Pump Motor Size (hp)		125	hp
Average Power Usage Total for all Pumps 6 pm- 6am (kW)		18.3	kW
Average Power Usage Total for all Pumps 6 pm- 6am (kW)		33.5	kW
Peak Pump Power Usage (kW)		0.0	kW
Existing Power Usage		33.5	kW
New Power Usage 6 pm to 6 am		18.3	kW
Total Power Saved		15.2	kW
Pre-Installation Energy Consumption		146,729	kWh
Post-Installation Energy Consumption		80,158	kWh
Total Energy Saved		66,572	kWh
Pre-Installation Demand		0.00	kW
Post-Installation Demand		0.00	kW
Total Demand Savings		0.00	kW

Table 5.16 Costs Analysis for EEM#5

Item Description	Quantity	Unit	Unit Cost	Total Cost
Programming Changes to SCADA	1	EA	$ 8,000	$ 8,000
Engineering Design and Project Management	1	EA	$ 8,000	$ 8,000
Construction Support	1	EA	$ 8,000	$ 8,000
			Subtotal	$ 24,000
Contingency			10%	$ 2,000
			Total	$ 26,000

5.2.9. EEM # 6 Modify Digester Mixing and Heating

The facility has 3 existing anaerobic digesters to process sludge from the primary and secondary processes. Digester No. 1 and No. 3 are in service. Digester No. 2 is not used. Digester No. 1 is 90 feet in diameter with a volume of 1.5 million gallons (mg). Digester No. 3 is 110 feet in diameter with a volume of 2.3 mg. The digesters are heated with three 50 hp heating recirculation pumps. The digesters are gas mixed with draft tubes. Digester No. 1 has two 100 hp and two 40 hp gas compressors for mixing. Digester No. 3 has three 150 hp gas compressors for mixing.

Heating

The heating recirculation pumps are torque flow style pumps equivalent to the WEMCO Model C style pump. These pumps have very low efficiencies but were historically installed for their robustness in pumping grit and high solids.

This measure evaluates replacing all three heating recirculation pumps with a screw centrifugal pump equivalent to the WEMCO Model Hydrostal. The Model Hydrostal pump is also designed for high solids such as digester sludge service, but is approximately 3 to 4 times more efficient as the Model C pump.

Savings and costs are calculated under this measure for replacing all three of the digester heating pumps.

Mixing

Gas mixing systems are less efficient than other types of digester mixing systems. In addition, the existing gas mixing system is grossly over sized. This measure proposes to replace the existing gas mixing system with a new high efficiency linear motion mixing system. The linear motion system mixing system uses a rising and plunging disk inside the digester to mix the contents. This system has been retrofitted successfully with substantial energy savings at several other digester facilities.

Savings and costs are calculated under this measure for replacing all of the gas compressors and draft tube mixers on Digesters No. 1 and No. 3.

Analysis EEM 6

To establish the energy baseline for this measure, the power usage of the existing pumps and gas compressors was monitored with power monitors from 8/5/2014 through

8/27/2014. The data indicated that 2 of the 3 heating recirculation pumps run 100% of the time (24 hrs/day) with the remaining pump off line. The data also indicate that only one gas compressor for each digester mixing systems operates 24 hrs per day. Based on this information, the total power usage for the existing condition was determined as indicated in Table 5.17.

Heating

To evaluate the changed condition for this measure, the flow and pressure conditions for the existing recirculation pumps were used in conjunction with pump curves for the WEMCO model Hydrostal pump to determine the pump power required for a replacement pump. This power was then compared to the measured power during the monitoring period for the existing pumps to determine the net energy savings.

Mixing

To evaluate the changed condition for this measure, a new mixing system using linear motion mixing was sized by the linear motion mixer manufacturer (Ovivo) for each digester. This sizing included total guaranteed mixing power for each digester. The power for the linear motion mixing was then compared to the measured power during the monitoring period for the existing gas compressors to determine the net energy savings.

Table 5.17 presents the energy savings analysis for this option based on the established baseline energy usage from the monitoring period compared to the implemented measure. A total of 1,315,257 kWh annually can be saved by implementing this measure. In addition 150 kW of power demand would be reduced by implementing this measure.

The cost to implement this measure is presented in Table 5.18. The largest cost is to purchase the new pumps and linear motion mixing system.

Table 5.17 Energy Savings Analysis for EEM#6

Existing Condition

Monitoring Period 8/5/2014 - 8/27/2014

Digester Equipment	Total No.	Motor Size (hp)	No. In Service
1) Heating Recirculation Pumps	3	50	2
2) Digester No. 1 Gas Mix Blowers	2	100	1
3) Digester No. 1 Gas Mix Blowers	2	40	0
4) Digester No. 3 Gas Mix Blowers	3	150	1

Average Power Demand	Power Draw (kW)
1) Heating Recirculation Pumps	74.6
2) Digester No. 1 Gas Mix Blowers	58.1
3) Digester No. 1 Gas Mix Blowers	0
4) Digester No. 3 Gas Mix Blowers	67.7
Total Existing Power Usage	200.3

New Condition

Monitoring Period 8/5/2014 - 8/27/2014

Digester Equipment	Total No.	Motor Size (hp)	No. In Service
1) Heating Recirculation Pumps	3	20	2
2) Digester No. 1 Linear Mixers	1	15	1
3) Digester No. 3 Linear Mixers	3	7.5	3

Average Power Demand	Power Draw (kW)
1) Digester No. 1 Recirculation Pump	13.4
2) Digester No. 3 Recirculation Pump	13.4
3) Digester No. 1 Linear Mixers	9.3
4) Digester No. 3 Linear Mixers	14.0
Total New Power Usage	50.2

Existing Power Usage	200.3	kW
New Power usage	50.2	kW
Total Power Saved	150.1	kW
Pre-Installation Energy Consumption	1,754,734	kWh
Post-Installation Energy Consumption	439,476	kWh
Total Energy Saved	1,315,257	kWh
Pre-Installation Demand	200.31	kW
Post-Installation Demand	50.17	kW
Total Demand Savings	150.14	kW

Table 5.18 Costs Analysis for EEM#6

Item Description	Quantity	Unit	Unit Cost	Total Cost
Wemco Hydrostal F4K-MH 15 hp motor	3	EA	$ 29,268	$ 87,804
Pump Installation	3	EA	$ 3,500	$ 10,500
Modify Existing Piping	3	EA	$ 2,500	$ 7,500
New Gauges and Instruments	3	EA	$ 1,500	$ 4,500
Ovivo Linear Mixer 15 hp motor (Digester No. 1)	1	EA	$ 226,038	$ 226,038
Digester No. 1 Mixer Installation	1	EA	$ 25,000	$ 25,000
Modify Existing Digester Roof	1	EA	$ 25,000	$ 25,000
Ovivo Linear Mixer 7.5 hp motor (Digester No. 3)	3	EA	$ 136,781	$ 410,343
Digester No. 3 Mixer Installation	3	EA	$ 25,000	$ 75,000
Modify Existing Digester Roof	3	EA	$ 25,000	$ 75,000
Miscellaneous Construction	1	EA	$ 15,000	$ 15,000
Engineering Design and Project Management	1	EA	$ 80,000	$ 80,000
Construction Support	1	EA	$ 80,000	$ 80,000
			Subtotal	$ 1,122,000
Contingency			10%	$ 112,000
			Total	$ 1,234,000

This page intentionally left blank

Appendix A – Energy Savings Calculations

The following workbooks are attached as part of this report:

1. E5 Mechanical Audit Spreadsheet Template v4 OWTP Option A.xlsx
2. E5 Mechanical Audit Spreadsheet Template v4 OWTP Option B.xlsx
3. Oxnard Analysis Rev 4-2.xlsx

Appendix B – Project Cost Estimates

See “Cost Summary” tab in attached Excel file:
Oxnard Analysis Rev 2-4.xls

APPENDIX B - MECHANICAL AUDIT REPORT

Mechanical Audit Report

A24CMC1

Provided For:

City of Oxnard

Oxnard Wastewater Treatment Plant

6001 South Perkins Road

Oxnard, CA 93033

Provided by:

The Energy Network

Audit Performed by:

QuEST

December 17, 2014

Version 4

This page left blank.

TABLE OF CONTENTS

1 Executive Summary

The Energy Network is pleased with the opportunity to provide this mechanical audit report to the City of Oxnard. The Energy Network, administered by Los Angeles County, was created by the California Public Utilities Commission to help eligible public agencies in Southern California harness their collective action, save energy, reduce operating costs and protect precious resources. To expand public agency participation in utility energy efficiency programs, The Energy Network is offering a range of energy efficiency services to assist public agencies with accelerating energy retrofits.

This report describes a package of recommended energy efficiency measures for the mechanical equipment at Oxnard Wastewater Treatment Plant (OWTP) estimated to reduce total annual energy costs by $2,034. In addition to reduced energy costs, the recommendations will provide the City of Oxnard with an opportunity to modernize outdated equipment, improve reliability and comfort, and replace ozone depleting R-22 refrigerant ,which is currently being phased out under the Montreal Protocol, with environmentally friendly refrigerants.

The Energy Network's engineering consultant, QuEST, Inc., performed a mechanical energy audit of the City of Oxnard's Wastewater Treatment Plant. The facility treats wastewater and monitors the quality of the final effluent to safeguard and preserve water resources. It consists of multiple buildings and open areas containing process infrastructure to treat wastewater.

The existing energy using systems are primarily process related equipment, exterior and interior lighting, and heating, ventilating and air conditioning (HVAC) equipment at some of the plant buildings. The HVAC equipment was audited at thirteen (13) buildings throughout the plant. The HVAC systems consist primarily of small heat pumps (HP) and air conditioning (AC) units ranging in size from 3 to 5 tons. There are only five (5) units with the cooling capacity greater than 5 tons. The total installed capacity of all units is 130 tons, however several units are not operational and the capacity of all functioning units is 80 tons. Energy usage related to the surveyed mechanical equipment represents a minor portion of the facility's total energy consumption, it is estimated that the HVAC units use less than 5% of the total energy.

1.1 Recommended Measures

The following energy efficiency measures (EEMs) have been evaluated and are recommended.

- *Replace Admin Bldg (1) 10-ton Rooftop Split System Outdoor HP Unit*
- *Replace Maintenance Bldg (1) 4-ton Rooftop Single Package HP*
- *Replace Maintenance Bldg (1) 5-ton Rooftop Single Package Gas/Elec Unit*
- *Replace Operations Center (1) 4-ton and (2) 3-ton Rooftop Single Package HPs*
- *Replace Effluent Electrical Room (1) 5-ton Split System AC Condensing Unit*
- *Replace Solids Processing (1) 3-ton Rooftop Split System Outdoor HP Unit*
- *Replace North Area Electrical Bldg (1) 7.5-ton Rooftop Single Package HP*
- *Replace Storage Bldg Server Room (1) 5-ton Split System AC Condensing Unit*
- *Replace New Headworks (1) 3-ton Rooftop Single Package AC*

If all of the measures listed above are implemented, the project will realize an estimated annual electricity savings of 27,075 kWh. Since the HVAC systems consume a small portion of the total energy, this reduction does not have a significant percentage reduction in the overall facility energy consumption.

The project savings, costs and financial analyses are summarized in Table 1.1.

Energy savings includes DEER Interactive Effects and Coincident Demand Factor. See the detailed calculations for more details. This may result in negative savings due to increase in heating and/or cooling demand. Annual Cost Savings is based on applicable electric and gas service rates.

The Gross Project Cost to your agency is estimated at $93,995, which includes all construction costs plus contingency costs. The Agency is receiving an estimated $24,401 of free services through The Energy Network. The Energy Network is covering the costs for project management, audit, design, construction management support, and measurement and verification, if applicable.

Total Incentives are based on the utility incentive rates. When subtracting incentives from the Gross Project Cost, the Net Project Cost to your agency is estimated at $72,995.

See Table 1.2 for a breakdown of the various project cost components.

In addition to the savings summarized in Table 1.1 the Agency could achieve additional cost savings by installing occupancy sensors to control temperature settings for electrical rooms or other areas with occasional and/or irregular occupancy. The potential savings are around 7,000 kWh and $500 per year and the cost around $2,700. Those estimates are highly dependent on the acceptable comfort conditions, type of sensors and compatibility with the existing thermostats. More details are provided at the end of Section 5.2.

Table 1.1 Proposed Mechanical Energy Efficiency Measures

City of Oxnard Wastewater Treatment Plant

			On-Bill Annual Savings[1]			Cost Savings, Project Costs, and Utility Incentives						
EEM #	Facility	Energy Efficiency Measure (EEM) Description	Electric Savings (kWh/yr)	Peak Savings (kW)	Gas Savings (therms/yr)	Annual Electric Cost Savings[2] ($/yr)	Annual Gas Cost Savings[2] ($/yr)	Annual Maintenance Savings[6] ($/yr)	TOTAL Annual Cost Savings[2] ($/yr)	Gross Project Costs[3] ($)	Total Incentives[4] ($)	Net Project Costs ($)
EEM-1	Oxnard Wastewater Treatment Plant	Replace Admin Bldg (1) 10-ton Rooftop Split System Outdoor HP Unit	3,274	2	-	$246	$0	$228	$474	$11,396	$4,000	$7,396
EEM-2	Oxnard Wastewater Treatment Plant	Replace Maintenance Bldg (1) 4-ton Rooftop Single Package HP	1,672	1	-	$126	$0	$185	$311	$9,273	$1,600	$7,673
EEM-3	Oxnard Wastewater Treatment Plant	Replace Maintenance Bldg (1) 5-ton Rooftop Single Package Gas/Elec Unit	1,150	1	10	$86	$10	$197	$294	$9,867	$2,000	$7,867
EEM-4	Oxnard Wastewater Treatment Plant	Replace Operations Center (1) 4-ton and (2) 3-ton Rooftop Single Package HPs	6,696	2	-	$503	$0	$515	$1,018	$25,751	$4,000	$21,751
EEM-5	Oxnard Wastewater Treatment Plant	Replace Effluent Electrical Room (1) 5-ton Split System AC Condensing Unit	1,824	1	-	$137	$0	$95	$232	$4,741	$2,000	$2,741
EEM-6	Oxnard Wastewater Treatment Plant	Replace Solids Processing (1) 3-ton Rooftop Split System Outdoor HP Unit	1,141	0	-	$86	$0	$87	$172	$4,334	$1,200	$3,134
EEM-7	Oxnard Wastewater Treatment Plant	Replace North Area Electrical Bldg (1) 7.5-ton Rooftop Single Package HP	6,218	1	-	$467	$0	$323	$790	$16,159	$3,000	$13,159
EEM-8	Oxnard Wastewater Treatment Plant	Replace Storage Bldg Server Room (1) 5-ton Split System AC Condensing Unit	3,828	1	-	$288	$0	$95	$382	$4,741	$2,000	$2,741
EEM-9	Oxnard Wastewater Treatment Plant	Replace New Headworks (1) 3-ton Rooftop Single Package AC	1,272	1	-	$96	$0	$155	$250	$7,733	$1,200	$6,533
Total			**27,075**	**9.6**	**10**	**$2,034**	**$10**	**$1,880**	**$3,924**	**$93,995**	**$21,000**	**$72,995**

Notes: [1] Energy savings include adjusted for interactive effects between measures. See the detailed calculation for more details. This may result in negative savings due to increase in heating and/or cooling demand. [2] Annual Cost Savings is based on applicable IOU service rates. [3] The Agency Project Cost includes construction costs and contingency. The Energy Network cost includes project management, audit, design, construction management support, and measurement and verification. [4] Total Incentives are based on the utility incentive rates. [5] IOU Annual Savings represent savings that are eligible for IOU incentives under the rule and guidelines of their efficiency programs. [6] Annual Maintenance Cost Savings is estimated using the CEC Proposition 39 approach of assuming 2% of construction cost annually, adjusted for inflation and discount rate.

Project Financial Analysis				
Net Present Value* (NPV)	Internal Rate of Return (IRR)	Savings-to-Investment Ratio (SIR)	Return on Investment (ROI)	Simple Payback (years)
($23,566)	0.1%	0.68	-47%	18.6

Notes: NPV and SIR are discounted at a rate of 5%. Analysis is based on cost savings, net project costs, and equipment measure life equal to Effective Useful Life values for SCE measure code. Utility rate escalation and inflation are included in the life cycle cost analysis.

the energy network
public agencies taking action to save energy

1.2 Project Cost Breakdown

Table 1.2 Project Cost Breakdown

Budget Component	Estimated Cost
Construction (JOC)	$85,450
Contingency	$8,545
Subtotal: Agency Gross Construction Costs	**$93,995**
SCE/SCG Incentives	$21,000
Subtotal: Agency Net Construction Costs	**$72,995**
Project Management	$960
Audit	$11,845
Design	$3,615
Construction Management Support	$5,020
M&V	$2,961
Subtotal: The Energy Network Costs	**$24,401**
TOTAL PROJECT COST	**$97,396**

1.3 Non Recommended Energy Efficiency Measures

Considering that the majority of the HVAC systems consist of small heat pumps and air conditioning units, the audit focused on retrofit options that could take advantage of the utility incentives available for the early retirement of aging, inefficient equipment. During the site survey, seven (7) HVAC units were identified as non--functioning, therefore they could not be included in the retrofit recommendation as detailed in Section 5 HVAC Systems and Recommendations. Per the utility program Equipment Eligibility Requirements, only operational units qualify for the incentive. However, a replacement with high efficiency units is recommended as a capital improvement project that would greatly improve occupants comfort and meet or exceed the current Title 24 efficiency requirements. Additionally, four (4) operational units were excluded from the recommended measures as they are less than 5 years old and meet the current minimum efficiency requirements. HVAC units excluded from the recommendations are listed in Section 5.3 Non-Recommended Measures.

2 Introduction

This section provides an overview of The Energy Network, the energy efficiency services available to participating agencies, and the Project Team that contributed to completing this report.

2.1 Program Overview

The Energy Network, administered by Los Angeles County, was created by the California Public Utilities Commission to help eligible public agencies in Southern California harness their collective action, save energy, reduce operating costs and protect precious resources.

To expand public agency participation in utility energy efficiency programs, The Energy Network is offering an unprecedented level of services. Our Turnkey Project Delivery method is aimed at minimizing strain on your agency's resources. The Network provides all of the services you need to carry out successful energy retrofit projects including project management, energy audits, retrofit design, construction management support, and expedited construction services.

Turnkey Project Delivery Services provided at no cost to your Agency include:

- Project Management
- Energy Audits
- Project Design
- Evaluating and Arranging Construction Financing
- Incentive Process Handling
- Retrofit Construction Management Support

Construction costs net of any applicable incentives would be covered by your agency, but The Energy Network offers expedited construction procurement services specifically designed to fast track energy efficiency retrofits and reduce your costs. Pools of pre-qualified mechanical and electrical contractors in your region have already been selected and awarded indefinite quantity construction contracts by the National Joint Powers Alliance® (NJPA) through a public competitively bid process.

By becoming a member of the NJPA, participating agencies can receive on call, energy retrofit construction services and be assured they are getting high quality firms that will perform work at guaranteed prices. Becoming a member of the NJPA can be done on-line at no-cost, no obligation and no liability.

Your agency saves time and money by not going through a lengthy qualification and bidding process, and the pricing for any work is transparent, detailed and guaranteed up front. And because the construction prices are set by the unit pricing in the catalog, the risk of inflated costs for change orders is greatly reduced. The Energy Network can help arrange financing for your energy efficiency projects, including utilizing our Master Lease Program financing designed specifically for public agency energy projects; and the entire utility incentive process is handled on your behalf.

After construction, The Network will help you realize your full energy savings by training your staff on the proper operation of the installed measures.

By providing unbiased expertise, project management, financing, and premium engineering services, The Energy Network addresses the common barriers that prevent many local governments and public agencies with limited resources from adopting energy saving measures. The Energy Network's services will complement and support services provided by other existing programs.

2.2 Project Team

Through The Energy Network, QuEST, Inc. performed a mechanical energy audit of the Oxnard Wastewater Treatment Plant operated by the City of Oxnard.

The project team consists of Thien Ng from the Capital Projects Management Division and Jeff Palacio from the Water Resources Division who provided invaluable assistance and access to the facility areas. The Energy Network's Project Manager is Douglas O'Brien. The personnel from QuEST that performed this audit is Franica Srdar with support from Irina Krishpinovich.

3 Facility Information

The Oxnard Wastewater Treatment Plant facility is located at 6001 South Perkins Road in Oxnard, CA. The facility is operated by the City of Oxnard. A description of the facility is provided below.

3.1 General Facility Description

The Oxnard Wastewater Treatment Plant consists of multiple buildings and open areas containing equipment and infrastructure supporting the wastewater treatment process. Following a three-step treatment process at the facility, most of the treated wastewater is discharged into the ocean.

3.2 Description of Areas Surveyed

The audit addressed mechanical equipment serving the following buildings: Administration and Laboratory, Maintenance, Collection System, Co-Generator, Operations Center, Effluent Electrical Room, Main Electrical, Small Electrical Room by Biofilter No. 1, Solids Processing, North Area Electrical, Headworks Controls, Storage and New Headworks. Majority of the buildings are small, single story buildings contain process related equipment and gear.

Administration and Laboratory building is typically occupied from 7:00 a.m. to 5:30 p.m., Monday through Friday (Admin section) and from 6:00 a.m. to 4:00 p.m., Monday through Saturday (Lab section). Maintenance building is typically occupied from 6:00 a.m. to 5:00 p.m., Monday through Friday while the Collection System building typical occupancy is from 6:00 a.m. to 4:00 p.m., Monday through Friday. Co-Generator building is typically occupied from 7:00 a.m. to 5:00 p.m., Monday through Sunday. Other buildings either do not have office or other type of space that is typically occupied, or staff is in and out thrpughout the day and night, therefore the HVCA equipment in all other buildings is scheduled on 24 hours per day, 7 days per week.

4 Historical Energy Use

4.1 Total Energy Use and Costs

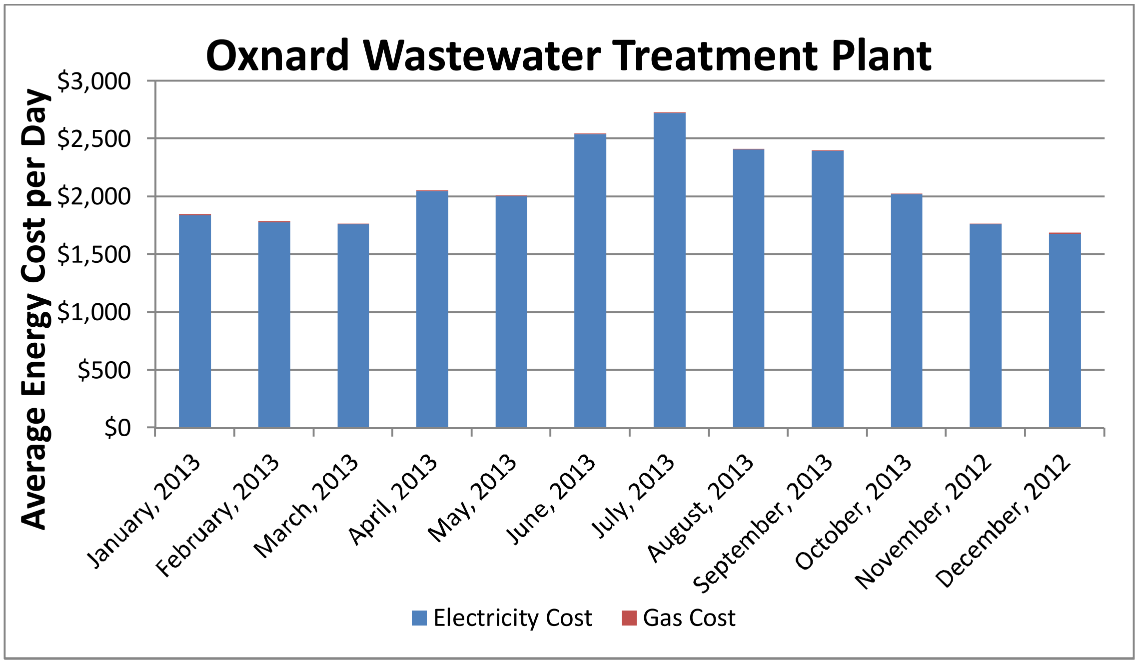
During a 12-month period from November 2012 through October 2013, the facility's total electricity consumption was 10,108,710 kWh, at a cost of $759,354, and the facility's total natural gas consumption was 1,847 therms, at a cost of $1,898. The total annual cost of energy at this site is approximately $761,251. Table 4.1 show the monthly breakdown of electric and gas usage and costs.

Table 4.1 Monthly Utility Usage and Cost

Month	Electricity Usage (kWh)	Demand (kW)	Electricity Cost ($)	Natural Gas (therms)	Gas Cost ($)	Total Utility Cost ($)
January, 2013	912,924	1,872	56,920	394	$347	$57,267
February, 2013	799,434	1,800	49,806	230	$226	$50,032
March, 2013	869,364	1,944	54,560	188	$181	$54,741
April, 2013	859,158	1,944	61,438	118	$123	$61,561
May, 2013	878,508	1,872	62,076	99	$109	$62,185
June, 2013	762,228	2,016	76,209	114	$131	$76,340
July, 2013	798,480	2,016	84,422	98	$116	$84,538
August, 2013	784,152	1,872	74,613	97	$111	$74,725
September, 2013	744,588	1,944	71,855	104	$117	$71,972
October, 2013	880,470	1,872	62,615	94	$103	$62,718
November, 2012	897,840	2,016	52,753	112	$123	$52,876
December, 2012	921,564	1,728	52,085	199	$211	$52,296
Totals	**10,108,710**	**2,016**	**$759,354**	**1,847**	**$1,898**	**$761,251**

Figure 4.1 depicts the total cost of energy broken down into electric and gas costs by month. This indicates that the daily energy cost is the highest during the summer months mostly due to higher electricity rates, especially for the summer on peak period.

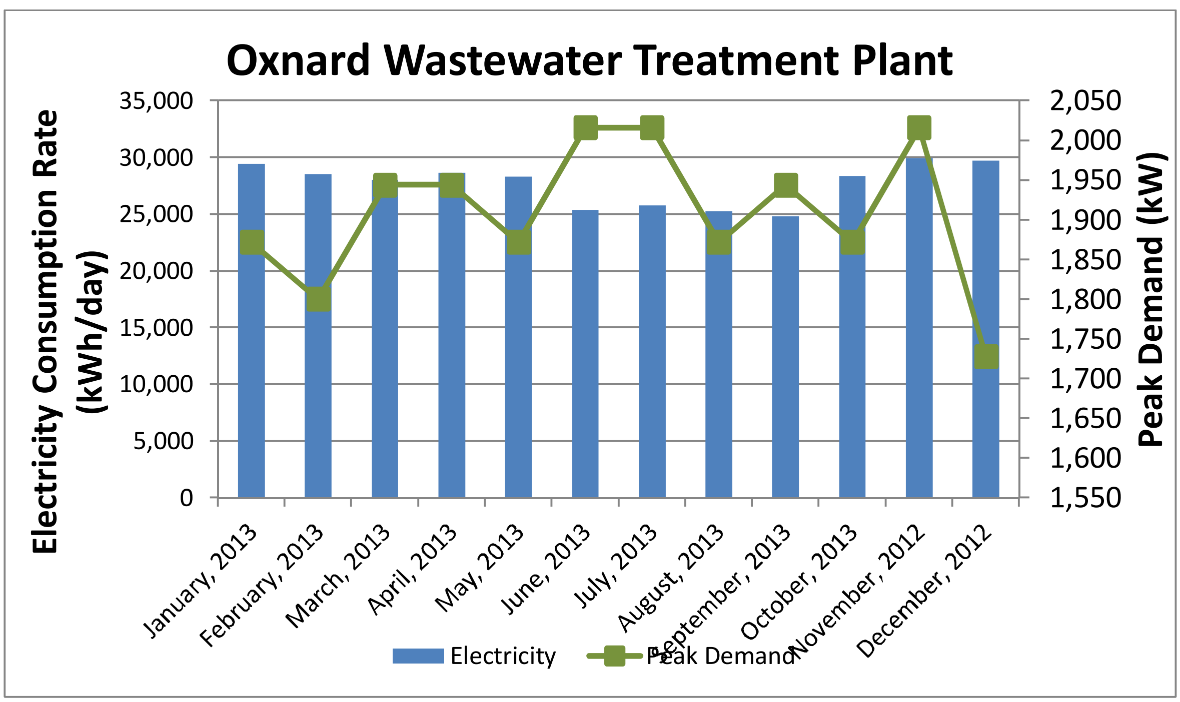
Figure 4.1: Normalized Monthly Energy Costs



4.2 Monthly Electricity Consumption and Demand

The monthly electrical data shows that there is little variance in the use of electricity since most of it is process related which is typically not subject to seasonal changes. Additionally, this facility is generating a significant portion of its electric needs and the amount of on-site generated electricity varies monthly and impacts the amount that is purchased from the utility.

Figure 4.2: Monthly Electricity Consumption and Demand

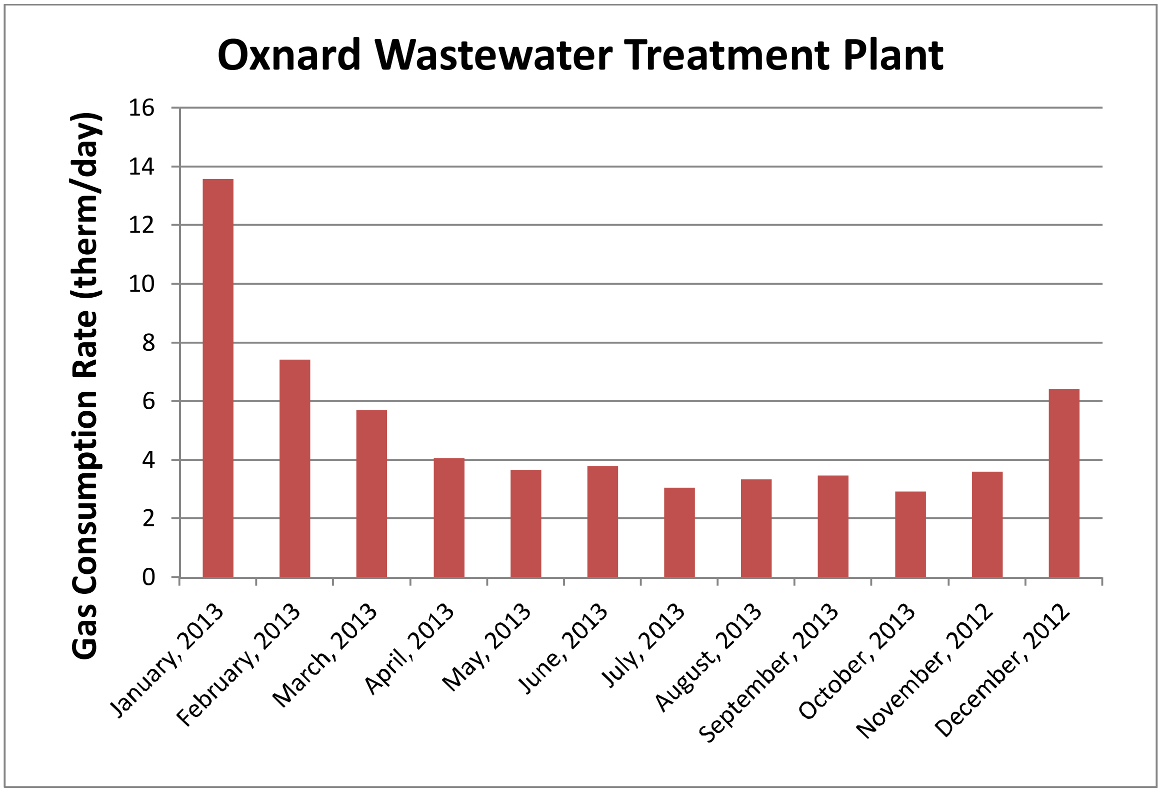


4.3 Monthly Natural Gas Consumption

The gas consumption at this facility is very small, averaging approximately 5 therms per day and as the below data shows the usage peaks in winter months.

The following figure shows the total annual gas consumption history.

Figure 4.3: Monthly Natural Gas Consumption



4.4 Energy Balance

An energy balance was not applicable in this instance as this industrial site uses the majority of energy for process associated equipment. Energy usage related to the surveyed mechanical equipment represents a minor portion of the total energy consumption.

5 HVAC Systems and Recommendations

The heating, ventilating and air conditioning (HVAC) systems are estimated to account for less than 5% of the total plant energy cost at the City of Oxnard Wastewater Treatment Plant. To identify and assess the feasibility of energy efficiency and improvement opportunities, an energy audit team visited the facility and performed visual inspections of the existing equipment and site conditions.

5.1 Existing Systems

The HVAC systems were audited at thirteen (13) buildings throughout the plant containing the total of twenty two (22) units. Majority of the HVAC systems consist of small package and split system heat pumps and air conditioning units ranging in size from 3 to 5 tons. There are five (5) units with the cooling capacity greater than 5 tons. Only one rooftop unit has electric cooling and gas heating and it is serving shop areas of the Maintenance building. The existing units range in age from over 15 years old to newer units that have been installed within the last 2 to 3 years. The HVAC systems are controlled by programmable thermostats which are maintained by a contractor.

Table 5.1 shows a summary of all HVAC equipment serving the Oxnard Wastewater Treatment Plant. In addition to the location, areas served, model numbers, capacities and efficiencies, the summary table also contains the operating hours and thermostat setpoints for each unit that were recorded during the audit.

Table 5.1 HVAC Equipment Summary

Building	HVAC Type	Unit Location	Area Served	Unit Operational (Yes/No)	Manufacturer	Model	Cooling Capacity (Tons)	EER/SEER Rating	Heating Capacity (Btu/Hr)	Heating Efficiency COP or %	Operating Hours	T-stat Settings
Administration & Laboratory	Split System HP	Rooftop	Office	Yes	Bryant	575CPX120000AA--	10	10.10	100,000	3.2	M - F 6 am - 6:15 pm	72/68
	Single Package HP	Rooftop	Lab	No	Carrier	50EQ-028---620	25	8.60	271,000	3.0	NA	NA
Maintenance	Single Package HP	Rooftop	Office	Yes	BDP	655AEX048000ACBG	4	10.10	47,500	3.1	M - F 5:30 am - 6:00 pm	72/69
	Single Package	Rooftop	Shop	Yes	Bryant	582ANW060000AAA6	5	10.00	90,000	80.1%	M - F 6:00 am - 6:00 pm	75/65
Collection System	Single Package HP	Rooftop	Office	No	Bryant	601AEXA060000AAA6	5	10.00	57,000	3.2	NA	NA
	Single Package HP	Rooftop	Restrooms/Showers	No	Bryant	655AEX060000AABG	5	10.00	57,000	3.2	NA	NA
Generator	Split System HP	Rooftop	Elec Room	No	Carrier	38ARZ008---601--	7	10.40	0	0.0	NA	NA
Operations Center	Single Package HP	Rooftop	Training Room	No	BDP	655AEX036000AA	3	10.10	35,400	3.1	NA	NA
	Single Package HP	Rooftop	Restrooms/Showers	Yes	Bryant	601AEXA048000AAA6	4	10.00	47,000	3.0	24/7	73/68
	Single Package HP	Rooftop	Computer Room	Yes	Carrier	50TFQ004-A-611--	3	10.20	34,400	3.4	24/7	72/66
	Single Package HP	Rooftop	Office	Yes	Carrier	50TFQ004-A-611--	3	10.20	34,400	3.4	24/7	73/64
Effluent Electrical Room	Split System AC	Outside on concrete pad	Elec Room	Yes	Bryant	113RNA060-H	5	13.20	0	0.0	24/7	72
	Split System HP	Outside on concrete pad	Gym	No	York	NA	NA	NA	NA	NA	NA	NA
Main Electrical	Split System AC *	Outside on concrete pad	Elec Room *	Yes	Guardian	GCGD60S21S2B	5	13.0	0	0.0	24/7	71/35
Small Bldg by Biofilter No. 1	Split System AC *	Outside on concrete pad	Elec Room *	Yes	Payne	PA13NR060-H	5	13.0	0	0.0	24/7	72
Solids Processing	Split System HP	Rooftop	Office and Elec Room	Yes	Bryant	213RNA036-C	3	13.20	35,000	3.5	24/7	72/60
North Area Electrical	Single Package HP	Rooftop	Office	Yes	Bryant	549BEX090000AK	7.5	10.30	85,000	3.3	24/7	72/70
	Single Package HP *	Rooftop	Elec Room *	Yes	Bryant	604BEXA60000AA--0	5	13.00	55,000	3.4	24/7	70
Headworks Controls	Split System AC	Outside wood beams	Elec Room	No	Bryant	597CN060-G	5	12	0	0.0	NA	NA
Storage	Split System AC	Outside on concrete pad	Server Room	Yes	Bryant	113REA060-D	5	13	0	0.0	24/7	67/65
New Headworks	Single Package HP *	Rooftop	Elec Room *	Yes	Carrier	50TCQD14ACA6A0A0A0	12.5	10.30	142,000	3.2	24/7	71/70
	Single Package AC	Rooftop	Office	Yes	Carrier	50HJ004---621CA	3	13.00	0	0.0	24/7	70
Total All Units							**130**		**1,090,700**			
Total Operational Units							***80***		***670,300***			

** Units under 5 years old, not recommended for replacement at this time*

Considering the type of equipment, efficiency, age and condition of some of the units, the audit focused on replacement of the existing units with new, high efficiency units. For a limited time, Southern California Edison (SCE) is partnering with local HVAC contractors and offering incentives for the HVAC Early Retirement. Currently installed and operational package or split air conditioner or heat pump systems replaced with a new high efficiency unit qualify for $400 per ton incentive. Under the HVAC Early Retirement process, an enrolled contractor submits the initial application, installs new qualifying equipment and receives incentive payment directly. This streamlined process would enable the Oxnard Wastewater Treatment Plant to upgrade the aging equipment with new, high efficiency HVAC units at a reduced cost without having to apply for a rebate.

As indicated in the table above, seven (7) units are non-functional and therefore cannot be included in the retrofit recommendations and benefit from the Early Retirement incentives. Additionally, four (4) operational units are under 5 years old so they are excluded from the replacement recommendations below. Those newer efficient units serve the following buildings/areas: Main Electrical, Electrical Room by Biofilter No. 1, North Area Electrical Room and New Headworks Office. The total of eleven (11) units is recommended for replacement as detailed in Section 5.2 Recommended Measures.

In addition to reducing energy consumption and costs, the retrofit recommendations would replace the ozone depleting refrigerant used in the existing units with environmentally friendly refrigerants. All existing units recommended for replacement contain hydrochlorofluorocarbon HCFC-22 refrigerant (also known as R-22) which is regulated as Class II controlled substance and is being phased out under the Montreal Protocol. As the production and import of R-22 is phased out over the coming years, it will become more difficult and expensive to maintain the existing R-22 systems. Since January 2010, chemical manufacturers are no longer able to produce, and companies no longer able to import, R-22 for use in new HVAC equipment but they can continue production and import of R-22 until 2020 for use in servicing existing equipment. The Clean Air Act does not allow any refrigerant to be vented into the atmosphere during installation, service, or retirement of equipment. Therefore, R-22 must be recovered and recycled (for reuse in the same system), reclaimed (reprocessed to the same purity standard as new R-22), or destroyed. After 2020, the servicing of R-22-based systems will rely solely on recycled or reclaimed refrigerants.

5.2 Recommended Measures

EEM 1: Replace Administration Building (1) 10-ton Rooftop Split System Outdoor HP Unit

This measure provides for the replacement of roof mounted outdoor unit serving the split system heat pump. The existing unit has a 10-ton cooling capacity with energy efficiency ratio (EER) of 10.1. The existing heating capacity is 100,000 Btu/hr with coefficient of performance (COP) of 3.2. This unit is approximately 10 years old and does not meet the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 38AUQ12 or similar unit with 11.5 EER , which exceeds the Title 24 minimum efficiency and meets the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. In addition to the efficiency improvements, further energy savings could be achieved by slightly reducing the operating hours and increasing the deadband between the cooling and heating setpoints. The unit is currently scheduled Monday to Friday from 6:00 a.m. to 6:15 p.m., the proposed schedule would start at 6:30 a.m. and stop at 5:30 p.m., more closely matching the occupancy schedule. The current Tstat setting is 72/68 ºF, it is recommended to increase the cooling setpoint to 74 ºF and keep the heating setpoint at 68 ºF.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions as well as reduced fan energy due to slightly shorter operating hours.

The measure would result in estimated annual electricity use and costs savings of 3,274 kWh and $474.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $11,396. When subtracting out available incentives, the Net Construction cost to your agency is $7,396.

EEM 2: Replace Maintenance Bldg (1) 4-ton Rooftop Single Package HP

This measure provides for the replacement of rooftop single package heat pump. The existing unit has a 4-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 10.1. The existing heating capacity is 47,500 Btu/hr with coefficient of performance (COP) of 3.1. This unit is approximately 16 years old and does not meet the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 50HC-05 or similar unit with 12.8 EER / 15.8 SEER, which exceeds the Title 24 minimum efficiency and the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The recommended unit includes the economizer which would bring in cool, outside air to cool the space during favorable weather conditions and reduce the number of hours when mechanical cooling is needed.

In addition to the efficiency improvements, further energy savings could be achieved by slightly reducing the operating hours and increasing the deadband between the cooling and heating setpoints. The unit is currently scheduled Monday to Friday from 5:30 a.m. to 6:00 p.m.., the proposed schedule would remain at 5:30 a.m. and stop at 5:00 p.m., more closely matching the occupancy schedule. The current Tstat setting is 72/69 ºF, it is recommended to increase the cooling setpoint to 74 ºF and reduce the heating setpoint to 68 ºF.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions as well as reduced fan energy due to slightly shorter operating hours.

The measure would result in estimated annual electricity use and costs savings of 1,672 kWh and $311.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $9,273. When subtracting out available incentives, the Net Construction cost to your agency is $7,673.

EEM 3: Replace Maintenance Bldg (1) 5-ton Rooftop Single Package Gas/Elec Unit

This measure provides for the replacement of rooftop single package gas/electric unit. The existing unit has a 5-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 10. The existing heating capacity is 90,000 Btu/hr with gas heating efficiency of 81% . This unit is approximately 11 years old and does not meet the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Trane model YHC-060 or similar unit with 12.85 EER / 15.0 SEER , which exceeds the Title 24 minimum efficiency and the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The recommended unit includes the economizer which would bring in cool, outside air to cool the space during favorable weather conditions and reduce the number of hours when mechanical cooling is needed.

In addition to the efficiency improvements, further energy savings could be achieved by slightly reducing the operating hours. The unit is currently scheduled Monday to Friday from 6:00 a.m. till 6:00 p.m., the proposed schedule would remain at 6:00 a.m. and stop at 5:00 p.m., more closely matching the occupancy schedule. The current Tstat setting is 75/65 ºF, it is recommended to keep the same setpoints.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions as well as reduced fan energy due to slightly shorter operating hours.

The measure would result in estimated annual electricity use and costs savings of 1,150 kWh and $294.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $9,867. When subtracting out available incentives, the Net Construction cost to your agency is $7,867.

EEM 4: Replace Operations Center (1) 4-ton and (2) 3-ton Rooftop Single Package HPs

This measure provides for the replacement of three (3) rooftop single package heat pumps. The existing units have a 3-ton and 4-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 10.2 and 10 . The existing heating capacity is 34,400 and 47,000 Btu/hr with coefficient of performance (COP) of 3.4 and 3.0. The 3-ton units are approximately 8 years old and the 4-ton unit is estimated to be 6 years old. The existing HPs do not meet the current Title 24 minimum efficiency requirements. The recommended replacement for the 4-ton unit would be a Carrier model 50HC-05 or similar unit with 12.8 EER / 15.8 SEER, and replacement for the 3-ton units would be a Carrier model 50XT-36 12 EER / 15 SEER or similar unit with 12 EER / 15 SEER. The replacement units exceed the Title 24 minimum efficiency and meet the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The recommended units include the economizer which would bring in cool, outside air to cool the space during favorable weather conditions and reduce the number of hours when mechanical cooling is needed.

The units are currently scheduled 24/7 and the Tstat settings range from 73/68 to 73/64 ºF. It is recommended to increase the cooling setpoint to 74 ºF and keep the existing heating setpoints.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions.

The measure would result in estimated annual electricity use and costs savings of 6,696 kWh and $1,018.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $25,751. When subtracting out available incentives, the Net Construction cost to your agency is $21,751.

EEM 5: Replace Effluent Electrical Room (1) 5-ton Split System AC Condensing Unit

This measure provides for the replacement of outdoor condenser serving the split system air conditioning unit. The existing unit has a 5-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 13.2. This unit is approximately 7 years old and meets the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 24ANB6-60 or similar unit with 12.5 EER / 15 SEER, which exceeds the Title 24 minimum efficiency and meets the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The unit is currently scheduled 24/7 and the Tstat setting is at 72 ºF. It is recommended to increase the cooling setpoint to 74 ºF.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions.

The measure would result in estimated annual electricity use and costs savings of 1,824 kWh and $232.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $4,741. When subtracting out available incentives, the Net Construction cost to your agency is $2,741.

EEM 6: Replace Solids Processing (1) 3-ton Rooftop Split System Outdoor HP Unit

This measure provides for the replacement of roof mounted outdoor unit serving the split system heat pump. The existing unit has a 3-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 13.2. The existing heating capacity is 35,000 Btu/hr with coefficient of performance (COP) of 3.5. This unit is approximately 7 years old and meets the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 25APA5-36 or similar unit with 12.5 EER / 15.5 SEER, which exceeds the Title 24 minimum efficiency and meets the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The unit is currently scheduled 24/7 and the Tstat setting is 72/60 ºF. It is recommended to increase the cooling setpoint to 74 ºF and keep the existing heating setpoint.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions.

The measure would result in estimated annual electricity use and costs savings of 1,141 kWh and $172.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $4,334. When subtracting out available incentives, the Net Construction cost to your agency is $3,134.

EEM 7: Replace North Area Electrical Bldg (1) 7.5-ton Rooftop Single Package HP

This measure provides for the replacement of rooftop single package heat pump. The existing unit has a 7.5-ton cooling capacity with energy efficiency ratio (EER) of 10.3. The existing heating capacity is 85,000 Btu/hr with coefficient of performance (COP) of 3.3. This unit is approximately 10 years old and does not meet the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 50HC 08 or similar unit with 12.1 EER / 13 IEER, which exceeds the Title 24 minimum efficiency and SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The unit is currently scheduled 24/7 and the Tstat setting is 72/70 ºF. It is recommended to increase the cooling setpoint to 74 ºF and reduce the heating setpoint to 68 ºF.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions.

The measure would result in estimated annual electricity use and costs savings of 6,218 kWh and $790.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $16,159. When subtracting out available incentives, the Net Construction cost to your agency is $13,159.

EEM 8: Replace Storage Bldg Server Room (1) 5-ton Split System AC Condensing Unit

This measure provides for the replacement of outdoor condenser serving the split system air conditioning unit. The existing unit has a 5-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 13. This unit is approximately 7 years old and meets the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 24ANB6-60 or similar unit with 12.5 EER / 15 SEER, which exceeds the Title 24 minimum efficiency and meets the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The unit is currently scheduled 24/7 and the Tstat setting is at 67 ºF. It is recommended to increase the cooling setpoint to 72 ºF. The server room setpoint could be increased even further and provide additional energy savings as it would reduce the number of hours that the compressor needs to operate to satisfy the higher room temperature. ASHRAE's Thermal Guidelines for data centers lists the recommended dry bulb temperature up to 80.6 °F and allowable temperatures as high as 113 °F depending on the data center classification.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions.

The measure would result in estimated annual electricity use and costs savings of 3,828] kWh and $382.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $4,741. When subtracting out available incentives, the Net Construction cost to your agency is $2,741.

EEM 9: Replace New Headworks (1) 3-ton Rooftop Single Package AC

This measure provides for the replacement of rooftop single package air conditioning unit. The existing unit has a 3-ton cooling capacity with seasonal energy efficiency ratio (SEER) of 13. This unit is approximately 7 years old and meets the current Title 24 minimum efficiency requirements. The recommended replacement unit would be a Carrier model 50XL-36 or similar unit with 12 EER / 15 SEER , which exceeds the Title 24 minimum efficiency and meets the SCE 2014 Qualifying Minimum Equipment Efficiencies for Commercial Air Conditioners and Heat Pumps. The recommended unit includes the economizer which would bring in cool, outside air to cool the space during favorable weather conditions and reduce the number of hours when mechanical cooling is needed.

The unit is currently scheduled 24/7 and the Tstat setting is at 70 ºF. It is recommended to increase the cooling setpoint to 74 ºF.

Savings for this measure will be realized through reduced cooling and heating energy necessary to satisfy zone comfort conditions.

The measure would result in estimated annual electricity use and costs savings of 1,272 kWh and $250.

The project costs covered by the Agency include construction, contingency and all NJPA processing fees equal to $7,733. When subtracting out available incentives, the Net Construction cost to your agency is $6,533.

Additional Measure to Consider: Install Occupancy Sensors for Electrical Rooms

The Agency could achieve additional cost savings by installing occupancy sensors to control temperature settings for electrical rooms and other areas with occasional and/or irregular occupancy. The recommendation is to use multi-technology wall or ceiling mounted occupancy sensors that incorporate both passive infrared and ultrasonic sensors into one unit, combining the long-range detection capabilities with the sensitivity to minor movements. New technology sensors provide much better controls than older models of occupancy sensors. Incorporating this technology with the existing or new HVAC thermostats, a room becomes aware that it is occupied and adjusts the interior environment accordingly without the need for programming schedules. For example, cooling set points for electrical rooms could be maintained at higher temperatures than the current settings but the set points would be adjusted automatically to the lower predetermined level when the room is physically occupied. Once a room is vacant, the sensor signals the HVAC controls to automatically perform a setback.

Energy savings are highly depended on the increased set points and the number of actual occupied hours in each area that is a candidate for HVAC occupancy sensors. Additional energy savings, above the savings accounted under the unit replacement and increasing the set points outlined in the above EEMs, are estimated to range from 800 kWh up to 1,500 kWh annually per electrical room. This estimate assumes that the thermostat could be maintained up to 80 ºF during the unoccupied time and when the occupancy is detected the set point is adjusted to 74 ºF. Increasing the room temperature even further would provide additional energy savings as it would reduce the number of hours that the compressor needs to operate to satisfy the higher room temperature. The estimated savings assumed that the higher set points would average 12 hours per day, some electrical rooms are probably mostly unoccupied while others have more frequent and longer occupancy where the temperature would need to be maintained at the lower level most of the time.

The facility personnel would determine the appropriate set points and areas where the occupancy sensors would provide energy savings benefits while still providing comfort levels when the areas are occupied. Although new sensors provide an adjustable “Verify Occupancy” time settings to allow random in and out occupancy for brief intervals without triggering the HVAC unit to occupied mode, electrical rooms that have very frequent in and out occupancy are probably not good candidates for this technology. Frequent room temperature changes would cause the HVAC units to cycle more than necessary and could shorten the equipment life.

Estimated costs depend on the type of sensor and compatibility with the existing thermostat, range from $300 to more than $600 per occupancy sensor for a complete purchase and setup, including installation, wiring, and programming.

The following areas are candidates for the occupancy sensor technology, however the facility personnel would determine the applicability based on the typical occupancy patterns: Effluent Electrical Room, Main Electrical Building, Small Electrical Building by Biofilter No. 1, North Area Electrical Room, Server Room and New Headworks Electrical Room. If occupancy sensors could be implemented in all of those buildings, the savings potential is around 7,000 kWh and $500 per year with the estimated costs around $2,700.

5.3 Non-Recommended Measures

The following retrofit options were not recommended as the existing energy equipment is not operational and does not qualify for the utility incentive. Additionally, once those units are replaced and brought back into service the energy use and costs for the OWTP would increase. However, a replacement with high efficiency units is recommended as a capital improvement project that would greatly improve occupants comfort, especially the Laboratory unit, and meet or exceed the current Title 24 efficiency requirements. The following non-functional units were excluded from the recommended measures:

- Laboratory Building - (1) 25-ton Single Package HP
- Collection System - (2) 5-ton Single Package HPs
- Generator - (1) 7-ton Split System HP
- Operations Center – (1) 3-ton Single Package HP
- Effluent Electrical Room - (1) 3 to 5-ton Split System HP (nameplate not available to verify the existing unit size)
- Headworks Controls - (1) 5-ton Split System AC

The following operational units were excluded from the recommended measures as they are less than 5 years old and meet the current minimum efficiency requirements:

- Main Electrical - Building - (1) 5-ton Split System AC
- Small Electrical Room by Biofilter No. 1 - (1) 5-ton Split System AC
- North Area Electrical Building - (1) 5-ton Single Package HP
- New Headworks - (1) 12.5-ton Single Package HP

6 Demand Response

Demand response (DR) programs address electric supply or price concerns that can be forecasted the day ahead or the day of an event, enabling a facility to curtail energy use during times of peak demand in return for an incentive. Considering that the installed capacity of all operational HVAC equipment is less than 100 kW and offers very a limited potential for DR programs, this facility was not evaluated for voluntary load curtailment actions.

7 Mechanical Analysis Methodology

7.1 Analytical Methodology and Assumptions

Annual energy savings are calculated by subtracting the post-project estimated energy consumption from the pre-project estimated energy consumption. Pre and post energy consumption are estimated using custom bin analysis.

Data used to develop the baseline energy consumption models include information obtained from the site surveys, mechanical schedules and utility data. Specifically, the following data was collected and used:

- Annual facility electricity and gas usage
- Design data including quantities, schematics, layouts, flow rates, and capacities
- Information from site surveys including mechanical and electrical equipment nameplate data and discussions with building engineering staff

- Operation schedules and setpoints obtained during the site survey and additionally provided by the facility
- Data sheets from equipment vendors

The baseline energy models were developed based on engineering calculations using the collected information and temperature bins. Temperature bins were arranged in 2°F intervals using annual hourly outdoor air dry bulb temperature data from Title 24 compliant CZ2010 weather data for Oxnard, CA. Because weather conditions, occupancy, and other factors vary from year to year, the estimated annual energy consumption is not expected to represent the actual energy consumption over the past year.

Once the baseline energy consumption was established, the expected energy consumption after implementation of an EEM was estimated by modifying input parameters in the models to reflect improvements to the efficiency and control of the equipment. As stated above, the estimated proposed energy consumption was then subtracted from the estimated baseline energy consumption to calculate the energy savings. Energy cost savings were then calculated by multiplying the energy savings by the appropriate energy rate.

The peak demand calculation was applicable for this measure and was calculated based upon the DEER peak demand definition as stated in the CPUC decision:

"Peak is defined as the average grid level impact for the measure from 2 p.m. to 5 p.m. during the three consecutive weekday period containing the weekday with the hottest temperature of the year".

An important step in the energy audit process is to take into account the interactive effects of installing various EEMs. 'Interactive effects' occur if two or more energy efficiency measures are installed and the realized savings are different than the sum of the estimated savings for the individual measures as stand-alone EEMs.

Consider the example of two EEMs; #1 where a new, more efficient chiller is installed and #2, where a new building automation system (BAS) is installed to shut off the air handler served by the chiller. Implementing either measure will save energy. However if both are installed, the realized savings will be less than the sum of the two measures estimated independently.

This interactive effect is accounted for by 'cascading' the calculations. In this process the proposed case for one measure is used as the baseline for the next measure. Depending on the order of implementation, savings from each individual measure will vary. The California Energy Commission's *Guide to Preparing Feasibility Studies for Energy Efficiency Projects* recommends analyzing measures that affect heating and cooling load first (such as installing controls to reduce hours of operation), then working "upward" to analyze improvements to the mechanical equipment. When reviewing the results of this report, please note that the best estimate of actual savings will be for the entire package of measures recommended. The savings of individual measures may be more or less than shown if not all of the other measures are implemented.

7.2 Project Cost Estimates

The project cost estimate is the sum of the construction cost estimate and the soft costs associated with the construction project. These cost components are described below.

Gross Project Costs: Gross Project Cost includes all costs including costs borne by the Agency and costs covered through the Energy Network services. The Agency cost includes construction and contingency costs. The Energy Network services provided at no cost to the

Agency includes project management, audit, design, construction management support, and measurement and verification

Total Incentives: total amount ($) of utility incentives available for the project.

Net Project Costs: Net Project costs are equal to the Gross Project Costs less the Total Incentives

7.2.1 Agency Project Costs and Incentives

Gross Construction Costs: The construction costs for each measure include direct labor, materials, equipment, the contractor's adjustment factor and all task order processing fees. These costs were estimated primarily from ezIQC Construction Task Catalogue (July 2013, HVAC Energy Efficiency), some contractor quotes and engineering estimates from similar projects. This estimate assumes a like for like replacement and additional potential costs such as curb adapters for rooftop units, indoor unit coil modifications for split systems, any ductwork adjustments and system repining are not included in the cost estimate.

Net Construction Costs: Gross Project Costs less the Total Incentives

Contingency: The contingency is included to cover potential increases in project scope that may occur due to unforeseen site conditions found during construction but missed in the initial audit, or refinements that occur when preparing the scope of work document.

7.2.2 The Energy Network Costs (provided at no cost to Agency)

Project Management: The Project Management cost covers the estimated cost for The Energy Network Project Manager to provide project management throughout the project.

Audit: The audit cost is the estimated cost to perform this audit and complete this report.

Design: The design costs cover the development of the project work scope that includes performance based project specifications

Construction Management Support by Consultant: The Energy Network's consultant will assist the Agency by providing Construction Management Support during construction performed by the contractor assigned from the pool of ezIQC contractors selected by the National Joint Powers Alliance. Construction Management Support will include review of submittals if applicable, assistance with coordination, progress review, monitoring of quantities and types of equipment installed, observation of controls commissioning if applicable, and document management.

Measurement & Verification (M&V): This is the cost of developing a M&V plan and performing M&V after the project is completed. Only a portion of projects will be selected to receive M&V.

7.3 Cost Effectiveness Analysis

The EEMs have been evaluated both for their technical feasibility, and for their overall financial benefit. This section describes the cost-effectiveness evaluation methods used in this report and the assumptions used to evaluate each of the recommended measures.

A Life Cycle Cost Analysis (LCCA) is employed for each measure. The LCCA methodology is based on the one laid out by the California Energy Commission Proposition 39 Program. The LCCA takes discount rate, inflation, utility rate escalation, and annual maintenance cost savings into account over the entire estimate life cycle of each measure. The measure LCCA cost streams are aggregated together into one project cost stream so that the agency can review the cost effectiveness of implementing all recommended measures at the same time in one project bundle. The program seeks to recommend project bundles to the agency that have a Savings-to-Investment Ratio (SIR) greater than 1.1, which is in line with the CA Proposition 39 program goals for public schools. There is more detail below on the financial metrics that go into these cost effectiveness calculations.

Energy savings includes DEER Interactive Effects and Coincident Demand Factor. See the detailed calculation for more details. This may result in negative savings due to increase in heating and/or cooling demand.

The Annual Cost Savings for each energy efficiency measure identified in this report have been evaluated using current utility rates the Agency pays for electricity and natural gas.

7.3.1 Financial Metrics Definitions

Lifecycle Analysis expressed as the Net Present Value (NPV): The NPV is a measure of the present value dollars of the net cost savings for a given energy project over its lifetime, including initial project costs, with discounting applied to cash flows that occur in the future. NPV is simply the present value (PV) of future cash flows minus the purchase price. NPV takes into account the time value of money and indicates what a project's lifetime cash flow is worth today. NPV is determined by calculating the amount of money in today's dollars that would have to be invested at the discount rate to reproduce the savings cash flow from the EEM and then subtracting the EEM implementation cost. If the NPV is greater than zero, the project is considered to be cost effective.

Savings-to-Investment Ratio (SIR) is the value of benefits from a project divided by its cost. Per CEC Proposition 39:

SIR = NPV / (Project Installation Cost – Rebates – Other Grants – Non-energy Benefits)

TEN does not use "Non-energy Benefits" in its financial models.

Internal Rate of Return (IRR): The internal rate of return is the interest rate that would be required to produce the financial savings from an EEM if the cost for implementing the EEM had been invested. In effect, the IRR is the discount rate which yields a Net Present Value of zero. Attractive projects have an IRR greater than the cost of money.

Return on Investment (ROI) is the annual percentage return from a project, where annual cost savings include the net present value of both utility cost savings and maintenance cost savings over the life of the project, per CEC Proposition 39 Guidelines. ROI is calculated as follows:

ROI = [Annual Cost Savings ($/yr) - Project Cost] / Project Cost ($)

Simple Payback Period: The simple payback period is the amount of time required to recover the initial costs of a project from its savings; it is calculated as Net Project Cost ($) / Annual Cost Savings ($/yr). A project is economically acceptable if the payback period is less than the length of the project life. A simple payback period ignores the time value of money and assumes that future savings occur in even amounts each year. The simple payback period is equal to the investment costs divided by the annual savings. For example, a $1,000 investment that saves $500 each year has a two-year simple payback period.

7.3.2 Financial Metrics Calculations

This section describes the assumptions used in the Analysis.

NPV assumes energy cost savings and project costs in the detailed audit calculation. Equipment measure life is based on Effective Useful Life values for each measure based on stipulated values for the SCE measure code, as shown in the "Analysis - Incentive Calc" worksheet. Per CEC Proposition 39:

Net Present Value = Energy Cost Savings + Maintenance Savings

Gross Project Cost is based the total construction costs for each measure include direct labor, materials, equipment, the contractor’s adjustment factor and all task order processing fees. The agency cost includes construction and contingency costs. The Energy Network cost includes project management, audit, design, construction management support, and measurement and verification.

Annual Cost Savings is based on electric service rates shown in the detailed audit calculation.

Discount Rate is assumed to be 5%, which is the value listed in CEC Proposition 39 Guidelines.

***NPV Term or Useful Measure* Life** = Depends on effective useful life of EEM; the Effective Useful Life values are either taken from the SCE measure code if applicable, or from the 2007 ASHRAE Handbook- HVAC Applications, Table 4 in Chapter 36.

Appendix A – Energy Savings Calculations

Electronic calculations are attached.

This page left blank.

Appendix B – Project Cost Estimates

EEM IMPLEMENTATION COST ESTIMATE		DATE: 9/29/2014
PROJECT:	City of Oxnard - OWTP	BASIS OF ESTIMATE (check all that apply):
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033	☐ R.S. MEANS ☐ DODGE
RCx PROVIDER:	The Energy Network and QuEST	☐ MFG'S QUOTES ☑ ENGINEERING ESTIMATE
MEASURE:	Replace 10-ton Rooftop Split System HP	☑ OTHER (eGordian NJPA)

		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 600	$ 600	$ 600
2	10 Ton 13 SEER Outdoor Heat Pump Unit	1	each	$ 7,400.00	$ 7,400	$ 850	$ 850	$ 8,250
3	Winterstart Control	1	each		$ -	$ 160	$ 160	$ 160
4	Corrosion protection for coils and cabinet (mat & labor total)	1	each	$ 850.00	$ 850		$ -	$ 850
5	Crane (est. average cost, will depend on how many units are done at the same time)	1	each	$ 500.00	$ 500		$ -	$ 500
					$ -		$ -	$ -
					$ -		$ -	$ -
				TOTAL	$ 8,750		$ 1,610	**$ 10,360**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE		DATE: 9/29/2014
PROJECT:	City of Oxnard - OWTP	BASIS OF ESTIMATE (check all that apply):
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033	☐ R.S. MEANS ☐ DODGE
RCx PROVIDER:	The Energy Network and QuEST	☐ MFG'S QUOTES ☑ ENGINEERING ESTIMATE
MEASURE:	Replace 4-ton Rooftop Single Package HP	☑ OTHER (eGordian NJPA)

		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 490	$ 490	$ 490
2	4 Ton Packaged Rooftop High Efficiency Heat Pump w/Economizer	1	each	$ 6,022.00	$ 6,022	$ 915	$ 915	$ 6,940
3	Corrosion protection for coils and cabinet (mat & labor total)	1	each	$ 1,000.00	$ 1,000		$ -	$ 1,000
4	Crane (included above)				$ -		$ -	$ -
					$ -		$ -	$ -
					$ -		$ -	$ -
				TOTAL	$ 7,022		$ 1,405	**$ 8,430**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE				DATE:	9/29/2014			
PROJECT:	City of Oxnard - OWTP					BASIS OF ESTIMATE (check all that apply):		
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033					☐ R.S. MEANS		
						☐ DODGE		
RCx PROVIDER:	The Energy Network and QuEST					☐ MFG'S QUOTES		
						☑ ENGINEERING ESTIMATE		
MEASURE:	Replace 5-ton Rooftop Single Package Gas/Electric Unit					☑ OTHER (eGordian NJPA)		
		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 170	$ 170	$ 170
2	5 Ton, High Efficiency, Gas Heat, Electric Cooling, DX Unitary Package Rooftop Unit	1	each	$ 6,325.00	$ 6,325	$ 325	$ 325	$ 6,650
3	Factory Installed Economizer	1	each	$ 650.00	$ 650	$ -	$ -	$ 650
4	Corrosion protection for coils and cabinet (mat & labor total)	1	each	$ 1,000.00	$ 1,000	$ -	$ -	$ 1,000
5	Crane (est. average cost, will depend on how many units are done at the same time)	1	each	$ 500.00	$ 500		$ -	$ 500
					$ -		$ -	$ -
					$ -		$ -	$ -
				TOTAL	$ 8,475		$ 495	**$ 8,970**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE				DATE:	9/29/2014			
PROJECT:	City of Oxnard - OWTP					BASIS OF ESTIMATE (check all that apply):		
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033					☐ R.S. MEANS		
						☐ DODGE		
RCx PROVIDER:	The Energy Network and QuEST					☐ MFG'S QUOTES		
						☑ ENGINEERING ESTIMATE		
MEASURE:	Replace 3-ton Rooftop Single Package HP					☑ OTHER (eGordian NJPA)		
		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 425	$ 425	$ 430
2	3 Ton Packaged Rooftop High Efficiency Heat Pump w/Economizer	1	each	$ 5,265.00	$ 5,265	$ 790	$ 790	$ 6,060
4	Corrosion protection for coils and cabinet (mat & labor total)	1	each	$ 1,000.00	$ 1,000		$ -	$ 1,000
5	Crane (included above)				$ -		$ -	$ -
					$ -		$ -	$ -
					$ -		$ -	$ -
				TOTAL	$ 6,265		$ 1,215	**$ 7,490**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE		DATE: 9/29/2014	
PROJECT:	City of Oxnard - OWTP	BASIS OF ESTIMATE (check all that apply):	
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033	☐	R.S. MEANS
		☐	DODGE
RCx PROVIDER:	The Energy Network and QuEST	☐	MFG'S QUOTES
		☑	ENGINEERING ESTIMATE
MEASURE:	Replace 5-ton Condensing Unit (on the ground)	☑	OTHER (eGordian NJPA)

		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 447	$ 447	$ 450
2	5 Ton 13 SEER Outdoor AC Unit	1	each	$ 1,610.00	$ 1,610	$ 635	$ 635	$ 2,250
3	Winterstart Control	1	each	$ 98.00	$ 80		$ -	$ 80
4	Add for 14 SEER	1	each	$ 337.00	$ 337		$ -	$ 340
5	Add for 15 SEER (assumed same add as 14 SEER)	1	each	$ 337.00	$ 337		$ -	$ 340
6	Corrosion protection for coils and cabinet	1	each	$ 850.00	$ 850		$ -	$ 850
					$ -		$ -	$ -
				TOTAL	$ 3,214		$ 1,082	**$ 4,310**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE		DATE: 9/29/2014	
PROJECT:	City of Oxnard - OWTP	BASIS OF ESTIMATE (check all that apply):	
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033	☐	R.S. MEANS
		☐	DODGE
RCx PROVIDER:	The Energy Network and QuEST	☐	MFG'S QUOTES
		☑	ENGINEERING ESTIMATE
MEASURE:	Replace 3-ton Rooftop Split System HP	☑	OTHER (eGordian NJPA)

		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 340	$ 340	$ 340
2	3 Ton 13 SEER Outdoor Heat Pump Unit	1	each	$ 1,151.00	$ 1,151	$ 515	$ 515	$ 1,670
3	Winterstart Control	1	each	$ 98.00	$ 98		$ -	$ 100
4	Add for 14 SEER	1	each	$ 242.00	$ 242		$ -	$ 240
5	Add for 15 SEER (assumed same add as 14 SEER)	1	each	$ 242.00	$ 242		$ -	$ 240
6	Crane (est. average cost, will depend on how many units are done at the same time)	1	each	$ 500.00	$ 500		$ -	$ 500
7	Corrosion protection for coils and cabinet	1	each	$ 850.00	$ 850		$ -	$ 850
				TOTAL	$ 3,083		$ 855	**$ 3,940**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE		DATE:	9/29/2014					
PROJECT:	City of Oxnard - OWTP				BASIS OF ESTIMATE (check all that apply):			
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033				☐ R.S. MEANS			
					☐ DODGE			
RCx PROVIDER:	The Energy Network and QuEST				☐ MFG'S QUOTES			
					☑ ENGINEERING ESTIMATE			
MEASURE:	Replace 7.5-ton Rooftop Single Package HP				☑ OTHER (eGordian NJPA)			

		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 595	$ 595	$ 600
2	7.5 Ton Packaged Rooftop Heat Pump	1	each	$ 10,167.00	$ 10,167	$ 1,110	$ 1,110	$ 11,280
3	Factory Installed Economizer	1	each	$ 1,805.00	$ 1,805		$ -	$ 1,810
4	Corrosion protection for coils and cabinet (mat & labor total)	1	each	$ 1,000.00	$ 1,000		$ -	$ 1,000
5	Crane (included above)				$ -		$ -	$ -
					$ -		$ -	$ -
					$ -		$ -	$ -
				TOTAL	$ 12,972		$ 1,705	**$ 14,690**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

EEM IMPLEMENTATION COST ESTIMATE		DATE:	9/29/2014					
PROJECT:	City of Oxnard - OWTP				BASIS OF ESTIMATE (check all that apply):			
LOCATION:	6001 South Perkins Road Drive, Oxnard CA 93033				☐ R.S. MEANS			
					☐ DODGE			
RCx PROVIDER:	The Energy Network and QuEST				☐ MFG'S QUOTES			
					☑ ENGINEERING ESTIMATE			
MEASURE:	Replace 3-ton Rooftop Single Package AC				☑ OTHER (eGordian NJPA)			

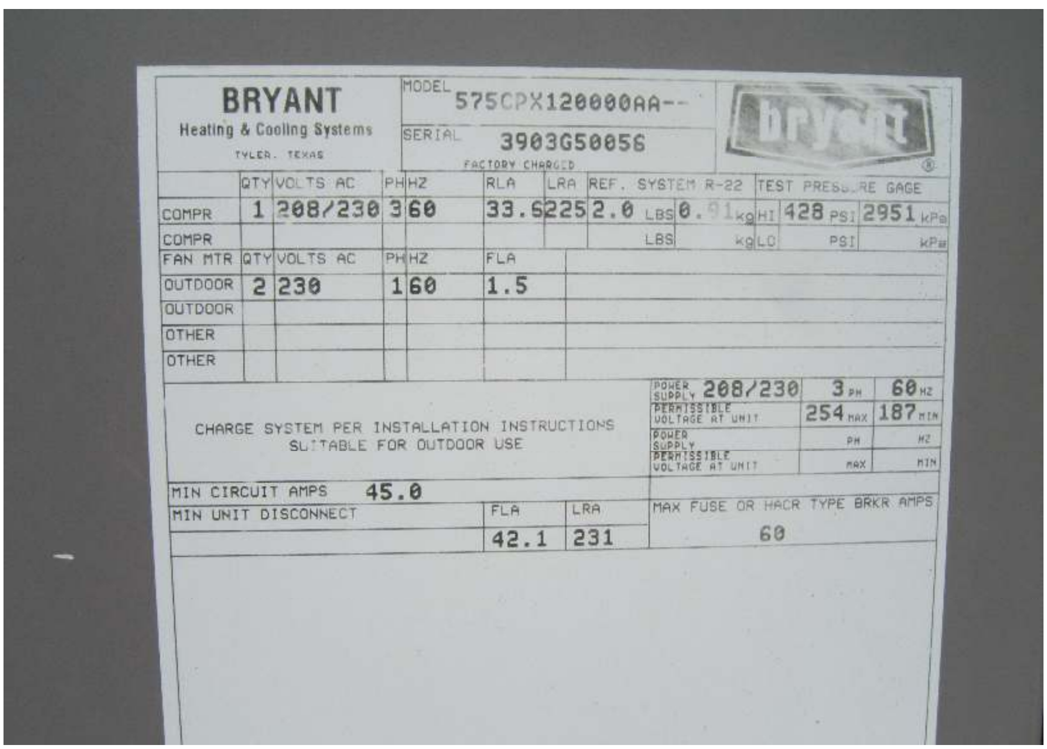
		Quantity		*Material*		*Labor*		
Item Number	**Description of Items**	**No. of Units**	**Unit of Measure**	**Cost per Unit**	**Total**	**Cost per Unit**	**Total**	**Total Cost incl. O&P and contingency**
1	Demo	1	each		$ -	$ 148	$ 148	$ 150
2	3 Ton, High Efficiency, Cooling Only DX Unitary Package Rooftop Unit	1	each	$ 5,075.00	$ 5,075	$ 300	$ 300	$ 5,380
3	Corrosion protection for coils and cabinet (mat & labor total)	1	each	$ 1,000.00	$ 1,000		$ -	$ 1,000
4	Crane (est. average cost, will depend on how many units are done at the same time)	1	each	$ 500.00	$ 500		$ -	$ 500
					$ -		$ -	$ -
					$ -		$ -	$ -
				TOTAL	$ 6,575		$ 448	**$ 7,030**

Note:
Costs indicated in this table are opinions of probable cost, and should not be considered bid costs.

This page left blank.

Appendix C – Photos

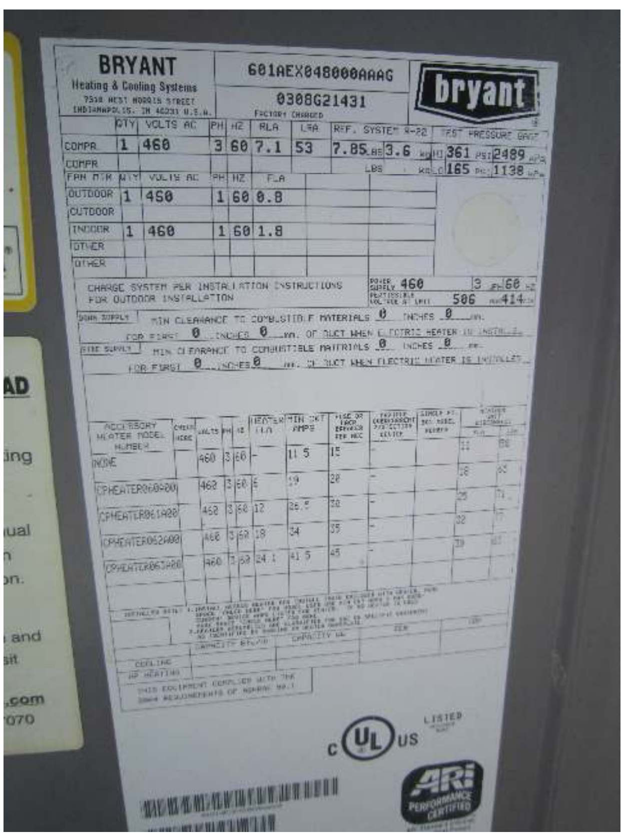
- Administration Building (1) 10-ton Rooftop Split System HP

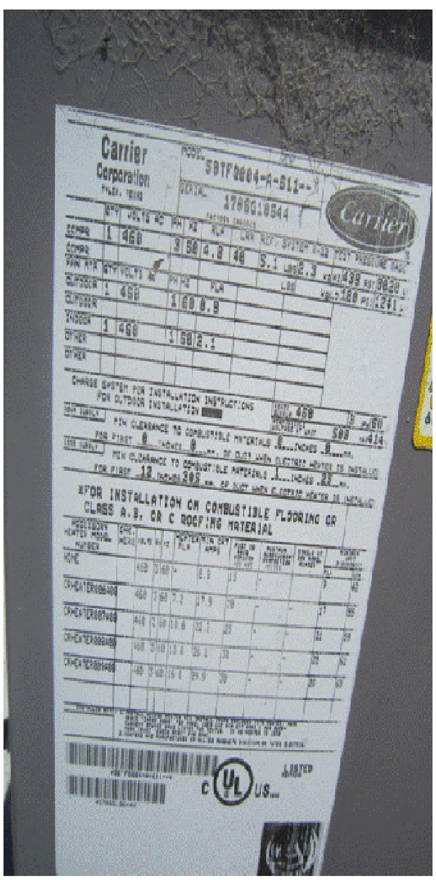


• Maintenance Building (1) 4-ton Rooftop Single Package HP

• Maintenance Bldg (1) 5-ton Rooftop Single Package Gas/Elec Unit

• Operations Center (1) 4-ton and (2) 3-ton Rooftop Single Package HPs



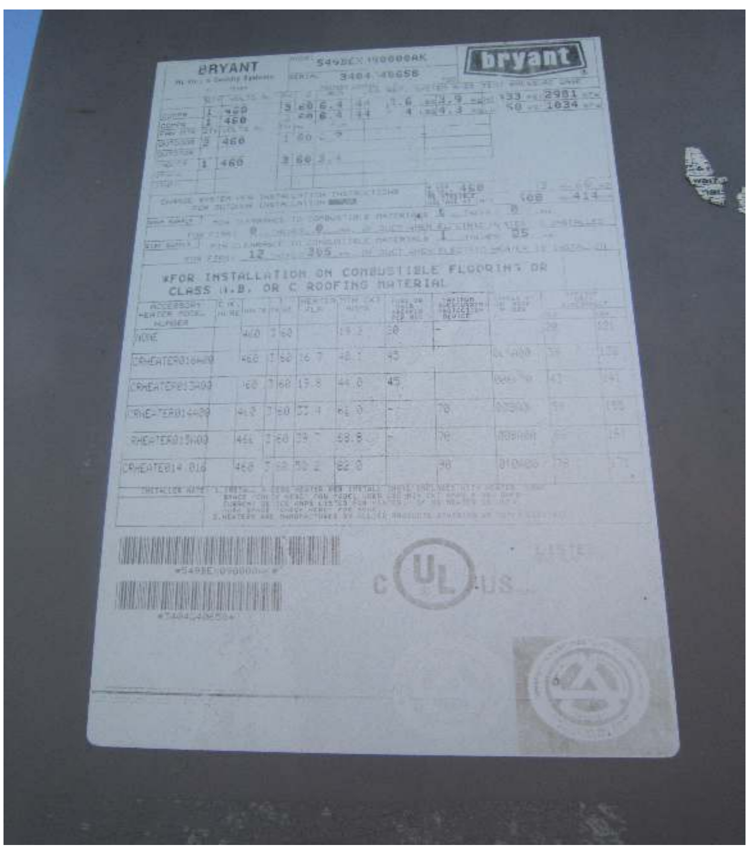

Carrier
Corporation
Carrier


Carrier
Corporation
Carrier

- Effluent Electrical Room (1) 5-ton Condensing Unit for Split System AC

• Solids Processing (1) 3-ton Rooftop Outdoor Unit for Split System HP

- North Area Electrical Bldg (1) 7.5-ton Rooftop Single Package HP



• Storage Bldg Server Room (1) 5-ton Condensing Unit for Split System AC


This Product is Protected By
Blygold
Corrosion Protection Coating System
For warranty/maintenance information, visit www.coilcoatinginc.com
Serial No. 04428
Industrial Coating & Coil
A division of Rahn Industries
For additional information call 877-724-6463
Blygold
CAUTION

- New Headworks (1) 3-ton Rooftop Single Package AC

This page left blank.

APPENDIX C - OXNARD WASTEWATER TREATMENT PLANT ENERGY EVALUATION REPORT

OXNARD WASTEWATER TREATMENT PLANT

ENERGY EVALUATION REPORT

July 2013

REGISTERED PROFESSIONAL ENGINEER
ROBERT A. GILLETTE
No. C25218
CIVIL
STATE OF CALIFORNIA

07/23/2013

COLORADO LICENSED
TROY A. HEDLUND
40717
PROFESSIONAL ENGINEER

07/23/2013

REGISTERED PROFESSIONAL ENGINEER
THOMAS G. MOSSINGER
No. 26798
MECHANICAL
STATE OF CALIFORNIA

07/23/2013

2700 Ygnacio Valley Road, Suite 300 ▪ Walnut Creek, California 94598 ▪ P. 925.932.1710 ▪ F. 925.930.0208

OXNARD WASTEWATER TREATMENT PLANT

ENERGY EVALUATION REPORT

TABLE OF CONTENTS

Page No.

CHAPTER 5 - FUNDING SOURCES

LIST OF TABLES

LIST OF FIGURES

INTRODUCTION AND BACKGROUND

1.1 INTRODUCTION

The purpose of this report is to summarize energy efficiency opportunities, including providing an assessment of biogas enhancement through the addition of alternative feedstocks to the City of Oxnard (City) Wastewater Treatment Plant (OWTP) anaerobic digesters, opportunities for replacement cogeneration facilities, and renewable energy production with photovoltaic systems. Planning level project cost estimates are presented for each of these opportunities, in addition to potential funding sources.

The City's resolution number 14,398 approving the final draft City of Oxnard Energy Action Plan (EAP) and confirmation of implementation of three EAP programs is included in Appendix A.

1.2 BACKGROUND

With rising energy costs on the horizon, projected shortfalls in power production from the power utilities, and the State's current goal to reduce greenhouse gas emissions, it is prudent for the City to investigate potential green energy sources. The OWTP currently consumes approximately 2,200 kilowatts (kW) daily. At an average current electrical power cost of approximately 11 cents per kW-hr (kWh), the annual average power bill for treatment would amount to approximately $2 million per year if all of this power were purchased from the local electric utility, Southern California Edison (SCE). Recognizing this as a significant potential operating expense and understanding the value of the digester gas produced on-site as part of the process of treating wastewater solids, the City has operated a cogeneration system utilizing on-site produced digester gas and natural gas for many years. The existing cogeneration system, consisting of three aging 500 kW engine generators, produce on average approximately 700 kW of electricity for the plant, reducing the power purchased from SCE. Through a dedicated effort to utilize the engine generators to reduce peak period power demands for the plant, the City has been able to realize significant benefit from the existing engine generators by reducing the purchased power costs to approximately $850,000 per year, or an effective power cost rate of $0.074/kWh of energy purchased.

Although the OWTP is a major consumer of power, it also provides some promising opportunities to producing power from green energy sources. While there are many green energy generation options, the systems most viable at the OWTP are:

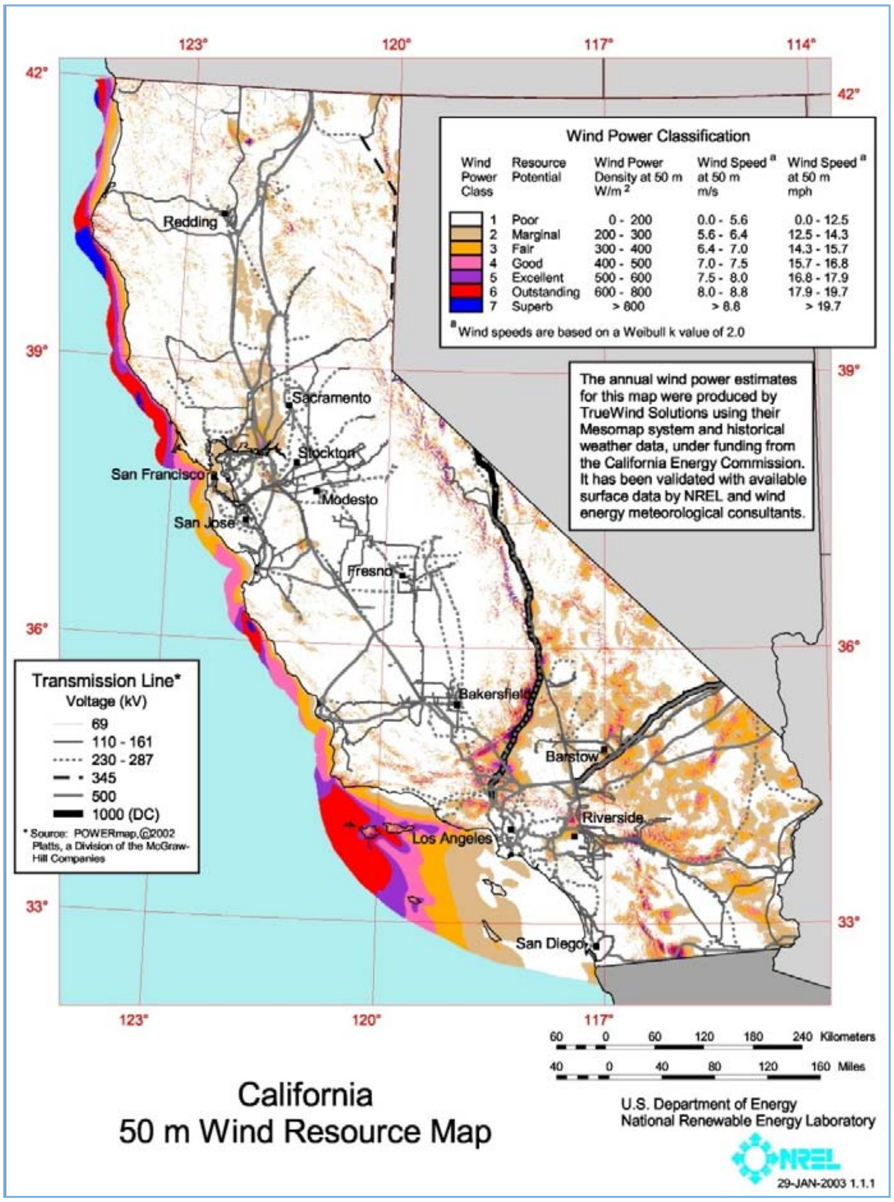
- Digester gas generation.

- Digester gas to fuel a replacement cogeneration system.
- Available roof, parking and basin areas for solar power using photovoltaic (PV) cells.

Other alternatives such as hydro generation and wind generation do not appear cost effective on this site.

Wind potential maps show very low potential for the Oxnard area (See Figure 1.1), meaning there is very little potential for generating a viable amount of wind energy, which would not justify the cost of an installation, as there would be no payback.

Figure 1.1 California Wind Resources Map



Hydro energy depends on having a suitable location where a significant flow is always being let down in pressure. Typical installations are pressure turnouts from supply aqueducts such as Metropolitan Water District's (MWD's) supply system down into City's. There are to our knowledge no areas with significant flows where pressure is being wasted through PRV's at the OWTP.

1.2.1 Existing Utility Demand

Table 1.1 summarizes the energy use and heat demand for the OWTP. While the City has a cogeneration system onsite, the system is currently at the end of its useful life, having been operated continuously since installation in the mid 1980s. The system consists of three 500 kW engine generator systems that are no longer made. The OWTP is also supplied by power purchased from SCE. Currently, most of the digester gas produced by the plants anaerobic digesters is utilized within the three engines, two of which are continuously operated at an output of approximately 350 kW each. The third engine is utilized during utility on peak periods; noon-6 pm, Monday-Friday during the summer period to control plant demand and to benefit from reducing purchases during very expensive on-peak utility periods.

The potential benefits of onsite renewable energy production include:

- Improved power supply reliability and redundancy.
- Reduced operational costs and stabilization of energy expenditures.
- Revenue stream from energy cost reduction from produced energy used at the plant.
- Reduced emissions of greenhouse gases.
- Greater flexibility in adapting to current and future greenhouse gas emissions regulations.

Table 1.1 Energy Demand Versus Power Produced[1,2]
Energy Evaluation
City of Oxnard

Average Heat Demand, million BTU/hr[1] (for heating anaerobic digesters)	2.6
Peak Heat Demand, million BTU/hr[1]	4.0
Average Cogeneration Heat produced BTU/hr	4.0
Average purchase of natural gas for Cogeneration (therms/hr)	17.8
Average Power Purchased, kW[2]	1306
Average Cogeneration Production from Existing Engines, kW	870

Notes:
(1) Information based on historical data from July 2011 through June 2012.
(2) Information derived from Southern California Edison (SCE) billing summaries for 2012.

1.2.2 Existing Anaerobic Digestion Facility

Primary and waste activated sludges are stabilized in mesophilic anaerobic digesters. Characteristics of the digesters are shown in Table 1.2.

Table 1.2 Anaerobic Digester Characteristics
Energy Evaluation
City of Oxnard

Parameter	Unit	Digester 1	Digester 2	Digester 3
Diameter	ft	90	90	100
Operating depth	ft	33	33	33
Operating volume	gallons	1,570,000	1,570,000	2,350,000
Mixing system	-	draft tube & gas	draft tube & gas	draft tube & gas

Based on flows, the OWTP operates two of their three digesters, and those are run in parallel. Performance data from 2012 was analyzed to determine the performance of the digesters. Hydraulic loads are summarized in Table 1.3 and volatile solids loading is shown in Table 1.4.

Table 1.3 Digester Hydraulic Loading (2012)
Energy Evaluation
City of Oxnard

Parameter	Unit	Digester 1	Digester 2(1)	Digester 3
Hydraulic Capacity				
20 day HRT	gallons/day	78,500	78,500	117,300
15 day HRT	gallons/day	104,700	104,700	156,400
Hydraulic Load				
Average month	gallons/day	61,500	---	87,500
Maximum month	gallons/day	75,300(2)	---	95,400(3)
Remaining Capacity – 20 day HRT				
Average month	gallons/day	17,100	78,500	29,800
Maximum month	gallons/day	29,400	78,500	61,000
Remaining Capacity – 15 day HRT				
Average month	gallons/day	43,200	78,500	68,900
Maximum month	gallons/day	29,400	104,700	61,000

Notes:
(1) Digester 2 was out of service during 2012 and remains so currently.
(2) Maximum month occurred during September.
(3) Maximum month occurred during June.

Table 1.4	Digester Volatile Solids Loading (2012) Energy Evaluation City of Oxnard			
Parameter	**Unit**	**Digester 1**	**Digester 2(1)**	**Digester 3**
Volatile solids load				
Average month	pounds per day	13,000	---	18,800
Maximum month	pounds per day	21,800(2)	---	23,900(2)
Volatile solids loading rate				
Average month	pounds per day/ cubic foot	0.06	---	0.06
Maximum month	pounds per day/ cubic foot	0.10(2)	---	0.08(2)

Notes:
(1) Digester 2 was out of service during 2012 and remains so currently.
(2) Maximum month occurred during September.

1.2.3 Digester Gas Production Projections

Anaerobic digestion is a biological process subject to a number of variables that affect digester gas production and use. For example, the net digester gas available for cogeneration varies with the season. Less digester gas is available in the winter because more gas is needed for heating the digesters in the cooler temperatures (the digesters must be maintained at a minimum temperature of 95 degrees Fahrenheit for maintaining optimum biological processes and biosolids regulatory requirements). Other factors affecting digester gas production include wastewater flows and loads received at the OWTP, the performance of the digestion process, the operation of the digesters (e.g. series or parallel operation), and co-digestion of sludge with higher energy wastes, such as fats, oils, and grease (FOG). Digester gas production is roughly proportionate to influent flows and loadings. If either flows or waste strengths vary, then digester gas production follows. In addition, digesters can experience a drop in digester gas production from process upsets, decreased detention time, poor mixing, or excessive grit and rag buildup in the digester tanks.

Monthly digester gas production data from 2012 was analyzed and is summarized in Table 1.5. Specific gas production appears lower than expected. Typical values range from 12 standard cubic feet per pound (scf/lb) to 17 scf/lb of volatile solids destroyed. Although Digester 3 clearly shows a higher specific gas production, this is likely the result of the FOG injection.

Table 1.5 Digester Gas Production (2012) Energy Evaluation City of Oxnard				
Parameter	**Unit**	**Digester 1**	**Digester 2(1)**	**Digester 3**
Gas production				
Average	cubic feet per month	3,248,500	---	7,034,400
Maximum	cubic feet per month	4,137,400(2)	---	7,461,400(3)
Average	cubic feet per day	108,300	---	234,500
Maximum	cubic feet per day	137,900	---	248,700
Specific gas production	cubic feet per pound of VS destroyed			
Average		8.50	---	12.34
Maximum		11.77(4)	---	15.20(5)

Notes:
(1) Digester 2 was out of service during 2012 and remains so currently.
(2) Maximum month occurred during April.
(3) Maximum month occurred during September.
(4) Maximum month occurred during May.
(5) Maximum month occurred during January.

1.2.4 Emission Regulations

1.2.4.1 Emissions Regulations

The existing engines have a valid Ventura County Air Pollution Control District (VAPCD) permit to operate, which is attached as Appendix A

Future operation of the existing or replacement engine-generators will likely be impacted by more restrictive emission requirements. Recently, the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) and the Bay Area Air Quality Management District (BAAQMD) have tightened the emission limits for nitrogen oxides (NO_x), volatile organic compounds (VOCs), and carbon monoxide (CO). All air districts have historically followed the lead of these three air districts in tightening emission regulations, especially for any new equipment, so it is likely that the similar restrictions will be adopted by the VAPCD in the future. While this is not anticipated to present significant issues with compliance in the near term, it should be considered a possibility at some point during the life of any new power generator system. Such changes to the emission regulations would likely require modifications to the existing engine generator systems to comply with more stringent emission regulations should these engines be kept in operation for the foreseeable future.

1.2.4.2 Greenhouse Gas Emissions Considerations

The California Air Resources Board (CARB) adopted the Global Warming Solutions Act in response to Assembly Bill 32 (AB 32) in September 2006. This Act was the first regulatory program in the U.S. to require public and private agencies statewide to reduce greenhouse gas (GHG) emissions. The GHGs included under AB 32 are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. The Act does not affect wastewater treatment facility process emissions, but it does cover onsite general stationary combustion sources such as cogeneration engines. An agency must report their annual (calendar year) emissions if it emits over 10,000 metric tons of CO_2 equivalent emissions from its stationary combustion units and they have an aggregate maximum rated heat input capacity of 12 million British thermal unit (Btu) per hour or greater.

In addition, the U.S. EPA's Mandatory GHG Reporting Rule (Reporting Rule) was adopted October 30, 2009. The Reporting Rule explicitly states that centralized domestic wastewater treatment systems are not required to report; however, any stationary combustion of fossil fuels taking place at a wastewater treatment facility may be considered a "large" source of GHGs if emitting a total of 25,000 metric tons of CO_2 equivalent emissions or more per calendar year.

The City's 2012 onsite stationary combustion of natural gas and biogas resulted in approximately 4,800 metric tons of CO_2 equivalent emissions including biogenic CO_2 (i.e., CO_2 from biogas combustion). This is well below each of the reporting thresholds discussed above.

BIOGAS ENHANCEMENT EVALUATION

2.1 INTRODUCTION

This analysis has focused on the Oxnard Wastewater Treatment Plant (OWTP) and the ability of its anaerobic digesters to produce more digester gas. The OWTP currently co-digests fats, oils, and grease (FOG) with primary and waste activated sludges. The FOG is brought in from grease trap/interceptor pumping by City of Oxnard (City) crews. This practice has a number of advantages:

- Assures that the FOG is not discharged to the sewers – reducing the FOG related stoppages and required cleaning.
- Controls the quality of the hauled-in materials because it is accomplished by City staff.
- Adds highly degradable material to the digesters which significantly increases the digester gas production and hence the biogenic electrical production.
- Minimally increases the sludge destruction, reducing the amount of biosolids that must be dewatered, hauled, and disposed, or beneficially used.
- Provides tipping fees for the hauled-in material.
- Assures that grease traps are pumped at regular intervals.

We recommend that the City continue this practice and increase it to the extent that staff is available to pump and haul the FOG to the OWTP. To offset Southern California Edison (SCE) costs, the City should aim to maximize cogeneration of electricity between noon and 6:00 p.m. when energy costs are the highest. Maximizing cogeneration can be accomplished by feeding FOG into the digesters so gas production is at its highest during this time-frame. To make better use of the gas production from FOG, we recommend a receiving and storage facility so the gas can be produced when it is needed for electrical power generation. Options for such a facility are evaluated further in this report.

The City does have additional digester capacity that could be used to produce additional digester gas. Other feedstocks that can be used include:

- Food processing wastes – this includes out dated or out of specification soft drink syrup, salad dressing, glycerin, frappuccino mix, cheese waste, or spoiled strawberries. These can be directly fed to the digesters.

- Source separated food wastes – such as restaurant scraps – this does help reduce the load on the sewer system, but requires restaurant training and a receiving and “macerating” system usually off site.

- Material recycling facility (MRF) separated food waste – Requires separation at the MRF and a separate processing system for the food wastes.

These feedstocks can be co-digested with the OWTP’s sludge or independently, such as in Digester 2.

With the increased emphasis on removal of organics from landfills to comply with the States adopted goal of diverting 75 percent of materials from landfills, use of existing digester capacity to digest organics is getting increased attention. However, food waste digestion will require further investigation into issues, including the types and amounts available in the Oxnard area, preprocessing requirements, and regulatory impacts. There are also organic wastes such as wood wastes and green wastes. However, these do not digest well in OWTP digesters.

Organic wastes can also be diverted to biofuel development and composting. Biofuel development is typically limited to rendering materials and yellow grease, which is sourced, separated from oil fryers, and refined to biodiesel. Composting is an excellent way to breakdown wood or green wastes and can be used for food wastes and FOG. It is not energy producing and a market for the compost product has to be developed.

Energy can be derived from organic waste through thermal conversion. These technologies include incineration, gasification, and pyrolysis, the latter two have gained attention because of their energy potential and low emissions. These processes involve applying a controlled amount of air/oxygen to heat the organics. Most of the volatile solids are converted by gasification to syngas. Pyrolysis generates an energy containing char in addition to the syngas. The syngas can be combusted to generate electricity or further refined to create a fuel. The char can replace coal usage.

We recommend conducting a feasibility analysis to determine the types and amounts of available organic materials in Oxnard. Based on this information, a further analysis should be completed to determine the best solution for the City to divert and process these organic wastes.

2.2 EXISTING FOG CONTROL PROGRAM

The City has a FOG Control Program that requires food establishments to install grease traps or interceptors prior to discharging their wastewater into collection system. The City program has jurisdiction over about 600 food establishments, of which less than 50 percent use the City’s service. About four 3,000-gallon truckloads are delivered to the OWTP per week on average.

The truck offloads directly into the Digester 3 sludge recirculation system, upstream of the draft tube-gas mixing system. FOG is conveyed directly from the truck in a "slug load" into the digestion system. This type of loading can make digesters vulnerable to process upsets, including inadequate solids destruction and foaming events, which can lead to odor and vector issues. In addition, slug loading limits the ability to get good mixing and to produce the gas when it is needed for power generation.

Typical programs offload FOG into storage tanks. The material is ground and mixed in the tank prior to metering it into the digestion process at a slow and constant input rate or based on when the gas is needed. These receiving stations are usually located near the digestion process.

2.2.1 FOG Collection Revenue

Trap sizes range from 750-4,750 gallons, for which the City currently charges $200 per trap/interceptor, regardless of size. The charge for this service is significantly different between the smaller and larger traps. Table 2.1 shows the cost per gallon for this service based on trap sizes found in the City's 2007 Sewer System Master Plan (SSMP).

Table 2.1 Grease Trap Cleaning Cost
Energy Evaluation
City of Oxnard

Trap Size (gallons)	Cost per Gallon
750	$0.27
1,000	$0.20
1,200	$0.17
1,250	$0.16
1,500	$0.13
1,750	$0.11
2,250	$0.09
3,000	$0.07
4,750	$0.04

The City's trap cleaning service fee of $200 per trap does not appear to generate enough revenue to cover the associated operational costs. Their cost to provide this service is estimated to be $306 per trap. This was calculated based on the following parameters:

- $250,000 for the truck, amortized over five years.
- $50 per hour labor.
- One person providing service.

- Four hours to clean, haul, and deliver FOG to OWTP.
- 10 mile round-trip between OWTP and food establishment.
- 4 miles per gallon fuel consumption.

The costs for the trap cleaning service appear to exceed the service fee by over 50 percent. We recommend restructuring this service fee to be based on a per gallon charge, which is consistent with others in the industry. Based on data from the City's SSMP, we estimate that a cost of $0.25 per gallon can completely offset the costs for providing this service. However, this per gallon cost will significantly increase the cleaning expense for those with large capacity traps.

2.3 FOG RECEIVING STATION DESIGN ALTERNATIVES

FOG receiving stations are designed based the amount of material that can be delivered and fed into the digester in a single day. Two approaches were considered for a FOG receiving station. The first approach considered sizing it based on doubling the current program. The second option was sized based on the capacity of the existing digesters to process FOG.

2.3.1 Option 1 – Station Design Based on Digester Feed Limit

Co-digestion of FOG is limited by 1) the ratio of volatile solids in FOG to those in sludge, 2) the volatile solids loading rate, and 3) hydraulic retention time.

2.3.1.1 FOG to Sludge Volatile Solids Ratio

Based on empirical date from both discussions with FOG system operators and literature review of articles on FOG systems, an upper limit of 30 percent FOG volatile solids to total volatile solids feed to a digester has been established. Loading rates greater than 30 percent make the digester more susceptible to upsets.

2.3.1.2 Volatile Solids Loading Rate

Co-digestion of FOG can increase the digester volatile solids loading rate. Typical design criteria for digester volatile solids loading rate (VSLR) is to maintain levels below 0.15 pounds per day of VS/cubic foot (ppd/cf) of digester feed. The addition of FOG has been shown to increase digester performance. This allows the VSLR to be raised to 0.20 ppd VS/cf without upsetting the digestion process.

2.3.1.3 Hydraulic Retention Time

The digestion hydraulic loading rate can limit the amount of FOG that can be digested. Anaerobic digesters are designed typically with a 20 day hydraulic retention time (HRT) at average month conditions with one digester out of service and 15 days at maximum month with all digesters in service.

Table 2.2 shows the comparison between the three design criteria above.

Table 2.2 Digester Feed Limit Evaluation
Energy Evaluation
City of Oxnard

	VS Ratio		**VSLR**		**HRT**	
Criteria	***Dig 1***	***Dig 3***	**Dig 1**	**Dig 3**	**Dig 1**	**Dig 3**
FOG VS Ratio, %	***30***	***30***	222	234	52	63
VSLR, ppd/cf	***0.08***	***0.08***	0.20	0.20	0.14	0.15
HRT, days (average month)	***22***	***23***	12	12	20	20

Note:
(1) Digester two assumed to be out of service.

Table 2.2 shows that the volatile solids ratio criterion governs the design. FOG receiving station design criteria based on maintaining a 30 percent ratio of volatile solids in FOG to those in the feed sludge are shown in Table 2.3. Figure 2.1 shows a layout of a 24,100-gallon receiving station.

Table 2.3 Digester Feed Limit FOG Station Design Criteria
Energy Evaluation
City of Oxnard

Parameter	**Unit**	**Value**
Capacity	gallons/day	24,100
Unload time	minutes	15
Transfer/Mixing pump(1)	gpm	350
Feed pump(2)	gpm	10

Notes:
(1) Based on unloading a 5,000-gallon truck with a constant speed pump.
(2) Variable speed pump for flexible feed control and to optimize digester gas production.

2.3.2 Option 2 – Double the Current FOG Collection

Four truckloads can be delivered to the OWTP each week under the current collection program. This option doubles this amount of delivered FOG. However, under the current program, FOG is collected and fed into the digester as dictated by the City crew’s schedule, which may not be conducive to maximizing cogeneration to offset SCE purchases.

The City’s power costs are the highest between noon and 6:00 p.m. FOG should be fed into the digesters to maximize gas production during this time-frame, and subsequently

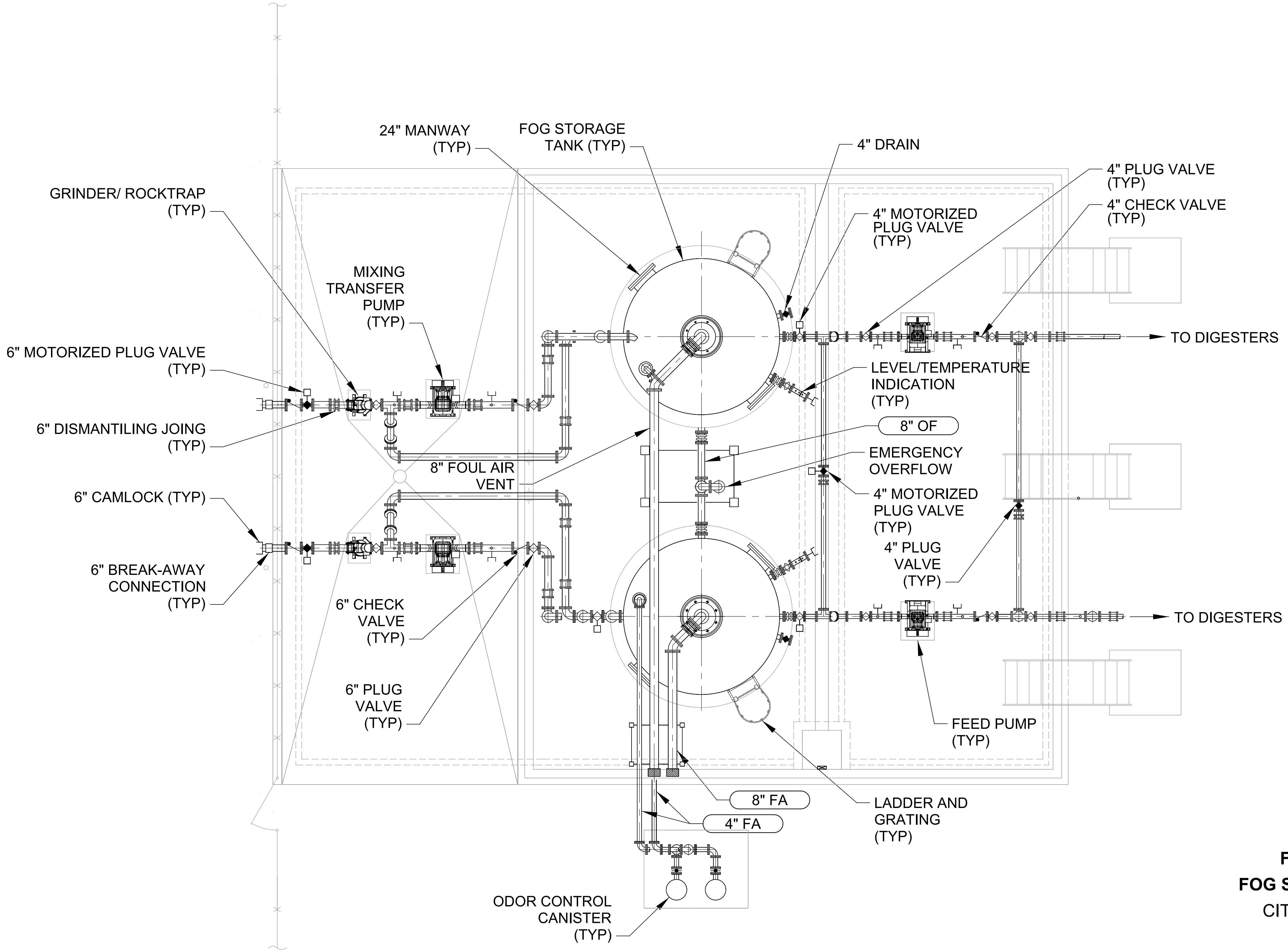


Figure No. 2.1
FOG STATION LAYOUT
CITY OF OXNARD

carollo

User: HGarcia Plot Date: 04-JUN-2013 4:46:32 PM IP_PWP:d0174150\8533A10FIG001.dgn maximize cogeneration of electricity. This strategy will provide the best opportunity to consistently offset SCE purchases.

To maximize the use of the gas production from FOG, we recommend that the City construct a receiving and storage facility. Deliveries would be made Monday-Friday and at most two trucks would be offloaded in a single day. Design criteria for this option are summarized in Table 2.4. The digester feed pump would have variable speed controls to allow staff to optimize digester gas production between noon and 6:00 p.m., during which they could maximize cogeneration of electricity. This station would only have one train.

Table 2.4 FOG Station Design Criteria for Double the Current Collection Program
Energy Evaluation
City of Oxnard

Parameter	Unit	Value
Capacity	gallons/day	6,000
Unload time	minutes	15
Transfer pump(1)	gpm	200
Mixing pump(1)	gpm	50
Feed pump(2)	gpm	20

Notes:
(1) Constant speed pump.
(2) Variable speed pump for flexible feed control and to optimize digester gas production.

2.3.3 Design Considerations

With a significant increase in biogas expected from the co-digestion facility, the digester gas handling systems (collection piping and flare) need to be evaluated to confirm that they are capable of handling any increased load. In addition, the cogeneration system should be able to process the increased load.

2.3.4 Digester Gas Generation Estimation

The addition of FOG will increase biogas production through the digestion of readily degradable fats in the feed. This biogas production was estimated with following assumptions:

- 5 percent total solids.
- 95 percent volatile solids.
- 90 percent volatile solids reduction.

- 20 cubic feet of gas per pound of volatile solid reduced.

The digester gas production estimates are summarized in Table 2.5.

Table 2.5 Estimate of Digester Gas Generation From FOG
Energy Evaluation
City of Oxnard

FOG Feed (gpd)	FOG Addition (ppd)	Digester Gas Production From FOG (cf/day)
24,100	10,000	171,700
2,400(1)	1,000	17,100
4,800(2)	2,000	34,200

Note:
(1) Based on current collection program with four truckloads of FOG delivered on a five days per week schedule.
(2) Based on double the current collection program for a total of eight truckloads of FOG delivered on a five days per week schedule.

2.4 FOG STATION FACILITY COMPONENTS

FOG is typically ground and stored in a continuously mixed and heated storage tank before being metered slowly into the digestion process. Metering allows a constant input rate and avoids slug loads to the digester, which can prevent full digestion of the FOG. The main components of the FOG station include:

- Transfer and mixing pump.
- Grinder.
- Storage tank.
- Feed pump.

2.4.1 Transfer and Mixing Pumps

Transfer pumps are used to pull FOG from the truck, through a grinder, and push it into the storage tank. These pumps are sized based on a desired time to empty a truck, which is between 10-15 minutes, which results in pump capacities between 200-350 gpm. Larger stations can employ these pumps for dual use – transfer and mixing. This flow rate would be too large for stations with smaller storage capacities, as in Options 2. Two pumps are used for this option– one for FOG transfer and one for tank mixing.

Rotary lobe and centrifugal chopper pumps are common pumps used for transfer and mixing applications. A comparison of these pumps relative to these duties is shown in Table 2.6.

OWTP staff indicated a preference for the rotary lobe style pump, so it was used to develop the FOG station cost estimates.

Table 2.6 Transfer/Mixing Pump Comparison
Energy Evaluation
City of Oxnard

Option	Pros	Cons
Rotary Lobe	• Lower life cycle cost • Operates at lower speed • Easier to prime • Main application is for sludge-like material	• Requires upstream grinder and rock trap • Higher horsepower
Centrifugal Chopper	• Lower horsepower • Upstream grinder is not required	• Higher life-cycle cost

2.4.2 Grinders

A grinder or macerator is necessary while offloading FOG to minimize ragging in the storage tanks and damage to pumps. A grinder with a built-in rock trap is preferable because they are easier to maintain. The Vogelsang Roto-cut unit was considered for cost estimating purposes.

2.4.3 Storage Tanks

Storage (equalization) tanks are used to store the FOG as it is pumped from the trucks so it can be metered into the digesters at a slow rate, which allows for a steady gas production rate from the digesters. The tanks are insulated and heat-traced, which keeps the FOG at a higher temperature and reduces the chance of plugging the FOG pipelines.

The four options considered for this study and a comparison between them is shown in Table 2.7.

Due to the high corrosion near the ocean, City staff expressed a preference for stainless steel tanks, which were used for cost estimating purposes.

Table 2.7	Storage Tank Comparison Energy Evaluation City of Oxnard	
Option	**Pros**	**Cons**
Cross-linked polyethylene	• Lower capital cost • Will no corrode • Integrally molded flanged outlet for ease of maintenance • Generally lighter than a steel tank	• Higher capital cost • Less structural integrity than non-composite tanks • Less fire resistance than non-composite tanks • Difficult to repair leaks
FRP	• Will not corrode • Generally lighter than a steel tank • Easier to repair	• High capital cost • Less structural integrity than non-composite tanks • Less fire resistance than non-composite tanks
Carbon Steel	• Lower capital cost • Better structural integrity than composite tanks • Better fire resistance than composite tanks • Easier to repair	• Can corrode over time and become susceptible to leaks if not maintained • Requires coating maintenance
Stainless Steel	• Corrosion issues minimized • No coating maintenance • Same structural integrity and fire resistance as carbon steel	• Highest capital cost (2x carbon steel) • Repairs are more difficult

2.4.4 Digester Feed Pumps

The feed pumps are used to pump the FOG from the storage tanks into the digesters at a relatively steady rate. The two styles of pumps that were evaluated for this application were rotary lobe pumps and progressing cavity pumps.

The rotary lobe pump is easier to maintain, and is able to run dry for short time periods without being damaged. The progressing cavity pumps are O&M expensive and labor intensive to repair the rotor and stator. A comparison of the two pumps is shown in Table 2.8.

Table 2.8	**Digester Feed Pump Comparison Energy Evaluation City of Oxnard**	
Option	**Pros**	**Cons**
Rotary Lobe	• Lower life cycle cost • Operates at lower speed • Easier to prime • Main application is for sludge-like material	• Requires upstream grinder and rock trap • Higher horsepower • Wears faster at higher pressures
Progressing Cavity	• Works well with high pressures	• Larger footprint • Higher maintenance cost for replacement of stator or rotor

Rotary lobe pumps were used for cost estimating purposes.

2.4.5 Odor Control System

Odor control on the storage tanks is very important, as odor from the FOG can be unpleasant. Each time the tank is filled with FOG, it expels an equal volume of air through the tank vents. This air should be captured and diverted through an odor control unit. Granular activated carbon (GAC) units are typical. Two GAC styles were evaluated:

- A skid-mounted canister system that would be located on grade near the tanks.
- A manhole style that would be located on the top of each tank.

It is easier and safer to wash and replace media at grade in the skid-mount canisters. Additionally, two large (one per two tanks) or four redundant canisters (allowing bypass) could be used in the skid-mounted setup, whereas four individual inserts would be required for the manhole type; therefore, if one manhole-type odor control unit is out of service, the entire tank will be out of service. A comparison of the two types is presented in Table 2.9.

Skid mounted canisters were used for cost estimating purposes.

Table 2.9	GAC Odor Control Unit Comparison Energy Evaluation City of Oxnard	
Option	**Pros**	**Cons**
Skid Mounted Canister	• Easier and safer to replace • Can use larger single unit • Can have redundant unit	• Additional piping
Manhole Insert	• No additional piping	• One unit per tank • Difficult to maintain on top of tank • Added weight to tank • If unit is out of service, so is the tank

2.4.6 Pipe Material

The piping material that was considered is glass lined ductile iron pipe. Glass lined pipe reduces the clogging issues associated with FOG, as the inside of the pipe is very smooth.

2.5 ESTIMATED COSTS

The construction costs for each option were estimated using the following contingencies:

- 25 percent estimating contingency.
- 15 percent general contractor overhead, profit, and risk.
- 6 percent escalation to midpoint.
- 8 percent sales tax applied to 50 percent of the direct costs.

The estimated construction costs for each option are summarized below:

- Option 1: Build a 25,000 gallon capacity receiving station. This size facility can accommodate the FOG that the existing digesters can process based on historical sludge flows. The maximum number of trucks this facility could accommodate is five 5,000-gallon trucks, back-to-back. The construction cost for this facility was estimated to be $2,600,000.
- Option 2: Build a 6,000 gallon capacity receiving station. This size is based on doubling the current program and would receive eight trucks of FOG per week. The maximum number of trucks assumed to be unloaded in a day is two. The construction cost for this facility was estimated to be $1,400,000. For a minimal equipment cost of

an additional $50,000, the tank size could be increased to the maximum of 15,000 gallons to allow for future expansion.

GREEN ENERGY OPPORTUNITIES

3.1 COGENERATION

Cogeneration equipment was sized to efficiently and economically utilize the digester gas generated at the Oxnard Wastewater Treatment Plant (OWTP). Various types of cogeneration technologies can be employed to produce power from digester gas. The following section summarizes each of the technologies and presents the specific model and size of the technology considered for the OWTP.

3.2 CONVENTIONAL RECIPROCATING ENGINES

Reciprocating engines, developed more than 100 years ago, were the first of the fossil fuel-driven distributed generation (DG) technologies. Reciprocating engines can be found in applications ranging from fractional horsepower units to 60-megawatt (MW) baseload electric power plants.

The engine cooling water and exhaust heat from reciprocating engines can be recovered in heat exchangers and used to provide heat for digester heating and/or facility hot water heating. Several lean burn reciprocating engine suppliers have new generation, high efficiency, low emission units available for use with biogas including Cummins, Waukesha, Caterpillar (MWM), and GE/Jenbacher. These new engines have efficiencies of approximately 40 percent, which stays nearly constant throughout the typical operating range of 50-100 percent engine load. These engines typically convert approximately 40 percent (as a percentage of fuel input energy) to electrical output and 40-45 percent to recoverable engine cooling water and exhaust heat. The total overall efficiency of these reciprocating engines is approximately 80-85 percent. The engines are lean-burn, spark-ignited, low emission gas engines and have digester gas burning experience. The GE/Jenbacher 852 kW and 1,137 kW engine generator units were used in the economic evaluation. Each were assumed to be housed in the existing cogeneration building.

Reciprocating engines have the greatest emissions of the cogeneration technologies. Ventura County Air Pollution Control District (VAPCD) requires an air containment discharge permit for operational use. Lean burn engines can currently meet the requirements, however, it is expected in the near future that post combustion (catalyst) after-treatment technology will be required to meet the required emission rates when fueled with digester gas in the appropriate size range. New engines if provided with adequately redundant fuel treatment can easily be configured with such treatment devices.

3.3 FUEL CELLS

Fuel cells utilize the hydrogen present in the methane-rich digester gas as a fuel source in an electrochemical process. The process converts the elemental carbon and hydrogen from the methane into carbon dioxide and hydrogen and in the process releases electrons which are captured as direct current (DC) electricity.

The fuel cells evaluated typically convert, as a percentage of fuel input power, 40-45 percent to electrical output and approximately 25 percent to recoverable exhaust heat for a total overall efficiency of approximately 65-70 percent.

Two manufacturers currently offer fuel cells for large-scale power generation with experience on digester gas, United Technologies Corporation (UTC) and Fuel Cell Energy (FCE). One other manufacturer, Bloom Energy is currently selling similar fuel cell but it has no experience with operation on digester gas and does not offer heat recovery. Both FCE and UTC manufacturers have provided fuel cells for applications utilizing digester gas; however, only FCE has units currently in operation. Many of these units operating on biogas are located in California. FCE utilizes a more efficient fuel cell technology than UTC, providing 40-45 percent fuel-to-electricity efficiency versus UTC's 35-40 percent. FCE produces three unit sizes: 300 kW, 1,400 kW and 2,800 kW. UTC produces 400 kW units. The FCE 1,400 kW fuel cell was used in the economic evaluation.

As an electrochemical process, fuel cells produce significantly less pollutant byproducts than combustion technologies. Fuel cells have approximately 1/100th the emissions generated by engine-generators. Fuel cells are exempt for air permit requirements.

3.4 MICROTURBINES

Microturbines are essentially small gas turbines operating at very high rpm to produce power and heat.

Microturbines are extremely low emission technologies and typically do not require an air permit for operation.

Microturbines evaluated typically convert 29 percent to electrical output (as a percentage of fuel input energy) and 29 percent to recoverable exhaust heat for a total overall efficiency of approximately 58 percent.

There are currently several commercial manufacturers offering microturbine power generating units. Only two, FlexEnergy (formally Ingersoll Rand) and Capstone, have experience utilizing digester gas as a fuel source. FlexEnergy offers 250 kW modular units. The Capstone units come in 30, 65 and multiples of 200 kW sizes.

Ingersoll Rand and Capstone have shipped world-wide more than 100 units operating on both natural gas and digester gas. Several dozens of 30 kW and 70 kW units and two

250 kW units are operating on digester gas. Two 250 kW units are in operation on a medium BTU gas at a Oil/Gas Producer in Grand Isle, LA and eight 250 kW units have recently been sold for operation on a medium BTU gas in both the United States and China.

For the purposes of this study, FlexEnergy 250 kW units were utilized in the economic model. Microturbines are exempt for air permit requirements.

3.5 ALTERNATIVE BENEFIT COMPARISON

A summary of the advantages and disadvantages for the three cogeneration systems as well as the no cogeneration option is included in Table 3.1.

Table 3.1 Alternative Benefit Comparison
Energy Evaluation
City of Oxnard

Alternative	Advantages	Disadvantages
Alternative 0 - No Cogeneration	• Simple operation • No capital costs	• No on-site renewable power generation • Does not take advantage of digester gas resource or reduce facility carbon footprint
Alternatives 1 & 2 - Two 852 kW or One 1,137 kW Reciprocating Engine Cogeneration Systems	• Proven technology utilizing biogas for over 40 years • New generation engines have very high efficiency, rivaling fuel cells	• Requires dedicated building for sound and weather protection • Complex equipment • Frequent operator attention required for operations and maintenance • Requires fuel treatment
Alternative 3 - Three 250 kW Microturbine Cogeneration System	• Ultra low emissions • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Lowest electrical efficiency • Requires extensive fuel treatment
Alternative 4 - 1,400 kW Fuel Cell Cogeneration System	• Ultra Low emissions • Highest efficiency • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Highest O&M costs • High capital costs • Requires extensive fuel treatment

3.6 COGENERATION

The following cogeneration alternatives were evaluated:

- **Alternative 0: Base Case – No Cogeneration System.** Assumes the existing cogeneration engines would be retired from service and not new cogeneration system would be installed to replace them. This represents the base case for the OWTP and presents the costs associated with utilizing digester gas to provide for OWTP heating needs and purchased power from SCE to provide the OWTP power needs.
- **Alternative 1: Two New 852 kW Engine Generator Cogeneration Systems with a New FOG Receiving Facility.** Assumes two new 852 kW reciprocating engine generator cogeneration systems will be installed to replace the existing cogeneration system. The new systems would include new gas treatment equipment and all required heat recovery and electrical interconnection equipment.
- **Alternative 2: New 1,137 kW Engine Generator Cogeneration System with a New FOG Receiving Facility.** Assumes a new 1,137 kW reciprocating engine generator cogeneration system will be installed to replace the existing cogeneration system. The new system would include new gas treatment equipment and all required heat recovery and electrical interconnection equipment.
- **Alternative 3: Three New 250 kW Microturbine Cogeneration Systems with a New FOG Receiving Facility.** Assumes three new 250 kW microturbine generator cogeneration systems will be installed to replace the existing cogeneration system. The new systems would include new gas treatment equipment and all required heat recovery and electrical interconnection equipment.
- **Alternative 4: New 1,400 kW Fuel Cell Cogeneration System with a New FOG Receiving Facility.** Assumes a new 1,400 kW fuel cell generator cogeneration system will be installed to replace the existing cogeneration system. The new system would include new gas treatment equipment and all required heat recovery and electrical interconnection equipment.

3.6.1 Life Cycle Cost Evaluation

3.6.1.1 Criteria and Financial Assumptions

Assumptions used for the life cycle cost analysis are shown in Table 3.2.

Table 3.2 Criteria and Financial Assumptions Energy Evaluation City of Oxnard	
Inflation (capital costs)	4.0%
Inflation (electricity costs)	5.0%
Inflation (natural gas costs)	4.0%
Inflation (O&M costs)	3.0%
Gross discount rate	5.0%
Digester Gas LHV, Btu/scf	580 Btu/scf
Engine availability percentage	90.0%
Microturbine availability percentage	95.0%
Fuel Cell availability percentage	95.0%
O&M rate for new engine alternatives $/kWh	$0.015
O&M rate for microturbine alternatives $/kWh	$0.015
O&M rate for fuel cell unit $/kWh	$0.040
O&M rate for fuel treatment system $/million Btu	$0.900
FOG Tipping Fee $/gallon	$0.050
Green Power Credit $/kWh	$0.005

3.6.1.2 Alternative Life Cycle Benefit Comparison

To evaluate the benefits and costs of these alternatives, both the projected capital costs of the installation and the yearly operations and maintenance (O&M) costs were calculated. The evaluation takes into account the value of, or purchase of electrical power. The method selected for this analysis was to determine the total present worth of the project. Each alternative was then compared to the base case alternative, no cogeneration.

Total project capital costs, including design and construction costs, for each alternative were estimated. Capital and life cycle costs are presented in Appendix A and B, respectively.

3.6.1.3 Qualitative Summary

Table 3.3 ranks the cogeneration alternatives utilizing weighted economic and non-economic criteria.

Table 3.3 Cogeneration Study Alternatives - Rating Matrix
Energy Efficiency Evaluation
City of Oxnard

Ranking Criteria		Present Worth of Life Cycle Cost[3]	Energy/ Greenhouse Gas Regulations	Protection Against Energy Price Volatility	Reliability/ Redundancy	O&M Complexity	Length of Permit Application Process	Proven Biogas Cogeneration Technology	Footprint	Efficient Use of Resources	Total Weighted Score[1]
Weighting Factor[2]		**5**	**5**	**3**	**4**	**4**	**3**	**3**	**3**	**5**	–
Project Alt.	**Description**										
0	Base Case, No Cogeneration	1	1	1	1	5	5	5	5	1	87
1	Two 852 kW Reciprocating Engine System	5	3	5	4	4	2	4	2	4	131
2	1,137 kW Reciprocating Engine System	4	3	3	2	4	2	4	3	4	115
3	Three 250 kW Microturbine System	2	3	2	4	3	4	2	4	2	99
4	1,400 kW Fuel Cell System	3	5	4	2	2	4	2	3	4	115

Notes:
(1) Total Weighted Score equals the sum of each criteria's weighted factor multiplied by its individual ranking for each respective alternative; highest value is most desirable/beneficial, lowest value is least desirable/beneficial.
(2) Weighting Factors: 5 - More Important, 1 - Less Important.
(3) Present worth of life cycle costs are based on the worst case digester gas projection as shown in Table 5.

Table 3.4 presents the cost estimates, along with the estimated 20-year net benefit and simple payback periods, for the alternatives described above.

Table 3.4 Cost Estimates for the Cogeneration Alternatives
Energy Efficiency Evaluation
City of Oxnard

	Estimated Net Project Cost ($)	Present Worth of Net Benefit compared to No Cogeneration ($)	Payback Period (years)
Alternative 1	$10,880,000	$22,100,000	8
Alternative 2	$9,070,000	$16,100,000	8
Alternative 3	$10,785,000	$9,400,000	11
Alternative 4	$13,370,000	$13,300,000	10

SOLAR EVALUATION

4.1 SOLAR PHOTOVOLTAIC CELLS

Photovoltaic (PV) systems convert light energy to electrical energy. PV cells consist of a junction between two thin layers of dissimilar semiconducting materials, known respectively as ‘p’ (positive) type and ‘n’ (negative) type semiconductors. ‘P’ type conductors consist of doped silicon with a deficit of free electrons; and ‘n’ type conductors consist of material with an excess of free electrons. A p-n junction is set up by joining these dissimilar semiconductors, which sets up an electric field in the region of the junction, due to the joining of the positive and negative layers.

Light consists of a stream of tiny particles of energy called photons. When light falls in the region of the p-n junction, the photons provide energy for the electrons from the ‘n’ type conductor to move to the ‘p’ type conductor. This movement of electrons induces direct current (DC) power. The DC power is converted to alternating current (AC) with inverters, since AC power is required to be compatible with the power grid. Typical DC to AC derating factors are 80 percent for most of today’s systems.

Solar power systems are available in the following configurations:

- Fixed panels. Fixed panels generate the least amount of electricity per panel but have low project and maintenance costs.
- Single-axis tracking panels. This arrangement consists of an automatic tracking system that tilts the angle of the PV cells on one axis (up or down) as the sun tracks over the horizon. Single tracking systems can generate up to 30 percent more than fixed panels, but the tracking system makes it more expensive than fixed panels, and requires more maintenance due to moving parts.
- Dual-axis concentrators. A dual-axis system can track up and down as well as left and right. The PV cells focus the sunlight on a small but efficient solar panel. However, their effectiveness requires high solar insolation (a measure of solar radiation energy). The insolation values at the Oxnard Wastewater Treatment Plant (OWTP) are not high enough to support the dual-axis system.
- Cylindrical reflective panels. This type of solar power system utilizes a solar panel installed within a tube. They have a very high output relative to square footage of area installed because the panels inside the tube generate electricity from both the sun’s direct rays as well as the rays reflected off the roof. However, similar to the dual-axis system, the cylindrical reflective panels need a high insolation value to justify its higher cost compared to PV cells, so this arrangement was not considered further for this facility plan.

The angle of solar incidence plays a significant role in the amount of electricity generated in the solar cell. In fixed cells, the ‘perfect’ angle is only incident on the solar cell for a small portion of the day, thus fixed cells are unable to generate as much electricity as single-axis tracking panels (which can “track” the solar rays in one axis) or dual-axis panels, which can move in two planes.

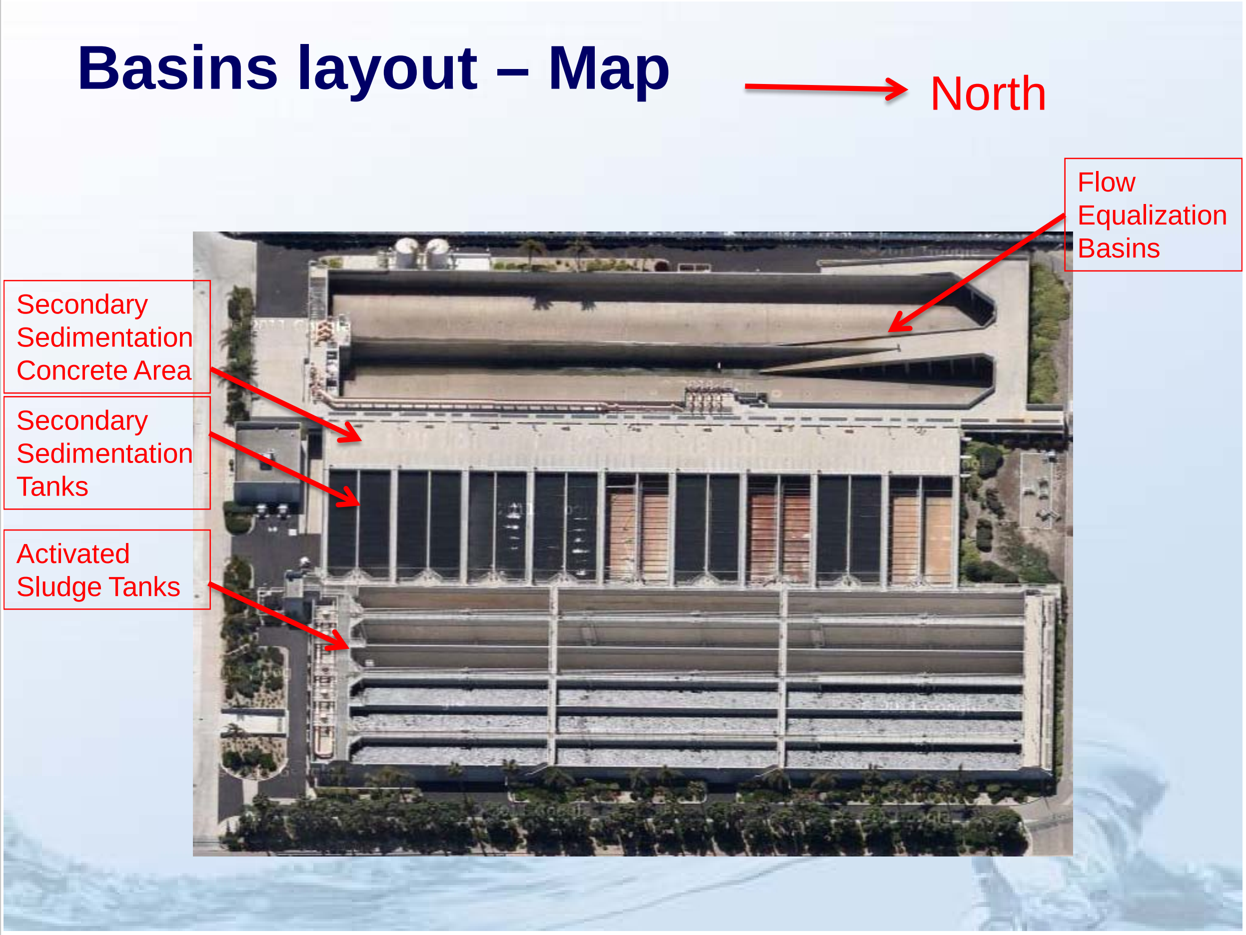
4.2 SOLAR EVALUATION

An economic analysis (provided in Appendix D) was prepared for the City of Oxnard (City) to evaluate the feasibility of installing solar panels at various locations in terms of the initial investment, maintenance (10 percent of initial investment), potential grants, projected benefits (net revenue), and payback time. The analysis considered three scenarios of solar panel layouts. The first scenario evaluated four potential layouts located at the existing OWTP: Activated Sludge Tanks, Flow Equalization Basins, and Secondary Sedimentation Tanks and Concrete covered area as shown in Figure 4.1. The second scenario evaluated consists of four rooftop mounted systems and four carport structures at the OWTP whose locations are shown in Figure 4.2. The third scenario evaluated was the City’s Material Recovery Facility (MRF) roof as shown in Figure 4.3, an arbitrary one-acre ground mounted system, which could be located at the MRF or at the recently constructed AWPF, and an arbitrary one-acre carport system, which could be located at the MRF or at the recently constructed AWPF. The potential incentives evaluated included the California Solar Initiative performance-based incentive for Southern California Edison based on Step 9 revised PBI rates (Senate Bill 585) of $0.114/kilowatt hour (kWh) which is applicable for the first five years of system operation only. To determine the net revenue produced by each system the plant electricity usage and cost data was utilized to determine an average commercial electricity rate of $0.075/kWh.

4.2.1 Solar Evaluation Methods and Assumptions

The first step to determining the size of a solar system is to determine the square footage available for the area under consideration. Once the total area that is available is known a factor must be applied using trigonometry to obtain an effective available area so the output of each panel is maximized by minimizing the shading of individual cells. The next step is to determine the number of panels that fit into the effective area and to calculate a total kW-dc output for the system. A third party calculation tool (PV (photovoltaic) Watts-Version 2), developed by the National Renewable Energy Laboratory (NREL) contains a database for solar radiation based on longitude and latitude, was used to determine the approximate energy output of the system (kWh) over the course of the year.

The average 60 cell panel has dimensions of approximately 3 feet (ft) by 5 ft and has a nominal power output of 240 Watts (W). It was assumed the panels would be mounted fixed tilt at an angle of 34.2 degrees with southern orientation to maximize solar exposure.

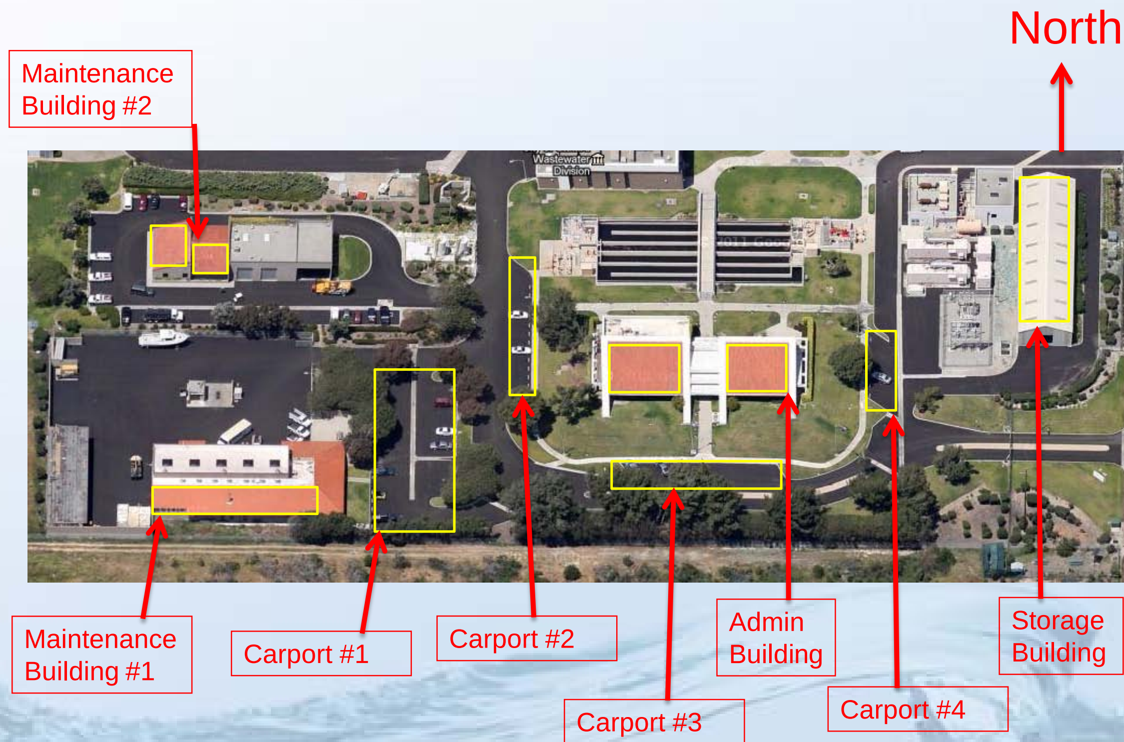


**SOLAR SCENARIO 1:
POTENTIAL SOLAR PANEL
BASIN'S AREA LOCATIONS**

FIGURE 4.1

CITY OF OXNARD
ENERGY EVALUATION

Rooftop and Carport layout – Map



SOLAR SCENARIO 2: CARPORTS AND ROOFTOPS AT WWTP

FIGURE 4.2

CITY OF OXNARD
ENERGY EVALUATION

MRF layout – Map

SOLAR SCENARIO 3: MRF ROOFTOP

FIGURE 4.3

CITY OF OXNARD
ENERGY EVALUATION

4.2.2 Solar Scenario 1: Basin's Area

All of the basin areas have a large area available for mounting the solar panels. Therefore, the basins solar system output ratings were large compared to the smaller carport and rooftop systems, which in turn made the energy produced by each system quite significant. The major issue with the solar systems at the basin areas is the structural requirements and costs of the support structure. The basins are open channels and therefore the materials of the support system would need to be water and corrosion resistant. Because the basins are open channels and wide, for example the Flow Equalization Basin is approximately 60 feet, then the supports will need to be larger to make the long spans as there is no convenient location to locate a support column in the middle of the structure. These two issues add significant structural costs to the total system costs (see Appendix D), making the support structure account for approximately 60 percent of the total system costs (Figure 4.5).

4.2.3 Solar Scenario 2: Carports and Rooftops at OWTP

The carports and rooftops identified at the OWTP had much smaller areas available for mounting the solar panels as compared to the basin areas. The smaller areas produced solar systems with much smaller outputs in terms of power, energy, and revenue generated. However, because rooftop and carport solar systems are very common installations the costs of the support structure only accounts for approximately 25 percent of the total system costs (Figure 4.4). This makes the carport and rooftop solar systems much more cost effective in terms of payback time. One distinct disadvantage of the carports and rooftops is the fact that the systems are distributed over a larger area across the site, which makes connecting the systems to the plant distribution system more difficult.

4.2.4 Solar Scenario 3: MRF Rooftop and Miscellaneous One Acre Rooftop and Carport

The MRF rooftop has the largest area available for mounting solar panels of the locations evaluated. The power and energy output of this system are therefore the greatest of all the systems. Because the MRF has a flat roof, the support structure for the associated solar system is comparable to the other rooftop locations in terms of the percentage of total system costs. This makes the MRF one of the most cost effective systems as well as one of the largest potential systems available. The one acre rooftop and carport structure are very similar to the carport and rooftop systems at the OWTP, but because they have a much larger area than the OWTP locations evaluated, the overall energy and revenue generated are greater.

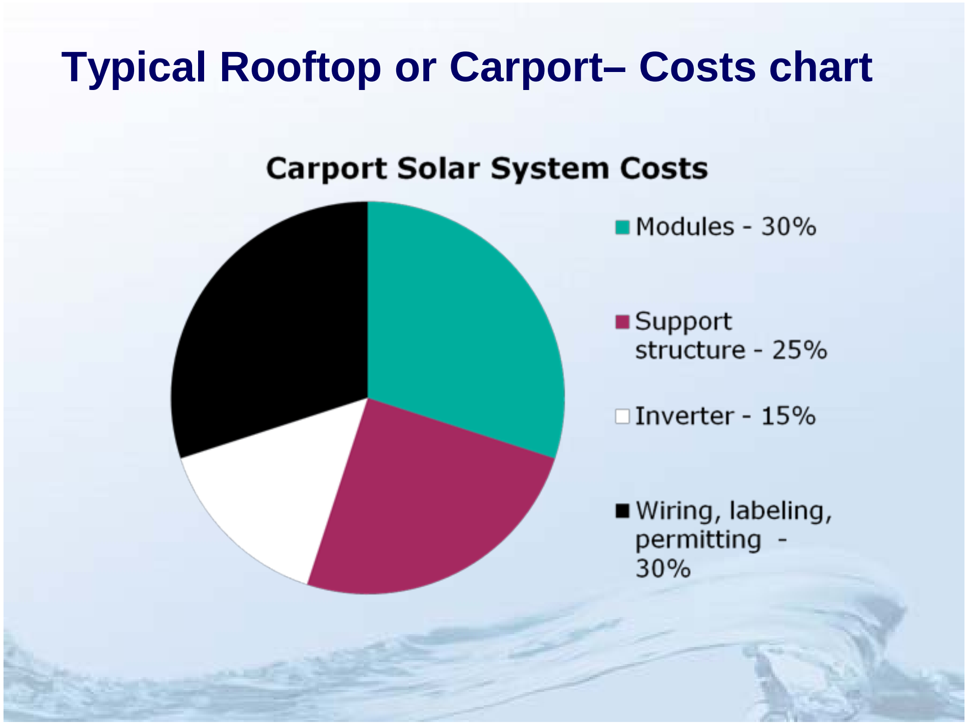
4.2.5 Solar Scenario Summary

A summary of the information discussed above is provided in Table 4.1.

Table 4.1	**Solar Scenarios – Comparison and Payback Summary[(1)] Energy Evaluation City of Oxnard**		
Location	**Size [kW-dc]**	**Upfront Capital Cost**	**Payback [Years]**
Sedimentation Basins- Concrete	176	$1,519,380)	>20
Sedimentation Basins- Tanks	561	$6,450,120	>20
Activated Sludge Tanks	320	$3,679,080	>20
Flow Equalization Basins	517	$5,945,040	>20
Maintenance Building #1	21	$81,880	17
Maintenance Building #2	14	$54,280	18
Admin Building	27	$103,040	18
Storage Building	57	$219,880	18
Carport #1	74	$284,280	17
Carport #2	30	$113,160	18
Carport #3	28	$107,640	18
Carport #4	16	$61,640	18
MRF Roof	846	$3,242,080	17
1 Acre Ground Mount	391	$1,500,520	18
1 Acre Carport	391	$1,500,520	18

Note:

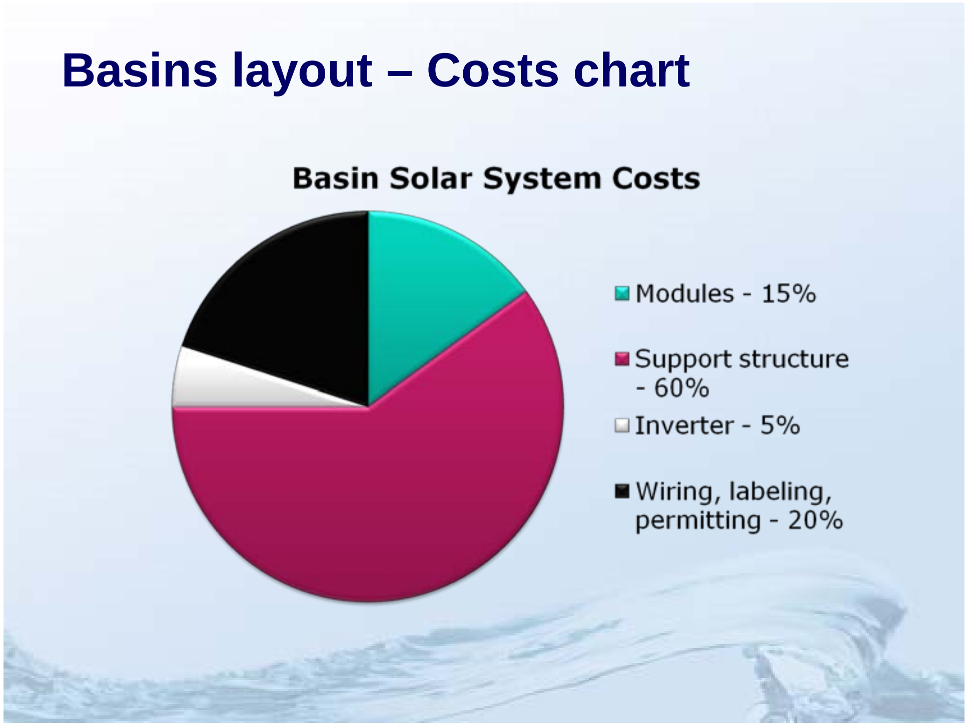
(1) Detailed calculations are shown in Appendix-D.



Typical Rooftop or Carport Costs Breakdown

FIGURE 4.4

CITY OF OXNARD
ENERGY EVALUATION



Typical Basin Layout Cost Breakdown

FIGURE 4.5

CITY OF OXNARD
ENERGY EVALUATION

FUNDING SOURCES

5.1 INTRODUCTION

Development of an effective funding strategy for green energy projects requires a clear understanding of the goals and objectives of the overall green energy plan, as well as a clear understanding of the opportunities surrounding each project. Further, all of the various types of renewable energy projects, waste-to-energy projects, and energy demand reduction projects require different funding strategies. A detailed funding strategy is not currently included herein, but can be developed after the City selects their preferred green energy project(s). Following is a high-level summary of the types of funding available for renewable energy projects, waste-to-energy projects, and energy demand reduction projects.

5.2 BACKGROUND ON GREEN ENERGY GRANT PROGRAMS

5.2.1 Innovation

Grants are generally made available by federal or state agencies for the express purpose of changing the “status quo” and advancing specific objectives of those agencies. A few grant programs are more like “entitlements” where funding is awarded to a city or a region based on a formula that might be tied to population or demographics. Most grants, however, are won through competition. The successful applicants must show that they are doing something innovative and beyond the standard operating procedure. For example, the grant programs to advance solar were much more robust 10-15 years ago as the solar industry was in its infancy and it was risky for cities to install the new technology. Today, the solar market is relatively mature, prices of panels have fallen significantly, Feed-In-Tariff programs are well established, and there are far fewer grant programs/incentives to install solar.

5.2.2 Integration

Green energy projects must be integrated with other sustainability or environmental efforts, such as air quality improvements, water quality improvements, and waste reduction, to gain the most from grant programs. This integration with other efforts shows funding agencies that other stakeholders support the project and that it will provide multiple benefits to the community. Integration can also allow greater access to funding. For example, the successful expansion of the fats, oils and grease (FOG) program could result in fewer pollutants entering the storm drain system and could ultimately contribute to improved water quality. Solid waste inputs to the landfill would also be reduced. Any or all of these benefits could be supported with grants from agencies with an interest in green energy, water quality, solid waste reduction or integrated sustainability initiatives. A highly competitive grant application clearly explains these connections through references of planning documents and letters of support from other stakeholders. The key to integrating green energy projects with other environmental efforts is to lay this groundwork early on in the planning process and be sure to engage potential community partners.

5.2.3 Timing

Grants are "perishable," that is, they are only available for a specific window of time. Solicitations might be one-time events, or might recur annually. Most are dependent upon state or federal appropriations. Furthermore, a project must be in the right state of readiness to align with the grant opportunity. For example, some grants require that CEQA documents and plans are complete at the time of application, or that significant matching funds are secured, and partners are fully committed.

5.2.4 Partners

It can be beneficial to work in partnership with others to implement green energy projects. Partners can expand the reach or effectiveness of the effort and increase access to funding. For example, agricultural producers have unique access to grant programs that incentivize participation in biofuel projects. Non-profits may have access to grants for outreach about pollution prevention or sustainability. Some grant programs target public-private partnerships.

5.3 SUMMARY OF POTENTIAL FUNDING OPPORTUNITIES

5.3.1 Fats Oils and Grease

5.3.1.1 Federal:

- Environmental Protection Agency (EPA) – Office of Solid Waste and Emergency Response (OSWER): EPA has funded several "fat-to-fuel" projects or studies through the conservation fund to support biodiesel and anaerobic digester facilities. http://www.epa.gov/oswer/iwg/index.html

- EPA – Pollution Prevention Program: Grant program supports technical assistance projects to help businesses identify better environmental strategies and solutions for reducing or eliminating waste at the source. http://www.epa.gov/p2/pubs/grants/ppis/2013rfpp2grant.pdf

- EPA - Water Quality Improvement Grants (various). http://water.epa.gov/grants_funding/

5.3.1.2 State:

- California Energy Commission - Process Energy - Agriculture Loan Solicitation: The California Energy Commission is offering below market rate loan funds for the purchase of proven cost-effective energy efficient and renewable generation emerging technologies applicable to the agricultural and food processing industries. http://www.energy.ca.gov/process/agriculture/loan_solicitation/index.html

- California Energy Commission - Renewable Energy and Conservation Planning Grants (RECPG): This program funds plans to develop or revise rules and policies that facilitate development of eligible renewable energy resources, and their associated electric transmission facilities, and the processing of permits for eligible renewable energy resources. http://www.energy.ca.gov/contracts/PON-12-403_NOPA.pdf

- California Public Utilities Commission (CPUC) - Self Generation Incentive Program (SGIP): The CPUC's SGIP provides incentives to support existing, new, and emerging distributed energy resources. Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/

- California Air Quality Board- - Air Quality Improvement Program: Incentive program administered by the Air Resources Board to fund clean vehicle and equipment projects, research on biofuels production and the air quality impacts of alternative fuels, and workforce training. http://www.arb.ca.gov/msprog/aqip/aqip.htm

- California Air Quality Board- - Carl Moyer Memorial Air Quality Standards Attainment Program provides grants for cleaner-than-required engines and equipment. Grants are administered by local air districts. http://www.arb.ca.gov/msprog/moyer/moyer.htm

- Cal-FOG Workgroup: The California Fats, Oils, and Grease work group (Cal FOG) was formed in 2001 as a result of increased regulatory focus on FOG-related sanitary sewer overflows (SSOs). The work group consists of wastewater agencies, regulators, consulting firms, and restaurant and related industry representatives. The focus of the work group is to utilize collective resources to develop FOG control tools and to provide technical support and information to the work group members. http://www.calfog.org/index.html

5.3.1.3 Private:

Partnerships with FOG service providers: Several private businesses offer FOG collection services, where the restaurant installs a grease recovery system and pays for a pickup service. The FOG providers often have biofuel systems that convert the grease to fuel. List of FOG haulers: http://www.calfog.org/Hauler.html

5.3.2 Cogeneration

5.3.2.1 <u>Federal:</u>

Department of Energy - Energy Efficiency Block Grants: Grants can be used for energy efficiency and conservation programs and projects communitywide, as well as renewable energy installations on government buildings. Availability varies from year to year. http://www1.eere.energy.gov/wip/eecbg.html

EPA – Clean Water State Revolving Fund – Green Project Reserve: The Green Project Reserve, or GPR, requires all Clean Water State Revolving Fund (CWSRF) programs to direct a portion of their capitalization grant toward projects that address green infrastructure, water efficiency, energy efficiency, or other environmentally innovative activities. CWSRF can forgive a portion of the loan principal. http://water.epa.gov/grants_funding/cwsrf/Green-Project-Reserve.cfm

5.3.2.2 <u>State:</u>

- California Energy Commission Energy Conservation Assistance Act (ECAA) program: Low interest low program for cities and schools to implement energy efficiency and renewable energy projects. http://www.energy.ca.gov/efficiency/financing/
- California Energy Commission – RECPG: (see above).
- CPUC – SGIP: (see above).
- California Air Quality Board – Air Quality Improvement Program: (see above).
- California Air Quality Board – Carl Moyer Memorial Air Quality (see above).
- Proposition 39 – Clean Energy Job Creation Fund: The Governor's May 2013 budget revision continued to direct the funds from the Clean Energy Job Creation Fund (Prop 39) entirely into schools. The LAO analysis states that this goes against the language in the bill, and indicates an opportunity for someone to litigate if this is how the Fund ends up being spent. The bill indicated that at least some of the funds would be available for energy efficiency and renewable energy projects at municipal buildings and facilities.

5.3.2.3 <u>Utilities:</u>

- Southern California Gas (So Cal Gas)
  - Only utility currently allowing digester gas into natural gas pipeline.
  - Co-Generation Project Grants: So Cal Gas has awarded grant funding to specific cogeneration projects in the past but does not appear to have an ongoing grant program for co-generation.

5.3.3 Solar Photovoltaic

5.3.3.1 Federal:

- Department of Energy - Energy Efficiency Block Grants: (see above).

5.3.3.2 State:

- CPUC, California Solar Initiative: Rebates for solar installation and Net Energy Metering (approximately 84 MW remaining for rebate in So Cal Edison, non-residential category)
  - Expected Performance-Based Buydowns: One-time payment based on estimated performance for systems under 30 kilowatts (kW) at $0.90/Watt (W).
  - Performance-Based Incentives (PBI): Monthly performance based payments for systems 30 kW and larger at $0.114/kilowatt hour (kWh).

- Proposition 39: (see above).

- CPUC - (SGIP): (see above).

- CA Cap and Trade and Renewable Energy Portfolio.
  - Renewable Energy Certificates (RECs): A REC represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source. The City could sell RECs to entities regulated under the Cap.

5.3.3.3 Utilities:

- Southern California Edison (SCE).
  - California Solar Initiative - Renewable Energy Project Grants (see above).
  - Feed-in Tariffs: The California feed-in tariff allows eligible customer-generators to enter into 10-, 15- or 20-year standard contracts with their utilities to sell the electricity produced by small renewable energy systems (up to 3 megawatts). [1]http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/feedintariffs.htm

5.3.3.4 Private

- Power purchase agreements

---

[1] The CPUC is currently in the process of implementing several statutory revisions to the Section 399.20 renewable feed-in tariff (FIT) program. As of May 9, 2013, the original FIT program as authorized by AB 1969 and implemented by Commission Decision (D.) 07-07-027 is still in effect. The revised FIT program (utilizing the renewable market adjusting tariff, or ReMAT) will become effective upon adoption of the revised standard contract and tariffs for each utility.

- PPA's: Private Solar Energy Providers will finance and install solar panels on city facilities. City agrees to buy back power from Provider over 15-25 years.
- Bond PPAs: Municipality issues taxable bonds for the solar project and enters a 15-25 year lease-purchase agreement with Solar Provider.

APPENDIX A – CITY EAP RESOLUTION AND VENTURA AIR POLLUTION CONTROL DISTRICT (VAPCD) PERMIT TO OPERATE

CITY COUNCIL OF THE CITY OF OXNARD

RESOLUTION NO. 14,398

RESOLUTION OF THE CITY COUNCIL OF THE CITY OF OXNARD APPROVING COMPLETION OF THE FINAL DRAFT OF THE CITY OF OXNARD ENERGY ACTION PLAN (EAP) AND CONFIRMATION OF IMPLEMENTATION OF THREE EAP PROGRAMS

WHEREAS, the California Global Warming Solutions Act of 2006 (known as AB 32) sets a mandate for the reduction of greenhouse gas emissions in California, and the Sustainable Communities and Climate Protection Act of 2008 (known as SB 375) requires emissions reductions through coordinated regional planning that integrates transportation, housing, and land-use policy; and

WHEREAS, because of the diversity of California's topography and different local climates, the effects of a changing climate on California communities are complex and will differ from community to community; and

WHEREAS, the Southern California Edison (SCE) 2010-12 Strategic Plan established the Energy Action Plan (EAP) as a planning tool to identify and quantify programs to use energy more efficiently and reduce greenhouse gas (GHG) emissions from local government operations and within their respective communities; and

WHEREAS, the 2030 General Plan, Programs SC-3.2 and SC-3.3 call for the completion of a City Government and Community EAP, respectively, and the EAP information contributes towards several other programs within Goal SC-3 "Energy Generation and Increased Efficiency"; and

WHEREAS, the calculations and expression of electricity and natural gas past and projected consumption in millions of tons of CO2 Equivalent (MTCO2e) contributes to the development of an inventory and monitoring of GHG emissions and development of an Oxnard Climate Action Adaptation Plan that are Policies SC-1.1 and SC-1.3 of the 2030 General Plan, respectively; and

WHEREAS, on October 1, 2009, the California Public Utilities Commission authorized SCE to conduct a solicitation for energy efficiency strategic planning activities, pursuant to which the City of Oxnard applied and received a grant of $275,000 to develop an Oxnard City Government and Community EAP; and

WHEREAS, in 2011 and utilizing the SCE funding, the City of Oxnard contracted with a team of qualified energy planning consulting firms to assist in preparing the Oxnard EAP; and

WHEREAS, in 2012, the consultants and City staff conducted a comprehensive analysis of City Government and community electricity and natural gas consumption between 2005 and 2010, projected electricity and natural gas consumption to 2020, identified a feasible reduction target with consideration for the mild Oxnard climate, and identified 18 City Government and 17 Community programs to achieve the target; and

WHEREAS, the consultants and City staff identified and involved City Government and community stakeholders, developed an EAP website seeking community input, distributed an Earth Day Promotional Flyer in English and Spanish, distributed a press release that resulted in several local newspaper articles, and held two community workshops on May 14, 2012; and

WHEREAS, the Planning Commission conducted a public comment session on the Final Draft EAP at its meetings on May 2, 2013 and June 6, 2013; and

WHEREAS, the City Council of the City of Oxnard received a summary report on EAP findings and programs, made comments on June 18, 2013, and will consider authorization and funding of individual EAP programs on a case by case basis; and

WHEREAS, Public Resources Codes 21102 and 21150 statutorily exempt from the California Environmental Quality Act (CEQA) a feasibility or planning study of possible future actions that have not been adopted or funded; and

WHEREAS, in order to achieve "Platinum Level" partner status under SCE's Energy Leader Program, SCE requests that the City Council commit to implementing three EAP programs identified in the EAP; and

WHEREAS, the 2030 General Plan, Chapter 9, Table 9-3, identifies three Initial Implementation Policies that effectively implement three corresponding EAP programs as shown below, and that the environmental effects of these three previously adopted, but not yet implemented, Implementation Measures were reviewed by the certified 2030 General Plan Final Program Environmental Impact Report in compliance with CEQA.

2030 General Plan Implementation Measure		EAP City or Community Program	
5.0	Purchase and use recycled materials and alternative and renewable energy sources as feasible in City operations.	G-11	Develop Energy-Efficient Product Procurement Policy
6.0	Work with local utility providers to create a public outreach program supporting energy conservation.	C-2	Additional Outreach to Residents
7.0	Provide information to businesses about how to reduce waste and pollution and conserve resources.	C-1	Additional Outreach to Commercial and Industrial Customers

NOW, THEREFORE, THE CITY COUNCIL OF THE CITY OF OXNARD DOES HEREBY RESOLVE AS FOLLOWS:

1. The Final Draft EAP dated April, 2013 is hereby approved as to form and content and attached hereto as Exhibit A, and made part of this Resolution.
2. The City of Oxnard commits to implementing EAP program C-1, C-2, and G-11 in partial satisfaction of the SCE Partnership Program Platinum level requirements.

PASSED AND ADOPTED this 25 day of June 2013, by the following vote:

AYES: Councilmembers Flynn, Ramirez, MacDonald, Padilla and Perello.

NOES: None.

ABSENT: None.

Tim Flynn

Tim Flynn, Mayor

ATTEST:

Daniel Martinez, City Clerk

APPROVED AS TO FORM:

FOR

Alan Holmberg, City Attorney

Ventura County
Air Pollution
Control District

669 County Square Drive
Ventura, California 93003

tel 805/645-1400
fax 805/645-1444
www.vcapcd.org

Michael Villegas
Air Pollution Control Officer

PERMIT TO OPERATE
Number 01137

Valid October 1, 2012 to September 30, 2013

This Permit Has Been Issued To The Following:

Company Name / Address:

City of Oxnard-Wastewater Division
6001 S. Perkins Rd.
Oxnard, CA 93033

Facility Name / Address:

Oxnard Wastewater Treatment Plant
6001 South Perkins Road
Oxnard, CA 93033

Permission Is Hereby Granted To Operate The Following:

2 - 500 BHP Caterpillar Effluent Pump Natural Gas Engines, Model G-398, Rich Burn (as defined in VCAPCD Rule 74.9), each equipped with NSCR 3-Way Catalytic Converter, Oxygen Sensor, and Air/Fuel Ratio Controller, for Rule 74.9 compliance, (Engines Nos. 1 & 3).
3 - 800 BHP Waukesha Electrical Generator Waste Gas Engines (as defined in VCAPCD Rule 74.9), Model P9390G, Rich Burn, equipped with Pre-Stratified Charge for Rule 74.9 compliance (Engines Nos. E7610.00, E7710.00 & E7810.00).
2 - 24000 Cubic Feet Per Hour Varec, Model 239, Waste Gas Burners (24 MMBTU/Hr on Natural Gas), 6" Feed Size, used for Digester Gas Incineration
1 - 48000 Cubic Feet Per Minute Air Capacity Odor Reduction Tower, B.F. Goodrich/Media Koro-Z, for odor reduction and H2S control
1 - Headworks Facilities controlled by a 25,000 SCFM US Filter LO/Pro Odor Control System consisting of a three-stage absorption system using Sodium Hydroxide and Sodium Hypochlorite for hydrogen sulfide removal; and equipped with a hydrogen sulfide analyzer.
1 - Odor Reduction Station (Solids Processing Building and Eastern Trunk Pump Station), Calvert FRP Fine Mist Tower, 10 Feet Diameter x 37 Feet High, 22,000 CFM Capacity, equipped with an Interscan Model LD-17 H2S Analyzer

Emergency Standby Diesel Engines For Electricity Generators

1 - 2250 BHP General Motors Emergency Standby Diesel Engine, Model 16-567-E4, Serial No. 66-HI-1082, no EPA Family Name, Model Year 1966
1 - 2250 BHP General Motors Emergency Standby Diesel Engine, Model 16-567-E-4, Serial No. 66-HI-1161, no EPA Family Name, Model Year 1966
1 - 2172 BHP Caterpillar Emergency Standby Diesel Engine, Model 3512B TA, Serial No. 1GZ02501, EPA Family Name 5CPXL58-6ERK, Model Year 2005
1 - 263 BHP Caterpillar Emergency Standby Diesel Engine, Model 3208, Serial No. 5YF00565, no EPA family Name, Model Year 1989

1 - 636 BHP Caterpillar Emergency Standby Diesel Engine, Model C15, Serial No. FSE00892, EPA Family Name 7CPXL15.2ESK, ARB Executive Order U-R-001-0308

1 - 250 BHP Cummins Emergency Standby Diesel Engine, Model QSB7-G3, Serial No. 73123393, EPA Family Name ACEXL0409AAB, Tier 3, CARB Executive Order No. U-R-002-0516, Located at Advanced Water Purification Site at 5700 South Perkins Road in Oxnard

Emergency Standby Diesel Engine For Air Compressor

1 - 139 BHP (104 KW) John Deere Emergency Diesel Engine, Model 4045HF275C, Serial No. PE 4045H376314, EPA Family Name 5JDXL06.8078, Model Year 2005

This Permit Has Been Issued Subject To The Following Conditions:

1. Permitted Emissions

Permitted Emissions	Tons/Year	Pounds/Hour
Reactive Organics	10.18	8.36
Nitrogen Oxides	15.33	27.76
Particulate Matter	1.16	1.61
Sulfur Oxides	2.54	1.69
Carbon Monoxide	145.35	84.54
Chlorine	0.75	0.52
Hydrogen Sulfide	9.47	2.16

2. Annual fuel consumption in the Caterpillar internal combustion engines, the Waukesha internal combustion engines, and the Varec Waste Gas Burners shall not exceed the following:

   a) Total natural gas consumption in the two (2) 500 HP Caterpillar internal combustion engines (Engine Nos. 1 & 3) shall not exceed 5.0 million cubic feet per year.

   b) Total digester waste gas consumption in the three (3) 800 HP Waukesha internal combustion engines (Engine Nos. E7610.00, E7710.00, & E7810.00) shall not exceed 155.00 million cubic feet per year.

   c) Incineration of digester gas in the Varec Waste Gas Burners shall not exceed 146.0 million cubic feet per year.

   In order to comply with this condition, permittee shall maintain and operate meters to measure and record gas consumption. The meters shall be operated and calibrated according to manufacturer's specifications. The gas meter records shall be summed on a monthly basis. The monthly totals shall be summed for the previous twelve calendar (12) months. Gas consumption totals for any twelve (12) calendar month rolling period in excess of the above limits shall be considered a violation of this condition.

3. Prior to exceeding any of the above limits, permittee shall submit an application to the APCD to increase those limits. Any request

to increase fuel use in the two (2) 500 HP Caterpillar internal combustion engines (Engines Nos. 1 & 3) shall be subject to APCD Rule 26.

4. Permittee shall comply with APCD Rule 74.9, "Stationary Internal Combustion Engines". This includes, but is not limited to, the following permit conditions.

5. Pursuant to Rule 74.9.F, Reporting Requirements, within 45 days of the end date of each permit renewal period, the operator of a permitted engine subject to the provisions of the rule shall provide the District with the following information:

   a) Engine manufacturer, model number, operator identification number and location of each engine.

   b) A summary of maintenance reports during the renewal period, including quarterly screening data if applicable.

   For each engine exempt pursuant to Subsection D.2, total annual operating hours shall be reported annually. For each engine exempt pursuant to subsection D.3, total annual hours of maintenance operaton shall be reported annually. Reports shall be provided to the District after every calendar year by February 15.

6. Emissions of oxides of nitrogen (NOx) from each of the two (2) 500 HP Caterpillar internal combustion engines (Engines Nos. 1 & 3) shall not exceed 25 parts per million (ppmv) as corrected to 15% oxygen.

7. Emissions of oxides of nitrogen (NOx) from each of the three (3) 800 HP Waukesha internal combustion engines (Engines Nos. E7610.00, E7710.00, & E7810.00) shall not exceed 50 parts per million (ppmv) as corrected to 15% oxygen. This condition is applied for APCD Rule 74.9.B.1 compliance. As of January 1, 1997, the NOx limits are 25 parts per million (ppmv) as corrected to 15% oxygen for rich burn engines fired on natural gas and 50 parts per million (ppmv) as corrected to 15% oxygen for rich burn engines fired on waste gas. As detailed in VCAPCD Rule 74.9.I.11, waste gas is defined as fuel gas produced at either waste water/sewage treatment facilities or landfills containing no more than 25 percent by volume supplemental gas.

8. Emissions from each engine shall not exceed 4500 ppm carbon monoxide, as corrected to 15% oxygen, pursuant to APCD Rule 74.9.B.1.

9. Emissions from each engine shall not exceed 250 ppm reactive organic compounds, as corrected to 15% oxygen, pursuant to APCD Rule 74.9.B.1.

10. In order to comply with the engine emission Conditions, permittee shall perform a source test every 24 months as required by VCAPCD

Rule 74.9. In addition, the NSCR system on the Caterpillar engines shall be maintained and operated with a minimum temperature rise across the catalyst of 15 degrees Fahrenheit.

11. Hydrogen Sulfide emissions from the Odor Reduction Tower shall not exceed 5 ppm by volume.

12. Hydrogen Sulfide emissions from the Odor Reduction Station shall not exceed 4 ppm by volume at the Solids Processing Building.

13. Hydrogen sulfide emissions from the 25,000 CFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities shall not exceed 3 ppm by volume. The chlorine concentration at the outlet of the 25,000 CFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities shall not exceed 0.1 ppm by volume. This condition is applied pursuant to Rule 51, "Nuisance"; and Rule 54, "Sulfur Compounds".

    In order to comply with this condition, permittee shall maintain the control system parameters (i.e., pH of scrubbing solution, ORP of the scrubbing solution, pressure drop across the control system, and space velocity through the control system) at values that ensure that the above hydrogen sulfide and chlorine concentrations are not exceeded.

    Permittee, upon request of the District, shall conduct testing to ascertain the hydrogen sulfide and chlorine emissions from the 25,000 CFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities, using APCD approved methods.

14. Permittee shall install and maintain a continuous hydrogen sulfide analyzer at the outlet of the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities to monitor the hydrogen sulfide concentration in ppm by volume at the outlet of the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities. The analyzer shall be installed, operated, and calibrated according to the manufacturer's specifications. This condition is applied to ensure compliance with Rule 51, "Nuisance"; and Rule 54, "Sulfur Compounds".

15. Permittee shall install and maintain pH and ORP (oxidation reduction potential) measuring and monitoring devices to measure and record the pH and ORP of the scrubbing solution in the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities. Permittee shall also install and maintain pressure monitoring devices to monitor the pressure drop across the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks. All devices shall be installed, operated, and calibrated according to the manufacturer's specifications. This condition is applied to

ensure compliance with the requirements of Rule 51, "Nuisance"; and Rule 54, "Sulfur Compounds".

16. The stack height of the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities shall be no less than 9 meters (29.5 feet). The stack diameter of at the outlet of the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities shall not exceed 0.9 meters (2.95 feet). The stack gas exit velocity from the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities shall be no less than 18.5 meters per second (60.7 feet per second). This condition is applied pursuant to Rule 51, "Nuisance"; and pursuant to Rule 54, "Sulfur Compounds".

17. All operations shall comply with the requirements of Rule 51, "Nuisance".

18. All equipment shall be maintained and operated in a manner that ensures compliance with all applicable Rule and permit conditions.

19. Permittee shall maintain records showing, for the 25,000 SCFM US Filter LO/PRO Odor Control System three-stage absorption system controlling the Headworks Facilities, on a monthly basis, a log of operating time for the control system, and monitoring equipment; records of the readings from the monitoring equipment showing the pressure drop across the control system; records of the readings from the monitoring equipment showing the hydrogen sulfide concentrations, pH of the scrubbing solution in the control system, and ORP of the scrubbing solution in the control system; and a log for the control system and monitoring equipment detailing all routine and non-routine maintenance performed. All records shall be compiled into monthly reports and shall be made available to APCD personnel upon request. All records shall be retained for at least two years and shall be made available to APCD personnel upon request.

20. The Hydrogen Sulfide analyzer on the Odor Reduction Tower shall be maintained in good working order at all times. The Hydrogen Sulfide analyzers on the Odor Reduction Station shall be maintained in good working order at all times. Malfunctions are subject to APCD Rule 32 (Breakdowns), as are all other air pollution related breakdowns at the plant. Analyzer outputs shall be continuously recorded on strip charts, or shall be recorded using an electronic data acquisition/storage system. Records or strip charts shall be maintained on site for at least two years and shall be made available to APCD personnel upon request.

21. When sodium hypochlorite is used, chlorine emissions from the Odor Reduction Station (Solids Processing Building and Eastern Trunk Pump Station Odor Reduction Station) shall not exceed 2 ppm by volume. Scrubber drain pH shall be maintained between 8.0 and 9.0 to ensure compliance with this requirement. Operation of the

Solids Processing Building and Eastern Trunk Pump Station Odor Reduction Station using sodium hypochlorite shall be limited to 2562 hours per year. In order to demonstrate compliance with this condition, the permittee shall maintain records of the hours of operation when using sodium hypochlorite and upon the request of the District, shall measure the chlorine emissions from the Odor Reduction Station (Solids Processing Building and Eastern Trunk Pump Station Odor Reduction Station).

22. Under no circumstances shall raw digester gas be vented to the atmosphere without prior approval from the APCD. All digester gas produced at the plant shall be flared, or disposed of in an alternative manner approved by the APCD.

23. Hydrogen Sulfide content of produced digester gas shall not exceed 100 ppm.

24. Hydrogen Sulfide content and heat content of the produced digester gas (in grains/100 cu. ft.) shall be determined by analytical means every 6 months, by an independent laboratory or the laboratory at the City of Oxnard Wastewater Treatment Facility, with results kept on file for inspection by APCD personnel for at least 2 years.

25. Annual hours of operation for maintenance and testing of each emergency engine shall not exceed 20 hours per year, except for the 2172 BHP and 636 BHP Caterpillar Emergency Standby Diesel Engines, which shall not exceed 50 hours per year. This limit does not include emergency operation when electrical line service has failed. When not being operated for maintenance or testing, the emergency engine shall only be used during a failure or loss of all or part of normal electrical power service to the facility. This condition is applied pursuant to the California ARB Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines.

    In order to comply with this condition, the engine shall be equipped with a non-resettable hour meter and the permittee shall maintain a log that differentiates operation during maintenance and testing from emergency operation. These records shall be compiled into a monthly total. The monthly operating hour records shall be summed for the previous 12 months. Total operating hours for any of these 12 month periods, excluding emergency operation, in excess of the specified annual limit shall be considered a violation of this condition.

26. The emergency diesel engine(s) shall be operated in compliance with all applicable requirements of the California ARB Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines, Section 93115 through 93115.15, Title 17, California Code of Regulations. This includes, but is not limited to, the following permit conditions.

27. Pursuant to Section 93115.5(b) of the ATCM for Stationary Compression Ignition Engines, effective January 1, 2006, no owner

or operator of an in-use emergency standby stationary diesel-fueled engine shall add to the engine or any fuel tank directly attached to the engine any fuel unless the fuel is CARB diesel fuel or another fuel that meets the requirements of Section 93115.5(b) of the ATCM.

28. Pursuant to Rule 74.9.D.3, an emergency engine is exempt from Rule 74.9, "Stationary Internal Combustion Engines", provided that it is operated during either an emergency or maintenance operation. Maintenance operation is limited to 50 hours per calendar year and is defined as "the use of an emergency standby engine and fuel system during testing, repair, and routine maintenance to verify its readiness for emergency standby use".

29. Permittee shall maintain records for the Hydrogen Sulfide analyzers on the Odor Reduction Tower and the Odor Reduction Station. Permittee shall maintain records of the hours of operation of the Solids Processing Building and Eastern Trunk Pump Station Odor Reduction Station when using sodium hypochlorite. Such records shall include the date and time. These records shall be compiled on a monthly basis. The compiled records shall be maintained for at least two years and shall be made available to APCD personnel upon request.

30. Permittee shall maintain records as required by VCAPCD Rule 74.9.E, and the monthly fuel consumption and hours of operation (when applicable) of the internal combustion engines. Permittee shall also maintain records showing the amount of digester gas produced and the disposition of this gas (amount expended to engines; amount expended to flare). All records shall be compiled into monthly reports and shall be maintained for at least two years.

31. Pursuant to Rule 74.9.F, Reporting Requirements, within 45 days of the end date of each permit renewal period, the operator of a permitted engine subject to the provisions of the rule shall provide the District with the following information:

    a) Engine manufacturer, model number, operator identification number and location of each engine.

    b) A summary of maintenance reports during the renewal period, including quarterly screening data if applicable.

    For each engine exempt pursuant to Subsection D.2, total annual operating hours shall be reported annually. For each engine exempt pursuant to subsection D.3, total annual hours of maintenance operaton shall be reported annually. Reports shall be provided to the District after every calendar year by February 15.

32. A log of engine operation for the emergency engine shall be maintained based on readings from a non-resettable hour meter. The log shall differentiate operation during maintenance and testing from operation during an emergency. The hours of operation shall

be totaled on a monthly basis and shall be summed for the previous 12 months.

This data shall be maintained for a minimum of three (3) years from the date of each entry and shall be made available to the APCD upon request.

33. On and after October 19, 2013, the two 500 BHP Caterpillar Effluent Pump Natural Gas Engines shall comply with 40 CFR Part 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP). This includes, but is not limited to, the following requirements for non-emergency 4 stroke rich burn spark ignited engines rated at less than or equal to 500 BHP that commenced construction before June 12, 2006:

    Pursuant to 40 CFR Part 63.6603, Table 2d, the permittee shall meet the following requirements:

    a) Change oil and filter every 1,440 hours of operation, or annually, whichever comes first. Permittee shall have the option to utilize an oil analysis program as described in 40 CFR Part 63.6625(i) in order to extend the specified oil change requirement; and
    b) Inspect spark plugs every 1,440 hours of operation, or annually, whichever comes first, and replace as necessary; and
    c) Inspect all hoses and belts every 1,440 hours of operation, or annually, whichever comes first, and replace as necessary.

    During periods of startup, the permittee shall minimize the RICE time spent at idle and minimize the RICE startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. The permittee shall operate and maintain the RICE and after-treatment control device (if any) according to the manufacturer's emission related instructions, or the permittee's own operation and maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

    The permittee shall keep the records of RICE maintenance (oil, spark plugs, hoses and belts) required by the RICE operation and maintenance plan. The hours of operation records and maintenance records shall be maintained for 5 years following the date of each occurrence and shall be made available to the APCD upon request.

34. On and after October 19, 2013, the three 800 BHP Waukesha Electrical Generator Waste Gas Engines shall comply with 40 CFR Part 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP). This includes, but is not limited to, the following requirements for non-emergency spark ignited engines fired on landfill gas or digester gas that commenced construction

before June 12, 2006:

Pursuant to 40 CFR Part 63.6603, Table 2d, the permittee shall meet the following requirements:

a) Change oil and filter every 1,440 hours of operation, or annually, whichever comes first. Permittee shall have the option to utilize an oil analysis program as described in 40 CFR Part 63.6625(i) in order to extend the specified oil change requirement; and
b) Inspect spark plugs every 1,440 hours of operation, or annually, whichever comes first, and replace as necessary; and
c) Inspect all hoses and belts every 1,440 hours of operation, or annually, whichever comes first, and replace as necessary.

During periods of startup, the permittee shall minimize the RICE time spent at idle and minimize the RICE startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. The permittee shall operate and maintain the RICE and after-treatment control device (if any) according to the manufacturer's emission related instructions, or the permittee's own operation and maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

The permittee shall keep the records of RICE maintenance (oil, spark plugs, hoses and belts) required by the RICE operation and maintenance plan. The hours of operation records and maintenance records shall be maintained for 5 years following the date of each occurrence and shall be made available to the APCD upon request.

Note that for the purposes of the RICE NESHAP, the subject engine(s) shall combust no less than 10% landfill gas or digester gas of the gross heat input on an annual basis.

35. The following condition regarding the RICE NESHAP applies to the following "existing" emergency diesel engines:

a) Two 2250 BHP General Motors
b) 2172 BHP Caterpillar
c) 263 BHP Caterpillar
d) 139 BHP John Deere

On and after May 3, 2013, these engines shall comply with 40 CFR Part 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP). This includes, but is not limited to, the following requirements for emergency compression ignition engines that commenced construction before June 12, 2006:

Pursuant to 40 CFR Part 63.6603, Table 2d, the permittee shall meet the following requirements:

a) Change oil and filter every 500 hours of operation, or annually, whichever comes first. Permittee shall have the option to utilize an oil analysis program as described in 40 CFR Part 63.6625(i) in order to extend the specified oil change requirement; and
b) Inspect air cleaner every 1,000 hours of operation, or annually, whichever comes first, and replace as necessary; and
c) Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

If an emergency RICE is operating during an emergency and it is not possible to perform the above maintenance, or if performing the maintenance would otherwise pose an unacceptable risk under federal, state, or local law, the maintenance can be delayed and should be performed as soon as practicable after the emergency has ended or the unacceptable risk has abated. All such maintenance delays shall be reported to the APCD Compliance Division.

During periods of startup, the permittee shall minimize the RICE time spent at idle and minimize the RICE startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. The permittee shall operate and maintain the RICE and after-treatment control device (if any) according to the manufacturer's emission related instructions, or the permittee's own operation and maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

Pursuant to 40 CFR Parts 63.6640(f) and 63.6675, the RICE cannot be used for peak shaving, as part of a financial arrangement to supply power into the grid, or as a part of a demand response program, unless specifically allowed by this permit. There is no time limit on the use of emergency RICE in emergency situations.

Pursuant to 40 CFR Parts 63.6655 and 63.6660, the RICE shall be equipped and operated with a non-resettable hour meter. The permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation, including operation for maintenance and testing. In addition, the permittee shall keep the records of RICE maintenance (oil, air cleaner, hoses and belts) required by the RICE operation and maintenance plan. The hours of operation records and maintenance records shall be maintained for 5 years following the date of each occurrence and shall be made available to the APCD upon request.

36. The 636 BHP Caterpillar and the 250 BHP Cummins emergency diesel engines is exempt from 40 CFR Part 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP) because they were constructed on or after June 12, 2006.

Within 30 days after receipt of this permit, the permittee may petition the Hearing Board to review any new or modified condition (Rule 22).

This permit, or a copy, shall be posted reasonably close to the subject equipment and shall be accessible to inspection personnel (Rule 19). This permit is not transferable from one location to another unless the equipment is specifically listed as being portable (Rule 20).

This Permit to Operate shall not be construed to allow any emission unit to operate in violation of any state or federal emission standard or any rule of the District.

Terri Thomas
Terri Thomas
Engineering Division

For:

Michael Villegas
Air Pollution Control Officer

APPENDIX B – PRELIMINARY SUMMARY OF COGENERATION ALTERNATIVES EVALUATION

Oxnard Preliminary Summary of Cogeneration Alternatives Evaluation

carollo
Engineers...Working Wonders With Water™

Date/time: 6/5/13 3:55 PM

Alternative	No Cogeneration - Base Case Operation	Two 852 kW Engine Generator Cogeneration	One 1,137 kW Engine Generator Cogeneration	Three 250 kW Microturbine Cogeneration System w/ FOG	One 1,400 kW Fuel Cell Cogeneration System w/ FOG
Average Net Power Generated (kW)	0	1,534	1,023	694	1,176
Estimated Project Cost (1) (2013 dollars)	$0	$13,313,020	$10,993,232	$12,135,427	$17,449,612
Estimated SGIP Grant Funding (2013 dollars)	$0	$2,433,600	$1,923,300	$1,350,000	$4,080,000
Estimated Net Project Cost (2013 dollars)	$0	$10,879,420	$9,069,932	$10,785,427	$13,369,612
20-year Average Digester Gas Consumed (scfd)	146,897	514,468	359,919	349,960	444,629
20-year Average Natural Gas Consumed (scfd)	0	3,249	0	0	0
20-year Average Annual NOx Emissions (lb/yr)	3,576	27,774	20,830	5,585	6,565
20-year Average Annual CO Emissions (lb/yr)	11,714	106,821	79,111	9,337	7,972
20-year Average Annual Energy CO2e Value (2) (metric-tons/yr)	10,111	8,262	9,306	10,063	8,746
20-Year Average Annual Costs/(Revenues)					
Natural gas costs	$0	$42,792	$0	$0	$0
Electricity cost savings	$0	($2,809,777)	($1,908,767)	($1,365,948)	($2,307,405)
Revenue for green power credit	($15,673)	($88,842)	($62,153)	($43,276)	($80,620)
O&M costs for Cogeneration & fuel treatment facilities	$0	$421,835	$289,397	$228,482	$743,929
20-Year Present Worth of Costs/(Revenues)					
Natural gas costs	$0	$476,791	$0	$0	$0
Base Cost for electricity	$40,052,817	$40,052,817	$40,052,817	$40,052,817	$40,052,817
Revenue for displaced electricity	$0	($30,829,906)	($20,943,696)	($14,987,681)	($25,406,145)
Revenue for green power credit	($226,042)	($1,281,329)	($896,411)	($624,150)	($1,167,020)
Revenue for FOG tipping fee	$0	($8,760,000)	($8,760,000)	($8,760,000)	($8,760,000)
O&M costs for fuel treatment facilities	$0	$1,581,139	$1,106,157	$1,075,549	$1,366,794
O&M costs for cogeneration facilities	$0	$3,192,754	$2,168,935	$1,510,179	$7,074,968
Estimated Project Cost (1) (2013 dollars)	$0	$13,313,020	$10,993,232	$12,135,427	$13,369,612
Total 20-Year Present Worth of Energy Cost (3)	**$39,826,775**	**$17,745,286**	**$23,721,034**	**$30,402,141**	**$26,531,026**
Present Worth of Net Benefit Compared to No Cogeneration System		**$22,081,489**	**$16,105,742**	**$9,424,634**	**$13,295,750**
Simple Payback Period of Cogeneration System, years		**8**	**8**	**11**	**10**

Note & Assumptions:

(1) This includes estimated construction cost plus cost for engineering, administration, contingencies and construction management
(2) CO2 equivalent (CO2e) emissions represent metric tons of Carbon Dioxide associated with purchased energy usage at the facility for Natural Gas and Electricity; based on EPA standards for overall emissions from regional power generation facilities, including CO2, N2O and CH4 emissions
(3) Total 20-year present worth of energy costs is the sum of the Present Worth values listed above
(4) Project Assumptions:

Inflation (capital costs)	4.0%
Inflation (electricity costs)	5.0%
Inflation (natural gas costs)	4.0%
Inflation (O&M costs)	3.0%
Gross discount rate	5.0%
Digester Gas LHV, Btu/scf	580
Engine availability percentage	90.0%
Microturbine availability percentage	95.0%
Fuel Cell availability percentage	95.0%
O&M rate for new engine alternatives $/kWh	$0.015
O&M rate for microturbine alternatives $/kWh	$0.015
O&M rate for fuel cell unit $/kWh	$0.040
O&M rate for fuel treatment system $/million Btu	$0.900
FOG Tipping Fee $/gallon	$0.050
Green Power Credit $/kWh	$0.005

(5) Project Data:

2012 ave. elect cost, $/kWhr	$0.105	Estimated
2012 ave. elect savings for existing generation, $/kWhr	$0.161	Based on current purchased energy costing $0.074/kWh on average
Est. 2012 ave. elect savings for new generation, $/kWhr	$0.133	Assumed to be less than existing due to not having a redundant unit
2012 NG cost, $/therm, HHV	$0.818	

Oxnard Cogeneration Study
Alternative 0
No Cogeneration - Base Case Operation

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Operation Data											
Average Digester Gas Available (million Btus)	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563
Boiler Fuel Consumed (million Btus)	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098
New Cogen Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Total Fuel Consumed (million Btus)	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098
Flared Digester Gas (million Btus)	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465
Cogen Heat Generated (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	-	-	-	-	-	-	-	-	-	-	-
Electricity Generated (MW-hrs)	-	-	-	-	-	-	-	-	-	-	-
Electricity Purchased (MW-hrs)	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Daily peak heat demand, million Btu/hr	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97
Cogen heating capacity, million Btu/hr	-	-	-	-	-	-	-	-	-	-	-
Excess (Required boiler make up) peak day, million Btu/hr	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 2,207,912	$ 2,318,307	$ 2,434,222	$ 2,555,934	$ 2,683,730	$ 2,817,917	$ 2,958,813	$ 3,106,753	$ 3,262,091	$ 3,425,195
Cost Savings from generated electricity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue for Green Power Credit	$ (15,673)	$ (12,461)	$ (13,084)	$ (13,738)	$ (14,425)	$ (15,146)	$ (15,903)	$ (16,698)	$ (17,533)	$ (18,410)	$ (19,330)
Revenue for FOG tipping fee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for engine generator facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Annual Costs	$ 3,629,734	$ 2,195,451	$ 2,305,224	$ 2,420,485	$ 2,541,509	$ 2,668,584	$ 2,802,014	$ 2,942,114	$ 3,089,220	$ 3,243,681	$ 3,405,865
Present Worth of Annual Costs	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339
TOTAL PRESENT WORTH	$39,826,775										
Annualized Total Project Capital Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annualized Total Project Benefit	$ 20,601	$ 12,461	$ 13,084	$ 13,738	$ 14,425	$ 15,146	$ 15,903	$ 16,698	$ 17,533	$ 18,410	$ 19,330
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Power Purchase Cost, $/kWh	$0.191	$0.116	$0.122	$0.128	$0.134	$0.141	$0.148	$0.155	$0.163	$0.171	$0.180
TOTAL COST OF OPTION	**$ 39,826,775**										

Oxnard Cogeneration Study
Alternative 0
No Cogeneration - Base Case Operation

		Life Cycle Present Worth of Annual Costs									
Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Operation Data											
Average Digester Gas Available (million Btus)	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563	72,563
Boiler Fuel Consumed (million Btus)	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098
New Cogen Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Total Fuel Consumed (million Btus)	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098	31,098
Flared Digester Gas (million Btus)	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465	41,465
Cogen Heat Generated (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	-	-	-	-	-	-	-	-	-	-	-
Electricity Generated (MW-hrs)	-	-	-	-	-	-	-	-	-	-	-
Electricity Purchased (MW-hrs)	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073	19,073
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Daily peak heat demand, million Btu/hr	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97
Cogen heating capacity, million Btu/hr	-	-	-	-	-	-	-	-	-	-	-
Excess (Required boiler make up) peak day, million Btu/hr	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)	(3.97)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 3,596,455	$ 3,776,278	$ 3,965,092	$ 4,163,346	$ 4,371,514	$ 4,590,090	$ 4,819,594	$ 5,060,574	$ 5,313,602	$ 5,579,282
Cost Savings from generated electricity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue for Green Power Credit	$ (15,673)	$ (20,297)	$ (21,312)	$ (22,377)	$ (23,496)	$ (24,671)	$ (25,905)	$ (27,200)	$ (28,560)	$ (29,988)	$ (31,487)
Revenue for FOG tipping fee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for engine generator facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Annual Costs	$ 3,629,734	$ 3,576,158	$ 3,754,966	$ 3,942,715	$ 4,139,850	$ 4,346,843	$ 4,564,185	$ 4,792,394	$ 5,032,014	$ 5,283,615	$ 5,547,795
Present Worth of Annual Costs	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339	$ 1,991,339
TOTAL PRESENT WORTH	$39,826,775										
Annualized Total Project Capital Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annualized Total Project Benefit	$ 20,601	$ 20,297	$ 21,312	$ 22,377	$ 23,496	$ 24,671	$ 25,905	$ 27,200	$ 28,560	$ 29,988	$ 31,487
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Power Purchase Cost, $/kWh	$0.191	$0.189	$0.198	$0.208	$0.218	$0.229	$0.241	$0.253	$0.265	$0.279	$0.293
TOTAL COST OF OPTION	**$ 39,826,775**										

Oxnard Cogeneration Study
Alternative 0
No Cogeneration - Base Case Operation

Life Cycle Present Worth of Annual Costs

Year	Average	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Existing Units 0 kW per unit											
Number of Units		0	0	0	0	0	0	0	0	0	0
Number of Units Operating		0	0	0	0	0	0	0	0	0	0
Fuel rate, Btu/kW-hr		13,758	13,758	13,758	13,758	13,758	13,758	13,758	13,758	13,758	13,758
Cogeneration heat recovery/fuel input		40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Power output, kW		-	-	-	-	-	-	-	-	-	-
Operating hours per year		7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744
Project cost estimate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291
Plant Natural Gas Usage, metric-ton/yr	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650
CH_4 and N_2O Emissions	9	9	9	9	9	9	9	9	9	9	9
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159
CH_4 and N_2O Emissions	2	2	2	2	2	2	2	2	2	2	2
ssions (Electricity + Stationary Combustion), metric-ton/yr:	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111
shold Check - Stationary Combustion ONLY), metric-ton/yr:	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 2.10 (NOx at 0.65 g/bhp-hr)	-	-	-	-	-	-	-	-	-	-	-
CO 8.10 (CO at 2.5 g/bhp-hr)	-	-	-	-	-	-	-	-	-	-	-
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088
CO 0.110 (boiler at 150 ppmv, 3% O2)	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488
CO 0.2	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293
Total, lb/yr											
NOx	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576
CO	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714

Oxnard Cogeneration Study
Alternative 0
No Cogeneration - Base Case Operation

			Life Cycle Present Worth of Annual Costs									
Year		**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Existing Units	0 kW per unit											
Number of Units			0	0	0	0	0	0	0	0	0	0
Number of Units Operating			0	0	0	0	0	0	0	0	0	0
Fuel rate, Btu/kW-hr			13,758	13,758	13,758	13,758	13,758	13,758	13,758	13,758	13,758	13,758
Cogeneration heat recovery/fuel input			40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Power output, kW			-	-	-	-	-	-	-	-	-	-
Operating hours per year			7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744
Project cost estimate		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plant CO_2e Emissions												
Plant Electricity Usage, metric-ton/yr		6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291	6,291
Plant Natural Gas Usage, metric-ton/yr		-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr												
CO_2 Emissions (Biogenic)		1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650
CH_4 and N_2O Emissions		9	9	9	9	9	9	9	9	9	9	9
Plant Digester Gas Usage for Cogeneration, metric-ton/yr												
CO_2 Emissions (Biogenic)		-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions		-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Flare, metric-ton/yr												
CO_2 Emissions (Biogenic)		2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159
CH_4 and N_2O Emissions		2	2	2	2	2	2	2	2	2	2	2
ssions (Electricity + Stationary Combustion), metric-ton/yr:		10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111	10,111
shold Check - Stationary Combustion ONLY), metric-ton/yr:		3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820	3,820
Plant Emissions of NOx and CO												
Cogen lb/MWh												
NOx 2.10 (NOx at 0.65 g/bhp-hr)		-	-	-	-	-	-	-	-	-	-	-
CO 8.10 (CO at 2.5 g/bhp-hr)		-	-	-	-	-	-	-	-	-	-	-
Boiler lb/Mbtu												
NOx 0.035 (boiler 30 ppmv, 3% O2)		1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088	1,088
CO 0.110 (boiler at 150 ppmv, 3% O2)		3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421
Flare lb/Mbtu (Estimate for enclosed flare)												
NOx 0.06		2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488	2,488
CO 0.2		8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293	8,293
Total, lb/yr												
NOx		3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576	3,576
CO		11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714	11,714

Oxnard Cogeneration Study
Alternative 1
Two 852 kW Engine Generator Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	Average	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Total Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Natural Gas Consumed (million Btus)	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249
Digester Gas Consumed (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	170	170	170	170	170	170	170	170	170	170	170
Electricity Generated (MW-hrs)	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876
Electricity Purchased (MW-hrs)	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97
Cogen heating capacity, million Btu/hr	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38
Excess (Required boiler make up) peak day, million Btu/hr	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41
Costs/(Revenues) for project											
Natural gas costs	$ 42,792	$ 28,741	$ 29,890	$ 31,086	$ 32,329	$ 33,623	$ 34,967	$ 36,366	$ 37,821	$ 39,334	$ 40,907
Base Cost for electricity	$ 3,650,335	$ 2,207,912	$ 2,318,307	$ 2,434,222	$ 2,555,934	$ 2,683,730	$ 2,817,917	$ 2,958,813	$ 3,106,753	$ 3,262,091	$ 3,425,195
Cost Savings from generated electricity	$ (2,809,777)	$ (1,699,499)	$ (1,784,474)	$ (1,873,697)	$ (1,967,382)	$ (2,065,751)	$ (2,169,039)	$ (2,277,491)	$ (2,391,365)	$ (2,510,933)	$ (2,636,480)
Revenue for Green Power Credit	$ (88,842)	$ (70,633)	$ (74,165)	$ (77,873)	$ (81,767)	$ (85,855)	$ (90,148)	$ (94,655)	$ (99,388)	$ (104,357)	$ (109,575)
Revenue for FOG tipping fee	$ (607,380)	$ (482,895)	$ (507,040)	$ (532,392)	$ (559,011)	$ (586,962)	$ (616,310)	$ (647,125)	$ (679,482)	$ (713,456)	$ (749,129)
O&M costs for fuel treatment facilities	$ 139,714	$ 103,991	$ 107,111	$ 110,324	$ 113,634	$ 117,043	$ 120,554	$ 124,171	$ 127,896	$ 131,733	$ 135,685
O&M costs for engine generator facilities	$ 282,121	$ 209,987	$ 216,286	$ 222,775	$ 229,458	$ 236,342	$ 243,432	$ 250,735	$ 258,257	$ 266,005	$ 273,985
Total Annual Costs	$ 390,038	$ 297,603	$ 305,916	$ 314,445	$ 323,195	$ 332,169	$ 341,374	$ 350,813	$ 360,492	$ 370,415	$ 380,588
Present Worth of Annual Costs	$ 221,613	$ 269,935	$ 264,262	$ 258,695	$ 253,232	$ 247,870	$ 242,608	$ 237,444	$ 232,376	$ 227,403	$ 222,522
TOTAL PRESENT WORTH	$4,432,266										
Annualized Total Project Capital Cost	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218
Annualized Total Project Benefit	$ 2,360,079	$ 1,010,091	$ 1,112,173	$ 1,219,559	$ 1,332,521	$ 1,451,343	$ 1,576,325	$ 1,707,782	$ 1,846,043	$ 1,991,458	$ 2,144,390
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.105	$0.099	$0.099	$0.100	$0.101	$0.101	$0.102	$0.102	$0.103	$0.104	$0.105
Power Purchase Cost, $/kWh	$0.191	$0.116	$0.122	$0.128	$0.134	$0.141	$0.148	$0.155	$0.163	$0.171	$0.180
TOTAL COST OF OPTION	**$ 15,311,686**										

Oxnard Cogeneration Study
Alternative 1
Two 852 kW Engine Generator Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Total Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Natural Gas Consumed (million Btus)	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249
Digester Gas Consumed (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108	47,108
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	170	170	170	170	170	170	170	170	170	170	170
Electricity Generated (MW-hrs)	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876	11,876
Electricity Purchased (MW-hrs)	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197	7,197
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97
Cogen heating capacity, million Btu/hr	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38	5.38
Excess (Required boiler make up) peak day, million Btu/hr	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41
Costs/(Revenues) for project											
Natural gas costs	$ 42,792	$ 42,543	$ 44,245	$ 46,015	$ 47,855	$ 49,770	$ 51,760	$ 53,831	$ 55,984	$ 58,223	$ 60,552
Base Cost for electricity	$ 3,650,335	$ 3,596,455	$ 3,776,278	$ 3,965,092	$ 4,163,346	$ 4,371,514	$ 4,590,090	$ 4,819,594	$ 5,060,574	$ 5,313,602	$ 5,579,282
Cost Savings from generated electricity	$ (2,809,777)	$ (2,768,304)	$ (2,906,719)	$ (3,052,055)	$ (3,204,658)	$ (3,364,891)	$ (3,533,136)	$ (3,709,792)	$ (3,895,282)	$ (4,090,046)	$ (4,294,548)
Revenue for Green Power Credit	$ (88,842)	$ (115,054)	$ (120,807)	$ (126,847)	$ (133,189)	$ (139,849)	$ (146,841)	$ (154,183)	$ (161,893)	$ (169,987)	$ (178,487)
Revenue for FOG tipping fee	$ (607,380)	$ (786,585)	$ (825,914)	$ (867,210)	$ (910,571)	$ (956,099)	$ (1,003,904)	$ (1,054,099)	$ (1,106,804)	$ (1,162,144)	$ (1,220,252)
O&M costs for fuel treatment facilities	$ 139,714	$ 139,755	$ 143,948	$ 148,267	$ 152,715	$ 157,296	$ 162,015	$ 166,875	$ 171,882	$ 177,038	$ 182,349
O&M costs for engine generator facilities	$ 282,121	$ 282,204	$ 290,671	$ 299,391	$ 308,372	$ 317,624	$ 327,152	$ 336,967	$ 347,076	$ 357,488	$ 368,213
Total Annual Costs	$ 390,038	$ 391,015	$ 401,701	$ 412,651	$ 423,871	$ 435,364	$ 447,136	$ 459,192	$ 471,536	$ 484,174	$ 497,110
Present Worth of Annual Costs	$ 221,613	$ 217,732	$ 213,031	$ 208,417	$ 203,889	$ 199,445	$ 195,084	$ 190,804	$ 186,603	$ 182,480	$ 178,434
TOTAL PRESENT WORTH	$4,432,266										
Annualized Total Project Capital Cost	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218	$ 900,218
Annualized Total Project Benefit	$ 2,360,079	$ 2,305,222	$ 2,474,359	$ 2,652,223	$ 2,839,258	$ 3,035,932	$ 3,242,736	$ 3,460,184	$ 3,688,820	$ 3,929,210	$ 4,181,955
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.105	$0.105	$0.106	$0.107	$0.107	$0.108	$0.109	$0.110	$0.111	$0.111	$0.112
Power Purchase Cost, $/kWh	$0.191	$0.189	$0.198	$0.208	$0.218	$0.229	$0.241	$0.253	$0.265	$0.279	$0.293
TOTAL COST OF OPTION	**$ 15,311,686**										

Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Total Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Natural Gas Consumed (million Btus)	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249
Existing Units 852 kW per unit											
Number of Units		2	2	2	2	2	2	2	2	2	2
Number of Units Operating		2	2	2	2	2	2	2	2	2	2
Fuel rate, Btu/kW-hr		8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Cogeneration heat recovery/fuel input		42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Power output, kW		1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704
Operating hours per year		7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744
Project cost estimate	$13,313,020	$13,313,020	$0	$0	$0	$0	$0	$0	$0	$0	$0
Grant, 2009 dollars		($2,433,600)									
Net Project Costs, 2009 dollars	$10,879,420										
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374
Plant Natural Gas Usage, metric-ton/yr	212	212	212	212	212	212	212	212	212	212	212
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671
CH_4 and N_2O Emissions	5	5	5	5	5	5	5	5	5	5	5
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
ssions (Electricity + Stationary Combustion), metric-ton/yr:	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262
shold Check - Stationary Combustion ONLY), metric-ton/yr:	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 2.10 (NOx at 0.65 g/bhp-hr)	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774
CO 8.10 (CO at 2.5 g/bhp-hr)	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
CO 0.110 (boiler at 150 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	-	-	-	-	-	-	-	-	-	-	-
CO 0.2	-	-	-	-	-	-	-	-	-	-	-
Total, lb/yr											
NOx	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774
CO	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821

Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Total Fuel Consumed (million Btus)	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162	112,162
Natural Gas Consumed (million Btus)	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249	3,249
Existing Units 852 kW per unit											
Number of Units		2	2	2	2	2	2	2	2	2	2
Number of Units Operating		2	2	2	2	2	2	2	2	2	2
Fuel rate, Btu/kW-hr		8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Cogeneration heat recovery/fuel input		42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Power output, kW		1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704
Operating hours per year		7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744	7,744
Project cost estimate	$13,313,020	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Grant, 2009 dollars											
Net Project Costs, 2009 dollars	$10,879,420										
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374	2,374
Plant Natural Gas Usage, metric-ton/yr	212	212	212	212	212	212	212	212	212	212	212
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671	5,671
CH_4 and N_2O Emissions	5	5	5	5	5	5	5	5	5	5	5
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
ssions (Electricity + Stationary Combustion), metric-ton/yr:	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262	8,262
shold Check - Stationary Combustion ONLY), metric-ton/yr:	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 2.10 (NOx at 0.65 g/bhp-hr)	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774
CO 8.10 (CO at 2.5 g/bhp-hr)	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
CO 0.110 (boiler at 150 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	-	-	-	-	-	-	-	-	-	-	-
CO 0.2	-	-	-	-	-	-	-	-	-	-	-
Total, lb/yr											
NOx	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774	27,774
CO	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821	106,821

Oxnard Cogeneration Study
Alternative 2
One 1,137 kW Engine Generator Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195
Total Fuel Consumed (million Btus)	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195
Flared Digester Gas (million Btus)	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718
Cogen Heat Generated (million Btus)	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	114	114	114	114	114	114	114	114	114	114	114
Electricity Generated (MW-hrs)	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068
Electricity Purchased (MW-hrs)	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cogen heating capacity, million Btu/hr	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65
Excess (Required boiler make up) peak day, million Btu/hr	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 2,207,912	$ 2,318,307	$ 2,434,222	$ 2,555,934	$ 2,683,730	$ 2,817,917	$ 2,958,813	$ 3,106,753	$ 3,262,091	$ 3,425,195
Cost Savings from generated electricity	$ (1,908,767)	$ (1,154,521)	$ (1,212,247)	$ (1,272,860)	$ (1,336,503)	$ (1,403,328)	$ (1,473,494)	$ (1,547,169)	$ (1,624,527)	$ (1,705,754)	$ (1,791,041)
Revenue for Green Power Credit	$ (62,153)	$ (49,415)	$ (51,885)	$ (54,480)	$ (57,204)	$ (60,064)	$ (63,067)	$ (66,220)	$ (69,531)	$ (73,008)	$ (76,658)
Revenue for FOG tipping fee	$ (607,380)	$ (482,895)	$ (507,040)	$ (532,392)	$ (559,011)	$ (586,962)	$ (616,310)	$ (647,125)	$ (679,482)	$ (713,456)	$ (749,129)
O&M costs for fuel treatment facilities	$ 97,743	$ 72,752	$ 74,934	$ 77,182	$ 79,498	$ 81,883	$ 84,339	$ 86,869	$ 89,475	$ 92,160	$ 94,924
O&M costs for engine generator facilities	$ 191,653	$ 142,650	$ 146,930	$ 151,338	$ 155,878	$ 160,554	$ 165,371	$ 170,332	$ 175,442	$ 180,705	$ 186,126
Total Annual Costs	$ 1,150,898	$ 736,483	$ 768,999	$ 803,011	$ 838,592	$ 875,814	$ 914,756	$ 955,499	$ 998,130	$ 1,042,738	$ 1,089,418
Present Worth of Annual Costs	$ 636,390	$ 668,011	$ 664,290	$ 660,639	$ 657,058	$ 653,546	$ 650,100	$ 646,719	$ 643,404	$ 640,151	$ 636,960
TOTAL PRESENT WORTH	$12,727,802										
Annualized Total Project Capital Cost	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492
Annualized Total Project Benefit	$ 1,748,945	$ 720,937	$ 798,817	$ 880,719	$ 966,850	$ 1,057,425	$ 1,152,670	$ 1,252,822	$ 1,358,132	$ 1,468,861	$ 1,585,286
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.119	$0.114	$0.114	$0.115	$0.115	$0.116	$0.116	$0.117	$0.117	$0.118	$0.118
Power Purchase Cost, $/kWh	$0.191	$0.116	$0.122	$0.128	$0.134	$0.141	$0.148	$0.155	$0.163	$0.171	$0.180
TOTAL COST OF OPTION	**$ 21,797,734**										

Oxnard Cogeneration Study
Alternative 2
One 1,137 kW Engine Generator Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195
Total Fuel Consumed (million Btus)	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195	76,195
Flared Digester Gas (million Btus)	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718	32,718
Cogen Heat Generated (million Btus)	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002	32,002
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	114	114	114	114	114	114	114	114	114	114	114
Electricity Generated (MW-hrs)	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068	8,068
Electricity Purchased (MW-hrs)	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005	11,005
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cogen heating capacity, million Btu/hr	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65
Excess (Required boiler make up) peak day, million Btu/hr	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)	(0.96)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 3,596,455	$ 3,776,278	$ 3,965,092	$ 4,163,346	$ 4,371,514	$ 4,590,090	$ 4,819,594	$ 5,060,574	$ 5,313,602	$ 5,579,282
Cost Savings from generated electricity	$ (1,908,767)	$ (1,880,593)	$ (1,974,623)	$ (2,073,354)	$ (2,177,022)	$ (2,285,873)	$ (2,400,167)	$ (2,520,175)	$ (2,646,184)	$ (2,778,493)	$ (2,917,418)
Revenue for Green Power Credit	$ (62,153)	$ (80,491)	$ (84,516)	$ (88,742)	$ (93,179)	$ (97,838)	$ (102,729)	$ (107,866)	$ (113,259)	$ (118,922)	$ (124,868)
Revenue for FOG tipping fee	$ (607,380)	$ (786,585)	$ (825,914)	$ (867,210)	$ (910,571)	$ (956,099)	$ (1,003,904)	$ (1,054,099)	$ (1,106,804)	$ (1,162,144)	$ (1,220,252)
O&M costs for fuel treatment facilities	$ 97,743	$ 97,772	$ 100,705	$ 103,726	$ 106,838	$ 110,043	$ 113,345	$ 116,745	$ 120,247	$ 123,855	$ 127,570
O&M costs for engine generator facilities	$ 191,653	$ 191,710	$ 197,461	$ 203,385	$ 209,487	$ 215,771	$ 222,245	$ 228,912	$ 235,779	$ 242,853	$ 250,138
Total Annual Costs	$ 1,150,898	$ 1,138,268	$ 1,189,391	$ 1,242,898	$ 1,298,900	$ 1,357,519	$ 1,418,879	$ 1,483,111	$ 1,550,353	$ 1,620,750	$ 1,694,454
Present Worth of Annual Costs	$ 636,390	$ 633,830	$ 630,760	$ 627,748	$ 624,793	$ 621,895	$ 619,052	$ 616,263	$ 613,527	$ 610,844	$ 608,211
TOTAL PRESENT WORTH	$12,727,802										
Annualized Total Project Capital Cost	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492	$ 750,492
Annualized Total Project Benefit	$ 1,748,945	$ 1,707,696	$ 1,836,395	$ 1,971,703	$ 2,113,955	$ 2,263,503	$ 2,420,719	$ 2,585,992	$ 2,759,729	$ 2,942,361	$ 3,134,337
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.119	$0.119	$0.120	$0.120	$0.121	$0.121	$0.122	$0.122	$0.123	$0.124	$0.124
Power Purchase Cost, $/kWh	$0.191	$0.189	$0.198	$0.208	$0.218	$0.229	$0.241	$0.253	$0.265	$0.279	$0.293
TOTAL COST OF OPTION	**$ 21,797,734**										

Oxnard Cogeneration Study
Alternative 2
One 1,137 kW Engine Generator Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year		Average	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
GE/Jenbacher	1,137 kW per unit											
Number of Units			1	1	1	1	1	1	1	1	1	1
Number of Units Operating			1	1	1	1	1	1	1	1	1	1
Fuel rate, Btu/kW-hr			8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Cogeneration heat recovery/fuel input			42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Power output, kW			1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137
Operating hours per year			7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Project cost estimate		$10,993,232	$10,993,232	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGIP Grant			($1,923,300)									
Net Project Costs		$9,069,932										
Plant CO_2e Emissions												
Plant Electricity Usage, metric-ton/yr		3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630
Plant Natural Gas Usage, metric-ton/yr		-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr												
CO_2 Emissions (Biogenic)		-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions		-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Cogeneration, metric-ton/yr												
CO_2 Emissions (Biogenic)		3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967
CH_4 and N_2O Emissions		4	4	4	4	4	4	4	4	4	4	4
Plant Digester Gas Flare, metric-ton/yr												
CO_2 Emissions (Biogenic)		1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704
CH_4 and N_2O Emissions		2	2	2	2	2	2	2	2	2	2	2
ssions (Electricity + Stationary Combustion), metric-ton/yr:		9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306
shold Check - Stationary Combustion ONLY), metric-ton/yr:		5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677
Plant Emissions of NOx and CO												
Cogen	lb/MWh											
NOx	2.10 (NOx at 0.65 g/bhp-hr)	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867
CO	8.10 (CO at 2.5 g/bhp-hr)	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567
Boiler	lb/Mbtu											
NOx	0.035 (boiler 30 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
CO	0.110 (boiler at 150 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
Flare	lb/Mbtu (Estimate for enclosed flare)											
NOx	0.06	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963
CO	0.2	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544
Total, lb/yr												
NOx		20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830
CO		79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111

Oxnard Cogeneration Study
Alternative 2
One 1,137 kW Engine Generator Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
GE/Jenbacher 1,137 kW per unit											
Number of Units		1	1	1	1	1	1	1	1	1	1
Number of Units Operating		1	1	1	1	1	1	1	1	1	1
Fuel rate, Btu/kW-hr		8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Cogeneration heat recovery/fuel input		42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Power output, kW		1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137
Operating hours per year		7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Project cost estimate	$10,993,232	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGIP Grant											
Net Project Costs	$9,069,932										
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630	3,630
Plant Natural Gas Usage, metric-ton/yr	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967	3,967
CH_4 and N_2O Emissions	4	4	4	4	4	4	4	4	4	4	4
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704	1,704
CH_4 and N_2O Emissions	2	2	2	2	2	2	2	2	2	2	2
ssions (Electricity + Stationary Combustion), metric-ton/yr:	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306	9,306
shold Check - Stationary Combustion ONLY), metric-ton/yr:	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 2.10 (NOx at 0.65 g/bhp-hr)	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867	18,867
CO 8.10 (CO at 2.5 g/bhp-hr)	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567	72,567
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
CO 0.110 (boiler at 150 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963	1,963
CO 0.2	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544
Total, lb/yr											
NOx	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830	20,830
CO	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111	79,111

Oxnard Cogeneration Study
Alternative 3
Three 250 kW Microturbine Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087
Total Fuel Consumed (million Btus)	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087
Flared Digester Gas (million Btus)	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826
Cogen Heat Generated (million Btus)	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	56	56	56	56	56	56	56	56	56	56	56
Electricity Generated (MW-hrs)	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773
Electricity Purchased (MW-hrs)	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cogen heating capacity, million Btu/hr	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30
Excess (Required boiler make up) peak day, million Btu/hr	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 2,207,912	$ 2,318,307	$ 2,434,222	$ 2,555,934	$ 2,683,730	$ 2,817,917	$ 2,958,813	$ 3,106,753	$ 3,262,091	$ 3,425,195
Cost Savings from generated electricity	$ (1,365,948)	$ (826,196)	$ (867,506)	$ (910,881)	$ (956,425)	$ (1,004,246)	$ (1,054,459)	$ (1,107,182)	$ (1,162,541)	$ (1,220,668)	$ (1,281,701)
Revenue for Green Power Credit	$ (43,276)	$ (34,406)	$ (36,127)	$ (37,933)	$ (39,830)	$ (41,821)	$ (43,912)	$ (46,108)	$ (48,413)	$ (50,834)	$ (53,375)
Revenue for FOG tipping fee	$ (607,380)	$ (482,895)	$ (507,040)	$ (532,392)	$ (559,011)	$ (586,962)	$ (616,310)	$ (647,125)	$ (679,482)	$ (713,456)	$ (749,129)
O&M costs for fuel treatment facilities	$ 95,039	$ 70,739	$ 72,861	$ 75,047	$ 77,298	$ 79,617	$ 82,005	$ 84,466	$ 87,000	$ 89,610	$ 92,298
O&M costs for microturbine facilities	$ 133,444	$ 99,324	$ 102,304	$ 105,373	$ 108,534	$ 111,790	$ 115,144	$ 118,598	$ 122,156	$ 125,821	$ 129,595
Total Annual Costs	$ 1,657,617	$ 1,034,477	$ 1,082,800	$ 1,133,436	$ 1,186,500	$ 1,242,108	$ 1,300,385	$ 1,361,462	$ 1,425,474	$ 1,492,564	$ 1,562,884
Present Worth of Annual Costs	$ 913,336	$ 938,301	$ 935,363	$ 932,481	$ 929,654	$ 926,880	$ 924,160	$ 921,491	$ 918,873	$ 916,305	$ 913,786
TOTAL PRESENT WORTH	$18,266,714										
Annualized Total Project Capital Cost	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440
Annualized Total Project Benefit	$ 1,100,278	$ 280,994	$ 343,067	$ 408,346	$ 476,994	$ 549,182	$ 625,091	$ 704,911	$ 788,840	$ 877,087	$ 969,872
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.184	$0.178	$0.179	$0.179	$0.180	$0.180	$0.181	$0.182	$0.182	$0.183	$0.184
Power Purchase Cost, $/kWh	$0.191	$0.116	$0.122	$0.128	$0.134	$0.141	$0.148	$0.155	$0.163	$0.171	$0.180
TOTAL COST OF OPTION	**$ 29,052,141**										

Oxnard Cogeneration Study
Alternative 3
Three 250 kW Microturbine Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087
Total Fuel Consumed (million Btus)	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087	74,087
Flared Digester Gas (million Btus)	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826	34,826
Cogen Heat Generated (million Btus)	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894	28,894
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	56	56	56	56	56	56	56	56	56	56	56
Electricity Generated (MW-hrs)	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773	5,773
Electricity Purchased (MW-hrs)	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299	13,299
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cogen heating capacity, million Btu/hr	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30
Excess (Required boiler make up) peak day, million Btu/hr	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)	(1.31)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 3,596,455	$ 3,776,278	$ 3,965,092	$ 4,163,346	$ 4,371,514	$ 4,590,090	$ 4,819,594	$ 5,060,574	$ 5,313,602	$ 5,579,282
Cost Savings from generated electricity	$ (1,365,948)	$ (1,345,786)	$ (1,413,075)	$ (1,483,729)	$ (1,557,916)	$ (1,635,811)	$ (1,717,602)	$ (1,803,482)	$ (1,893,656)	$ (1,988,339)	$ (2,087,756)
Revenue for Green Power Credit	$ (43,276)	$ (56,044)	$ (58,846)	$ (61,789)	$ (64,878)	$ (68,122)	$ (71,528)	$ (75,105)	$ (78,860)	$ (82,803)	$ (86,943)
Revenue for FOG tipping fee	$ (607,380)	$ (786,585)	$ (825,914)	$ (867,210)	$ (910,571)	$ (956,099)	$ (1,003,904)	$ (1,054,099)	$ (1,106,804)	$ (1,162,144)	$ (1,220,252)
O&M costs for fuel treatment facilities	$ 95,039	$ 95,067	$ 97,919	$ 100,856	$ 103,882	$ 106,999	$ 110,208	$ 113,515	$ 116,920	$ 120,428	$ 124,041
O&M costs for microturbine facilities	$ 133,444	$ 133,483	$ 137,488	$ 141,612	$ 145,861	$ 150,237	$ 154,744	$ 159,386	$ 164,168	$ 169,093	$ 174,165
Total Annual Costs	$ 1,657,617	$ 1,636,590	$ 1,713,848	$ 1,794,833	$ 1,879,725	$ 1,968,716	$ 2,062,008	$ 2,159,809	$ 2,262,341	$ 2,369,837	$ 2,482,538
Present Worth of Annual Costs	$ 913,336	$ 911,315	$ 908,890	$ 906,513	$ 904,180	$ 901,892	$ 899,647	$ 897,445	$ 895,285	$ 893,167	$ 891,088
TOTAL PRESENT WORTH	$18,266,714										
Annualized Total Project Capital Cost	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440	$ 892,440
Annualized Total Project Benefit	$ 1,100,278	$ 1,067,425	$ 1,169,989	$ 1,277,819	$ 1,391,181	$ 1,510,357	$ 1,635,642	$ 1,767,345	$ 1,905,792	$ 2,051,326	$ 2,204,304
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.184	$0.184	$0.185	$0.186	$0.187	$0.187	$0.188	$0.189	$0.190	$0.190	$0.191
Power Purchase Cost, $/kWh	$0.191	$0.189	$0.198	$0.208	$0.218	$0.229	$0.241	$0.253	$0.265	$0.279	$0.293
TOTAL COST OF OPTION	**$ 29,052,141**										

Oxnard Cogeneration Study
Alternative 3
Three 250 kW Microturbine Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Ingersoll Rand 250 kW per unit											
Number of Units		3	3	3	3	3	3	3	3	3	3
Number of Units Operating		3	3	3	3	3	3	3	3	3	3
Fuel rate, Btu/kW-hr		11,870	11,870	11,870	11,870	11,870	11,870	11,870	11,870	11,870	11,870
Cogeneration heat recovery/fuel input		39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Power output, kW		750	750	750	750	750	750	750	750	750	750
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322
Project cost estimate	$12,135,427	$12,135,427	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGIP Grant		($1,350,000)									
Net Project Costs	$10,785,427										
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386
Plant Natural Gas Usage, metric-ton/yr	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858
CH_4 and N_2O Emissions	4	4	4	4	4	4	4	4	4	4	4
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813
CH_4 and N_2O Emissions	2	2	2	2	2	2	2	2	2	2	2
ssions (Electricity + Stationary Combustion), metric-ton/yr:	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063
shold Check - Stationary Combustion ONLY), metric-ton/yr:	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 0.56 (per Ingersoll Rand microturbine)	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495
CO 0.38 (per Ingersoll Rand microturbine)	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
CO 0.110 (boiler at 150 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090
CO 0.2	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965
Total, lb/yr											
NOx	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585
CO	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337

Oxnard Cogeneration Study
Alternative 3
Three 250 kW Microturbine Cogeneration System w/ FOG

			Life Cycle Present Worth of Annual Costs								
Year		**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Ingersoll Rand	250 kW per unit											
Number of Units			3	3	3	3	3	3	3	3	3	3
Number of Units Operating			3	3	3	3	3	3	3	3	3	3
Fuel rate, Btu/kW-hr			11,870	11,870	11,870	11,870	11,870	11,870	11,870	11,870	11,870	11,870
Cogeneration heat recovery/fuel input			39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
Power output, kW			750	750	750	750	750	750	750	750	750	750
Operating hours per year			8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322
Project cost estimate		$12,135,427	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGIP Grant												
Net Project Costs		$10,785,427										
Plant CO_2e Emissions												
Plant Electricity Usage, metric-ton/yr		4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386	4,386
Plant Natural Gas Usage, metric-ton/yr		-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr												
CO_2 Emissions (Biogenic)		-	-	-	-	-	-	-	-	-	-	-
CH_4 and N_2O Emissions		-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Cogeneration, metric-ton/yr												
CO_2 Emissions (Biogenic)		3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858	3,858
CH_4 and N_2O Emissions		4	4	4	4	4	4	4	4	4	4	4
Plant Digester Gas Flare, metric-ton/yr												
CO_2 Emissions (Biogenic)		1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813
CH_4 and N_2O Emissions		2	2	2	2	2	2	2	2	2	2	2
ssions (Electricity + Stationary Combustion), metric-ton/yr:		10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063	10,063
shold Check - Stationary Combustion ONLY), metric-ton/yr:		5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677	5,677
Plant Emissions of NOx and CO												
Cogen	lb/MWh											
NOx	0.56 (per Ingersoll Rand microturbine)	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495
CO	0.38 (per Ingersoll Rand microturbine)	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372
Boiler	lb/Mbtu											
NOx	0.035 (boiler 30 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
CO	0.110 (boiler at 150 ppmv, 3% O2)	-	-	-	-	-	-	-	-	-	-	-
Flare	lb/Mbtu (Estimate for enclosed flare)											
NOx	0.06	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090
CO	0.2	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965	6,965
Total, lb/yr												
NOx		5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585	5,585
CO		9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337	9,337

Oxnard Cogeneration Study
Alternative 4
One 1,400 kW Fuel Cell Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	5,763	6,798	6,302	5,785	5,247	4,685	6,798	6,302	5,785	5,247	4,685
New Cogen Fuel Consumed (million Btus)	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365
Total Fuel Consumed (million Btus)	94,128	95,163	94,667	94,150	93,611	93,049	95,163	94,667	94,150	93,611	93,049
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	94,128	95,163	94,667	94,150	93,611	93,049	95,163	94,667	94,150	93,611	93,049
Flared Digester Gas (million Btus)	14,785	13,750	14,246	14,763	15,301	15,863	13,750	14,246	14,763	15,301	15,863
Cogen Heat Generated (million Btus)	20,268	19,440	19,837	20,250	20,681	21,131	19,440	19,837	20,250	20,681	21,131
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	140	140	140	140	140	140	140	140	140	140	140
Electricity Generated (MW-hrs)	9,787	10,486	10,136	9,787	9,437	9,088	10,486	10,136	9,787	9,437	9,088
Electricity Purchased (MW-hrs)	9,286	8,587	8,937	9,286	9,636	9,985	8,587	8,937	9,286	9,636	9,985
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	4,611	5,438	5,041	4,628	4,197	3,748	5,438	5,041	4,628	4,197	3,748
Daily peak heat demand, million Btu/hr	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cogen heating capacity, million Btu/hr	2.31	2.22	2.26	2.31	2.36	2.41	2.22	2.26	2.31	2.36	2.41
Excess (Required boiler make up) peak day, million Btu/hr	(2.30)	(2.39)	(2.35)	(2.30)	(2.25)	(2.20)	(2.39)	(2.35)	(2.30)	(2.25)	(2.20)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 2,207,912	$ 2,318,307	$ 2,434,222	$ 2,555,934	$ 2,683,730	$ 2,817,917	$ 2,958,813	$ 3,106,753	$ 3,262,091	$ 3,425,195
Cost Savings from generated electricity	$ (2,307,405)	$ (1,500,550)	$ (1,523,059)	$ (1,544,066)	$ (1,563,367)	$ (1,580,738)	$ (1,915,125)	$ (1,943,852)	$ (1,970,663)	$ (1,995,297)	$ (2,017,467)
Revenue for Green Power Credit	$ (80,620)	$ (69,166)	$ (70,078)	$ (70,917)	$ (71,674)	$ (72,340)	$ (88,275)	$ (89,439)	$ (90,510)	$ (91,476)	$ (92,326)
Revenue for FOG tipping fee	$ (607,380)	$ (482,895)	$ (507,040)	$ (532,392)	$ (559,011)	$ (586,962)	$ (616,310)	$ (647,125)	$ (679,482)	$ (713,456)	$ (749,129)
O&M costs for fuel treatment facilities	$ 120,708	$ 90,862	$ 93,100	$ 95,370	$ 97,669	$ 99,995	$ 105,334	$ 107,929	$ 110,560	$ 113,225	$ 115,922
O&M costs for fuel cell facilities	$ 623,221	$ 494,413	$ 493,968	$ 493,052	$ 491,636	$ 489,691	$ 573,161	$ 572,645	$ 571,582	$ 569,940	$ 567,686
Total Annual Costs	$ 1,182,518	$ 740,576	$ 805,199	$ 875,269	$ 951,186	$ 1,033,376	$ 876,702	$ 958,969	$ 1,048,240	$ 1,145,027	$ 1,249,881
Present Worth of Annual Costs	$ 658,071	$ 671,724	$ 695,561	$ 720,086	$ 745,279	$ 771,121	$ 623,056	$ 649,068	$ 675,705	$ 702,948	$ 730,780
TOTAL PRESENT WORTH	$13,161,414										
Annualized Total Project Capital Cost	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269
Annualized Total Project Benefit	$ 1,361,548	$ 361,067	$ 406,839	$ 452,685	$ 498,479	$ 544,085	$ 834,946	$ 893,575	$ 952,245	$ 1,010,795	$ 1,069,045
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.179	$0.155	$0.160	$0.166	$0.172	$0.179	$0.162	$0.167	$0.173	$0.180	$0.187
Power Purchase Cost, $/kWh	$0.191	$0.116	$0.122	$0.128	$0.134	$0.141	$0.148	$0.155	$0.163	$0.171	$0.180
TOTAL COST OF OPTION	**$ 26,531,026**										

Oxnard Cogeneration Study
Alternative 4
One 1,400 kW Fuel Cell Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Operation Data											
Average Digester Gas Available (million Btus)	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913	108,913
Boiler Fuel Consumed (million Btus)	5,763	6,798	6,302	5,785	5,247	4,685	6,798	6,302	5,785	5,247	4,685
New Cogen Fuel Consumed (million Btus)	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365	88,365
Total Fuel Consumed (million Btus)	94,128	95,163	94,667	94,150	93,611	93,049	95,163	94,667	94,150	93,611	93,049
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	94,128	95,163	94,667	94,150	93,611	93,049	95,163	94,667	94,150	93,611	93,049
Flared Digester Gas (million Btus)	14,785	13,750	14,246	14,763	15,301	15,863	13,750	14,246	14,763	15,301	15,863
Cogen Heat Generated (million Btus)	20,268	19,440	19,837	20,250	20,681	21,131	19,440	19,837	20,250	20,681	21,131
Peak Electricity Required by Plant (kW)	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Average Electricity Required by Plant (kW)	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Parasitic Electrical Usage (kW)	140	140	140	140	140	140	140	140	140	140	140
Electricity Generated (MW-hrs)	9,787	10,486	10,136	9,787	9,437	9,088	10,486	10,136	9,787	9,437	9,088
Electricity Purchased (MW-hrs)	9,286	8,587	8,937	9,286	9,636	9,985	8,587	8,937	9,286	9,636	9,985
Required plant heat - (million Btus)	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878	24,878
Excess boiler heat req'd (million Btus)	4,611	5,438	5,041	4,628	4,197	3,748	5,438	5,041	4,628	4,197	3,748
Daily peak heat demand, million Btu/hr	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cogen heating capacity, million Btu/hr	2.31	2.22	2.26	2.31	2.36	2.41	2.22	2.26	2.31	2.36	2.41
Excess (Required boiler make up) peak day, million Btu/hr	(2.30)	(2.39)	(2.35)	(2.30)	(2.25)	(2.20)	(2.39)	(2.35)	(2.30)	(2.25)	(2.20)
Costs/(Revenues) for project											
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Cost for electricity	$ 3,650,335	$ 3,596,455	$ 3,776,278	$ 3,965,092	$ 4,163,346	$ 4,371,514	$ 4,590,090	$ 4,819,594	$ 5,060,574	$ 5,313,602	$ 5,579,282
Cost Savings from generated electricity	$ (2,307,405)	$ (2,444,239)	$ (2,480,902)	$ (2,515,121)	$ (2,546,560)	$ (2,574,856)	$ (3,119,537)	$ (3,166,330)	$ (3,210,003)	$ (3,250,128)	$ (3,286,241)
Revenue for Green Power Credit	$ (80,620)	$ (112,664)	$ (114,150)	$ (115,517)	$ (116,750)	$ (117,834)	$ (143,791)	$ (145,687)	$ (147,432)	$ (149,006)	$ (150,390)
Revenue for FOG tipping fee	$ (607,380)	$ (786,585)	$ (825,914)	$ (867,210)	$ (910,571)	$ (956,099)	$ (1,003,904)	$ (1,054,099)	$ (1,106,804)	$ (1,162,144)	$ (1,220,252)
O&M costs for fuel treatment facilities	$ 120,708	$ 122,111	$ 125,119	$ 128,169	$ 131,259	$ 134,385	$ 141,560	$ 145,047	$ 148,583	$ 152,165	$ 155,789
O&M costs for fuel cell facilities	$ 623,221	$ 664,450	$ 663,852	$ 662,620	$ 660,717	$ 658,103	$ 770,280	$ 769,587	$ 768,159	$ 765,952	$ 762,922
Total Annual Costs	$ 1,182,518	$ 1,039,529	$ 1,144,283	$ 1,258,033	$ 1,381,442	$ 1,515,213	$ 1,234,699	$ 1,368,112	$ 1,513,076	$ 1,670,442	$ 1,841,112
Present Worth of Annual Costs	$ 658,071	$ 578,849	$ 606,838	$ 635,392	$ 664,497	$ 694,137	$ 538,695	$ 568,479	$ 598,776	$ 629,572	$ 660,853
TOTAL PRESENT WORTH	$13,161,414										
Annualized Total Project Capital Cost	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269	$ 1,106,269
Annualized Total Project Benefit	$ 1,361,548	$ 1,450,657	$ 1,525,727	$ 1,600,790	$ 1,675,636	$ 1,750,032	$ 2,249,122	$ 2,345,214	$ 2,441,229	$ 2,536,892	$ 2,631,902
COST FOR ELECTRICITY											
Power Generation Cost, $/kWh	$0.179	$0.170	$0.176	$0.182	$0.189	$0.196	$0.179	$0.185	$0.192	$0.199	$0.206
Power Purchase Cost, $/kWh	$0.191	$0.189	$0.198	$0.208	$0.218	$0.229	$0.241	$0.253	$0.265	$0.279	$0.293
TOTAL COST OF OPTION	**$ 26,531,026**										

Oxnard Cogeneration Study
Alternative 4
One 1,400 kW Fuel Cell Cogeneration System w/ FOG

Life Cycle Present Worth of Annual Costs

Year	Average	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
FCE DFC1400 1,400 kW per unit											
Number of Units		1	1	1	1	1	1	1	1	1	1
Number of Units Operating		1	1	1	1	1	1	1	1	1	1
Fuel rate, Btu/kW-hr		7,584	7,819	8,069	8,335	8,619	7,584	7,819	8,069	8,335	8,619
Cogeneration heat recovery/fuel input		22%	22%	23%	23%	24%	22%	22%	23%	23%	24%
Power output, kW		1,400	1,358	1,316	1,274	1,232	1,400	1,358	1,316	1,274	1,232
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322
Project cost estimate	$17,449,612	$17,449,612	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGIP Grant		($4,080,000)									
Net Project Costs	$13,369,612										
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	3,063	2,832	2,947	3,063	3,178	3,293	2,832	2,947	3,063	3,178	3,293
Plant Natural Gas Usage, metric-ton/yr	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	306	361	334	307	278	249	361	334	307	278	249
CH_4 and N_2O Emissions	2	2	2	2	2	1	2	2	2	2	1
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601
CH_4 and N_2O Emissions	4	4	4	4	4	4	4	4	4	4	4
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	770	716	742	769	797	826	716	742	769	797	826
CH_4 and N_2O Emissions	1	1	1	1	1	1	1	1	1	1	1
ssions (Electricity + Stationary Combustion), metric-ton/yr:	8,746	8,517	8,632	8,746	8,861	8,976	8,517	8,632	8,746	8,861	8,976
shold Check - Stationary Combustion ONLY), metric-ton/yr:	5,684	5,685	5,684	5,684	5,683	5,682	5,685	5,684	5,684	5,683	5,682
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 0.50 (Assumed for Mercury 50 Gas Turbine)	5,476	5,825	5,651	5,476	5,301	5,126	5,825	5,651	5,476	5,301	5,126
CO 0.40 (Assumed for Mercury 50 Gas Turbine)	4,381	4,660	4,521	4,381	4,241	4,101	4,660	4,521	4,381	4,241	4,101
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	202	238	221	202	184	164	238	221	202	184	164
CO 0.110 (boiler at 150 ppmv, 3% O2)	634	748	693	636	577	515	748	693	636	577	515
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	887	825	855	886	918	952	825	855	886	918	952
CO 0.2	2,957	2,750	2,849	2,953	3,060	3,173	2,750	2,849	2,953	3,060	3,173
Total, lb/yr											
NOx	6,565	6,888	6,726	6,564	6,403	6,242	6,888	6,726	6,564	6,403	6,242
CO	7,972	8,158	8,063	7,970	7,878	7,789	8,158	8,063	7,970	7,878	7,789

Oxnard Cogeneration Study
Alternative 4
One 1,400 kW Fuel Cell Cogeneration System w/ FOG

		Life Cycle Present Worth of Annual Costs									
Year	**Average**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
FCE DFC1400 1,400 kW per unit											
Number of Units		1	1	1	1	1	1	1	1	1	1
Number of Units Operating		1	1	1	1	1	1	1	1	1	1
Fuel rate, Btu/kW-hr		7,584	7,819	8,069	8,335	8,619	7,584	7,819	8,069	8,335	8,619
Cogeneration heat recovery/fuel input		22%	22%	23%	23%	24%	22%	22%	23%	23%	24%
Power output, kW		1,400	1,358	1,316	1,274	1,232	1,400	1,358	1,316	1,274	1,232
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322
Project cost estimate	$17,449,612	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGIP Grant											
Net Project Costs	$13,369,612										
Plant CO_2e Emissions											
Plant Electricity Usage, metric-ton/yr	3,063	2,832	2,947	3,063	3,178	3,293	2,832	2,947	3,063	3,178	3,293
Plant Natural Gas Usage, metric-ton/yr	-	-	-	-	-	-	-	-	-	-	-
Plant Digester Gas Usage for Boiler, metric-ton/yr											
CO_2 Emissions (Biogenic)	306	361	334	307	278	249	361	334	307	278	249
CH_4 and N_2O Emissions	2	2	2	2	2	1	2	2	2	2	1
Plant Digester Gas Usage for Cogeneration, metric-ton/yr											
CO_2 Emissions (Biogenic)	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601	4,601
CH_4 and N_2O Emissions	4	4	4	4	4	4	4	4	4	4	4
Plant Digester Gas Flare, metric-ton/yr											
CO_2 Emissions (Biogenic)	770	716	742	769	797	826	716	742	769	797	826
CH_4 and N_2O Emissions	1	1	1	1	1	1	1	1	1	1	1
ssions (Electricity + Stationary Combustion), metric-ton/yr:	8,746	8,517	8,632	8,746	8,861	8,976	8,517	8,632	8,746	8,861	8,976
shold Check - Stationary Combustion ONLY), metric-ton/yr:	5,684	5,685	5,684	5,684	5,683	5,682	5,685	5,684	5,684	5,683	5,682
Plant Emissions of NOx and CO											
Cogen lb/MWh											
NOx 0.50 (Assumed for Mercury 50 Gas Turbine)	5,476	5,825	5,651	5,476	5,301	5,126	5,825	5,651	5,476	5,301	5,126
CO 0.40 (Assumed for Mercury 50 Gas Turbine)	4,381	4,660	4,521	4,381	4,241	4,101	4,660	4,521	4,381	4,241	4,101
Boiler lb/Mbtu											
NOx 0.035 (boiler 30 ppmv, 3% O2)	202	238	221	202	184	164	238	221	202	184	164
CO 0.110 (boiler at 150 ppmv, 3% O2)	634	748	693	636	577	515	748	693	636	577	515
Flare lb/Mbtu (Estimate for enclosed flare)											
NOx 0.06	887	825	855	886	918	952	825	855	886	918	952
CO 0.2	2,957	2,750	2,849	2,953	3,060	3,173	2,750	2,849	2,953	3,060	3,173
Total, lb/yr											
NOx	6,565	6,888	6,726	6,564	6,403	6,242	6,888	6,726	6,564	6,403	6,242
CO	7,972	8,158	8,063	7,970	7,878	7,789	8,158	8,063	7,970	7,878	7,789

Input data for Life Cycle Cost Analysis

Lastest revision = 2/26/2009

GENERAL ASSUMPTIONS

Annual ave. plant heat load, electrical demand, gas production are ratioed to plant flow for duration of project.

FINANCIAL ASSUMPTIONS

Present worth year		2013	
First year of evaluation		2015	
Project duration, years		20	
Inflation (capital costs)		4.0%	
Inflation (electricity costs)		5.0%	
Inflation (natural gas costs)		4.0%	
Inflation (O&M costs)		3.0%	
Gross discount rate		5.0%	
Digester Gas LHV, Btu/scf		580	
Existing Engine availability percentage		85%	
Engine availability percentage		90%	
Microturbine availability percentage		95%	
Fuel Cell availability percentage		95%	
O&M rate for existing engines $/kWh	$	0.040	
O&M rate for new engine alternatives $/kWh	$	0.015	Typical for new engine maintenance for DG fueled unit with DG treatment
O&M rate for microturbine alternatives $/kWh	$	0.015	From previous project discussions with the mfg for DG fueled unit
O&M rate for fuel cell unit $/kWh	$	0.040	
O&M rate for fuel treatment system $/million Btu	$	0.900	
FOG Tipping Fee $/gallon	$	0.050	
Green Power Credit $/kWh	$	0.005	
NOx offset costs $/ton	$	-	
CO offset costs $/ton	$	-	
Grant Incentive (1 = yes, 0 = no)		0	
NG Usage (when appropriate) (1 = yes, 0 = no)		1	
CO_2 Electricity Emissions factor, lb/MWh		724.12	The Climate Registry GRP V1.1, EPA eGrid 2007 FL State
CH_4 Electricity Emissions factor, lb/MWh		0.03024	The Climate Registry GRP V1.1, EPA eGrid 2007 FL State
N_2O Electricity Emissions factor, lb/MWh		0.00808	The Climate Registry GRP V1.1, EPA eGrid 2007 FL State
CO_2 Emissions factor for Stationary Combustion of N.G., kg/MMBtu		53.06	The Climate Registry GRP V1.1, Table 12.1
CH_4 Emissions factor for Stationary Combustion of N.G., kg/MMBtu			
Engine Generators		0.5669	The Climate Registry GRP V1.1, Table 12.7
Turbines		0.0038	The Climate Registry GRP V1.1, Table 12.7
Fuel Cells		0.0009	The Climate Registry GRP V1.1, Table 12.7
N_2O Emissions factor for Stationary Combustion of N.G., kg/MMBtu		0.0009	The Climate Registry GRP V1.1, Table 12.7
CO_2 Emissions factor for Stationary Combustion of Digester Gas in Boile		53.06	The Climate Registry GRP V1.1, Table 12.1
CH_4 Emissions factor for Stationary Combustion of Digester Gas in Boile		0.0009	The Climate Registry GRP V1.1, Table 12.7
N_2O Emissions factor for Stationary Combustion of Digester Gas in Boile		0.0009	The Climate Registry GRP V1.1, Table 12.7
CO_2 Emissions factor for Stationary Combustion of Digester Gas (Bioge		52.07	The Climate Registry GRP V1.1, Table 12.2
CH_4 Emissions factor for Stationary Combustion of Digester Gas, kg/MM		0.0009	US EPA Proposed Mandatory Reporting Rule, Table C-3
N_2O Emissions factor for Stationary Combustion of Digester Gas, kg/MM		0.0001	US EPA Proposed Mandatory Reporting Rule, Table C-3

Forcasting Assumptions

Year			**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Process Data													
Average plant flow (million gallons/day)			20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Plant electrical cons. Baseload, ann. average (kw-hr/day)			52,254	52,254	52,254	52,254	52,254	52,254	52,254	52,254	52,254	52,254	52,254
Plant electrical demand, ann. average (kw)			2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Plant electrical demand, ann. peak (kw)			2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Scenario 2													
Average digester gas available (scf/day)		0%	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762
Average digester gas heating value (million Btu/hr)			8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Average plant heat load (million Btu/hr)			2.63	2.63	2.63	2.63	2.63	2.63	2.63	2.63	2.63	2.63	2.63
Peak plant heat load (million Btu/hr)			3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97
Scenario 1													
Average digester gas available (scf/day)		0%	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468
Average digester gas heating value (million Btu/hr)			12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Average plant heat load (million Btu/hr)			2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84
Peak plant heat load (million Btu/hr)			4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cost Data													
Electricity ($/MWh)	Sensitivity	1.00	115.76	121.55	127.63	134.01	140.71	147.75	155.13	162.89	171.03	179.59	188.56
Natural Gas - Low Use ($/MMBtu)	Factor	1.00	8.85	9.20	9.57	9.95	10.35	10.76	11.19	11.64	12.11	12.59	13.09
Electricity - Existing Engine Savings($/MWh)	Sensitivity	1.00	170.45	178.97	187.92	197.31	207.18	217.54	228.41	239.83	251.83	264.42	277.64
Electricity ($/MWh)	105.00	$/MWh	115.76	121.55	127.63	134.01	140.71	147.75	155.13	162.89	171.03	179.59	188.56
Natural Gas - Low Use ($/MMBtu, LHV)	8.18	$/MMBtu	8.85	9.20	9.57	9.95	10.35	10.76	11.19	11.64	12.11	12.59	13.09
Electricity - Existing Engine Savings ($/MW	160.66	$/MWh	170.45	178.97	187.92	197.31	207.18	217.54	228.41	239.83	251.83	264.42	277.64

Projected Data	Current 2013	1st year 2015	future 2034												
Plant flow, mgd		20.5	20.5	Scenario 1	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762
Gas prod., scfd		514,468	514,468	Scenario 2	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468
Gas prod., scfm		357	357												
Elect usage, kWh/d		52,254	52,254												
Average elect demand, kW		2,177	2,177												
Peak elect demand, kW		2,722	2,722	assumed at 25% more than average											
Ave. elect cost, $/kWhr	0.105														
Ave. elect savings existing, $/	0.161														
NG cost, $/therm, HHV	0.818														

	Scenario 1	Scenario 2
Average Heat Demand, million Btu/hr	2.63	2.84
Peak Heat Demand, million Btu/hr	3.97	4.61

Forcasting Assumptions

Year			**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Process Data											
Average plant flow (million gallons/day)			20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Plant electrical cons. Baseload, ann. average (kw-hr/day)			52,254	52,254	52,254	52,254	52,254	52,254	52,254	52,254	52,254
Plant electrical demand, ann. average (kw)			2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Plant electrical demand, ann. peak (kw)			2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722	2,722
Scenario 2											
Average digester gas available (scf/day)		0%	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762
Average digester gas heating value (million Btu/hr)			8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Average plant heat load (million Btu/hr)			2.63	2.63	2.63	2.63	2.63	2.63	2.63	2.63	2.63
Peak plant heat load (million Btu/hr)			3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97	3.97
Scenario 1											
Average digester gas available (scf/day)		0%	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468
Average digester gas heating value (million Btu/hr)			12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Average plant heat load (million Btu/hr)			2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84	2.84
Peak plant heat load (million Btu/hr)			4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Cost Data											
Electricity ($/MWh)	Sensitivity	1.00	197.99	207.89	218.29	229.20	240.66	252.70	265.33	278.60	292.53
Natural Gas - Low Use ($/MMBtu)	Factor	1.00	13.62	14.16	14.73	15.32	15.93	16.57	17.23	17.92	18.64
Electricity - Existing Engine Savings($/MWh)	Sensitivity	1.00	291.52	306.10	321.40	337.47	354.34	372.06	390.67	410.20	430.71
Electricity ($/MWh)	105.00	$/MWh	197.99	207.89	218.29	229.20	240.66	252.70	265.33	278.60	292.53
Natural Gas - Low Use ($/MMBtu, LHV)	8.18	$/MMBtu	13.62	14.16	14.73	15.32	15.93	16.57	17.23	17.92	18.64
Electricity - Existing Engine Savings ($/MW	160.66	$/MWh	291.52	306.10	321.40	337.47	354.34	372.06	390.67	410.20	430.71

Projected Data	Current 2013	1st year 2015	future 2034										
Plant flow, mgd		20.5	20.5	Scenario 1	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762	342,762
Gas prod., scfd		514,468	514,468	Scenario 2	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468	514,468
Gas prod., scfm		357	357										
Elect usage, kWh/d		52,254	52,254										
Average elect demand, kW		2,177	2,177										
Peak elect demand, kW		2,722	2,722	assumed at									
Ave. elect cost, $/kWhr	0.105												
Ave. elect savings existing, $/	0.161												
NG cost, $/therm, HHV	0.818												

APPENDIX C – PROJECT COST ESTIMATES

Engineers...Working Wonders With Water®

PROJECT SUMMARY

Project:	**Cogeneration Project - Three 250 KW Microturbines**	**Estimate Class:**	**Detailed Design**
Client:	**Oxnard**	**PM:**	
Location:	**Oxnard, CA**	**PE**	
Zip Code:	**93030**	**Date:**	**4/25/2013**
Carollo Job #	**8533A10**	**By:**	**TGM**
		Reviewed:	

NO.	DESCRIPTION			TOTAL
01	Engine-Generators, Switchgear and systems			$2,505,000
02	Gas Conditioning			$1,357,000
03	Metal Building (946K X 0.74 = 700K)			$700,000
04	Yard Piping & Paving			$524,000
05	Eletrical Power Connections			$215,000
		SUBTOTAL		**$5,301,000**
	Additions			
	FOG System		$1,312,479	
				$1,312,479
		TOTAL DIRECT COST		**$6,613,479**
	Contingency (except EG and Gas Cond equip. cost)		10.0%	$384,098
		Subtotal		**$6,997,577**
	General Contractor Overhead, Profit & Risk		15.0%	$1,049,637
		Subtotal		**$8,047,213**
	Escalation to Mid-Point		6.0%	$482,833
		Subtotal		**$8,530,046**
	Sales Tax (Based on 50% of Direct Costs)		8.00%	$264,539
	Estimated Construction Cost			**$8,794,585**
	Design, Construction Management, Admn.		25.0%	$2,198,646
	ESTIMATED PROJECT COST			**$10,993,232**

The cost estimate herein is based on our perception of current conditions at the project location. This estimate reflects our professional opinion of accurate costs at this time and is subject to change as the project design matures. Carollo Engineers have no control over variances in the cost of labor, materials, equipment; nor services provided by others, contractor's means and methods of executing the work or of determining prices, competitive bidding or market conditions, practices or bidding strategies. Carollo Engineers cannot and does not warrant or guarantee that proposals, bids or actual construction costs will not vary from the costs presented as shown.

Footnotes:
1) The above estimate of probable construction costs includes zero dollars for mitigation of hazardous or potentially hazardous materials.
2) The above estimate of probable construction costs is based on selection of GE JMS 416 1137 KW engine-generator.

Engineers...Working Wonders With Water®

PROJECT SUMMARY

Project:	**Cogeneration Project - Two 850 KW Engines**	**Estimate Class:**	**Detailed Design**
Client:	**Oxnard**	**PM:**	
Location:	**Oxnard, CA**	**PE**	
Zip Code:	**93030**	**Date:**	**4/25/2013**
Carollo Job #	**8533A10**	**By:**	**TGM**
		Reviewed:	

NO.	DESCRIPTION		TOTAL
01	Engine-Generators, Switchgear and systems		$3,814,544
02	Gas Conditioning		$1,357,000
03	Metal Building		$850,000
04	Yard Piping & Paving		$524,000
05	Eletrical Power Connections		$215,000
	SUBTOTAL		**$6,760,544**
	Additions		
	FOG System	$1,312,479	
			$1,312,479
	TOTAL DIRECT COST		**$8,073,023**
	Contingency (except EG and Gas Cond equip. cost)	10.0%	$399,082
	Subtotal		**$8,472,105**
	General Contractor Overhead, Profit & Risk	15.0%	$1,270,816
	Subtotal		**$9,742,920**
	Escalation to Mid-Point	6.0%	$584,575
	Subtotal		**$10,327,495**
	Sales Tax (Based on 50% of Direct Costs)	8.00%	$322,921
	Estimated Construction Cost		**$10,650,416**
	Design, Construction Management, Admn.	25.0%	$2,662,604
	ESTIMATED PROJECT COST		**$13,313,020**

The cost estimate herein is based on our perception of current conditions at the project location. This estimate reflects our professional opinion of accurate costs at this time and is subject to change as the project design matures. Carollo Engineers have no control over variances in the cost of labor, materials, equipment; nor services provided by others, contractor's means and methods of executing the work or of determining prices, competitive bidding or market conditions, practices or bidding strategies. Carollo Engineers cannot and does not warrant or guarantee that proposals, bids or actual construction costs will not vary from the costs presented as shown.

Footnotes: 1) The above estimate of probable construction costs includes zero dollars for mitigation of hazardous or potentially hazardous materials.

2) The above estimate of probable construction costs is based on selection of GE JMS 416 1137 KW engine-generator.

Engineers...Working Wonders With Water®

PROJECT SUMMARY

Project:	**Cogeneration Project - Three 250 KW Microturbines**	**Estimate Class:**	**Detailed Design**
Client:	**Oxnard**	**PM:**	
Location:	**Oxnard, CA**	**PE**	
Zip Code:	**93030**	**Date:**	**4/25/2013**
Carollo Job #	**8533A10**	**By:**	**TGM**
		Reviewed:	

NO.	DESCRIPTION		TOTAL
01	Microturbine-Generators, Switchgear and systems		$3,049,000
02	Gas Conditioning		$1,357,000
03	Metal Building (900K X 0.74 = 700K)		$700,000
04	Yard Piping & Paving		$629,000
06	Eletrical Power Connections		$250,000
	SUBTOTAL		**$5,985,000**
	Additions		
	FOG System	$1,312,479	
			$1,312,479
	TOTAL DIRECT COST		**$7,297,479**
	Contingency (except EG and Gas Cond equip. cost)	10.0%	$427,248
	Subtotal		**$7,724,727**
	General Contractor Overhead, Profit & Risk	15.0%	$1,158,709
	Subtotal		**$8,883,436**
	Escalation to Mid-Point	6.0%	$533,006
	Subtotal		**$9,416,442**
	Sales Tax (Based on 50% of Direct Costs)	8.00%	$291,899
	Estimated Construction Cost		**$9,708,341**
	Design, Construction Management,Admn	25.0%	$2,427,085
	TOTAL ESTIMATED CONSTRUCTION COST		**$12,135,427**

The cost estimate herein is based on our perception of current conditions at the project location. This estimate reflects our professional opinion of accurate costs at this time and is subject to change as the project design matures. Carollo Engineers have no control over variances in the cost of labor, materials, equipment; nor services provided by others, contractor's means and methods of executing the work or of determining prices, competitive bidding or market conditions, practices or bidding strategies. Carollo Engineers cannot and does not warrant or guarantee that proposals, bids or actual construction costs will not vary from the costs presented as shown.

Footnotes: 1) The above estimate of probable construction costs includes zero dollars for mitigation of hazardous or potentially hazardous materials.

Engineers...Working Wonders With Water®

PROJECT SUMMARY

Project:	**Cogeneration Project - One 1,400 KW Fuel Cell**	**Estimate Class:**	**4**
Job #:	**Oxnard**	**PM:**	
Location:	**Oxnard, CA**	**PE**	
Zip Code:	**93030**	**Date:**	**4/25/2013**
Carollo Job #	**8533A10**	**By:**	**TGM**
		Reviewed:	

NO.	DESCRIPTION		TOTAL
01	Demolition		$0
02	Yard		$285,434
03	Fuel Cell Facility		$2,754,602
			$0
			$0
			$0
			$0
			$0
			$0
			$0
	FOG System		$1,312,479
			$0
			$0
	TOTAL DIRECT COST		**$4,352,514**
	Contingency	10.0%	$435,251
	Subtotal		**$4,787,766**
	General Contractor Overhead, Profit & Risk	15.0%	$718,165
	Subtotal		**$5,505,930**
	Escalation to Mid-Point	6.0%	$330,356
	Subtotal		**$5,836,286**
	Sales Tax (Based on Materials)	8.0%	$466,903
	Subtotal		**$6,303,189**
	Bid Market Allowance	0.0%	$0
	Subtotal		**$6,303,189**
	Fuel Cell Procurement		$5,512,500
	Subtotal		**$11,815,689**
	DGFCS Prepurchase		$2,144,000
	TOTAL ESTIMATED CONSTRUCTION COST		**$13,959,689**
	Engineering, Legal & Administration Fees	25.0%	$3,489,922
	Owner's Reserve for Change Orders	0.0%	$0
	TOTAL ESTIMATED PROJECT COST		**$17,449,612**

The cost estimate herein is based on our perception of current conditions at the project location. This estimate reflects our professional opinion of accurate costs at this time and is subject to change as the project design matures. Carollo Engineers have no control over variances in the cost of labor, materials, equipment; nor services provided by others, contractor's means and methods of executing the work or of determining prices, competitive bidding or market conditions, practices or bidding strategies. Carollo Engineers cannot and does not warrant or guarantee that proposals, bids or actual construction costs will not vary form the costs presented as shown.

APPENDIX D – SOLAR PHOTO VOLTAIC CALCULATIONS

APPENDIX D – SOLAR PHOTOVOLTAIC CALCULATIONS

Location	Effective Area Available [sq ft]	One Panel Area [sq ft]
Activated Sludge Tanks	20004.20235	15
Flow Equalization Basins	32310.15829	15
Secondary Sedimentation Basins - Concrete	11013.54961	15
Secondary Sedimentation Basins - Basins	35063.54569	15
Maintenance Building #1	1348.597911	15
Maintenance Building #2	899.0652741	15
Admin Building	1685.747389	15
Storage Building	3596.261097	15
Carport #1	4635.80532	15
Carport #2	1854.322128	15
Carport #3	1755.986864	15
Carport #4	1011.448433	15
MRF roof	52874.09901	15
1 acre ground mount	24476.97572	15
1 acre carport	24476.97572	15

Location	Total Panels in Area	Effective Panels
Activated Sludge Tanks	1333.61349	1333
Flow Equalization Basins	2154.010553	2154
Secondary Sedimentation Basins - Concrete	734.2366405	734
Secondary Sedimentation Basins - Basins	2337.569713	2337
Maintenance Building #1	89.90652741	89
Maintenance Building #2	59.93768494	59
Admin Building	112.3831593	112
Storage Building	239.7507398	239
Carport #1	309.053688	309
Carport #2	123.6214752	123
Carport #3	117.0657909	117
Carport #4	67.42989556	67
MRF roof	3524.939934	3524
1 acre ground mount	1631.798382	1631
1 acre carport	1631.798382	1631

Location	Solar Panel Output [W-dc]	System Output [kW-dc]
Activated Sludge Tanks	240	319.92
Flow Equalization Basins	240	516.96
Secondary Sedimentation Basins - Concrete	240	176.16
Secondary Sedimentation Basins - Basins	240	560.88
Maintenance Building #1	240	21.36
Maintenance Building #2	240	14.16
Admin Building	240	26.88
Storage Building	240	57.36
Carport #1	240	74.16
Carport #2	240	29.52
Carport #3	240	28.08
Carport #4	240	16.08
MRF roof	240	845.76
1 acre ground mount	240	391.44
1 acre carport	240	391.44

	Activated Sludge Tanks	Flow Equalization Basins Pump Station	Secondary Sedimentation Concrete	Secondary Sedimentation Tanks
Solar PV System Output Rating (kW-ac)	255.94	413.57	140.93	448.70
AC to DC Derating Factor	0.8	0.8	0.8	0.8
Solar PV System Output Rating (kW-dc)	319.92	516.96	176.16	560.88
Module Pricing ($/W-dc peak)	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Module Price % of Installed Cost	15%	15%	20%	15%
Installed System Per Unit Cost ($/W-dc peak)	$ 10.00	$ 10.00	$ 7.50	$ 10.00
Estimated Installation Cost	$ 3,199,200	$ 5,169,600	$ 1,321,200	$ 5,608,800
Contingency (15%)	$ 479,880	$ 775,440	$ 198,180	$ 841,320
Total Installation Cost	$ 3,679,080	$ 5,945,040	$ 1,519,380	$ 6,450,120

	Maintenance Building #1	Maintenance Building #2	Admin Building	Storage Building
Solar PV System Output Rating (kW-ac)	17.09	11.33	21.50	45.89
AC to DC Derating Factor	0.8	0.8	0.8	0.8
Solar PV System Output Rating (kW-dc)	21.36	14.16	26.88	57.36
Module Pricing ($/W-dc peak)	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Module Price % of Installed Cost	30%	30%	30%	30%
Installed System Per Unit Cost ($/W-dc peak)	$ 3.33	$ 3.33	$ 3.33	$ 3.33
Estimated Installation Cost	$ 71,200	$ 47,200	$ 89,600	$ 191,200
Contingency (15%)	$ 10,680	$ 7,080	$ 13,440	$ 28,680
Total Installation Cost	$ 81,880	$ 54,280	$ 103,040	$ 219,880

	Carport #1	Carport #2	Carport #3	Carport #4
Solar PV System Output Rating (kW-ac)	59.33	23.62	22.46	12.86
AC to DC Derating Factor	0.8	0.8	0.8	0.8
Solar PV System Output Rating (kW-dc)	74.16	29.52	28.08	16.08
Module Pricing ($/W-dc peak)	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Module Price % of Installed Cost	30%	30%	30%	30%
Installed System Per Unit Cost ($/W-dc peak)	$ 3.33	$ 3.33	$ 3.33	$ 3.33
Estimated Installation Cost	$ 247,200	$ 98,400	$ 93,600	$ 53,600
Contingency (15%)	$ 37,080	$ 14,760	$ 14,040	$ 8,040
Total Installation Cost	$ 284,280	$ 113,160	$ 107,640	$ 61,640

	MRF Roof	1 Acre Groundmount	1 Acre Carport
Solar PV System Output Rating (kW-ac)	676.61	313.15	313.15
AC to DC Derating Factor	0.8	0.8	0.8
Solar PV System Output Rating (kW-dc)	845.76	391.44	391.44
Module Pricing ($/W-dc peak)	$ 1.00	$ 1.00	$ 1.00
Module Price % of Installed Cost	30%	30%	30%
Installed System Per Unit Cost ($/W-dc peak)	$ 3.33	$ 3.33	$ 3.33
Estimated Installation Cost	$ 2,819,200	$ 1,304,800	$ 1,304,800
Contingency (15%)	$ 422,880	$ 195,720	$ 195,720
Total Installation Cost	$ 3,242,080	$ 1,500,520	$ 1,500,520

Location	Estimated Cost of System	Estimated Yearly Revenue (Plant Rate)	Estimated Yearly Rebates (CSI)
Activated Sludge Tanks	$3,679,080	$35,983	$54,694
Flow Equalization Basins	$5,945,040	$58,145	$88,380
Secondary Sedimentation Basins	$7,969,500 (Total) $1,519,380 (Concrete) $6,450,120 (Tanks)	$82,898 (Total) $19,813 (Concrete) $63,085 (Tanks)	$126,005 (Total) $30,116 (Concrete) $95,889 (Tanks)

Location	Estimated Cost of System	Estimated Yearly Revenue	Estimated Yearly Rebates (CSI)
Maintenance Building #1	$81,880	$2,402	$3,652
Maintenance Building #2	$54,280	$1,593	$2,421
Admin Building	$103,040	$3,023	$4,595
Storage Building	$219,880	$6,452	$9,806

Location	Estimated Cost of System	Estimated Yearly Revenue	Estimated Yearly Rebates (CSI)
Carport #1	$284,280	$8,341	$12,678
Carport #2	$113,160	$3,320	$5,047
Carport #3	$107,640	$3,158	$4,801
Carport #4	$61,640	$1,808	$2,749

Location	Estimated Cost of System	Estimated Yearly Revenue	Estimated Yearly Rebates (CSI)
MRF Roof	$3,242,080	$95,130	$144,595
1 Acre Ground Mount	$1,500,520	$44,030	$66,920
1 Acre Carport	$1,500,520	$44,030	$66,920

Oxnard Preliminary Summary of Solar Alternatives Evaluation

carollo
Engineers...Working Wonders With Water™

Date/time: 4/30/13 4:41 PM

Alternative	Existing Cogen only	Activated Sludge Tanks	Flow Equalization Basins	Secondary Sedimentation Basins-Concrete	Secondary Sedimentation Basins - Tanks
Average Net Power Generated (kW)	633	688	721	663	729
Estimated Project Cost [(1)] (2013 dollars)	$0	$3,679,080	$5,945,040	$1,519,380	$6,450,120
20-Year Present Worth of Costs/(Revenues)					
Natural gas costs	$2,284,557	$2,284,557	$2,284,557	$2,284,557	$2,284,557
Base Cost for electricity	$40,052,817	$40,052,817	$40,052,817	$40,052,817	$40,052,817
Revenue for displaced electricity	($17,826,207)	($19,176,830)	($20,008,684)	($18,569,901)	($20,194,104)
Revenue for green power credit	($527,436)	($536,172)	($541,553)	($532,247)	($542,752)
Revenue from CSI funding	$0	($221,271)	($357,552)	($121,838)	($387,929)
O&M costs for solar facilities	$0	$443,567	$955,682	$244,245	$1,036,875
O&M costs for cogeneration facilities	$4,133,203	$4,133,203	$4,133,203	$4,133,203	$4,133,203
Estimated Project Cost [(1)] (2013 dollars)	$0	$3,679,080	$5,945,040	$1,519,380	$6,450,120
Total 20-Year Present Worth of Energy Cost [(3)]	**$28,116,934**	**$30,658,951**	**$32,463,510**	**$29,010,216**	**$32,832,787**
Present Worth of Net Benefit Compared to No Cogeneration System		**($2,542,016)**	**($4,346,575)**	**($893,281)**	**($4,715,852)**
Simple Payback Period of Cogeneration System, years		**65**	**74**	**49**	**74**

Note & Assumptions:

(1) This includes estimated construction cost plus cost for engineering, administration, contingencies and construction management
(3) Total 20-year present worth of energy costs is the sum of the Present Worth values listed above
(4) Project Assumptions:

Inflation (capital costs)	4.0%	
Inflation (electricity costs)	5.0%	
Inflation (natural gas costs)	4.0%	
Inflation (O&M costs)	3.0%	
Green Power Credit $/kWh	$0.005	
(5) Project Data:		
2012 ave. elect cost, $/kWhr	$0.105	Estimated
2012 ave. elect savings for existing generation, $/kWhr	$0.161	Based on current purchased energy costing $0.074/kWh on average
Est. 2012 ave. elect savings for solar generation, $/kWhr	$0.161	Assumed to be less than existing due to not having a redundant unit

Oxnard Preliminary Summary of Solar Alternatives Evaluation

carollo

Engineers... Working Wonders With Water™

Date/time: 4/30/13 4:36 PM

Alternative	Existing Cogen only	Maintence Building #1	Maintenance Building #2	Admin Building	Storage Building
Average Net Power Generated (kW)	633	636	635	637	643
Estimated Project Cost [1] (2013 dollars)	$0	$81,880	$54,280	$103,040	$219,880
20-Year Present Worth of Costs/(Revenues)					
Natural gas costs	$2,284,557	$2,284,557	$2,284,557	$2,284,557	$2,284,557
Base Cost for electricity	$40,052,817	$40,052,817	$40,052,817	$40,052,817	$40,052,817
Revenue for displaced electricity	($17,826,207)	($17,916,384)	($17,885,986)	($17,939,688)	($18,068,366)
Revenue for green power credit	($527,436)	($528,019)	($527,823)	($528,170)	($529,002)
Revenue from CSI funding	$0	($14,774)	($9,794)	($18,591)	($39,673)
O&M costs for solar facilities	$0	$9,872	$8,726	$16,564	$35,346
O&M costs for cogeneration facilities	$4,133,203	$4,133,203	$4,133,203	$4,133,203	$4,133,203
Estimated Project Cost [1] (2013 dollars)	$0	$81,880	$54,280	$103,040	$219,880
Total 20-Year Present Worth of Energy Cost [3]	**$28,116,934**	**$28,103,152**	**$28,109,980**	**$28,103,731**	**$28,088,763**
Present Worth of Net Benefit Compared to No Cogeneration System		**$13,783**	**$6,954**	**$13,203**	**$28,172**
Simple Payback Period of Cogeneration System, years		**17**	**18**	**18**	**18**

Note & Assumptions:

(1) This includes estimated construction cost plus cost for engineering, administration, contingencies and construction management
(3) Total 20-year present worth of energy costs is the sum of the Present Worth values listed above
(4) Project Assumptions:

Inflation (capital costs)	4.0%	
Inflation (electricity costs)	5.0%	
Inflation (natural gas costs)	4.0%	
Inflation (O&M costs)	3.0%	
Green Power Credit $/kWh	$0.005	

(5) Project Data:

2012 ave. elect cost, $/kWhr	$0.105	Estimated
2012 ave. elect savings for existing generation, $/kWhr	$0.161	Based on current purchased energy costing $0.074/kWh on average
Est. 2012 ave. elect savings for solar generation, $/kWhr	$0.161	Assumed to be less than existing due to not having a redundant unit

Oxnard Preliminary Summary of Solar Alternatives Evaluation

carollo
Engineers ... Working Wonders With Water™

Date/time: 4/30/13 4:31 PM

Alternative	Existing Cogen only	Carport No. 1	Carport No. 2	Carport No. 3	Carport No. 4
Average Net Power Generated (kW)	633	646	638	638	636
Estimated Project Cost [1] (2013 dollars)	$0	$284,280	$113,160	$107,640	$61,640
20-Year Present Worth of Costs/(Revenues)					
Natural gas costs	$2,284,557	$2,284,557	$2,284,557	$2,284,557	$2,284,557
Base Cost for electricity	$40,052,817	$40,052,817	$40,052,817	$40,052,817	$40,052,817
Revenue for displaced electricity	($17,826,207)	($18,139,291)	($17,950,833)	($17,944,753)	($17,894,091)
Revenue for green power credit	($527,436)	($529,461)	($528,242)	($528,203)	($527,875)
Revenue from CSI funding	$0	($51,292)	($20,417)	($19,421)	($11,121)
O&M costs for solar facilities	$0	$34,274	$18,191	$17,303	$9,909
O&M costs for cogeneration facilities	$4,133,203	$4,133,203	$4,133,203	$4,133,203	$4,133,203
Estimated Project Cost [1] (2013 dollars)	$0	$284,280	$113,160	$107,640	$61,640
Total 20-Year Present Worth of Energy Cost [3]	**$28,116,934**	**$28,069,088**	**$28,102,435**	**$28,103,144**	**$28,109,038**
Present Worth of Net Benefit Compared to No Cogeneration System		**$47,847**	**$14,499**	**$13,790**	**$7,896**
Simple Payback Period of Cogeneration System, years		**17**	**18**	**18**	**18**

Note & Assumptions:

(1) This includes estimated construction cost plus cost for engineering, administration, contingencies and construction management
(3) Total 20-year present worth of energy costs is the sum of the Present Worth values listed above
(4) Project Assumptions:

Inflation (capital costs)	4.0%	
Inflation (electricity costs)	5.0%	
Inflation (natural gas costs)	4.0%	
Inflation (O&M costs)	3.0%	
Green Power Credit $/kWh	$0.005	

(5) Project Data:

2012 ave. elect cost, $/kWhr	$0.105	Estimated
2012 ave. elect savings for existing generation, $/kWhr	$0.161	Based on current purchased energy costing $0.074/kWh on average
Est. 2012 ave. elect savings for solar generation, $/kWhr	$0.161	Assumed to be less than existing due to not having a redundant unit

Oxnard Preliminary Summary of Solar Alternatives Evaluation

carollo
Engineers... Working Wonders With Water™

Date/time: 5/16/13 3:35 PM

Alternative	**Existing Cogen only**	**MRF roof**	**1 acre ground mount**	**1 acre carport**	**0**
Average Net Power Generated (kW)	633	778	700	700	633
Estimated Project Cost (1) (2013 dollars)	$0	$3,242,080	$1,500,520	$1,500,520	$0
20-Year Present Worth of Costs/(Revenues)					
Natural gas costs	$2,284,557	$2,284,557	$2,284,557	$2,284,557	$2,284,557
Base Cost for electricity	$40,052,817	$40,052,817	$40,052,817	$40,052,817	$40,052,817
Revenue for displaced electricity	($17,826,207)	($21,396,797)	($19,478,769)	($19,478,769)	($17,826,207)
Revenue for green power credit	($527,436)	($550,532)	($538,125)	($538,125)	($527,436)
Revenue from CSI funding	$0	($584,964)	($270,737)	($270,737)	$0
O&M costs for solar facilities	$0	$390,880	$241,213	$241,213	$0
O&M costs for cogeneration facilities	$4,133,203	$4,133,203	$4,133,203	$4,133,203	$4,133,203
Estimated Project Cost (1) (2013 dollars)	$0	$3,242,080	$1,500,520	$1,500,520	$0
Total 20-Year Present Worth of Energy Cost (3)	**$28,116,934**	**$27,571,244**	**$27,924,679**	**$27,924,679**	**$28,116,934**
Present Worth of Net Benefit Compared to No Cogeneration System		**$545,691**	**$192,256**	**$192,256**	**$0**
Simple Payback Period of Cogeneration System, years		**17**	**18**	**18**	**#DIV/0!**

Note & Assumptions:

(1) This includes estimated construction cost plus cost for engineering, administration, contingencies and construction management
(3) Total 20-year present worth of energy costs is the sum of the Present Worth values listed above
(4) Project Assumptions:

Inflation (capital costs)	4.0%	
Inflation (electricity costs)	5.0%	
Inflation (natural gas costs)	4.0%	
Inflation (O&M costs)	3.0%	
Green Power Credit $/kWh	$0.005	

(5) Project Data:

2012 ave. elect cost, $/kWhr	$0.105	Estimated
2012 ave. elect savings for existing generation, $/kWhr	$0.161	Based on current purchased energy costing $0.074/kWh on average
Est. 2012 ave. elect savings for solar generation, $/kWhr	$0.161	Assumed to be less than existing due to not having a redundant unit

APPENDIX D - PRELIMINARY IDENTIFICATION OF IMMEDIATE NEEDS FOR THE OXNARD WASTEWATER TREATMENT PLANT AND COLLECTION SYSTEM SEWERS AND LIFT STATIONS

MEMORANDUM

Date: September 26, 2014

To: Thien Ng (Oxnard)

From: Liberato Tortorici (KEH)

Cc: Jeff Miller (Oxnard)
John Jardin (KEH)
Mike Wilson (KEH)

Reviewed By: Ken Hume (KEH)
Ray Fakhoury (KEH)

Subject: Preliminary Identification of Immediate Needs for the Oxnard Wastewater Treatment Plant and Collection System Sewers and Lift Stations.

1. INTRODUCTION

Task 3 (Plant Optimization) of the Wastewater Operations Support Contract involves working closely with City staff to identify and prioritize immediate repair and maintenance needs for the City's wastewater treatment plant.

2. FOCUS OF MEMORANDUM

This Technical Memorandum focuses on the preliminary identification of immediate needs at the Oxnard Wastewater Treatment Plant (OWTP), and the City's Sewerage Collection System and Sewerage Lift Stations that should be considered for further investigation and implementation.

The **i**mmediate needs presented in this Technical Memorandum include our team's recommended order of priority, opinion of probable implementation costs, and a risk assessment opinion for each Immediate Needs project.

3. IMMEDIATE NEEDS ASSESSMENT APPROACH

The preliminary list of potential Immediate Needs presented herein were identified based on input and information collected from the OWTP operations and maintenance staff; interviews with OWTP staff; limited site observations and inspections by OWTP staff and our team of the OWTP facilities and collection system facilities; input received from OWTP staff at workshops conducted on August 27 and 28, 2014; and review of previous assessment reports and studies completed for the OWTP and collection system facilities. These previous reports and studies are listed below.

- Oxnard Wastewater Treatment Plant – Initial (Level 1) Assessment Study by Malcolm Pirnie, Inc. (February 2001).

- Oxnard Wastewater Treatment Plan – Level 2 Assessment Study by Malcolm Pirnie, Inc. (March 2006.)
- Oxnard Wastewater Treatment Plant – Revised Centrifuge Study Report by Malcolm Pirnie, Inc. (June 2007).
- Oxnard Wastewater Treatment Plant – Unit Process and Optimization Study by Penfield & Smith and Michael K Nunley & Associates (June 2011).

On August 21, 2014 KEH submitted a draft version of this technical memorandum for City review and subsequently conducted workshops on August 27th and August 28th to solicit input and comments from City staff. This final Technical Memorandum reflects input and comments provided by City staff at the workshops.

4. IMMEDIATE NEEDS PRIORITY CATEGORIES

Three categories of immediate needs have been identified and are recommended by our team for prioritizing immediate needs identified herein. Definitions of these priority categories are provided below.

4.1 Priority 1 Immediate Needs

In March 2014 the Wastewater Division staff made a presentation to the City Council entitled the *Oxnard Wastewater Treatment Plant Assessment and Optimization Bio-Tower Update.* This update identified that **safety** related repairs and improvements should be considered as high priority items, and recommended that **safety** related repairs and improvements be addressed immediately. Our team reviewed the information presented to the City council and reviewed these recommendations with City staff. These recommendations along with additional items discussed during our discussions with City staff have been categorized as Priority 1 Immediate Needs. The Priority 1 Immediate Needs are listed in Table 1.

4.2 Priority 2 Immediate Needs

In response to complaints lodged by the general public in late 2013 about odors being generate and released from the sewerage collection system within the Oxnard Community the Wastewater Division staff immediately implemented measures to reduce the odors and eliminate odor complaints. The City's immediate response to the odor complaints, which was met with positive reaction from the Oxnard Community, are reflective of the City's commitment to foster and maintain "good neighbor" relationships throughout the Oxnard Community and underscores the importance to **avoid public nuisances** in order to avoid potential claims against the City.

KEH recommends that the proactive **Avoidance of Public Nuisances** such as odors beyond the OWTP fence line and odors from the sewerage collection system and pump stations, wastewater spills, and by-pass of partially treated effluent to the ocean outfall be categorized as Priority 2 Immediate Needs. The Priority 2 Immediate Needs are listed in Table 2.

4.3 Priority 3 Immediate Needs

KEH recommends that **Operability/Maintenance Enhancement** improvements and upgrades not related to safety issues or public nuisance issues but which can potentially increase plant efficiencies, reduce costs and/or help protect the City's investment in the existing treatment plant and collection system facilities be categorized as Priority 3 Immediate Needs. The Priority 3 Immediate Needs are listed in Table 3.

5. ESTIMATES OF PROBABLE IMPLEMENTATION COSTS

The estimates of probable implementation costs presented herein include preliminary design costs, construction costs total capital costs. The basis for preparation of these estimates are as follows.

5.1 Estimates of Probable Pre-Design Investigations Costs

In cases where identified Immediate Needs projects are not yet fully developed enough to generate complete project definitions and/or accurate and reliable estimates of probable construction and total capital costs, it is recommended that pre-design investigations be undertaken to fully define the project needs and to estimate the construction and capital costs before any detailed design efforts are initiated. The pre-design activities and estimated pre-design investigation budgets are identified in the attached Tables 1, 2 and 3.

5.2 Estimates of Probable Construction Costs

The estimates of Probable Construction Costs identified in Tables 1, 2 and 3 were generated as follows:

- Inflation adjustments of previous estimates identified in the Oxnard Wastewater Treatment Plant – Level 1 and/or Level 2 Assessment Studies identified under Part 3.
- Inflation and prorated "size" adjustments of similar projects competed previously by our team.
- Recent equipment cost estimates obtained from equipment manufacturers.
- These estimates include a contingency factor of 30% to 35% depending on our team's opinion on the level of project detail and definition currently available for each project.

5.3 Estimates of Probable Total Capital Costs

The estimates of Probable Capital Cost identified in Tables 1, 2 and 3 were generated by applying a 40% mark-up on the estimates of probable construction costs. The additional 40% includes the following markups.

- Design Services: 12.5%
- Office Support Services during Construction and Start-up: 6%
- Construction Management and Inspection Services: 12.5%
- City Administration and Permitting: 6%
- Project Contingencies: 3%

The 3% project contingency markup is in addition to the 30% to 35% construction contingencies included in the estimates of probable construction costs.

6. RISK ASSESSMENT CATEGORIES

Our team recommends that risk assessment impact be categorized in the following categories described below.

6.1 **High Risk** (**H**) is assigned to projects where there is potential for serious personnel injury or death; the potential for general personnel health and safety infractions; the potential for public nuisances that could result in complaints or claims filed against the City; and the potential for regulatory non-compliance fines that could be levied against the City.

6.2 **Moderate Risk** (**M**) is assigned to projects where the potential for minor personnel injury might exist; and where the City's ability to provide continued unit process reliability and redundancy could be seriously compromised.

6.3 **Low Risk (L)** is assigned to projects where the City's ability to provide a cost efficient and effective treatment and overall system operation and performance could be compromised.

7. PRELIMINARY LIST OF IMMEDIATE NEEDS

The lists of Priority 1, 2 and 3 Immediate Needs provided in Tables 1, 2 and 3 include a Priority Number, Project Title, Impact Area, General Description, Estimates of Probable Costs, and a Risk Assessment Value.

7.1 Priority 1 Immediate Needs – Safety

The Priority 1 Immediate Needs provided in Table 1 identifies eleven projects. Further discussion for some of the projects shown in Table 1 is provided below.

Priority 1.1 – Arc Flash Pre-Design Studies

The completion of the Arc Flash pre-design investigations is of paramount importance to the City because there is the potential for serious bodily injury or death to plant personnel. The Arc Flash studies are being performed by Carollo Engineers under the Public Works Department Master Plan Update Contract. Since the results from the Arc Flash study will not be available for several months, our team in collaboration with City staff have identified several precautionary measures that can be implemented immediately by City to reduce the potential for serious bodily injury. These measures are presented below.

1. Post arc flash warning signs on all entrances to all buildings identified in Table 1, Priority Improvement 1.1.

2. Install weather proof cabinets on the exterior of buildings at main access door to each buildings, and equip the cabinets with Class 3 Personal Protective Equipment (PPE).

3. Train OWTP operators on the use of PPE and the procedures to be followed if they need to access MCC panels in the absence of a qualified electrician.

4. Post signs on all MCC's in all buildings identified in Table 1, Priority Improvement 1.1 that will prohibit unauthorized access and the opening of any panel doors unless done by a qualified electrician, and that will require the qualified electrician to be properly outfitted with the appropriate Class 3 PPE including, but not limited to, protective face shields, and protective clothing.

Priority 1.6 – Bio-Filter Removal Pre-Design

The recommended pre-design investigations identified in Table 1will require close coordination with OWTP operations staff, Prouyses and Carollo Engineers to ensure that all interim improvements, particularly those related to SCADA, will be compatible with the master plan recommendations so that the potential for additional costs to the City are minimized.

Priority 1.7 – Primary Clarifier Access Catwalk Improvements

During the aforementioned workshops replacement of the access cat walks was identified as a top priority that should be implemented as soon as possible.

Until the replacement of access catwalks are completed, the City should implement the following recommendations.

1. Install chains and caution signs on all access stairways to the primary clarifiers to prohibit unauthorized access.

2. Do not allow access to the catwalks unless there is another authorized individual present.

Priority 1.10 – HVAC/Air Handling Unit Replacement

During the aforementioned workshops replacement of the HVAC/Air Handling Units that serve the Laboratory was identified as a top priority that should be implemented as soon as possible.

Priority 1.11 – Belt Filter Press Building Air Quality Assessment

During the aforementioned workshops an assessment of the air quality within the building during operation was identified as a top priority that should be undertaken as soon as possible.

7.2 Priority 2 Immediate Needs – Avoidance of Public Nuisances

The list of Priority 2 Immediate Needs provided in Table 1 identifies five projects. These are listed below and further expanded and defined in Table 2.

Priority 2.1 – Collection System Magnesium Hydroxide Addition Pre-Design Investigations

Priority 2.2 – Secondary Sedimentation Tanks "Sea Gull" Netting

Priority 2.3 – Primary Effluent Emergency Storage Pre-Design Investigations

Priority 2.4 – Headworks Area Odor Control Optimization Pre-Design Investigations

Priority 2.5 – Influent Screens Odor Control Pre-Design Investigations

7.3 Priority 3 Immediate Needs

The list of Priority 3 Immediate Needs provided in Table 1 identifies eleven projects. These are listed below and further expanded and defined in Table 3.

Priority 3.1 – 3WHP Improvements

Priority 3.2 – RAS/WAS Flow Meter Upgrades

Priority 3.3 – Gravity Thickener Improvements

Priority 3.4 – Effluent Conveyance Improvements Pre-Design Investigations

During the aforementioned workshops power supply redundancy for the effluent pumps was identified as a critical item that needs to be included in the pre-design investigations. Power supply redundancy options to be investigated will include all electrical driven pumps, combination of electrical driven and engine driven pumps; and standby power for electrical driven pumps.

Priority 3.5 – AST Area Walkways Lighting Replacements

Priority 3.6 – Cell Phone Coverage Booster Antenna

During the aforementioned workshops expandable and reliable cell phone coverage throughout the entire plant was identified as a safety concern and a top priority that should be implemented as soon as possible.

Priority 3.7 – DAF Polymer Improvements

Priority 3.8 – Digester Improvements

Priority 3.9 – Sludge Dewatering Improvements

Priority 3.10 – Primary Clarifier Improvements

Priority 3.11 – Co-Gen Cooling Water Improvements

8. ESTIMATES OF PROBABLE IMPLEMENTATION COSTS

A summary of the estimates of probable pre-design investigations costs, construction costs and total capital costs for the Priority 1, 2 and 3 Immediate Needs Improvements listed in Tables 1, 2 and 3 are shown in Table 4. All estimates of probable costs are based on July 2014 dollars and may need to be adjusted the based on the anticipated final implementation schedules that will be identified in the final technical memorandum. The implementation schedules will be discussed with the City at the upcoming workshop to review this draft technical memorandum.

The estimates of probable construction costs and probable total capital costs for projects requiring pre-design design investigations cannot be finalized until this work is completed.

Table 4. Summary of Immediate Needs Probable Costs

Improvements Category	Pre-Design Investigations Cost Estimates	Construction Cost Estimates	Capital Cost Estimates
Priority 1	$157,644	$4,409,200	$6,172,900
Priority 2	$135,442	$51,500	$72,100
Priority 3	$148,280	$14,078,800	$19,710,300
Additional Costs Based on Predesign Investigations		TBD	TBD

9. IMPLEMENTATION SCHEDULES

Each of the Priority 1, 2 and 3 Immediate Needs projects identified in Tables 1, 2 and 3 include Risk Assessment Values that have been assigned to help establish the top priority projects for immediate implementation by the City. The Risk Assessment Categories are identified as High (H), Moderate (M) and Low (L) as defined under Part 6, and were assigned based on input from City staff at the workshops conducted on August 27th and August 28th.

It is suggested that the City review all Immediate Needs projects identified with High Risk Values and prioritize these projects based on the City's capacity to fund the identified estimates of probable construction costs and probable total capital costs. This prioritization may require the City to undertake a comprehensive funding analysis to establish a realistic expenditure schedule that can match the City's budget constraints, and to identify potential funding mechanisms that the City's maybe need to pursue.

Our immediate attention regarding schedules for implementation focuses on High (H) and Moderate (M) priority pre-design investigations that need to be completed before design and construction of these High and Moderate priority projects can move forward. These pre-design investigations are listed below in the order they appear in Tables 1, 2 and 3. The time-lines for implementation of these High and Moderate priority pre-design investigations are shown in Figure 1.

- Priority 1.1 – Arc Flash Pre-Design Investigations

  This is being undertaken by Carollo as part of their Master Planning efforts. However, the pre-cautionary measures identified under Part 7.1 should be undertaken by the City as soon as possible.

- Priority 1.3 – Electrical Vault Repairs Pre-Design Investigations

- Priority 1.6 – Biofilter Removal Pre-Design Investigations
  - 1.6.1 – Advance Primary Treatment Polymer Addition

- 1.6.2 – Biofilter Removal Contingency Plan

- Priority 1.11 – Belt Filter Press Building Air Quality Assessment
- Priority 2.1 – Collection System Magnesium Hydroxide Addition Pre-Design Investigations
- Priority 2.3 – Primary Effluent Emergency Storage Pre-Design Investigations
- Priority 2.4 – Headworks Odor Control Optimization Pre-Design Investigations
- Priority 2.5 – Influent Screens Odor Containment Pre-Design Investigations
- Priority 3.4 – Effluent Conveyance Pre-Design Investigations
- Priority 3.5 – AST Walkway Lights Pre-Design Investigations
- Priority 3.6 – Cell Phone Coverage Pre-Design Investigations
- Priority 3.9 – Sludge Dewatering Pre-Design Investigations
- Priority 3.10 – Primary Clarifier Covers and Odor Control Pre-Design Investigations

10. OTHER "NEEDS SURVEY" IMPROVEMENTS

In addition to the immediate needs presented in this technical memorandum, the City's OWTP and collection system staffs have identified other upgrade and improvement needs. These improvements should be part of the long term master planning efforts that the City is currently undertaking. A preliminary list of these additional needs is provided below.

7.1 Staffing and Training

1. Update CRP Training and conduct training courses.
2. Update General and Activity Specific Training and conduct training courses.
3. Train operators on OWTP laboratory sample analysis procedures.
4. Replace aging personnel chairs and computer work stations

7.2 Collection System Vehicles

1. Replace aging collection system and maintenance vehicle fleet.
2. Purchase additional "Vactor" truck(s).
3. Purchase additional "Camera" truck(s).
4. Install new "tablet" map-book technology in essential collection system vehicles.

7.3 Maintenance Materials and Spare Parts

1. Conduct an inventory of spare parts, tools and maintenance materials and restock inventory.
2. Assess storage requirements and increase number of storage cabinets and storage shelves.
3. Assess purchasing rules and procedures.
   - Increase purchase order (PO) limits
   - Accelerate the PO process.

7.4 Co-Generation Facilities

1. Conduct a focused assessment of all co-generation facilities as part of the global Master Planning effort.
2. Replace co-generation facilities identified in the global Master Planning effort, including improvements to the cooling water system identified under item 3.11 of the Priority 3 Immediate Needs identified in Table 3.

7.5 Lift Stations

1. Conduct a focused assessment of lift station power reliability and redundancy as part of the global Master Planning effort.
2. Upgrade Collection System lift station power supply and power redundancy facilities identified in the global Master Planning effort.

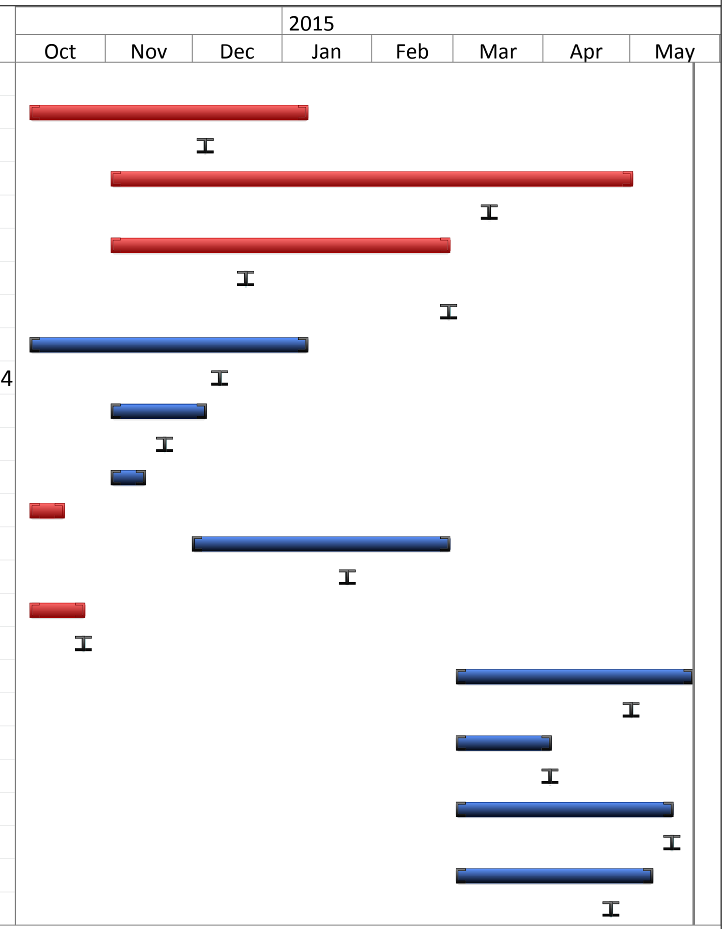
7.6 Central Trunk Sewer

1. Conduct a focused condition assessment of the Central Trunk Sewer as part of the global Master Planning effort.

We recommend that the City review these additional needs with Carollo Engineers in a workshop setting to ensure that these needs are included in the Master Plan update effort.

Figure 1
Preliminary Implementation Schedule
Immediate Needs Technical Memorandums

ID		Task Name	Duration	Start	Finish
1					
2		**1.6 Advanced Primary Treatment Polymer Addition**	**70 days**	**Mon 10/6/14**	**Fri 1/9/15**
3		Draft TM	1 day	Fri 12/5/14	Fri 12/5/14
4		**1.6 Biofilter Removal Contingency Plan**	**130 days**	**Mon 11/3/14**	**Fri 5/1/15**
5		Draft TM	1 day	Fri 3/13/15	Fri 3/13/15
6		**2.1 Magnesium Hydroxide Addition**	**85 days**	**Mon 11/3/14**	**Fri 2/27/15**
7		Design for "Turnkey" Interim Installation	1 day	Fri 12/19/14	Fri 12/19/14
8		Conceptual Design for Permenant System	1 day	Fri 2/27/15	Fri 2/27/15
9		**3.9 Sludge Dewatering**	**70 days**	**Mon 10/6/14**	**Fri 1/9/15**
10		Update Centrifuge Study TM	1 day	Wed 12/10/14	Wed 12/10/14
11		**1.3 Electrical Vault Repairs**	**25 days**	**Mon 11/3/14**	**Fri 12/5/14**
12		Draft TM	1 day	Fri 11/21/14	Fri 11/21/14
13		**3.5 AST Walkways Lights**	**10 days**	**Mon 11/3/14**	**Fri 11/14/14**
14		**3.6 Cell Phone Coverage**	**10 days**	**Mon 10/6/14**	**Fri 10/17/14**
15		**3.10 Primary Clarifiers Cover & Odor Control**	**65 days**	**Mon 12/1/14**	**Fri 2/27/15**
16		Draft TM	1 day	Fri 1/23/15	Fri 1/23/15
17		**1.11 BFP Building Air Quality Assesment**	**15 days**	**Mon 10/6/14**	**Fri 10/24/14**
18		Assessment TM	1 day	Fri 10/24/14	Fri 10/24/14
19		**2.3 Primary Effluent Emergency Storage**	**60 days**	**Mon 3/2/15**	**Fri 5/22/15**
20		Draft TM	1 day	Fri 5/1/15	Fri 5/1/15
21		**2.4 Headworks Odor Control Optimatization**	**25 days**	**Mon 3/2/15**	**Fri 4/3/15**
22		Assessment TM	1 day	Fri 4/3/15	Fri 4/3/15
23		**2.5 Influent Screen Odor Control Containment Optimization**	**55 days**	**Mon 3/2/15**	**Fri 5/15/15**
24		Assessment TM	1 day	Fri 5/15/15	Fri 5/15/15
25		**3.4 Effluent Conveyance**	**50 days**	**Mon 3/2/15**	**Fri 5/8/15**
26		Draft TM	1 day	Fri 4/24/15	Fri 4/24/15



Project: ImmediateNeedsSchedul
Date: Fri 9/26/14

Task	Inactive Task	Start-only
Split	Inactive Milestone	Finish-only
Milestone	Inactive Summary	Deadline
Summary	Manual Task	Critical
Project Summary	Duration-only	Critical Split
External Tasks	Manual Summary Rollup	Progress
External Milestone	Manual Summary	

Table 1
Priority 1 - Immediate Needs (Safety)

Priority Number	Project Title	Impact Areas	Description	Estimated Predesign Budget	Estimated Construction Costs	Total Capital Costs	Risk Value
1.1	Arc Flash Studies	Buildings	Carollo to conduct comprehensive, plant wide ARC Flash Studies as part of Master Planning Efforts.	Under Carollo's Master Plan Consultant.	TBD	TBD	**H**
		MCC's					**H**
		Main Switchgear					**H**
		Co-Generation					**H**
		16KV Switchgear					**H**
		North Area Electrical					**H**
		Headworks Electrical					**H**
1.2	Roof Rehabilitation	Buildings	Rehabilitate and refurbish building roofs, flashings, and roof penetrations to eliminate leaks.				
		Main Switchgear			$20,300	$28,420	H
		Co-Generation			$59,000	$82,600	H
		16KV Switchgear			$38,800	$54,320	H
		North Area Electrical			$38,800	$54,320	H
		Plant Control Center			$33,700	$47,180	H
		Administration			$59,000	$82,600	M
		Subtotal 1.2			**$249,600**	**$349,440**	
1.3	Electrical Vault Repairs	Plant Wide	Repair corroded concrete surfaces, install protective coatings; and replace corroded conduit and wires with new conduits, wires, and Junction boxes.	$26,240	TBD	TBD	H
1.4	Eyewash / Shower Stations	Plant Wide	Exercise all Stations and refurbish/repair as needed.		OWTP Staff		H
1.5	Chemical Storage Tanks Sight Glasses	Plant Wide Chemical Bulk Storage	Install protective "cages" on all sight glasses.		$24,000	$33,600	H
1.6	BioFilter Removal Pre-design Investigations	Biofilters	Undertake a comprehensive pre-design effort to decommission and ultimately remove the biotowers from service.				H
			Predesign Elements to Include:				
			1. Enhanced primary treatment chemical addition "bench scale" and pilot scale testing with polymer and ferric chloride to evaluated impacts on TSS and TBOD5 removal efficiency and subsequent loads on the activated sludge system.	$11,160	TBD	TBD	H
			2. Development of contingency plan to decommission the biotowers and for operation of the activated sludge system should the biofilters fail or need to be taken out of service prior to completion of capital improvements to the activated sludge system.	$104,188	TBD	TBD	H
		Subtotal 1.6		**$115,348**			
1.7	Primary Clarifier Access Walkways	Primary Clarifiers	1. Replace the catwalks.		$268,300	$375,620	H
			2. Install walkways with handrails and hose stations in a 4-quadrant interior layout for cleaning of launders		$552,100	$772,940	H
		Subtotal 1.7			**$820,400**	**$1,148,560**	
1.8	Fall & Slip Prevention		1. Refurbish BFP Building roof and skylights to eliminate leaks.		$70,800	$99,120	H
			2. Install non-skid epoxy floor coating on BFP Building ground floor and belt filter press floor.		$105,000	$147,000	H

Table 1
Priority 1 - Immediate Needs (Safety)

			3. Install permanent access stairs and platforms on DAF area and BFP area polymer mixing tanks.		$5,500	$7,700	H
			4. Install containment structure around DAF area bulk polymer storage tank.		$42,000	$58,800	M
			5. Install access walkways and maintenance platforms for gravity thickeners roof mounted air handling units.		$53,600	$75,040	H
			6. Install headwork's blower building and electrical building roof access caution signs and fall prevention cables.		$5,300	$7,420	H
			7. Expandable base fall arrest system for sewage lift stations, collection system manholes, vortex structures, and junction structures, and BILCO fall prevtion grating at LS 29		$73,100	$102,340	H
			8. Install access ladders for AST's.		$47,900	$67,060	H
			9. Install acces ladder at AWPF Supply Fans		$16,100	$22,540	H
		Subtotal 1.8			**$419,300**	**$587,020**	
1.9	"Below" Cover Structures Rehabilitation	Plant wide					
			1. Influent sewer vortex structures. Repair deteriorated concrete surfaces and install new protective coatings on all "below cover" surfaces.		$366,000	$512,400	H
			2. Influent junction structure. Repair coatings on all vertical walls to depth of 2 feet below cover and 1 foot above cover, all surfaces of below cover beams with 6 inch overlap on top surfaces and all surfaces of above cover curbs.		$83,700	$117,180	M
			3. Influent screen channels. Repair coatings on surfaces identified in 1.9.1.		$139,400	$195,160	M
			4. Grit Chamber and bypass Channels. Repair Coatings on surface identified in item 1.9.1.		$148,600	$208,040	M
			5. Influent Pump Station Wet Well. Repair Coatings on surface identified in item 1.9.1.		$185,400	$259,560	M
			6. RAS / WAS Wet well.		$142,100	$198,940	H
			7. Lift Station 29.		$179,800	$251,720	M
		Subtotal 1.9			**$1,245,000**	**$1,743,000**	
1.10	HVAC Replacements	Buildings	Replace HVAC and air handling units.				
		Gravity Thickeners			$107,900	$151,060	M
		Main Switchgear			$49,000	$68,600	H
		Co-generation			$352,300	$493,220	H
		16KV Switchgear			$40,500	$56,700	H
		North Area Electrical			$59,100	$82,740	M
		Plant Control Center			$190,800	$267,120	M
		Administration			$190,800	$267,120	M
		Laboratory			$95,400	$133,560	H
		Collection / Main			$102,900	$144,060	M
		Primary / DAF			$97,900	$137,060	L
		Maintenance			$212,400	$297,360	M
		Vacuum Filter			$38,800	$54,320	L
		BFP Building Personnel Areas			$59,100	$82,740	M
		Digester Control Building			$54,000	$75,600	M
		Subtotal 1.10			**$1,650,900**	**$2,311,260**	
1.11	BFP Building Air Quality Investigation	BFP Building	Conduct pre-design assessment of air quailty in building during operation	$16,056	TBD	TBD	H

Table 2
Priority 2 - Immediate Needs (Avoidance of Public Nuisance)

Priority Number	Project Title	Impact Areas	Description	Estimated Predesign Budget	Estimated Construction Costs	Total Capital Costs	Risk Value
2.1	Collection System Magnesium Hydroxide Addition Predesign Investigations	Collection System (Redwood Trunk, Central Trunk, Eastern Trunk)	1. Conduct additional magnesium hydroxide pilot addition study for the Eastern Trunk Sewer.	$12,763	TBD	TBD	**H**
			2. Conduct site visit to the CSDLAC to obtain full scale information on dosages, points of chemical adddition, mixing, design sizing and storage criteria, P-trap manhole, and / or curtain wall design criteria for selected manholes.	$3,883			**H**
			3. Conduct site visits to potential chemical storage sites for each of the three trunk sewers.	$3,530			**H**
			4. Prepare "turn-key" installtion definitions and skectches for installation of interim chemical addition systems by City staff.	$21,976	TBD	TBD	**H**
			5. Prepare a TM with conceptual skectches and equipment lists prior to detailed design of permenant systems	$21,900	TBD	TBD	**H**
		Subtotal 2.1		**$64,052**	**TBD**	**TBD**	
2.2	SST OSHA " Sea Gull" Netting	SSTS	Complete the installation of netting on the secondary sedmintation tanks for elimination of sea gulls congregation.		$51,500	$72,100	**H**
2.3	Primary Effluent Emergnecy Storage Predesign Investigations	Interstage PS and CCT primary effluent bypass.	Condcut a predesign investigation to evaluate emergency storage options for primary effluent, including continuation of storage in one primary clarifier , storage in the CCT, storage in the bio-filter lower structure, and pumping equipment and power supply redundancy at the interstage PS.	$30,244	TBD	TBD	**H**
2.4	HW Odor Control Optimization Predesign Investigations	Headworks	1. Conduct odor control ventiallation " air flow" check balancing measurements on the ventillation system.	$2,670			**M**
			2. Confirm the installation of odor control ductwork, including balancing dampers in accordance with the original contract documents for the Headworks area improvements project.	$2,407			**M**
			3. Identify additional improvements such as the installation of strategy pressure monitoring gauges to enhance operation and control of the odor control system.	$1,923			**M**
			4. Prepare an assessment TM with conceptual sketches and equipment lists prior to detailed design.	$10,900			
		Subtotal 2.4		**$17,900**			
2.5	Influent Screens Odor Control Predesign Investigations	Headworks	1. Conduct an alternative analysis for reduction of fecal matter capture on the influent screens and acummaltion of fecal matter on the screenings conveyor.	$6,220			**M**
			2. Conduit alternatives analysis for enclosing the influent screening conveyor belt and ventilation of the contained atompshpere to the Headworks odor control scrubbers.	$5,480			**M**
			3. Prepare an assessment TM with conceptual sketches and equipment lists prior to detailed design.	$11,546			**M**
		Subtotal 2.5		**$23,246**			

Table 3
Priority 3 - Immediate Needs (Operability and Maintenance Enhancements)

Priority Number	Project Title	Impact Areas	Description	Estimated Predesign Budget	Estimated Construction Costs	Total Capital Costs	Risk Value
3.1	3WHP Improvements	3WHP Pump Station	1. Replace manually cleaned basket strainers with automatic " self cleaning" basket strainers.		$206,000	$288,400	**L**
			2. Replace the 3WHP pumps and drives.		$377,600	$528,640	**M**
3.2	RAS & WAS Flow Meters	RAS and WAS flow metering	Refurbish and replace meters as necessary.		$215,100	$301,100	**M**
3.3	Gravity Thickener Improvements	Gravity Thickener	1. Permanently repair or replace leaking section(s) of the feed sludge manifold.		$52,800	$73,920	**M**
			2. Replace GT 1 and GT 2 "top mounted" air handling units. This immediate need will be coordinated with Priority 1 Immediate need 1.8.5.		$118,800	$166,320	**M**
			3. Replace GT 1 collector mechanism, launders, and repair concrete surfaces. Place GT1 back in service before you remove GT2 out of service.		$1,048,400	$1,467,760	**M**
			4. Replace GT 2 collector mechanism, launders, and repair concrete surfaces. Place GT2 back in service.		$1,048,400	$1,467,760	**M**
3.4	Effluent Conveyance Improvements	CCT & Effluent Pump Station	1. Conduct a "low flow" inspection of the gravity pipeline check valve to determine repair needs.	$2,034			**M**
			2. Schedule "low flow" repair of the check valve.		TBD	TBD	M
			3. Coordinate an inspection / assessment of the Big Red effluent pump station by the pump manufacturer to determine repair / replacement needs to eliminate vibration concerns.	$1,554			L
			4. Implement manufacturer recommendations for repair / replacement improvements to Big Red.	TBD	TBD	TBD	L
			5. Revist the Effluent Pump Station Wet Well Study.	$2,035			L
			6. Power supply redundancy / reliability Predesign Investigations	$21,476	TBD	TBD	L
3.5	AST Walkway Lights	AST	Replace the handrail mounted walkway lights with corrosion resistant LED lights.	$4,040	TBD	TBD	M
3.6	Cell Phone Coverage	Plant Wide	1. Coordinate a site visit with the OWTP cell phone service provider for recommendations for expanded and reliable coverage throughout the plant.	$1,221	TBD	TBD	H
			2. Implement recommendations of cell phone service provider for "booster" antennas.	TBD	TBD	TBD	
3.7	DAF Polymer System and Air Compressors	DAF Thickeners	1. Upsize and replace DAF system air compressors.		$145,400	$203,560	L
			2. Upgrade the DAF polymer solution to re-establish the contiguous batching system.		$26,800	$37,520	L
3.8	Digester Improvement	Digesters	1. Digester No. 2				H
			1.1 Clean digester. NOT NECESSARY; DIGESTER RECENTLY CLEANED		$0	$0	
			1.2 Replace cover with cover identical to Digester No. 1		$1,596,800	$2,235,520	
			1.3 Repair interior concrete coatings and install coating on underside of new cover.		$393,200	$550,480	
			1.4 Refurbish and recoat draft tube assembly.		$55,100	$77,140	
			1.5 Replace heat exchangers and gas piping		$258,100	$361,340	
			2. Digester No. 1				M
			2.1 Clean digester.		$392,800	$549,920	
			2.2 Repair interior coatings		$441,800	$618,520	
			2.3 Refurbish and recoat draft tube assembly.		$55,100	$77,140	
			2.4 Replace heat exchangers and gas piping		$258,100	$361,340	
			3. Digester No. 3				M
			3.1 Clean digester.		$480,100	$672,140	
			3.2 Repair interior coatings		$541,800	$758,520	
			3.3 Refurbish and recoat draft tube assembly.		$66,000	$92,400	

Table 3
Priority 3 - Immediate Needs (Operability and Maintenance Enhancements)

			3.4 Replace heat exchangers.		$258,100	$361,340	
		Subtotal 3.8			**$4,797,000**	**$6,715,800**	
3.9	Sludge Dewatering Improvements	Sludge Dewatering	1. Update the MPI 2007 Centrifuge Study Report including consideration of the alternatives presented in the PS/MKA 2014 Unit Process Evaluation and Optimization Study.	$14,080	TBD	TBD	M
			2. Pre-desing investigations with manufacturer to define requirements to refurbish 2 BFP's on an interim basis until the BFP's are replaced with an alternative technology.	$12,120	TBD	TBD	H
			3. Upgrade BFP Polymer solution make up system to re-establish the continuous batching system.		$26,100	$36,540	M
			4. Replace " wet sprinkler" piping in the BFP Building.		$82,600	$115,640	H
		Subtotal 3.9			**$108,700**	**$152,180**	
3.10	Primary Clarifier Improvements	Primary Clarifier	1. Replace scum / sludge collectors and scum beach.		$4,267,500	$5,974,500	M
			2. Replace Launders with FRP Launders and supports.		$634,800	$888,720	M
			3. Concrete repairs and coatings.		$327,900	$459,060	M
			4. Replace or refurbish the primary sludge pumps.		$252,900	$354,060	M
			5. Replace or refurbish the scum ejectors.		$252,900	$354,060	M
			6. Predesign investigations for the primary clarifier covers and odor control.	$77,248	TBD	TBD	
3.11	Co-Gen Cooling Water System at CCT	Co-Gen Cooling Water	1. Install new automatic strainer on 3WHP cooling water loop at CCT		$188,800	$264,320	
			2. Modify cooling water loop with loop extension into CCT	$12,472	TBD	TBD	