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2015
Integrated Resource Plan Report

Prepared for:

Glendale Water and Power

June 30, 2015

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EXHIBITS

PACE GLOBAL
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EXECUTIVE SUMMARY

Siemens Industry Inc., for its Pace Global business ("Pace Global"), in coordination with Glendale Water and Power ("GWP"), has prepared this 2015 Integrated Resource Plan ("IRP") covering the 20-year planning period from 2015 to 2035. The purpose of this document is to provide a roadmap for future resource decisions for GWP, covering issues around the local natural gas-fired Grayson power plant, landfill gas generation, future renewable additions, replacement of coal-fired generation, distributed energy resources, storage technology, and energy efficiency, among others.

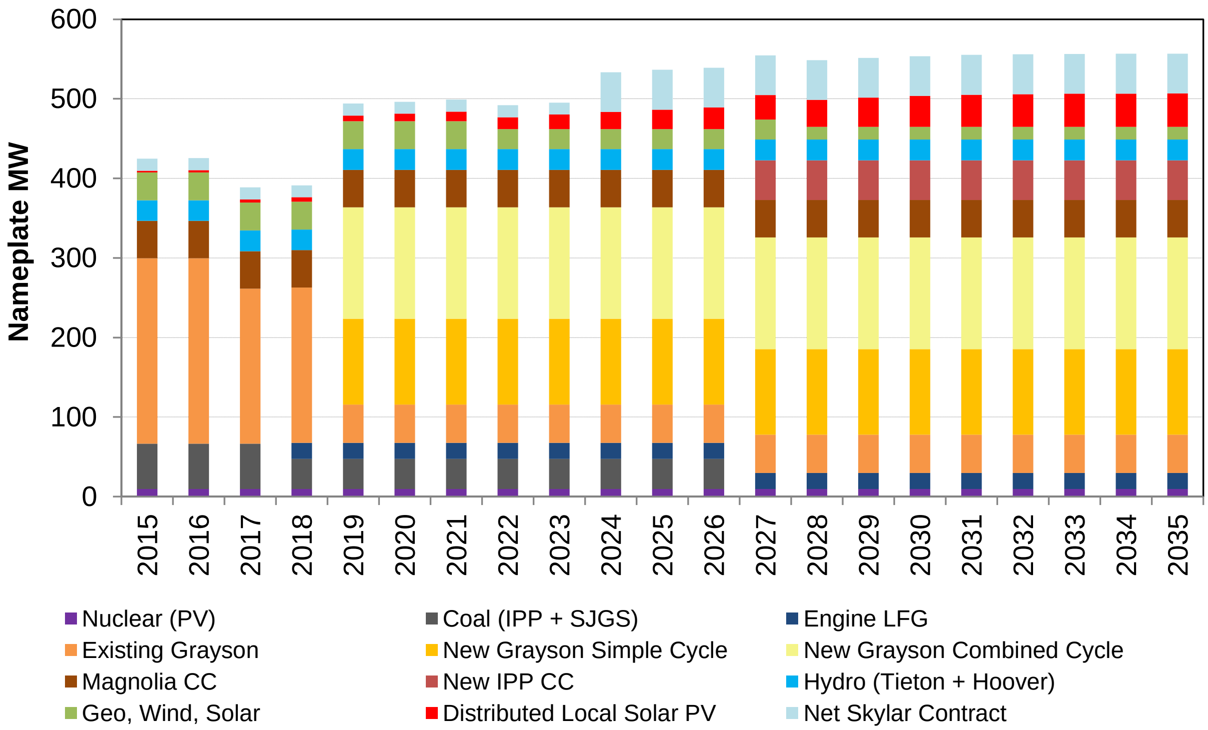
PREFERRED RESOURCE PLAN STRATEGY

The IRP assessment covers a range of key decisions for GWP over the next several years. Therefore, there are several elements that make up the preferred resource plan strategy. Certain items require near-term action, others establish a guidepost for measuring future decisions, and some still require further study. Since planning is a dynamic process, it is likely that some elements of this current plan will evolve, as market conditions change, as new regulations are introduced or enter into force, and as technology improves. However, the following actions comprise the key recommendations of this IRP:

- **Grayson:** Proceed with a re-powering of the natural gas-fired Grayson Power Plant with a combination of simple cycle and combined cycle combustion turbines totaling around 250 MW, pending further engineering study. Find a long-term municipal partner to contract for a share of the new plant's capacity and energy in order to reduce market exposure associated with potential excess energy sales.
- **Landfill Gas ("LFG") Combustion:** Proceed with new generation in the form of reciprocating engines at Scholl Canyon in order to lower generation costs and reduce regulatory costs and risks associated with the existing LFG pipeline.
- **Renewable Portfolio Standard ("RPS") Compliance:** Increase renewable energy from LFG through new generation at Scholl Canyon, and prepare to integrate new renewables with a more flexible, re-powered Grayson. Pursue a diverse mix of wind, solar, and geothermal renewable resources when opportunities arise.
- **Coal Replacement:** Replace San Juan Generating Station with market energy and new capacity at Grayson, Scholl Canyon, and new renewables. Consider participation in a new combined cycle at the Intermountain Power Plant ("IPP"), but maintain flexibility for other options that can replace GWP's current IPP position.
- **Greenhouse Gas (GHG) Compliance:** Continue to build an inventory of free allowances until 2020. Depending on regulatory developments at the state and federal level, prepare for flexibility in replacement of IPP capacity and in the quantity of new renewable additions to the portfolio.
- **Transmission Capacity:** Continue to study a new transmission connection to the California Independent System Operator ("CAISO"), but plan to buy additional transmission rights (as needed) from the Los Angeles Department of Water and Power ("LADWP") unless the risks of a new transmission build can be controlled.
- **Energy Storage:** Continue to monitor storage applications as costs decline for batteries or other technologies. For any potential storage projects, energy shifting benefits, as well as regulation and spinning reserve benefits, should be considered, especially as negotiations with LADWP proceed around scheduling deviation penalties.
- **Distributed Generation - Solar Photovoltaics (PV):** Monitor the build-out of customer-sited solar, which could total 10 MW by 2020 and 40 MW by 2030. Prepare for system impacts through more flexible generation, including new resources at Grayson and storage resources.
- **Retail Rates:** Develop a plan for changes in rate design post-2018 in order to take advantage of smart meter infrastructure. Consider time of use ("TOU") rates as a means of shifting load away from peak periods.

A summary of the preferred resource plan's capacity is shown in Exhibit 1. By 2020, new LFG capacity and a re-powered Grayson are projected to be in service. Coal-fired resources are projected to be phased-out in exchange for natural gas and renewable capacity, including customer-sited, distributed solar PV.

Exhibit 1: Summary of Preferred Resource Plan (MW)

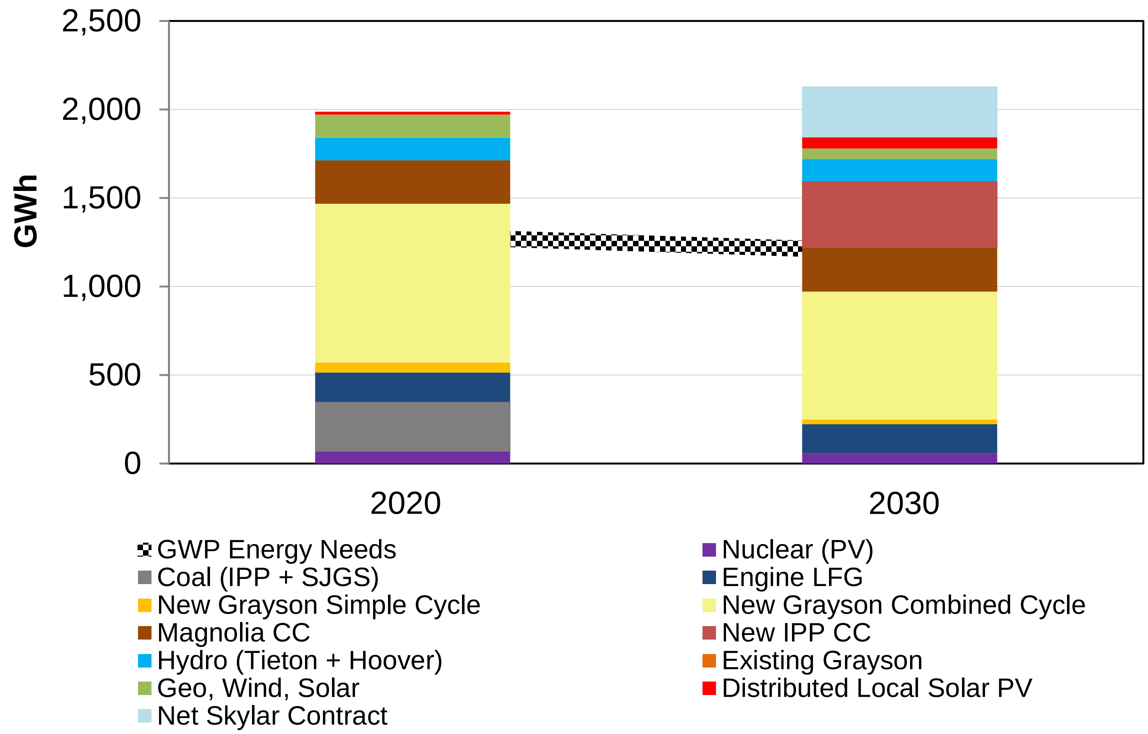


Note that the "Net Skylar Contract" and refers to Skylar's obligation to deliver to GWP minus GWP's obligation to deliver back to Skylar. Further detail on this contract is provided in the GWP Situation Assessment chapter of this report.

Source: Pace Global

Exhibit 2 summarizes the projected energy requirements (in the hatched horizontal bar) for GWP, along with projected generation of energy by resource for 2020 and 2030 (in the stacked vertical bars) in the preferred resource plan. As is shown, a new combined cycle at Grayson is expected to provide a significant amount of the portfolio's energy needs after it enters into operation. Exhibit 2 also shows how coal-fired generation is phased out and replaced by natural gas-generation at various locations and how renewables, in the form of LFG, hydroelectric generation, geothermal, wind, and solar (both utility-scale and through distributed PV), are expected to maintain RPS compliance under existing rules. Notably, GWP's energy resources are projected to be greater than its needs, meaning that excess sales opportunities are likely to be available.

Exhibit 2: Projected Portfolio Energy Resources over Time



Note that the "Net Skylar Contract" and refers to Skylar's obligation to deliver to GWP minus GWP's obligation to deliver back to Skylar. Further detail on this contract is provided in the GWP Situation Assessment chapter of this report.

Source: Pace Global analysis

SUMMARY OF KEY METRICS FOR PREFERRED RESOURCE PLAN

In evaluating the merits of the preferred resource plan, this IRP assessed the performance of various portfolio options across a series of GWP's key objectives and metrics. The remainder of this report details the development of such objectives and the analysis performed to record all metrics, while the following summarizes the performance of the preferred plan:

- Cost: The preferred plan has the lowest expected cost across all alternatives;
- Risk: The preferred plan offers a hedge against high market prices and offers more local control of generation in the event of emergencies; since there is a larger reliance on excess energy sales, a partner for long-term offtake of capacity or energy is recommended in order to mitigate the risk of relying on short-term, spot markets;
- Reliability: The preferred plan meets reliability standards better than other alternatives;
- Environmental Stewardship: The preferred plan meets current renewable requirements, with flexibility to adapt to potential changes; although CO_2 emissions from local generation are expected to increase from current levels at Grayson due to re-powering, this is in part the result of displacement of less efficient natural gas-fired generation in the broader market of southern California; CO_2 emissions from GWP's coal-fired resources will be eliminated by 2025.
- Management of Debt Levels: The preferred plan requires the most capital investment of all alternatives, which requires GWP to monitor financial requirements over time.

PLANNING ENVIRONMENT AND IRP PROCESS

GWP has commissioned this IRP in order to develop a single, integrated process under which to evaluate a wide range of future resource decisions. While GWP has previously conducted studies on various planning topics, this IRP represents its first comprehensive assessment of major future drivers of the electric utility's operations.

KEY PLANNING ISSUES UNDER CONSIDERATION

GWP identified several key planning issues that require consideration in the IRP. The overall assessment has been designed to address all issues through resource evaluation and screening, portfolio modeling, and special studies. The main planning elements are summarized here, with supporting detail found throughout the remainder of this report.

Grayson

The Grayson Power Plant is GWP's local, natural gas-fired generating station that has been in service since the early 1940s. There are currently six operational units at the facility, which burn natural gas along with landfill gas from Scholl Canyon. Given the age of the units, all but one is likely to be shut down within a decade. Therefore, a primary element of this IRP is to evaluate potential resource options that could represent a re-powering strategy at Grayson.

Shift from Coal – San Juan and IPP

GWP's ownership stake in the San Juan coal-fired power plant is ending at the end of 2017 due to unit retirements. This will result in a loss of 19 MW of capacity. In addition, GWP currently has a contract for 38 MW of power from the Intermountain Power Project ("IPP"), a coal-fired plant in Utah. Given current contractual conditions, the coal capacity will be leaving GWP's portfolio by mid-2025 and replacement options need to be considered. Current alternatives include exiting the site completely and participating in new natural gas-fired plants at the site, among other options. This IRP evaluates the various options for replacing coal capacity over time.

Landfill Gas at Scholl Canyon

GWP currently burns landfill gas ("LFG") from the Scholl Canyon landfill at the Grayson Power Plant. However, the current combustion is inefficient and the pipeline transporting LFG from Scholl Canyon to Grayson is subject to increasing maintenance costs and regulatory risks. The IRP evaluates options to build new generation capacity at the landfill to burn the LFG locally.

Renewables and Future RPS Targets

GWP is currently meeting the California renewable portfolio standard ("RPS"), which requires 33% of electricity sales to come from renewable generation by 2020. However, over time, existing renewable contracts are due to expire, and there is the clear potential for the state standard to increase to 50% by 2030. As a result, the IRP evaluates a wide range of potential renewable resource options to meet both existing and potentially new RPS levels.

Carbon Rules and Compliance

Assembly Bill 32 ("AB32") currently regulates carbon dioxide ("CO_2") through a cap-and-trade regime. This regulation has provided GWP with a set of free allowances to use for compliance. However, those free allowances run out at the end of the decade, likely driving higher costs for GWP's portfolio. Beyond 2020, further statewide regulation, along with the U.S. Environmental Protection Agency's Clean Power Plan, could result in new targets for emission reductions. This IRP has analyzed a range of potential carbon prices in order to assess GWP's portfolio performance in the future.

Local Distributed Energy Resources and Storage

New technology is currently changing the electric utility business and offering new opportunities for resource additions to GWP's portfolio. Distributed energy resources are likely to become more widespread, primarily as a result of customers installing distributed solar behind the meter. The IRP analysis, therefore, performs an assessment of the potential penetration of solar PV at the distributed level within GWP's service territory under various potential scenarios over time.

Storage resources are also available for GWP with various potential applications. These include:

- Grid-scale storage for intermittent resource firming;
- Substation-scale storage for regulation and deviation control at the intertie with LADWP;
- Behind-the-meter-scale storage for load shifting.

The IRP analysis assesses the opportunities for deployment of new storage technology for these various applications in the future.

Energy Efficiency and the Impact of Rate Design on Load

GWP currently has significant energy efficiency targets, and the IRP's load forecast explicitly assesses their impact on future load growth expectations in the service territory. Further, new rate design, especially time of use ("TOU") rate structures, is under consideration, given the deployment of smart meters throughout GWP's system. In order to assess the potential impact of new rate design, the IRP analyzes the impact of TOU rates on hourly load profiles and overall portfolio costs.

Additional Transmission Interconnections

Reductions to the local generating capacity at Grayson could require additional transmission capacity in order to meet local reliability standards. This could be accomplished through renting of new transmission capacity from LADWP or building and owning a new transmission interconnection with the California ISO. The IRP evaluates the costs and risks of both options, within the context of different resource strategies for Grayson.

IRP PROCESS AND PLANNING CRITERIA

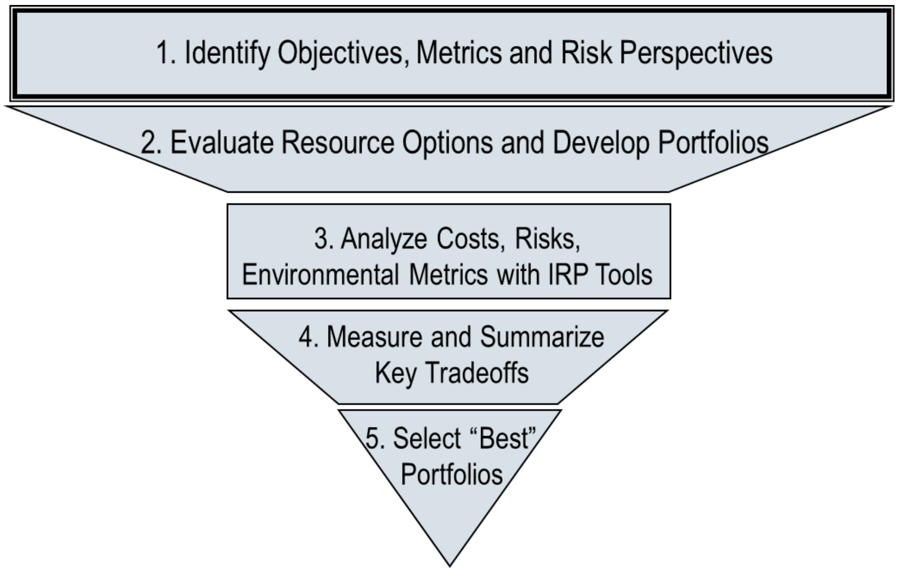
In order to facilitate effective resource assessment and decision-making in the context of such a diverse set of issues, Pace Global has deployed a five-step process in the development of the IRP. As seen in Exhibit 3, this five-step process first identifies objectives and metrics and then evaluates all feasible resource options for analysis across a range of risks, in order to produce sufficient information to select a preferred portfolio and make prudent business decisions.

As a critical first step in this process, Pace Global and GWP have established several key objectives that are important to the electric utility as it considers its future strategy. For each objective, Pace Global and GWP have also identified a specific metric that can be recorded.

Exhibit 4 lists the objectives and metrics used to drive the IRP assessment. The remainder of this document outlines the steps that were taken to identify and develop resource options and portfolios for evaluation against the objectives and metrics. In addition to supporting chapters on the various analysis details and assumptions, the report is organized as follows:

- GWP Situation Assessment – a review of GWP's current system;
- Screening Analysis – a step-by-step overview of the screening assessments performed around each of GWP's key issues;
- Portfolio Analysis – a thorough evaluation of the key results for each of the integrated portfolios against all key metrics to allow for evaluation and measurement of tradeoffs.

Exhibit 3: IRP Process Overview



Source: Pace Global

Exhibit 4: Summary of Objectives and Metrics

Objective	Metric
Minimize Cost	Levelized NPV ($/MWh) generation portfolio costs
Improve Rate Stability/ Manage Risks to Ratepayers	Range of $/MWh levelized costs across scenarios
	Reliance on market transactions (% of total costs)
Improve Reliability	Frequency and total MWh of loss of load events
Enhance Environmental Stewardship	CO_2 emissions; Renewable %
Manage Debt Levels	Total invested capital

Sources: Pace Global and GWP

GWP SITUATION ASSESSMENT

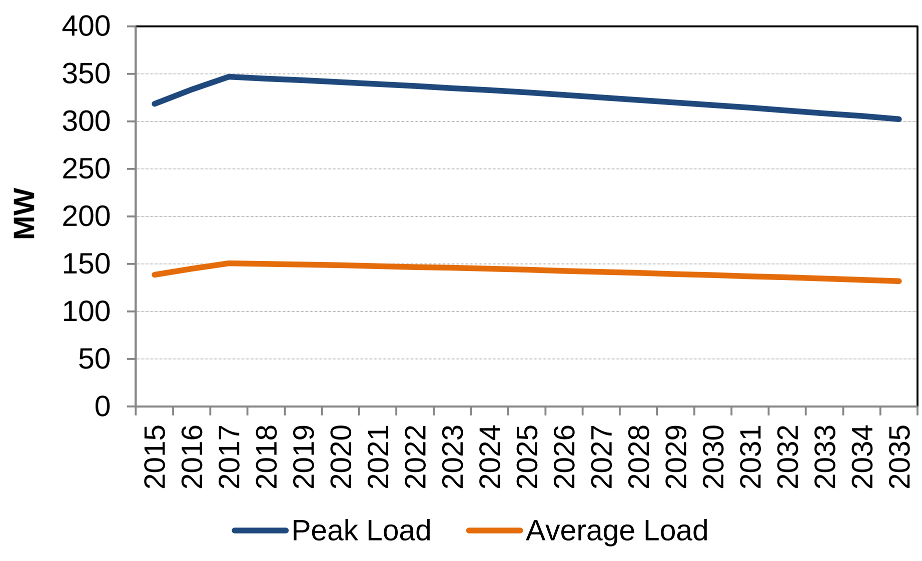
LOAD GROWTH OVERVIEW

Pace Global developed a reference case load forecast for GWP, taking into consideration the historical relationship between demand growth and weather and economic variables, which are the key drivers of loads, as well as adjustments for other drivers including customer additions, energy efficiency and DSM penetration, and electric vehicle usage. The forecast process included the following major steps:

- Perform an historical econometric analysis of key weather and economic drivers;
- Develop the base load forecast driven by normal weather, projections for economic variables, and known customer additions;
- Make adjustments for energy efficiency, demand side management ("DSM"), and plug-in electric vehicle penetration.

The load forecast expects growth in the near-term as a result of some customer additions and economic growth. However, over the long term, energy efficiency penetration is expected to more than offset any load gains from economic growth, new customers, and electric vehicle adoption. From 2015 to 2035, the compound annual growth rate for both peak and average demand is projected to be -0.25%. The load forecast summary is presented in Exhibit 5, while the details of the forecast methodology and all associated analyses are summarized in Appendix I: Load Forecast Details. In addition to the reference case forecast, Pace Global also developed different load growth trajectories for use in scenario analysis. These are summarized in the chapter on MarketLink Scenario Details.

Exhibit 5: Load Forecast Summary

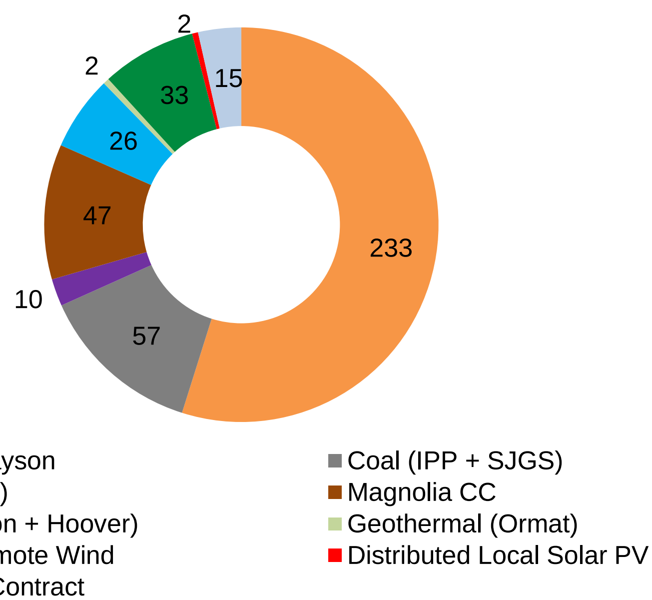


Source: Pace Global

EXISTING SUPPLY RESOURCES

GWP maintains a diverse supply profile, with capacity available from natural gas, coal, landfill gas, and a range of other renewables. Exhibit 6 summarizes the current capacity mix for GWP.[1] Currently, GWP maintains over 200 MW of capacity at the Grayson site to burn landfill gas and to provide natural gas-fired generation during peak load conditions. The Magnolia combined cycle plant in neighboring Burbank also provides a local source of natural gas combined cycle generation. GWP also imports a significant amount of energy from remote nuclear, coal, hydro, wind, and geothermal resources. Finally, GWP has a combination of long-term contracts that nets 15 MW of capacity available during the peak time period through 2023 and 50 MW after 2023.[2] Exhibit 7 provides additional detail for each plant or contract in the current portfolio.

Exhibit 6: Current Capacity Mix (MW)



Sources: GWP and Pace Global

[1] Note that capacity represents the available MW for each resource type. Since energy generation is based on resource availability and variable cost of operations, the mix of actual energy production varies considerably from capacity.
[2] This contract is termed "Net Skylar Contract" in Exhibit 6 and refers to Skylar's obligation to deliver to GWP minus GWP's obligation to deliver back to Skylar. Currently, this nets 15 MW to GWP. Exhibit 7 shows the individual details of each element of this contract arrangement.

Exhibit 7: GWP Plant and Contract Details

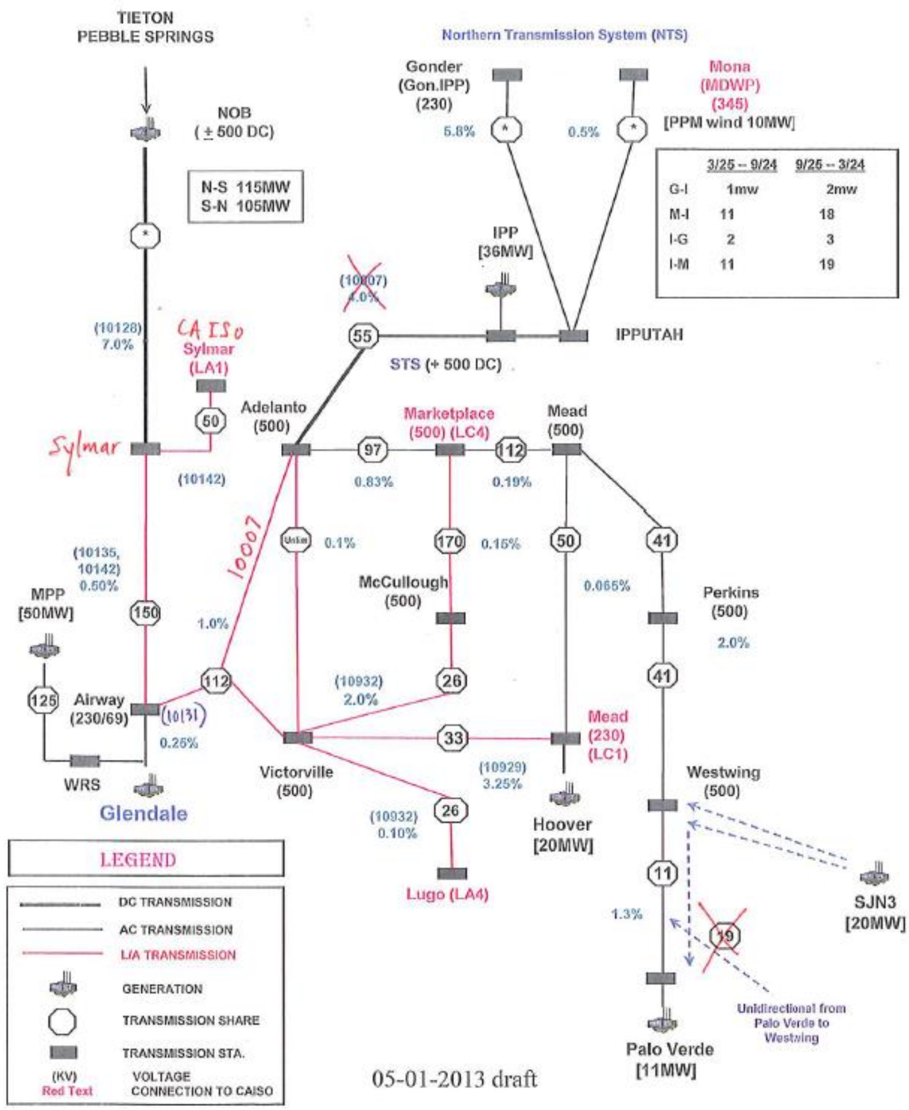
Plant (Contract) Name	Primary Fuel and Unit Type	Capacity (MW)	Comments
Grayson 3	Natural Gas ST	17	
Grayson 4	LFG/ Natural Gas ST	28	
Grayson 5	Natural Gas ST	38	
Grayson 8A	Natural Gas CC	34	
Grayson 8B/C	Natural Gas CC	68	
Grayson 9	Natural Gas CT	48	
Magnolia	Natural Gas CC	47.0	
Palo Verde	Nuclear	9.5	
Intermountain	Coal	38.0	
San Juan	Coal	19.0	
Hoover Dam	Hydro	17.0	
High Winds	Wind	3.0	3 MW of energy delivered 24x7
SW Wyoming Wind	Wind	10.0	24x7 Winter period
Ormat	Geothermal	2.1	
Pebble Springs	Wind	20.0	10 MW 24x7 March-October
Tieton	Hydro	9.0	Energy is shaped to the summer
Skylar Sales		35.0	24x7 Glendale Energy Sales at Mead
Skylar Purchase		50.0	7x16 Purchase of power at Mead (50% REC; 50% of WECC average CO2)

Source: GWP and Pace Global

TRANSMISSION TOPOLOGY

Exhibit 8 displays GWP's current transmission system overview, highlighting the various transmission paths available to import remote energy to serve load requirements. Overall, GWP has capability to import 100 MW from the Northwest and 112 MW from resources to the East in addition to the local capability to access energy from Magnolia. The remote transmission links terminate at the Airway substation. GWP currently has rights to 55 MW of transmission capacity from the IPP site, through LADWP to the Airway substation (part of the 112 MW noted above). GWP must maintain an interest in a power plant at the site or these transmission rights (including the capacity in LADWP) are likely forfeited.

Exhibit 8: Transmission System Overview



Source: GWP

SPINNING RESERVE AND LADWP CONTROL AREA

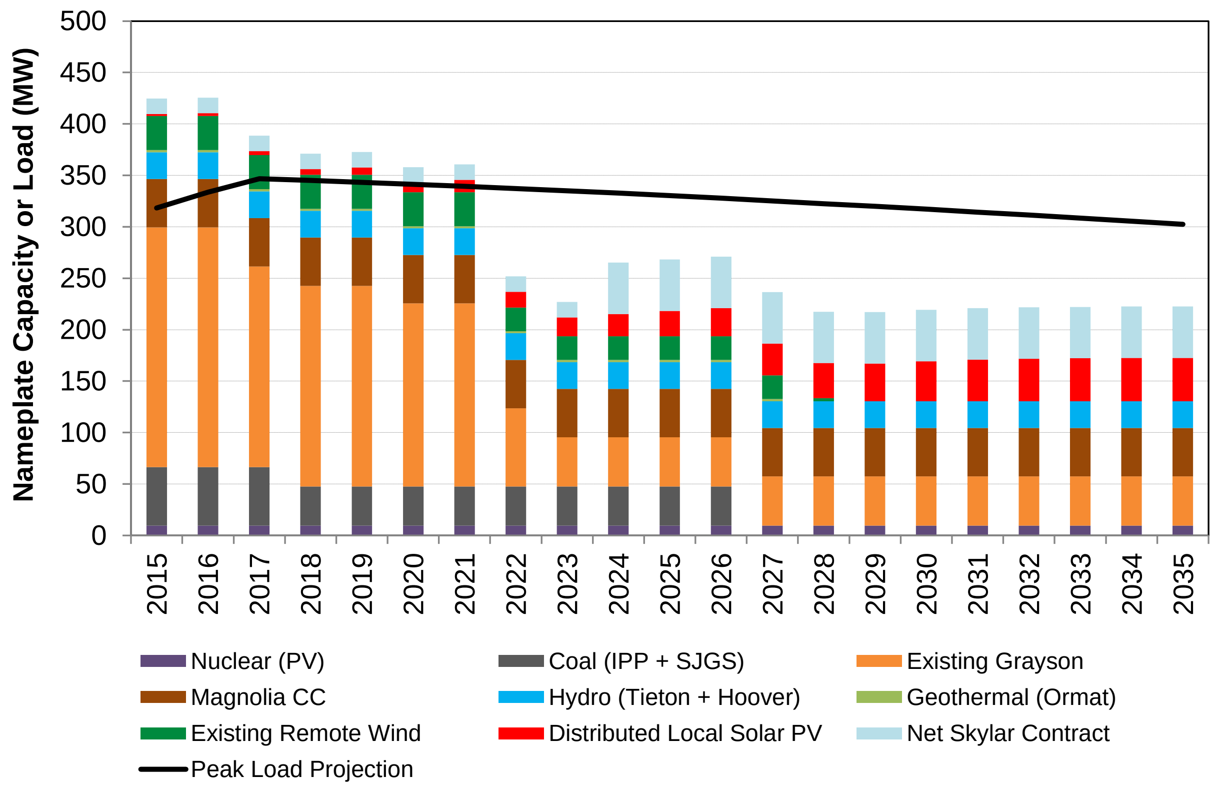
Given that GWP is within the Los Angeles Department of Water and Power ("LADWP") balancing authority, several critical constraints around system operations exist:

- Transmission limitations (as summarized in Exhibit 8) constrain imported power from the connected external locations;
- Spinning reserve and non-spinning reserve must be maintained within the GWP system to provide backup in case the single largest contingency resource (either a transmission path or generating resource) fails.

SUPPLY AND DEMAND BALANCE

Given current supply and peak load expectations, GWP currently maintains a sufficient capacity margin to support reliability and reserve requirements. However, over the next several years, units at the existing Grayson plant are expected to face shutdowns due to reliability concerns and cost-prohibitive maintenance requirements. These retirements are expected through the remainder of the decade and into the 2020s. After 2022, current projections suggest that Unit 9 will be the only unit remaining at Grayson. In addition, retirements at the San Juan coal plant will result in a loss of 19 MW of coal-fired capacity by 2018. Therefore, by the early 2020s, GWP faces a potential capacity shortage. The supply and demand balance expectations are shown in Exhibit 9.

Exhibit 9: Business as Usual Long Term Supply and Demand Balance

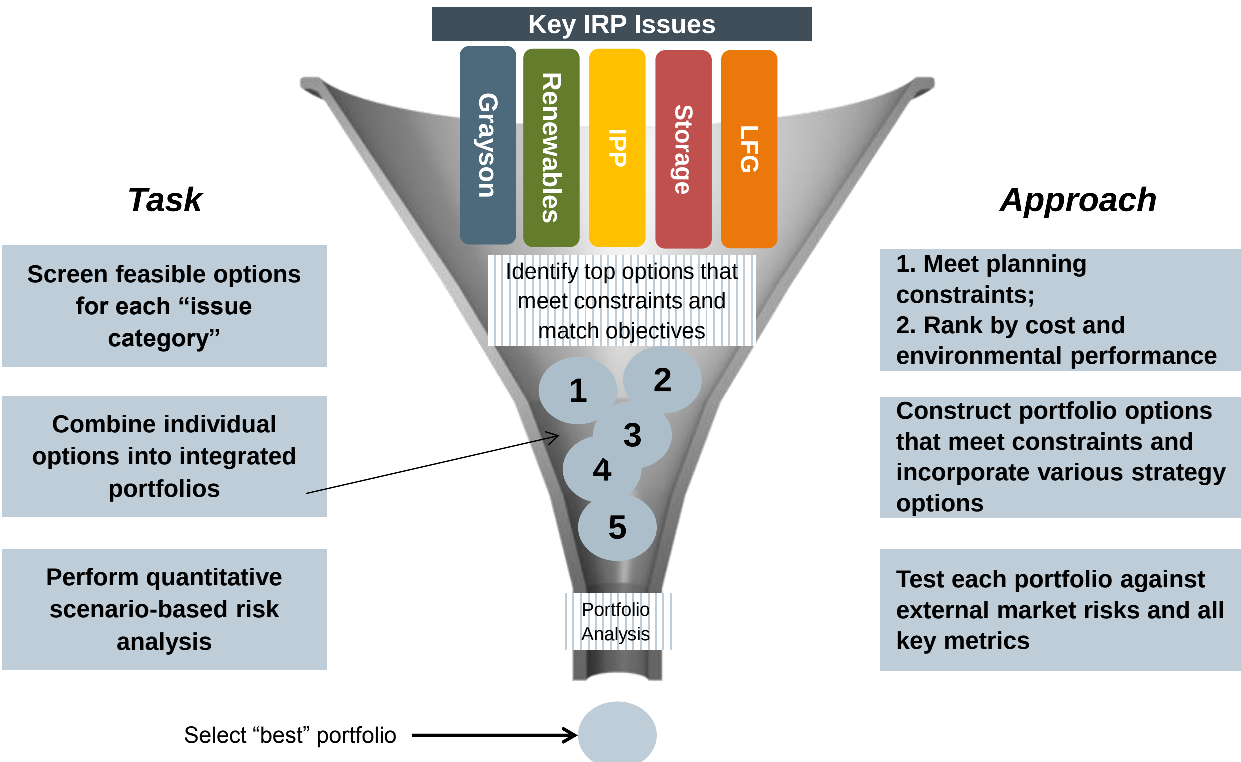


Sources: GWP and Pace Global

SCREENING ANALYSIS

Given the large number of questions facing GWP and the large diversity of options for future resource decisions, Pace Global developed a structured screening process prior to the integrated portfolio analysis. Exhibit 10 displays a conceptual overview of the screening process, which is designed to identify key issues associated with the IRP and identify the best or most likely resource options within each issue category to facilitate the development of integrated portfolio themes. The upper part of the exhibit reflects the screening process on key IRP issues, with the lower part representing the fuller portfolio analysis that is performed only for the integrated portfolios that result from screening.

Exhibit 10: Overview of Screening Process



Source: Pace Global

The IRP screening process identified several key issues:

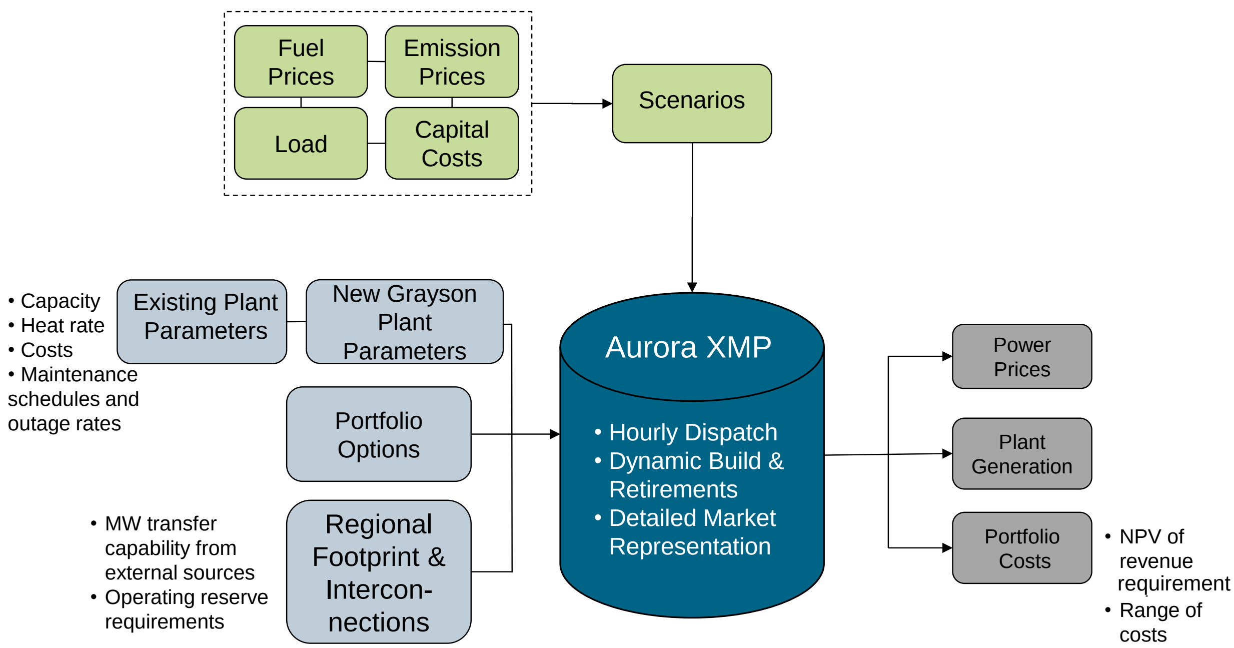
- What, if any, re-development and re-powering activities should be carried out at the existing Grayson Power Plant site ("Grayson");
- What mix of long-term renewable portfolio additions should GWP secure to meet state RPS regulations;
- What strategy should GWP pursue at the existing Intermountain Power Plant ("IPP") site for ultimate replacement of coal-fired generating capacity;
- What are the impacts and benefits of utilizing various types of energy storage technologies at the grid level, distribution level, and behind the meter;
- What strategy should GWP pursue for landfill gas ("LFG") generation.

MODELING FRAMEWORK

Pace Global utilized the AURORAxmp Electric Market Model (“Aurora”), developed by EPIS, to perform all analysis related to system dispatch and portfolio costs. Aurora was deployed as a zonal chronological dispatch model that simulates the behavior of power markets based on a production cost basis, with the ability to track specific portfolio performance. Aurora solves for each simulated hour a set of prices, revenues, dispatch costs, and emissions for specified regions and plants. With Aurora, Pace Global was able to simulate the entire GWP portfolio in the larger WECC market. The general structure of the model, with key inputs and outputs, is shown in Exhibit 11.

Based on information supplied by GWP, Pace Global developed an independent GWP zone within Aurora, with connections to various other entities (CAISO, LADWP, Magnolia Power Plant) that reflect Glendale’s existing transmission topology. Pace Global, in conjunction with GWP, also developed an hourly load forecast for Glendale through 2035 (see Appendix I: Load Forecast Details for information on that process).

Exhibit 11: Overview of Aurora Modeling Process



Source: Pace Global

GRAYSON SCREENING

The first category of screening analysis conducted by Pace Global considered the question of the Grayson site. Grayson is comprised of multiple units built between 1941 (Unit 1) and 2004 (Unit 9). As currently configured, the plants are not cost-competitive with market-supplied energy and face significant maintenance costs and challenges. They are primarily utilized to provide spinning and non-spinning reserves for Glendale and to burn local landfill gas. There is significant concern about their long-term viability as a stable supply of energy during high demand periods and as a supply of spinning reserves.

The first step in the screening involved a detailed feasibility assessment of the resource options and configurations that could be sited at Grayson in three major size categories. Plant parameters were developed by Stantec and provided to Pace Global along with operational details. These Grayson options were divided into three distinct groups by capacity added: 150 MW, 200 MW, and 250 MW.[3] The details of nine unique options are shown in Exhibit 12.

Exhibit 12: Grayson Configuration Options

Configuration Name (Series)	Wartsila 18V50SG		LM6000PG Sprint Simple Cycle		LM6000PG Sprint 1x1 Combined Cycle	
	Number of Units	*Capacity (MW)*	*Number of Units*	*Capacity (MW)*	*Number of Units*	*Capacity (MW)*
150A	3	55.0 MW	2	107.8 MW		
150B			3	161.7 MW		
200A	3	55.0 MW	3	161.7 MW		
200B			4	215.5 MW		
200C			3	161.7 MW	1	70.1 MW
250A	3	55.0 MW	4	215.5 MW		
250B			5	269.4 MW		
250C			4	215.5 MW	1	70.1 MW
250D			2	107.8 MW	2	140.2 MW

Source: Stantec, in consultation with GWP.

As shown in Exhibit 12, the nine portfolio configurations comprise three major resource types, each with different sizes, heat rates, costs, and other operational parameters. Exhibit 13 summarizes the key operational assumptions for each option. Notably, although the Wartsila engine has greater flexibility in sizing and a lower heat rate than an LM6000 combustion turbine in simple cycle form, due to emission constraints, it can only operate at a minimum capacity of 90%. This has implications for spinning reserve requirements, as discussed below.

Exhibit 13: Grayson Option Operational Assumptions[4]

Resource Option	Capacity (MW)	Full Load Heat Rate (HHV – Btu/kWh)	Minimum Capacity (%)	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Wartsila 18V50SG	18.333	8,368	90%	1,173	58.6	2.5
LM6000PG Sprint Simple Cycle	53.886	9,824	29%	1,145	28.6	4.5
LM6000PG Sprint 1x1 Combined Cycle	70.106	7,541	34%	1,408	49.3	5.3

Source: Stantec, in consultation with GWP.

Pace Global performed detailed screening analysis within Aurora, incorporating these Grayson options,

[3] These labels are for convenience. Exact MW amounts studied are shown in Exhibit 12.
[4] Note that all specific resource options shown were developed from available data and in order to establish planning-level operational and cost estimates. The IRP does **not** limit or pre-determine GWP's choice of technology or vendor for re-powering. See appendix material for full summary of operational details developed by Stantec in screening exercise.

along with other key portfolio constraints such as spinning reserve requirements. The analysis ranked the total net portfolio costs of each option, inclusive of market purchases, market sales, generation costs, and emission costs from 2019 (when planned new capacity would be operational) through 2035. The portfolios which performed the best were carried forward to the next stage in the screening. The following sections describe the testing process and screening analysis results.

Spinning Reserve Constraint Testing and Demonstration

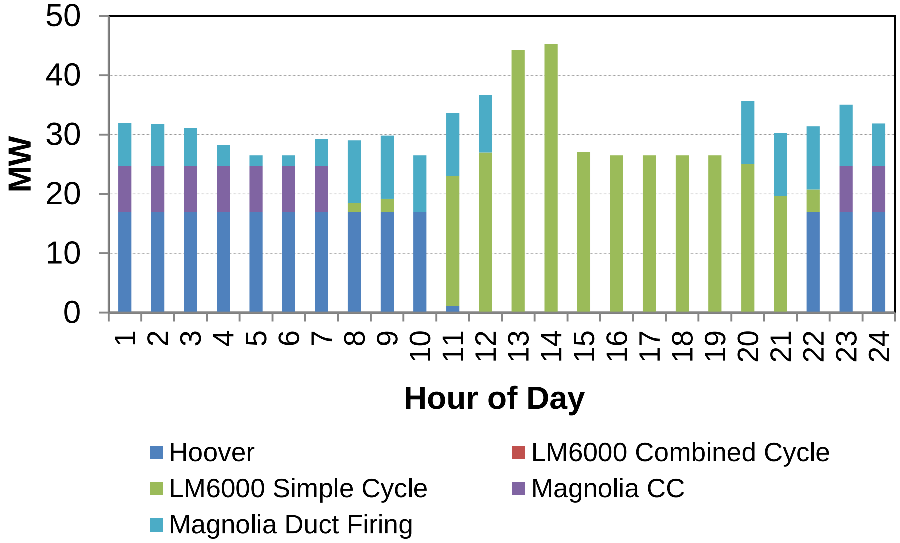
A critical element of the Grayson re-powering screening was to incorporate the non-spinning and spinning reserve constraints that exist for GWP in operating its power system. For planning purposes, Unit 9 at Grayson is assumed to be available to meet non-spinning reserve requirements at all times, while sufficient spinning reserves must also be available to meet at least one-half of the single largest contingency. Within the analysis framework, Pace Global's assessment incorporated the following methodology to account for spinning reserve requirements:

- The GWP portfolio is established as its own operating pool in Aurora;
- Spinning reserve requirements are set for the GWP pool on a MW basis, with flexibility to change hourly depending on GWP's single largest contingency (SLC);
- Eligible units to provide spin are flagged as candidates for the dispatch solution (these include local Grayson options, Hoover when not used for energy, and Magnolia);
- Aurora tracks the flow over the NW DC line on an hourly basis. This DC line, when fully utilized, is Glendale's largest contingent unit and the spinning reserve requirement is 50 MW;
- When the DC line is not utilized, the model will flag the largest unit that is operating (generally the new LM6000 units – either the simple cycle or the 1x1 combined cycle depending on the portfolio) and calculate the spinning reserve target accordingly;
- Pace Global developed what Aurora calls a "computational data set" to perform hourly tracking of the single largest contingency and feed the value into the reserve target field in the model. As the chronological hourly dispatch is performed, the simulation optimizes all resources between energy and reserve requirements.

Within this framework, units are reserved to provide spin on an hourly basis, which impacts the ability of each plant to produce energy for the portfolio. For example, the Wartsila portfolio options must run at a 90% minimum load when operating, so their ability to provide spinning reserve is minimal, forcing other units to offer this service when the SLC is high. So although Wartsila heat rates and costs are competitive versus the alternatives, their lack of flexibility increases the overall costs for meeting both energy and spinning reserve needs, compared with portfolios that exclude the Wartsila units.

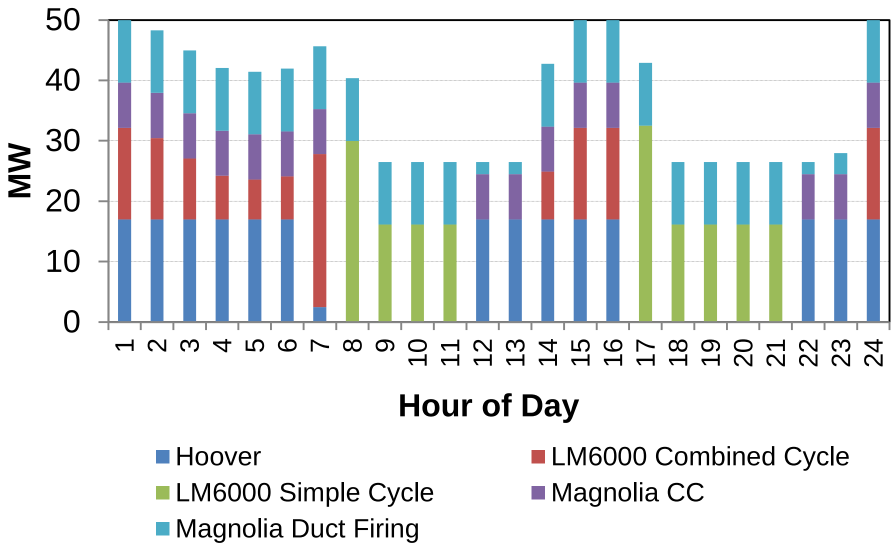
To illustrate the nature of the spinning reserve requirements, Exhibit 14 and Exhibit 15 display sample hourly spinning reserve commitments from the GWP portfolio for representative days in the summer and winter under a re-powering portfolio with LM6000 simple cycle and combined cycle turbines. In the summer during off-peak hours, Hoover and Magnolia are available for spin, while during the on-peak hours, Hoover and the combined cycles are used for energy and a local LM6000 fills the spinning reserve needs. This is shown in Exhibit 14. In the winter, Hoover is used less for energy and is more available for spin. In the example shown in Exhibit 15, the DC line is being heavily utilized for many hours, resulting in spinning reserve requirements up to 50 MW, which are met by a combination of resources, including local LM6000s.

Exhibit 14: Spinning Reserve Resources – Sample Summer Day after Re-Powering



Source: Pace Global analysis.

Exhibit 15: Spinning Reserve Resources – Sample Winter Day after Re-Powering



Source: Pace Global analysis

Additional Transmission Costs

It was determined by GWP that the 150 MW and 200 MW options would require additional import capacity for Glendale to meet load and reliability criteria. This would allow GWP to import more energy, but would also increase the costs of those portfolios. In order to account for these costs, the portfolio screening analysis evaluated two distinct options for GWP to procure more transmission capacity:

- Rent from LADWP;
- Build and own a new transmission connection to the California ISO through interconnection to Southern California Edison ("SCE").

For the rent option, the analysis included additional charges based on the current Los Angeles Department of Water and Power ("LADWP") Open Access Transmission Tariff ("OATT"). Exhibit 16 summarizes these charges, along with the annual costs associated with portfolios that require 50 MW of additional transmission capacity ("200 Series") and those that require 100 MW of additional transmission capacity ("150 Series").

Exhibit 16: Additional Transmission Costs

		Additional 50 MW	*Additional 100 MW*
	$/MW	**"200 Series" Cost (Millions $)**	**"150 Series" Costs (Millions $)**
Schedule 1	1,310	0.07	0.13
Schedule 2	4,990	0.25	0.50
Schedule 7	44,990	2.25	4.50
Total	**51,290**	**2.56**	**5.13**

Source: GWP and LADWP OATT schedule

For the build and own option, Pace Global relied on a report produced by Stantec on the costs of interconnection between the SCE substation at Eagle Rock and GWP's Kellogg substation.[5] The total capital costs of the new transmission interconnection were estimated at $66 million, amounting to an annual cost in the "150 Series" of $3.4 million when amortized over a long-term period at GWP's cost of debt.

Building and owning new transmission capacity appears less expensive under baseline cost estimates, but it carries several significant risks and uncertainties. These include:

- Cost uncertainties around transmission development as well as potential transmission system impacts that may require mitigation and additional upgrade costs;
- The uncertainty of the reliability of a new connection to CAISO;
- An increase in GWP's single largest contingency through a new large transmission interconnection could increase other costs of operating the portfolio.

As a result of the risks, portfolios were developed with the costs associated with the rent option (Exhibit 16), with further study of the build option recommended.

Costs for Air Permits

In addition, each portfolio faces a different requirement associated with emission offset fees required by the Southern California Air Quality Management District ("AQMD"). In order to capture differences in offset fee requirements by portfolio, Pace Global incorporated the costs associated with each portfolio concept that were developed by Stantec.[6] The total expected fees and annual charge assessment

[5] See appendix material: "Interim Screening Report: New Interconnection Options for the City of Glendale Water & Power."
[6] See appendix material: "Air Permitting Feasibility Study for Grayson Power Plant."

assuming an amortization over the study period are summarized in Exhibit 17 for a selection of the top-performing portfolios.

Exhibit 17: Expected Air Quality Management District Fees by Portfolio

	150B	200B	200C	250D
Upfront AQMD Fees	23.4	33.7	31.0	30.6
Annual AQMD Fee at GWP Cost of Debt	1.1	1.6	1.5	1.5

Note: The first row in this table shows the total estimated upfront costs of acquiring the emission permits themselves. The second row indicates the annual charge if GWP were to finance these costs at its cost of debt.

Source: Stantec

Overall Portfolio Costs for Grayson Options

Once all constraints and additional costs were accounted for, Pace Global's analysis simulated each individual Grayson repower concept within the integrated hourly dispatch model. The simulation included the following:

- Full representation of GWP's load forecast;
- Full representation of GWP's existing portfolio, inclusive of owned resources and contracts;
- A "proxy" representation of generic renewable additions over time in order to include likely remote renewable capacity that will enter the portfolio in the 2020s;
- Dynamic spinning reserve requirements that change by hour and based on the configuration of the various Grayson options.

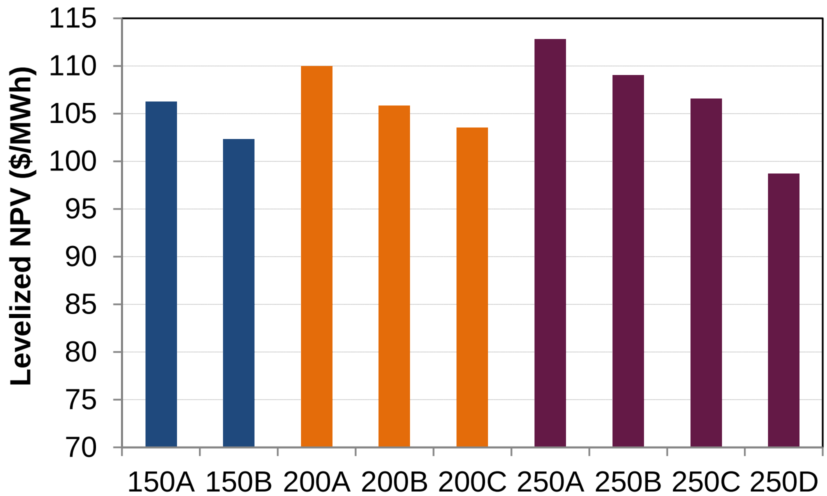
The screening exercise was able to narrow the list of Grayson options from nine to four. Exhibit 18 displays the levelized net present value of total GWP portfolio costs over the 2019-2035 time period for each Grayson configuration. The following conclusions were reached:

- The Wartsila "A" family is higher cost than the other LM6000 options within each capacity grouping. This is due to the very high minimum operating level required for Wartsila operations. As a result of this constraint, the "A" options effectively generate energy at times when it is not economic and lack the flexibility available to the LM6000s to optimize energy production and spinning reserves from local resources.
- The 250D portfolio achieves the lowest cost as a result of significant market sales opportunities that develop with 140 MW of efficient combined cycle capacity.
- Even with additional transmission cost requirements, the 150B portfolio is competitive on a cost basis.[7]
- The 200B and 200C portfolios are within the top four options, although both are slightly higher than the best-performing 150 and 250 portfolios at this step of the screening phase.
- Similar to 250D, the 250A and 250B portfolios also build more capacity than is needed for future peak load expectations, but since they comprise only simple cycle capacity additions, they do not realize the benefit of sufficient market sales to offset the fixed capital costs of construction. While the 250C concept's combined cycle units lower costs, testing indicates that it is significantly higher cost than 250D and more costly than the two 200 series options.

Overall, the screening tests concluded that four Grayson portfolio configurations are the most competitive options for further screening and portfolio development. These include 150B, 200B, 200C, and 250D.

[7] This conclusion excludes other critical criteria, discussed in the Portfolio Analysis chapter.

Exhibit 18: Screening Results for Grayson Options

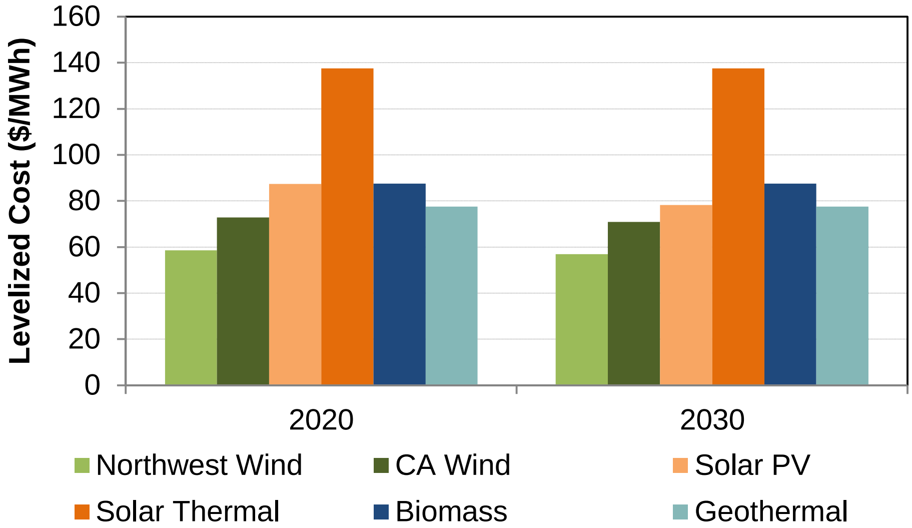


Source: Pace Global analysis

RENEWABLE SCREENING

After completing the initial round of Grayson screening, Pace Global assessed the long-term RPS compliance strategy for GWP through the analysis of multiple renewable technology options. The initial analysis included a technology cost screen to identify feasible intermittent and baseload renewable options and to rank them in order of cost. Exhibit 19 summarizes the levelized costs of six renewable options that were evaluated in the first level of renewable screening and their associated cost estimates per MWh in 2020 and 2030. As shown, the options are organized into 3 major categories: wind, solar, and baseload renewables. Within these categories, remote wind from the Northwest, solar PV, and geothermal are the preferred options on the basis of expected costs.

Exhibit 19: Levelized Cost of Electricity for Remote Renewable Options



*Notes: Northwest wind capacity factor at 38%, CA wind capacity factor at 32%.
Solar PV capacity factor at 22%, solar thermal capacity factor at 37%.
Both biomass and geothermal capacity factors assumed to be 80%, with $25/MWh fuel costs for biomass.

Source: Pace Global analysis

Given the findings from the levelized cost-based screening, Pace Global developed four renewable portfolio concepts to run in conjunction with the portfolios that were ranked best from the Grayson screening. These renewable portfolios were as follows:

- 100% intermittent supplies (50% from NW Wind, 50% from SW solar PV);
- 50% baseload geothermal and 50% *firmed*[8] intermittent supplies (50% from NW Wind, 50% from SW solar PV with a gas CT to firm supply during lower production hours);
- 50% baseload geothermal and 50% intermittent supplies (50% from NW Wind, 50% from SW solar PV) with no explicit firming costs beyond local generation resources;
- An even split among baseload geothermal, *firmed* intermittent, and intermittent supplies.

Exhibit 20 summarizes the composition of the four renewable portfolio concepts that were developed for further quantitative screening. Although the total *capacity* in MW is different across each concept, the portfolios all meet the same *energy* requirements for RPS compliance. In order to ensure the performance of different renewable options was not materially different under the various Grayson configurations, each of the four renewable options was run with each of the remaining Grayson options from the first round of screening.

[8] Note that "firmed" means that a third party would provide a constant source of renewable energy by using a backup natural gas-fired combustion turbine.

Exhibit 20: Summary of Renewable Portfolio Concepts (New MW by 2035)

Portfolio Concept	Wind	Solar	Geothermal	Remote CT Capacity for Firming
100% Intermittent	13	13		
50% Baseload; 50% Remote *Firmed* Intermittent	7	7	4	12
50% Baseload; 50% Intermittent	7	7	4	
33% Baseload; 33% Remote *Firmed* Intermittent; 33% Intermittent	9	9	2.5	8

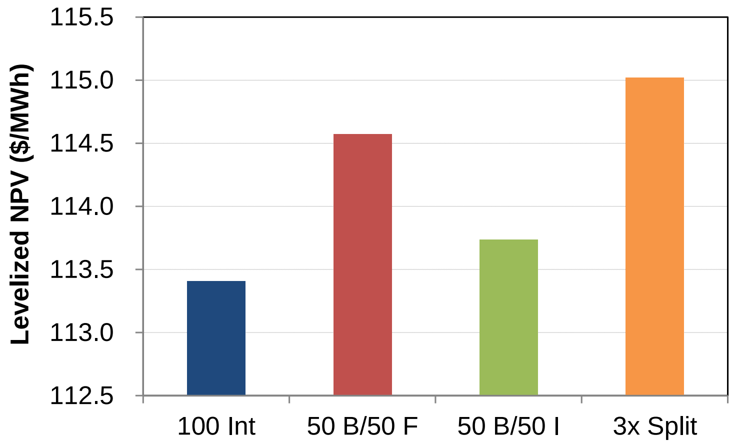
Note that all MW values represent incremental capacity additions beyond those that already exist in GWP's portfolio. Further, this screening only assumed the current 33% RPS and does not include capacity required to meet a potential 50% RPS. This scenario is evaluated further in the portfolio analysis.

Source: Pace Global analysis

The result of the analysis suggested that the 50% baseload/ 50% intermittent portfolio and the 100% intermittent portfolio were the lowest cost options across all the Grayson combinations tested. These portfolios allow GWP to internally balance the intermittent nature of remote renewable supply with local Grayson resources, while the geothermal offers a cost-effective baseload supply of energy.

Exhibit 21 displays the costs of the various portfolio options, indicating that the 100% intermittent and 50% baseload/ 50% intermittent portfolios are the most attractive options. The graphic displays the average levelized NPV of portfolio costs for each renewable option across the Grayson portfolio families that were established after the first round of screening. Although the total costs are close across the renewable concepts, this is due to the fact that the portfolios are all identical until new remote renewables are needed in the 2020s. The screening analysis clearly indicates that reliance on new local Grayson resources for firming services is cost-effective, suggesting that integrated portfolio concepts should consider only the 100% Intermittent and 50% Baseload/ 50% Intermittent renewable strategies.

Exhibit 21: Summary of Renewable Screening Results



100 Int: 100% Intermittent
50 B/ 50 F: 50% Baseload; 50% Remote *Firmed* Intermittent
50 B/ 50 I: 50% Baseload; 50% Intermittent
3x Split: 33% Baseload; 33% Remote *Firmed* Intermittent; 33% Intermittent

Source: Pace Global analysis

IPP SCREENING

In addition to remote renewable options, GWP is faced with current questions about how to replace existing capacity at the coal-fired Intermountain Power Plant ("IPP"). Due to emissions regulations, continued operations of the plant by Southern California utilities will not be allowed after current contracts expire. Replacement generation is expected to be operational by 2025. In order to evaluate options at this site, Pace Global conducted a screening analysis of feasible replacement strategies. GWP is considering the following three options:

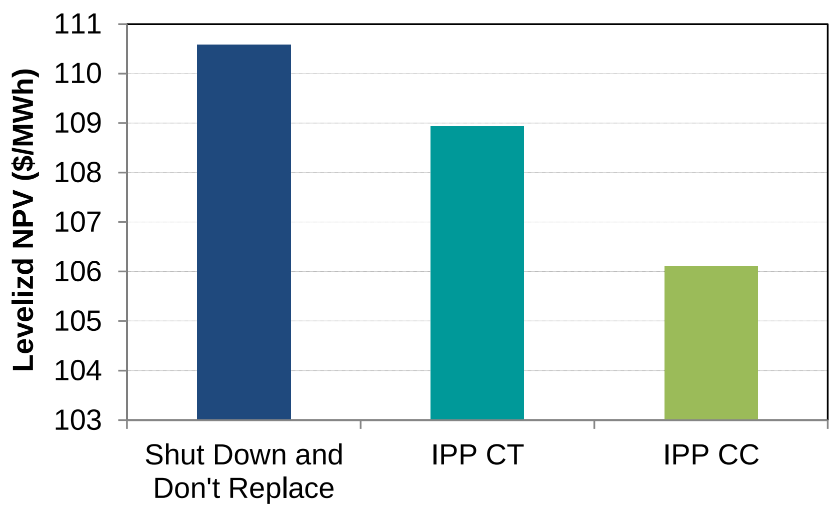
- Join a consortium of existing plant owners to develop a new, large natural gas-fired combined cycle ("CC") plant on the site;
- Work with another municipal utility to develop a smaller LMS100 gas-fired combustion turbine on the site; or
- Let IPP shut down without replacement with new capacity at the site.

Each option has benefits and drawbacks:

- Entering into a new partnership for a large CC would benefit GWP with an efficient energy source, burning relatively inexpensive Rockies gas, but GWP would likely have little operational control over plant operations and would be obligated to take the energy on a baseload schedule.
- Joining with another City to share a smaller LMS100 would allow for greater operational control, but would not provide a significant dispatch cost advantage compared to a locally-operated CT.
- Dropping out of the IPP site would reduce GWP's fixed cost generation obligations but would also result in significant new transmission costs to replace transmission rights that are associated with existing contracts.

Pace Global first analyzed all three options by testing each strategy against a single portfolio concept from the initial rounds of screening analysis (in this case 200C) in order to evaluate the impacts on overall portfolio costs associated with new capacity and different transmission rights. The analysis suggests that the option to be part of a new, large CC project at the existing site is the most cost-effective. The analysis projects high dispatch for the new efficient CC, which adds significant energy value and some small amounts of spinning reserve capability. The LMS100 has the next lowest costs, as it offers some incremental generation and spinning reserve capacity, but this does not make up for the significant energy value attributable to the CC. The "shut down" portfolio is highest cost due to the fact that transmission replacement costs are higher than any savings associated with purchasing market power. These results are summarized in Exhibit 22.

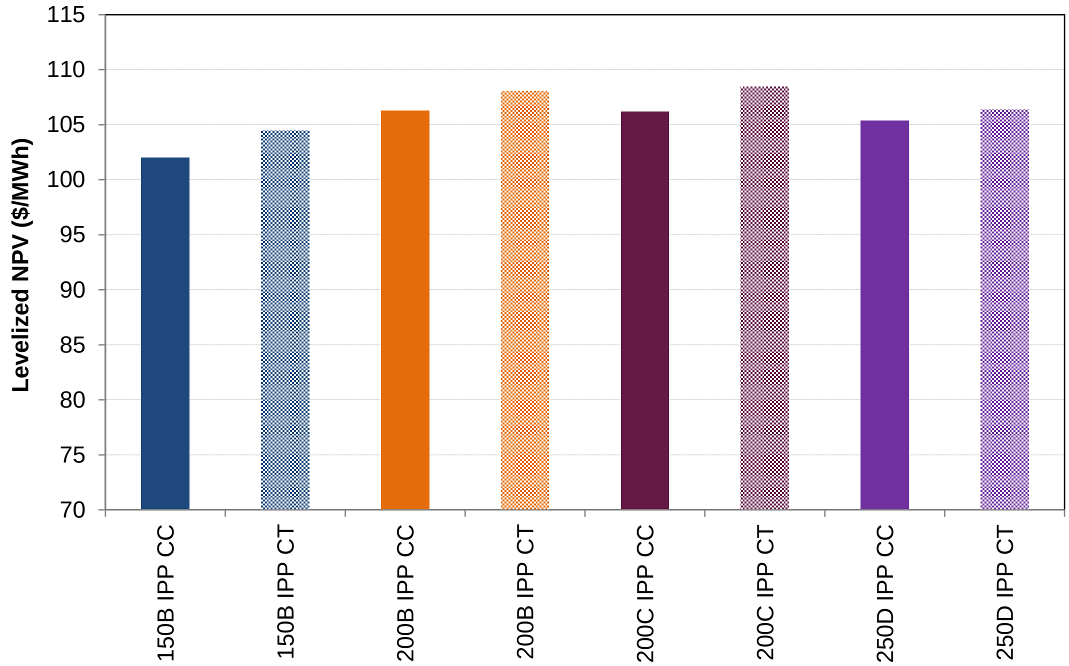
Exhibit 22: Initial IPP Screening Results



Source: Pace Global analysis

Given that the two portfolio options that added capacity performed the best, Pace Global performed further screening analysis to assess whether the decisions at Grayson would influence the performance of the IPP options. In this analysis, the IPP CT option and the IPP CC option were each evaluated against each of the top four Grayson options reviewed in the first phase of screening. Although the relative benefit of the CC differed slightly across Grayson options and was almost zero in the 250D portfolio with significant local CC capacity, the IPP combined cycle strategy was consistently more cost-effective. This is shown in Exhibit 23. As a result of this analysis, further portfolio analysis incorporated the gas CC option at IPP.

Exhibit 23: IPP Screening Results across Grayson Options



Source: Pace Global analysis

STORAGE OPTIONS SCREENING

The IRP process has identified three different potential applications for storage resource additions:

- Grid-scale storage designed to firm remote renewable resources;
- Behind-the-meter scale storage designed to shift load; and
- Substation scale storage designed to provide ancillary services such as frequency regulation through automatic generation control ("AGC") or spinning reserves.

Grid-Scale Storage

In evaluating grid-scale storage solutions, Pace Global screened a variety of battery options by reviewing publicly available data from project experience and actual deployment in areas like Hawaii, bids received by the Southern California Public Power Authority ("SCPPA") for storage resources[9], and information provided by storage solution vendors. It was determined that Lithium-Ion battery storage with a four-hour storage duration is currently the most feasible technology for potential deployment. The key characteristics for this storage option are shown in Exhibit 24.

[9] Bids submitted to SCPPA were redacted to protect commercially sensitive information.

Exhibit 24: Summary of Lithium Ion Battery Characteristics for Grid-Scale Storage

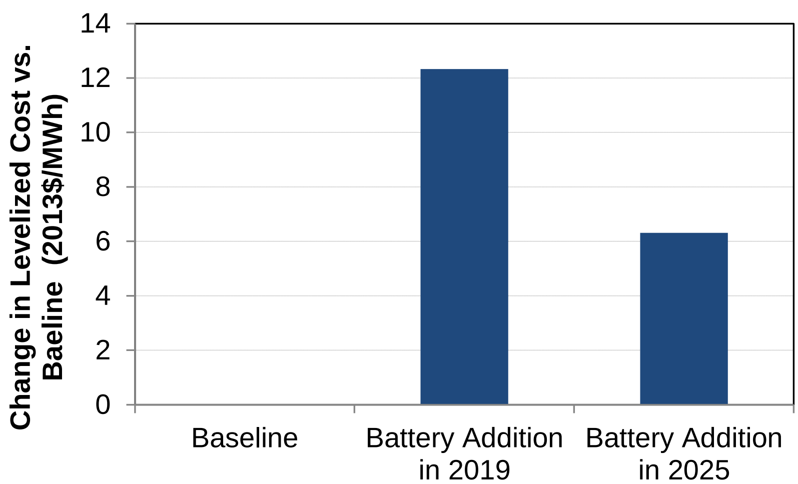
Category	Characteristic
Storage Duration	4 Hours
Round Trip Efficiency	85-90%
Battery Life	11-15 Years
FOM (2013$/kW-yr)	101
2015 Cost (2013$/kW)	4,681
2019 Cost (2013$/kW)	1,500
2025 Cost (2013$/kW)	1,000

Source: Pace Global analysis, bids to SCPPA, Hawaii Power Supply Improvement Plan ("PSIP") quotes, Navigant Consulting

In order to then test the impact of new grid-scale storage on GWP's portfolio costs, one integrated portfolio from the initial screening review (in this case 200 C) was evaluated with and without 50 MW of grid-scale batteries added either in 2019 or 2025. The battery additions were evaluated by deploying Aurora's storage logic designed to levelize demand net of "must run" resources. This effectively optimizes the battery resource dispatch to charge when net load inclusive of renewable generation is low and discharge when load is high. This technique is designed to assess the performance of the batteries in firming the intermittency of the remote renewables.

Overall, even with projected price reductions, the high fixed costs of grid level battery storage are found to outweigh the benefits of the resource firming that can be achieved. As shown in Exhibit 25, with a battery addition in 2019, the overall levelized costs of the test portfolio under Reference Case conditions over the 2019-2035 time period increased by about $12/MWh. On a baseline levelized cost around $100/MWh, this represents a 12% higher overall system cost every year. If the battery addition is delayed in anticipation of cost declines, the economics improve, but overall levelized portfolio costs are still higher than the baseline portfolio by about $6/MWh. Given the results of this screening analysis, grid-scale battery additions are not recommended for inclusion in further portfolio development. This conclusion should be revisited if storage prices fall sufficiently, compared with the assumptions used here.

Exhibit 25: Grid-Scale Battery Screening Results



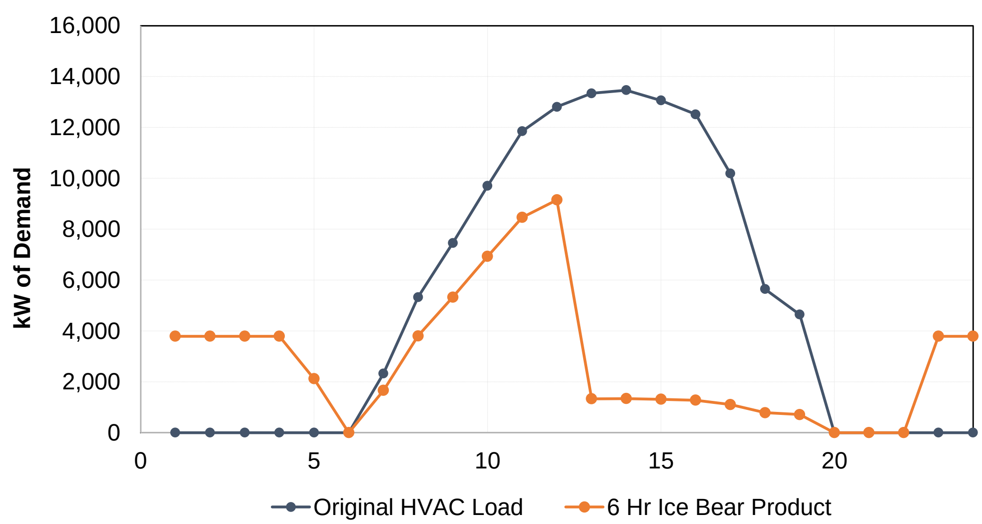
Source: Pace Global analysis

Behind-the-Meter-Scale Storage – Ice Bear

In evaluating behind-the-meter-scale storage resource options, Pace Global has focused on the potential deployment of Ice Bear technology throughout the GWP service territory. The Ice Bear system is developed by Ice Energy and works in conjunction with commercial air conditioning systems. The system uses and stores energy at night and then delivers it during the day when air conditioning loads are highest. Pace Global's assessment has tested the impact of Ice Bear deployment on GWP's portfolio costs using hourly operational profiles and cost information provided by Ice Energy.

The cost of Ice Bear installation is assumed to be $1,360/kW, with an additional 2% service cost to cover O&M, inflating at an annual rate of 2.5%. The six-hour Ice Bear product effectively increases system demand in the overnight hours, while reducing load during the afternoon peak. Pace Global was provided with a full 8,760 hourly operational projection, which has been assessed in our analysis. Exhibit 26 shows a projection of original HVAC load for commercial customers along with the impact of 10 MW of Ice Bear storage.

Exhibit 26: Ice Bear Load Impact Profile – 10 MW for Typical Summer Day



Source: Ice Energy

Similar to the screening for grid-scale storage, one integrated portfolio from the initial screening review (in this case 200C) was evaluated with both 10 MW and 20 MW of Ice Bear resource additions. Overall, Pace Global has found the following:

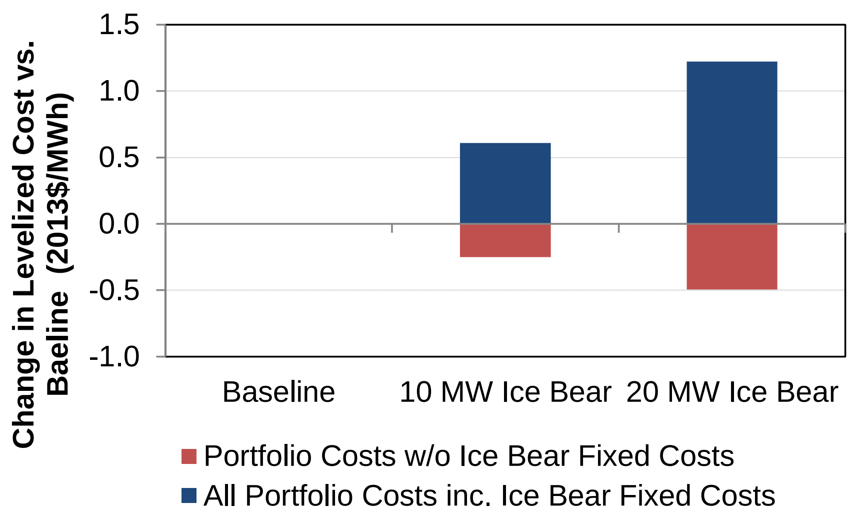
- The load shifting contributes to an increase in combined cycle run time (during off-peak hours) and a decrease in energy costs and net market purchases.
- On net (but prior to accounting for the capital and operating costs of Ice Bear), this contributes to a savings for the system's costs on the order of 0.1% to 0.2% for 10 MW and 20 MW additions, respectively.
- The $1,360/kW capital costs plus incremental operating costs, however, overwhelm this savings under the assumption that GWP pays all costs of installation and operation.
- Given the fact that GWP is not capacity short, especially after re-powering at Grayson, there is no incremental capacity value (avoided cost) assumed for the Ice Bear additions. If avoided costs

were assumed for both generation/transmission capacity and at the distribution level, the economics could improve.

- Without capacity value, if customers bore 65% of the costs, the Ice Bear additions would breakeven for GWP portfolio costs.

Exhibit 27 displays the impact on total GWP portfolio costs under the screening cases performed with 10 MW and 20 MW Ice Bear additions. As can be seen, prior to accounting for the fixed capital and maintenance costs associated with the Ice Bear additions, GWP's system realizes a cost savings. However, once all costs are accounted for, the portfolios with Ice Bear additions are more costly than the baseline by between $0.6-$1.2/MWh.

Exhibit 27: Ice Bear Storage Screening Results



Note: All Ice Bear costs are assumed by GWP; no avoided capacity or distribution costs are included in the analysis.

Source: Pace Global analysis

Substation-Level Storage: Intra-Hour Analysis

Current Situation

GWP is facing new requirements for intra-hour balancing of loads and resources, including dynamic scheduling of the Intermountain Power Project and balancing area requirements and fees proposed by LADWP. As a result, the IRP has identified and analyzed two options to mitigate scheduling deviations and lower system costs.

In addition to conventional options, GWP is interested in exploring the use of an energy storage solution to address energy deviations (schedule minus actual) resulting in inadvertent power exchange with LADWP. The LADWP is proposing a new penalty mechanism wherein any deviation in excess of 8 MW (absolute value, integrated over a 15 minute period) will be levied a penalty charge based on LADWP's OATT. GWP's own calculations estimate that penalty payments would have been in the range of $5-6 million based on tie line data for Year 2014. A battery energy storage solution ("BESS") may be able to help reduce the magnitude and frequency of the deviations and serve to mitigate the risk of paying penalties for inadvertent exchange. In addition, the same BESS can also provide spinning reserves and relieve other units from providing that service so that they can be dispatched for energy or used for non-spinning reserves.

More generally, the tie line deviations are an artifact of a larger issue on the system with lack of Automatic Generation Control ("AGC"). Frequency and tie line deviations can result from small load and generation changes that cannot be compensated. This is attributable to lack of AGC equipment. Along with mitigating deviations, GWP also requires an ability to continue to meet the contingency reserve standard before the Grayson repowered units are available.

Options for Alternative Regulation and Spinning Resource Strategies

GWP has identified two strategies for improving intra-hour balancing of loads and improving spinning reserve resource flexibility:

- Install a cost-effective amount of battery energy storage to be used for regulation (prior to and after Grayson re-power) and to provide spinning reserve when available; keep Unit 9 on non-spin reserve status;
- Use Unit 9 in the near term (prior to Grayson re-power) for regulation and spinning reserve; buy non-spin reserves from LADWP; in 2020 and beyond, Unit 9 goes back to non-spin and new Grayson units pick up regulation/spin requirements.

The planned deployment of new batteries and Unit 9 before and after the planned re-powering at Grayson for each strategy is summarized in Exhibit 28.

Exhibit 28: Summary of Services under New Battery or Unit 9 Strategies

Strategy	Battery services	Unit 9 services pre-re-powering	Unit 9 services post-re-powering
Deploy new batteries	Regulation and spin	Non-spin	Non-spin
Upgrade Unit 9 to AGC	N/A	Regulation and spin	Non-spin

Source: Pace Global and GWP

Key Attributes of a BESS

A BESS offers a potential solution to both the frequency regulation and contingency reserve requirements for GWP and hence was evaluated as a viable substation-level storage solution against the alternative of changing the operational strategy of Unit 9. The following summarizes how a BESS can provide key ancillary services for GWP:

- **Regulation Services**: Regulation is the use of online generation, storage, or load that is equipped with AGC and that can change output quickly (MW/min) to track the moment-to-moment fluctuations in customer loads and to correct for fluctuations in generation. Regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area.

  The BESS is fast-acting with high ramp rates, and it responds to AGC signals to provide regulation up or regulation down services. While there are quite a few battery technologies, Lithium Ion batteries are beginning to see wide adoption for this application. For regulation services, the energy need is not as great, but the batteries have high duty cycles. Batteries may need to respond multiple times each hour, for the full year, resulting in very high asset utilization.

- **Spinning Reserve Services**: A BESS can be used to provide spinning reserves, which are required in order to cover the energy needs in the event of a failure of an operating resource. A 30-minute storage is usually enough, as batteries can be immediately deployed to respond to system contingencies and can remain operational for 10 minutes until a fast-start reserve generating unit can be deployed. A BESS in a spinning reserve application is subjected to fewer duty cycles (potentially 20 to 50 a year).

In the analysis performed as part of this IRP, a single 30-minute BESS is assumed to provide both regulation and spinning reserve services. The battery can perform both functions as long as it has enough charge to provide 10 minutes of spinning reserve at any given point in time.

Cost Assumptions for BESS

The annual battery costs consist of three elements: the amortized capital costs, the ongoing FOM, and the augmentation FOM. The amortized capital costs are based on installed costs of $1,150/kW amortized over a battery life of 10 years at a rate consistent with Glendale's cost of debt (4.5%). Below is more detail on the individual components of the battery costs:

- Capital Cost: Pace Global assumes a $1,150/kW capital cost based on review of public sources and discussions with vendors, primarily through our affiliates at Siemens Energy, Inc. The current price point for such batteries varies, but on average the cost is about $1,150/kW for a 30-minute BESS. In terms of storage space, a 2 MW battery can fit in a 54 foot trailer, so for a 20 MW battery application, about 10 such trailers would be required. The cost estimate of $1,150/kW include standard "balance of plant" items, including inverters, transformers, and control systems to integrate the facility with GWP's infrastructure.

- Ongoing fixed operations and maintenance ("FOM") Costs: The ongoing FOM is associated with periodic maintenance on all parts of the system including fire suppression, cooling, fans, inverter maintenance, fuses, fans, cooling, capacitors, transformer, sensors (pressure, temperature), switchgear (both medium voltage and high voltage), and protective relays. In addition, there is periodic tightening of all connections at different parts of the system and grounding verification. The ongoing FOM for the BESS is assumed to be $10/kW-yr. based on discussions with battery vendors and review of publicly available information.

- Augmentation FOM: Augmentation FOM can be a significant cost adder to the total FOM costs of the BESS. The augmentation FOM relates to the replacement of degraded battery cells over the life of the BESS. Pace Global has assumed a degradation of 5% each year, two years from the start of installation of the BESS. The degradation assumes that 5% of the battery capacity has to be replaced each year at the prevailing capital cost of the battery and amortized over a 10 year period. This schedule results in increasing augmentation expenses over time as batteries age and have to be replaced.

Exhibit 29 summarizes the annual costs of the BESS inclusive of FOM cost and degradation assumptions for each of four capacity sizes that have been evaluated.

Exhibit 29: Annual Cost of BESS across Various Capacity Sizes

	10 MW ($000)	20 MW ($000)	30 MW ($000)	40 MW ($000)
Year 1	1,426	2,853	4,279	5,706
Year 2	1,426	2,853	4,279	5,706
Year 3	1,459	2,917	4,376	5,835
Year 4	1,490	2,981	4,471	5,961
Year 5	1,521	3,043	4,564	6,086
Year 6	1,552	3,105	4,657	6,210
Year 7	1,583	3,166	4,750	6,333
Year 8	1,614	3,228	4,841	6,455
Year 9	1,644	3,288	4,932	6,576
Year 10	1,674	3,348	5,022	6,696

Note that these costs represent all-in, annual expected costs, inclusive of capital, augmentation, and FOM. Since capital is amortized over 10 years, augmentation capital would be assumed in years beyond the 10-year period shown in this display. While those costs are included in any economic analysis, they are not shown here.

Source: Pace Global

Evaluation Approach Overview

In order to evaluate the potential cost savings associated with potential introduction of new flexible resources, the following approach was developed:

- Evaluate the potential for cost savings associated with reductions in tie-line deviations from historical 4-second data for 2014 with new batteries (at various sizes) or an upgraded Unit 9 in place, using fees for regulation from LADWP's OATT and the current penalty structure proposed by LADWP for Excess Deviations.
- Based on the performance of the battery or Unit 9 in regulating the system, evaluate the MW available in any given hour for spinning reserve in order to evaluate the impact on GWP's system cost of reducing spinning needs for the existing portfolio (i.e., without batteries or Unit 9 on AGC), inclusive of a future re-powering at Grayson after 2019. For this study, Grayson is assumed to be repowered using the 250D option.
- Evaluate the economic benefits of reduced tie-line deviations and additional spinning reserve capacity against the following costs:
  - For the battery: capital and operating costs
  - For the Unit 9 option: capital costs of upgrading Unit 9 to AGC, the additional operating costs (including fuel) associated with having the unit running and available for regulation and spinning reserve, and the costs of purchasing needed non-spin reserves from LADWP when Unit 9 is removed from non-spin service.

Data Review

The primary data associated with the first step in the analysis is 4-second deviation data provided by GWP for 2014. Pace Global reviewed the data for outliers and to summarize the characteristics of the deviations. There were 79 instances where deviations were greater than or equal to the absolute value of 100 MW. Based on discussions with GWP, these outliers have been replaced with zeros to avoid the influence of bad data. Exhibit 30 represents a distribution of deviations after revising the outliers for each month. The data shows that there are greater instances of negative deviations than positive deviations, which indicates that the actual flow is less than the scheduled flow in most situations. Consequently, the regulation resource will have to provide more regulation down services (i.e., absorbing energy) than regulation up services (i.e., discharging energy). The analysis assumes that the pattern of data for 2014 will persist going forward.

Exhibit 30: Frequency Summary of Deviation Data by Month

Greater than	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
-100	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-90	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-80	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-70	0.00%	0.00%	0.00%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-60	0.00%	0.00%	0.00%	0.00%	0.11%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-50	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.04%	0.05%	0.00%	0.00%	0.03%	0.03%
-40	0.00%	0.00%	0.00%	0.00%	0.12%	0.00%	0.07%	0.23%	0.07%	0.00%	0.04%	0.01%
-30	0.00%	0.08%	0.00%	0.01%	0.28%	0.16%	1.04%	0.45%	0.22%	0.09%	0.09%	0.04%
-20	0.05%	0.74%	0.17%	0.56%	1.69%	1.43%	3.32%	2.96%	2.61%	2.64%	0.58%	0.53%
-10	62.14%	55.15%	54.91%	60.29%	57.58%	61.46%	50.72%	50.92%	56.62%	52.68%	51.71%	55.31%
0	37.76%	43.71%	44.72%	38.14%	38.07%	36.27%	41.35%	43.75%	37.45%	42.67%	46.83%	44.01%
10	0.05%	0.32%	0.20%	0.40%	1.78%	0.64%	2.70%	1.53%	2.50%	1.89%	0.71%	0.04%
20	0.00%	0.00%	0.00%	0.33%	0.26%	0.05%	0.57%	0.08%	0.42%	0.03%	0.00%	0.04%
30	0.00%	0.00%	0.00%	0.09%	0.00%	0.00%	0.12%	0.03%	0.09%	0.00%	0.00%	0.00%
40	0.00%	0.00%	0.00%	0.12%	0.00%	0.00%	0.04%	0.00%	0.02%	0.00%	0.00%	0.00%
50	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%
60	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
70	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
80	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
90	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
100	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Source: Pace Global analysis of GWP 2014 data

Regulation Model and Methodology Overview

Pace Global developed a spreadsheet model to simulate the performance of a BESS or Unit 9 in responding to tie-line deviations through regulation signals. The objectives of the methodology are (1) to minimize Glendale's penalty cost from excess deviations above 8 MW and (2) to track the availability of the resource to also provide spinning reserve, after accounting for its regulation service requirements.

Battery Modeling

For simulating the operations of the BESS, the regulation model tracks charge and discharge signals in response to deviations from historical 2014 data and estimates the charged state of the battery system in 4-second intervals and 15-minute intervals. For battery modeling, it is important to note that energy tracking is more important than capacity. This means that a 20 MW battery can absorb more than 20 MW for short durations of time, but with a 30-minute cycle duration, will only be able to absorb a total of 10 MWh before needing to re-set.[10]

Given operating restrictions that are dictated by warranty guidelines, the charged state of the battery cannot exceed 80% of the total capacity. Thus, it has been assumed in the analysis that the charge cannot exceed 80% of capacity even if a deviation signal would suggest more absorption is necessary. Similarly, the charged state of the battery cannot fall below 17% of the total capacity of the battery. These levels are reflective of current warranty guidelines in the industry, as reported to Siemens Energy, Inc.

[10] The total charge is calculated by multiplying the 20 MW capacity with a 30 minute (0.5 hour) charge. Note that this analysis assumed an 80% charge maximum due to warranty constraints, so this calculation is for illustrative purposes only.

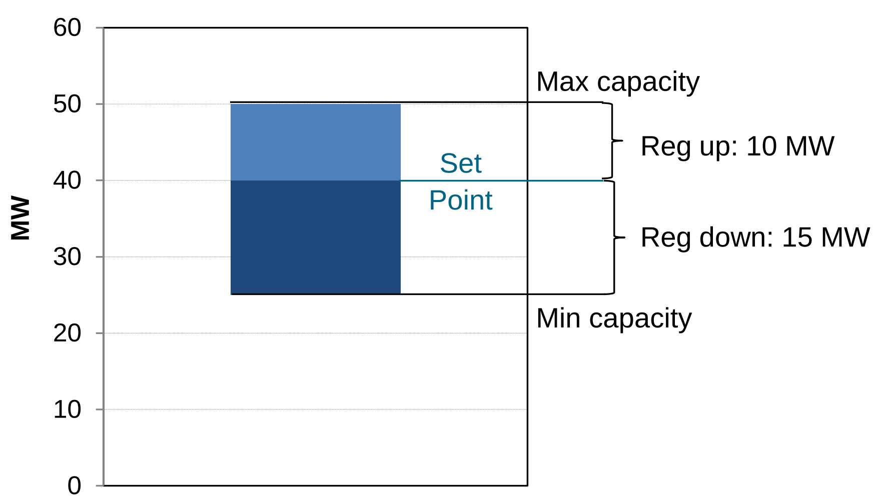
The battery is utilized in the modeling simulation in any event where the deviation at the tie-line with LADWP exceeds the absolute value of 8 MW. (LADWP has proposed that the first 8 MW of deviation not be charged.) Because the deviation may occur in both positive and negative directions, the model's logic attempts to ensure that the battery remains charged close to 50% of total capacity to maximize responsiveness. Thus, when tie-line deviations are not exceeding the absolute value of 8 MW, the battery is assumed to be "re-setting" its charge in order to be optimally positioned for future deviations. For example, if large deviations required the battery to absorb energy for a period of time such that its charge moved to 70%, the model's logic would effectively "dump" energy in subsequent hours where tie-line deviations don't exceed the absolute value of 8 MW in order to re-set the charge level towards 50%.

Based on this logic, the model tracks the battery operations and resulting tie-line deviations *after* battery usage for each 4-second interval and 15-minute aggregate. Based on the output of this analysis, the model can then record the availability of the battery to provide spinning reserve in any given hour. If 10 minutes or more of charge is available, the full capacity of the battery is assumed to be available for spinning reserve. Conversely, if at any given point during an hour, the battery has less than 10 minutes of charge available, it is assumed that no spinning reserve capacity is available from the BESS for that hour.

Unit 9 Modeling

For simulating Unit 9 under AGC, the regulation model tracks the available capacity from Unit 9 to serve in either a regulation up or regulation down capacity. Given that the deviation data analysis indicated that regulation down responses are more frequently needed than regulation up responses, the unit's set point is defined accordingly in the model. Thus, as a 50 MW unit with a 25 MW minimum capacity, the assumption is that the unit will be set to operate at 40 MW, with capability to regulate up for 10 MW and to regulate down for 15 MW. This is illustrated in Exhibit 31.

Exhibit 31: Illustration of Unit 9 Regulating Range



Source: Pace Global

Given these operating assumptions, Unit 9 is assumed able to respond up or down to the deviations according to this range. For example, a regulation up signal of up to 10 MW and a regulation down signal of up to 15 MW will be fully captured. However, if a regulation down signal of 30 MW was observed, Unit 9 would be able to meet 15 MW, but still leave a deviation of 15 MW. Unlike the battery regulation analysis, which is constrained by *energy* charge, Unit 9's *capacity* is constrained between 25 MW and 50 MW.

For purposes of tracking spinning reserve availability, the regulation model aggregates the average output of Unit 9 over the course of each hour. The difference between the maximum capacity (50 MW) and the average position in response to the regulation behaviour is assumed to be available to provide spinning reserve.

Regulation Analysis Results

Overall, the various battery sizes that have been tested contribute to modest penalty avoidance savings for GWP, but are unable to eliminate the deviations that are large and persistent. In fact, the 10 MW BESS does not have enough charge to provide any savings from penalties, while the larger sizes mitigate some deviations, but cannot avoid the large ones. The large events seen in April, May, July, and August cannot be mitigated by the batteries at any size tested.

While Unit 9 mitigates maximum deviations for all months, it only has the capability of reducing deviations by 10-15 MW at a time (given its set point of 40 MW, a maximum capacity of 50 MW, and a minimum capacity of 25 MW). Therefore, large deviations still persist, driving continued penalties.

Exhibit 32 summarizes the maximum excess deviation and associated penalty under each strategy compared with the current baseline data (Grayson reference case 250D) without any regulating resource. The shaded cells represent months that have experienced a reduction in excess deviations compared to the "raw data" situation (2014 actual deviations). The 10 MW BESS strategy realizes no savings, while the 40 MW strategy realizes $1.2 million in savings. Unit 9 achieves about $900,000 in cost reductions.

Exhibit 32: Summary of Maximum Excess Deviations and Total Penalties for Strategies

Excess Deviation (MW)						
Month	Raw	10MW	20MW	30MW	40MW	Unit 9 on AGC
1	1.880	1.880	0.742	0.000	0.000	1.499
2	13.548	13.548	13.548	6.149	4.013	6.559
3	9.833	9.833	9.833	7.806	4.095	7.833
4	42.216	42.216	42.216	42.216	34.830	38.094
5	48.258	48.258	48.258	48.258	48.258	41.258
6	13.745	13.745	12.279	11.002	6.562	11.353
7	41.021	41.021	41.021	41.021	41.021	39.021
8	33.267	33.267	33.267	33.267	33.267	26.267
9	28.908	28.908	28.908	28.908	16.821	26.908
10	10.525	10.525	7.417	4.352	0.000	8.525
11	25.365	25.365	25.365	25.365	23.658	18.163
12	17.587	17.587	13.163	13.163	10.697	13.468

Penalty Cost - All values in $000						
Month	Raw	10MW	20MW	30MW	40MW	Unit 9 on AGC
1	$36,568	$36,568	$14,433	$0	$0	$29,155
2	$263,513	$263,513	$263,513	$119,591	$78,044	$127,576
3	$191,255	$191,255	$191,255	$151,833	$79,638	$152,355
4	$821,110	$821,110	$821,110	$821,110	$677,437	$740,933
5	$938,621	$938,621	$938,621	$938,621	$938,621	$802,471
6	$267,349	$267,349	$238,828	$213,986	$127,625	$220,811
7	$797,861	$797,861	$797,861	$797,861	$797,861	$758,961
8	$647,047	$647,047	$647,047	$647,047	$647,047	$510,897
9	$562,254	$562,254	$562,254	$562,254	$327,169	$523,354
10	$204,716	$204,716	$144,264	$84,646	$0	$165,816
11	$493,354	$493,354	$493,354	$493,354	$460,141	$353,267
12	$342,060	$342,060	$256,024	$256,024	$208,048	$261,958

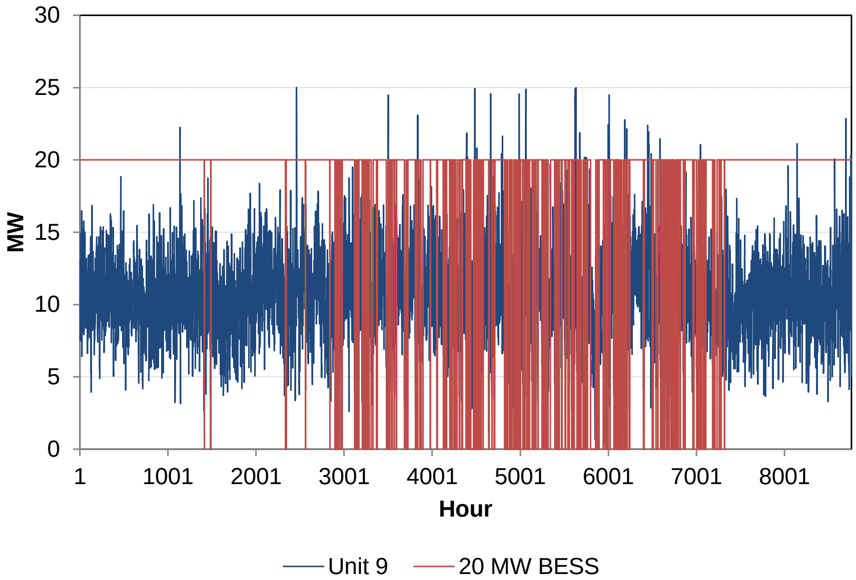
Total Penalty Cost ($)	$5,565,707	$5,565,707	$5,368,565	$5,086,328	$4,341,632	$4,647,555
Annual Penalty Savings ($000)	N/A	$0	$197	$479	$1,224	$918
Percentage of Penalty Savings (%)	N/A	0.00%	3.54%	8.61%	21.99%	16.50%

Source: Pace Global

Spinning Reserve Modeling Overview

Pace Global deployed the Aurora dispatch model to evaluate the impact of additional spinning reserve from the BESS or Unit 9 on total portfolio costs. Extra resource availability effectively reduces the need for other natural gas-fired plants in the portfolio to burn fuel and be available to provide spin. As referenced above, the battery options are able to provide spin up to their capacity any time when the charge is able to sustain output for at least 10 minutes, which represents ~33% of the total. Unit 9 provides a level of spin equal to the difference between its maximum capacity (50 MW) and the level of output at any given point in time based on its regulation deployment. Therefore, a 20 MW battery will have a spinning reserve availability of *either* 20 MW *or* 0 MW in any given hour, while Unit 9's availability will vary *between* 0 MW and 25 MW. This is shown in Exhibit 33, which displays the modelled hourly spinning reserve availability for each of the resource options.

Exhibit 33: Hourly Available Capacity for Spinning Reserve – Unit 9 vs. 20 MW BESS



Source: Pace Global

Spinning Reserve Analysis Results

The spinning reserve analysis indicates that the introduction of new BESS capacity has the potential to reduce the required spin that is reserved from GWP's local resources (either the current Grayson boilers now or new resources after the potential re-powering). This has the effect of saving fuel from being burned to run natural gas-fired plants that would otherwise be uneconomic to operate or generating more economic energy rather than holding units in reserve. Under the Unit 9 strategy, spinning reserve savings are achieved prior to re-powering when Unit 9 displaces the need for existing Grayson units to be online for spin purposes. However, after the re-powering, it is assumed that Unit 9 will be no longer attractive as a spinning reserve resource and will return to its role as a non-spin plant.

An illustration of the annual average spinning reserve commitment by resource for the base case (the 250D portfolio without a battery) and with a 20 MW battery system is shown in Exhibit 34 in order to illustrate the impact of the introduction of new spinning resources. A shift in the deployment of battery resources for spinning reserve has the effect of reducing portfolio fuel costs and avoiding the opportunity costs of holding resources for reserves as opposed to generating energy at certain times, which results in savings for GWP.

Exhibit 34: Average Spinning Reserve Usage by Resource – with and without BESS

Resource	With Battery		Without Battery	
	Pre-Re-Power (MW)	Post-Re-Power (MW)	Pre-Re-Power (MW)	Post-Re-Power (MW)
LM6000 PG Sprint 1x1	0.00	2.00	0.00	7.99
LM6000 PG Sprint SC	0.00	5.64	0.00	13.25
Magnolia CC	1.59	2.07	2.41	2.75
Magnolia Duct	6.07	7.10	8.61	9.74
Current Grayson Boilers	9.67	0.00	23.12	0.00
Hoover	10.42	10.42	10.42	10.42
Battery (20 MW Case)	17.06	17.06	N/A	N/A
Total	**44.81**	**44.28**	**44.56**	**44.14**

Source: Pace Global

In order to quantify this savings, Pace Global performed a dispatch simulation of GWP's portfolio with and without the new spinning reserve resource options to record the total cost impact on the system. Exhibit 35 shows the annual savings in total portfolio costs for each of the four BESS options and Unit 9 over a ten-year period. As is shown, each option provides a net savings to the portfolio by lowering the opportunity cost of holding reserves or avoiding fuel costs associated with running plants only for reserves. After the assumed re-powering at Grayson (after year 4 in the table), the savings are projected to decline due to the introduction of new, more efficient capacity that provides spinning reserves or energy. For Unit 9, no savings are achieved after year 4, as the plant is assumed to return to a non-spin resource.

Exhibit 35: Portfolio Cost Impacts Due to Spinning Reserve Savings

	10 MW Battery for Spin ($000)	20 MW Battery for Spin ($000)	30 MW Battery for Spin ($000)	40 MW Battery for Spin ($000)	Grayson 9 Spin (prior to re-power) ($000)
Year 1	(1,076)	(2,170)	(2,896)	(3,497)	(3,792)
Year 2	(1,215)	(2,364)	(3,247)	(3,942)	(4,509)
Year 3	(936)	(1,975)	(2,544)	(3,053)	(3,075)
Year 4	(1,076)	(2,170)	(2,896)	(3,497)	(3,792)
Year 5	(806)	(1,751)	(2,325)	(2,464)	0
Year 6	(956)	(1,976)	(2,834)	(2,993)	0
Year 7	(783)	(1,870)	(2,687)	(2,971)	0
Year 8	(841)	(1,912)	(2,823)	(3,069)	0
Year 9	(968)	(1,778)	(2,828)	(3,183)	0
Year 10	(988)	(1,987)	(2,880)	(3,315)	0
Levelized Annual Savings	**($969)**	**($2,004)**	**($2,798)**	**($3,209)**	**($1,632)**

*Notes: All values are differences between a base case (250D portfolio) and the specified strategy. The negative numbers represent savings.

The shaded cells starting in Year 5 represent the time after the assumed re-powering at Grayson.

Unit 9 is assumed to go back to non-spin operations after re-powering, although the levelized annual savings is still presented over a ten-year period.

Source: Pace Global

Summary of Economic Analysis Results

The economic analysis for each of the strategies includes a series of costs and savings, which are outlined in Exhibit 36. The following major findings have been made:

- The spinning reserve and regulation savings associated with Unit 9 are close to (or exceed) the costs associated with purchasing non-spin prior to re-powering plus spending on an AGC upgrade. This is shown in Exhibit 37, which displays the comparison of cost savings (in the stacked bar) against the total annual costs of the change in operational strategy.[11] As a result, changing the operating strategy for Unit 9 could be economically attractive. It is important to note, however, that the cost of non-spin purchases from LADWP is highly uncertain and that potential regulatory restrictions on Unit 9 operations as a result of air quality rules have not been considered in this study.
- On the other hand, the annual costs for the BESS are expected to be greater than the combined savings from both regulation and spinning reserve operations. As such, this strategy is not economic, especially given the fact that BESS operations are unable to meaningfully impact deviation penalties under the current LADWP penalty structure proposal. This is shown over a ten-year operational period in Exhibit 38.

[11] Note that the period of analysis for this strategy is only four years, since Unit 9 is assumed to return to a non-spin position after the Grayson re-powering.

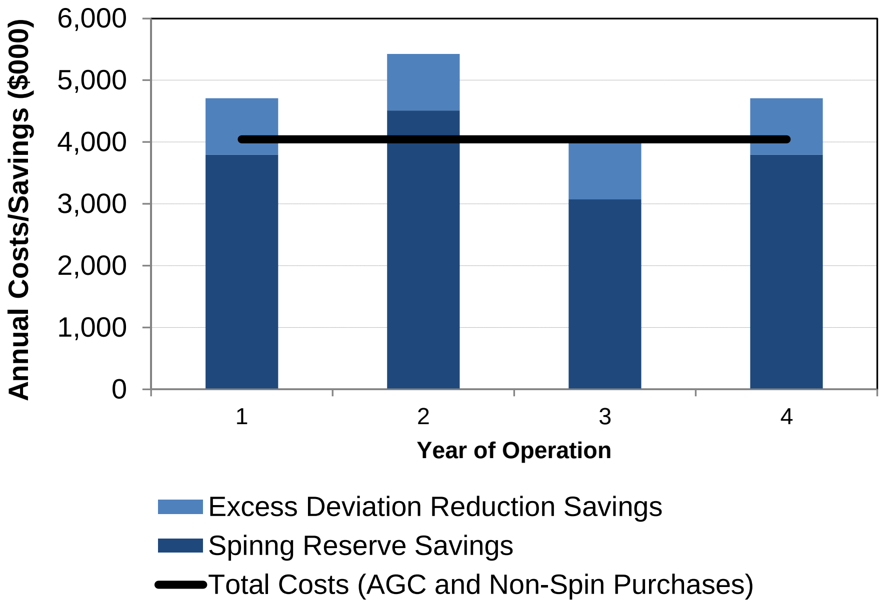
Exhibit 36: Summary of Costs and Savings Elements for Each Strategy

	BESS		Unit 9	
	Elements	*Notes and Sources*	*Elements*	*Notes and Sources*
Costs	Capital, FOM, and augmentation costs for batteries	See Exhibit 29.	Capital costs for AGC, Costs of buying non-spin for 4 years prior to re-power when Unit 9 is converted to spin	Stantec estimated \$55,000 - \$75,000 for AGC, and this analysis uses \$75,000 to be conservative; LADWP non-spin purchases assumed to be \$9/MW-h during off-peak hours and \$14/MW-h during on-peak hours*
Savings	Penalty avoidance for regulation; spinning reserve savings	See Exhibit 35 and Exhibit 32.	Penalty avoidance for regulation; spinning reserve savings	See Exhibit 35 and Exhibit 32.

*Note: The costs for non-spinning reserve purchases from LADWP are based on current planning estimates. While these rates are under review and could be altered, they represent the best information at the time of this study.

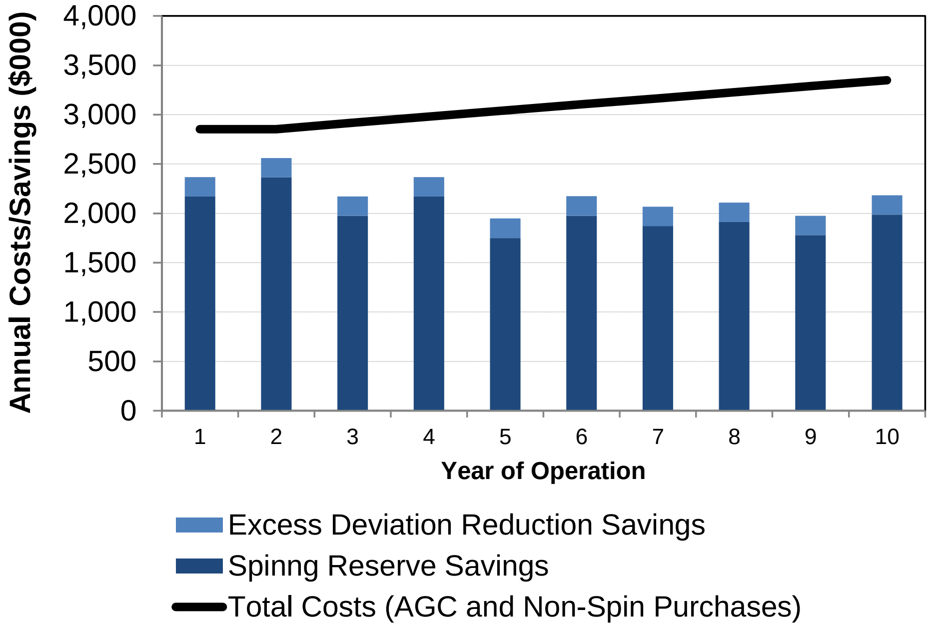
Sources: Pace Global, Stantec, and GWP

Exhibit 37: Summary of Costs and Savings for Unit 9 Strategy



Sources: Pace Global

Exhibit 38: Summary of Costs and Savings for BESS Strategy (20 MW Example)



Sources: Pace Global

LFG OPTIONS SCREENING

One major component of the IRP process is to identify the best strategy for developing capacity devoted to burning landfill gas. The IRP process first assumes that the combustion of LFG is moved from Grayson to Scholl Canyon in order to avoid significant costs associated with air permitting (as identified by Stantec) and to avoid the costs and regulatory uncertainty of maintaining the LFG pipeline currently used to transport LFG from Scholl Canyon to Grayson. Pace Global performed a quantitative economic screening assessment of three options developed by Venture Engineering, which are summarized in Exhibit 39.[12] Pace Global's screening analysis has accounted for the following:

- The total capital costs associated with turbines, engines and other equipment associated with operations and environmental compliance;
- Total annual fixed and variable operations and maintenance costs assuming a service contract with the vendor;
- The impact of varying levels of electricity generation on the remaining operations of GWP's system, as well as renewable requirements to meet the RPS standard.[13]

[12] See appendix material on LFG and air permitting details: "Phase I – Task #5 Operating on LFG Only at The Scholl Canyon Landfill" and "Emissions Signatures for Landfill and Digester Gas Fuels"

[13] Note that since the LFG electricity qualifies as renewable, an option that generates more MWh from LFG will require fewer remote renewables than the alternative to meet the RPS.

Exhibit 39: LFG Option Operational Assumptions[14]

Resource Option	Quantity	Annual Renewable Generation (MWh)	Equipment Cost (Millions $)	O&M Costs (Millions $)	Annual Equipment Cost Payment (Millions $)
Solar Mercury 50 Turbine	4	153,300	22.1	2.8	1.1
Solar Taurus 60 Turbine	3	131,400	17.2	1.7	0.8
Caterpillar CG260-16 IC engine	6	165,564	16.3	1.8	0.8

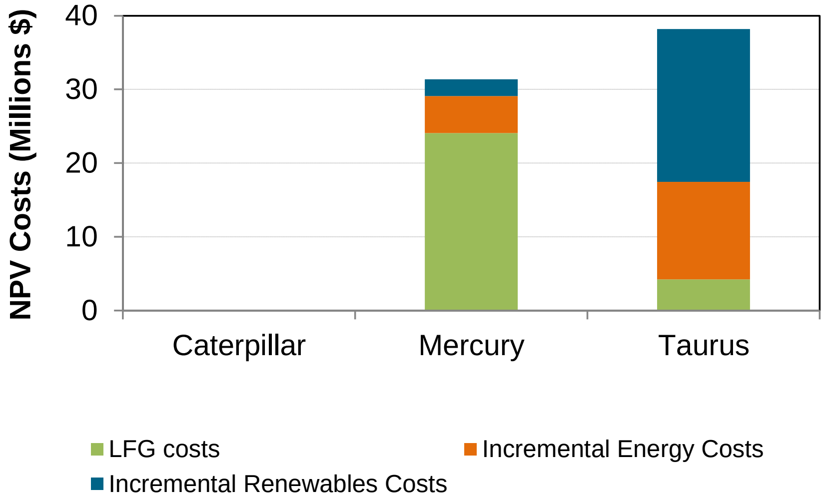
Source: Venture Engineering, in consultation with GWP and Pace Global.

Pace Global's dispatch analysis shows that the Caterpillar engine option has the lowest overall cost impact on the portfolio, as a result of low capital and O&M costs along with a favorable heat rate, driving more energy production than the other options. Among the Solar turbine options, the Mercury's energy benefits slightly outweigh higher capital and O&M costs when compared with the Taurus. Exhibit 40 summarizes the results of each of the three options, indicating that the Mercury and Taurus face incremental costs above those for the Caterpillar. As is shown:

- The Mercury has the highest capital costs, followed by Taurus and Caterpillar (shown in green);
- The Caterpillar can produce the most energy from the LFG of the three options, meaning that it will require less additional energy from market purchases or other local generation. Therefore, the Mercury and Taurus options have incremental energy costs when compared with the Caterpillar (shown in orange).
- The Caterpillar's additional energy benefit also reduces costs associated with renewable procurement, meaning that the alternatives must procure more additional renewable energy at an earlier date. The impact of these costs is shown in blue.
- Overall, the Caterpillar option has an NPV savings of over $30 million versus Mercury and nearly $40 million when compared to the Taurus.

[14] Note that all specific resource options shown were developed from available data and in order to establish planning-level operational and cost estimates. The IRP does **not** limit or pre-determine GWP's choice of technology or vendor.

Exhibit 40: LFG Screening Analysis Results



Source: Pace Global analysis.

Further, when compared to the current costs of burning the LFG at Grayson, the Caterpillar option shows significant savings. Given current operations and maintenance costs, expected ongoing capital expenditures at Grayson, and the estimated payment to the city of $2.5 million per year for access to the landfill gas, the effective cost of current LFG energy is nearly $50/MWh. The effective cost of generating LFG energy from a new Caterpillar plant, including all capital, operations and maintenance, and city payment is only about $30/MWh. These savings are also magnified when the impacts of avoided energy purchases and renewable procurement are included.

PORTFOLIO ANALYSIS

INTEGRATED PORTFOLIO DEVELOPMENT

The findings of the screening analysis ultimately supported the development of nine integrated portfolios for assessment across a range of external market conditions. Exhibit 41 summarizes each of these portfolio options, with descriptions of their components under each of the major screening categories. The portfolios can be summarized as follows:

- A "run to fail" option, with no investment of new capital at Grayson beyond current plans for life extension plus a new CC at the IPP site and a diverse renewable mix to meet 33% RPS;
- The 150B portfolio with engines at Scholl Canyon to burn LFG, a new CC at the IPP site, and two different renewable options to meet 33 % RPS;
- The 200B portfolio with engines at Scholl Canyon to burn LFG, a new CC at the IPP site, and two different renewable options to meet 33 % RPS;
- The 200C portfolio with engines at Scholl Canyon to burn LFG, a new CC at the IPP site, and two different renewable options to meet 33 % RPS;
- The 250D portfolio with engines at Scholl Canyon to burn LFG, a new CC at the IPP site, and two different renewable options to meet 33 % RPS.

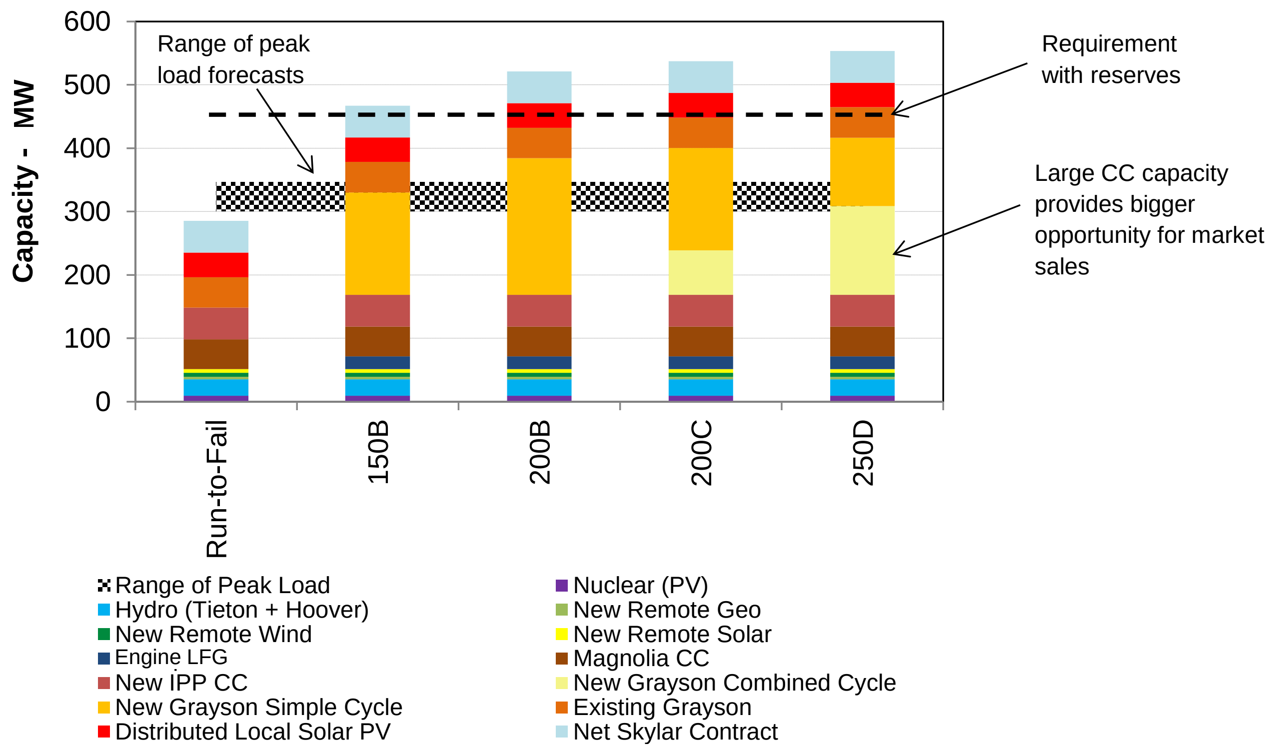
Exhibit 42 further summarizes the composition of each of the major portfolio concepts in 2030, highlighting the total available capacity in each option against the expectations for peak load and associated reserves. Exhibit 43 summarizes the projected energy production for each of the portfolios for both 2020 and 2030, highlighting the evolution of the portfolios over time and the differences between energy production and installed capacity. As can be seen, the portfolios with new combined cycles at Grayson have the capability to produce more energy than is required for meeting GWP's native system needs, opening up the opportunity for revenues from sales of surplus power.

Exhibit 41: Summary of Integrated Portfolio Options

Candidate Portfolio		Grayson	LFG	IPP	Renewables
1.	Run to Fail	No new investments beyond limited capital extension	No new investment	CC	Wind/ Solar/ Geothermal
2.	150B/ wind/ solar	3 simple cycles	Caterpillar	CC	Wind/ Solar
3.	150B/ wind/ solar/ geo	3 simple cycles	Caterpillar	CC	Wind/ Solar/ Geothermal
4.	200B/ wind/ solar	4 simple cycles	Caterpillar	CC	Wind/ Solar
5.	200B/ wind/ solar/ geo	4 simple cycles	Caterpillar	CC	Wind/ Solar/ Geothermal
6.	200C/ wind/ solar	3 simple cycles 1 combined cycle	Caterpillar	CC	Wind/ Solar
7.	200C/ wind/ solar/ geo	3 simple cycles 1 combined cycle	Caterpillar	CC	Wind/ Solar/ Geothermal
8.	250D/ wind/ solar	2 simple cycles 2 combined cycles	Caterpillar	CC	Wind/ Solar
9.	250D/ wind/ solar/ geo	2 simple cycles 2 combined cycles	Caterpillar	CC	Wind/ Solar/ Geothermal

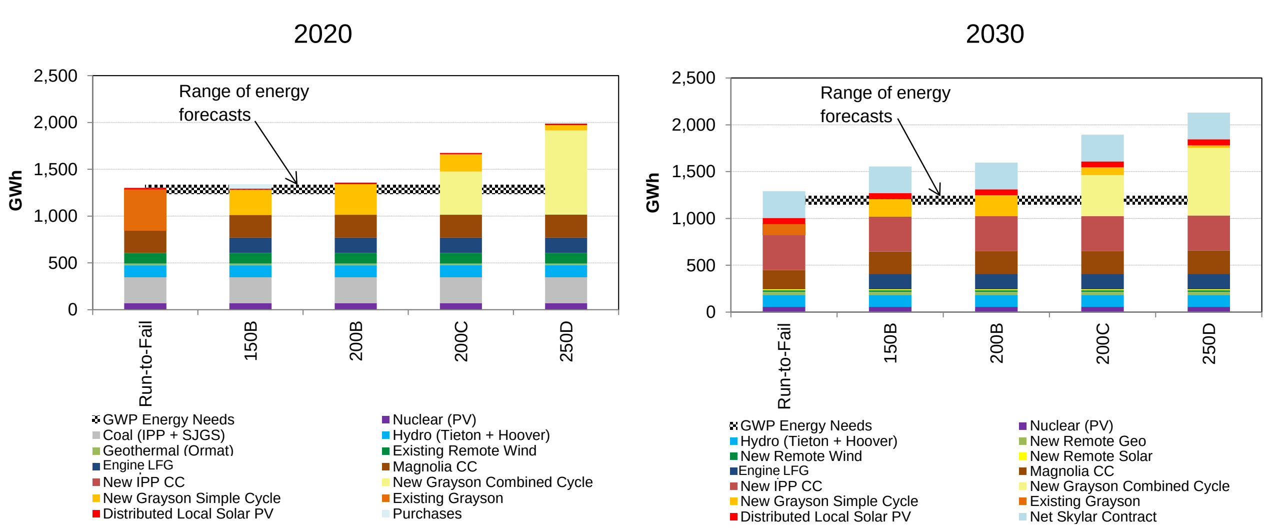
Source: Pace Global analysis.

Exhibit 42: Supply and Demand Balance for Integrated Portfolio Options - 2030



Source: Pace Global analysis.

Exhibit 43: Energy Needs and Resources for Integrated Portfolio Options



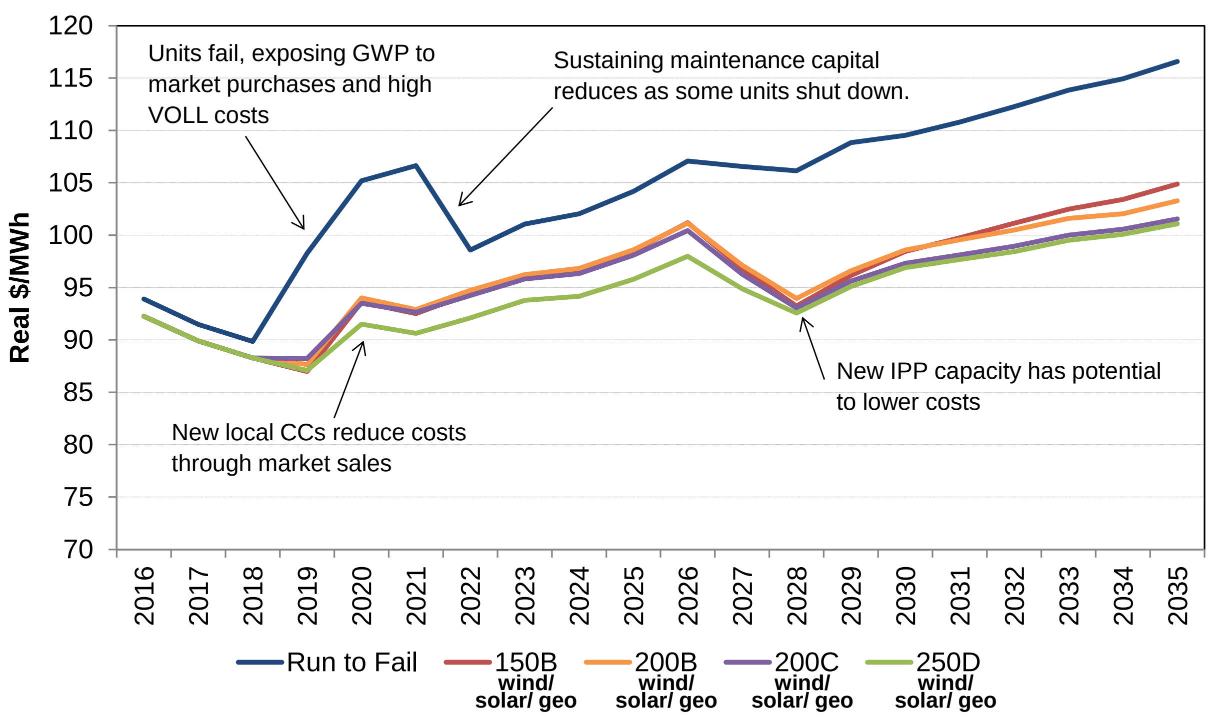
Source: Pace Global analysis.

REFERENCE CASE PORTFOLIO ANALYSIS – COST ASSESSMENT

Each of the integrated portfolios was analyzed through the hourly dispatch simulation methodology summarized in Exhibit 11. This analysis incorporated all existing resources and contracts (see Exhibit 7), expectations for GWP's future hourly loads (see Appendix I: Load Forecast Details), as well as expectations for distributed solar additions installed by customers (see chapter on Solar Penetration Analysis). The portfolio analysis assesses the total costs of GWP's generation over time for each option, with the key findings summarized in Exhibit 44.[15]

Overall, the cost analysis indicates that the "Run to Fail" portfolio is higher cost due to significant spending on maintenance capital and operations, high exposure to the market as units are expected to fail, and high value of lost load ("VOLL") costs as a result of expected outage events (see chapter on Loss of Load Equivalent Analysis). The lowest cost portfolio option is 250D, driven primarily by the ability of new combined cycle capacity to generate excess market sales.

Exhibit 44: Annual Portfolio Cost Projections – Reference Case



Source: Pace Global analysis.

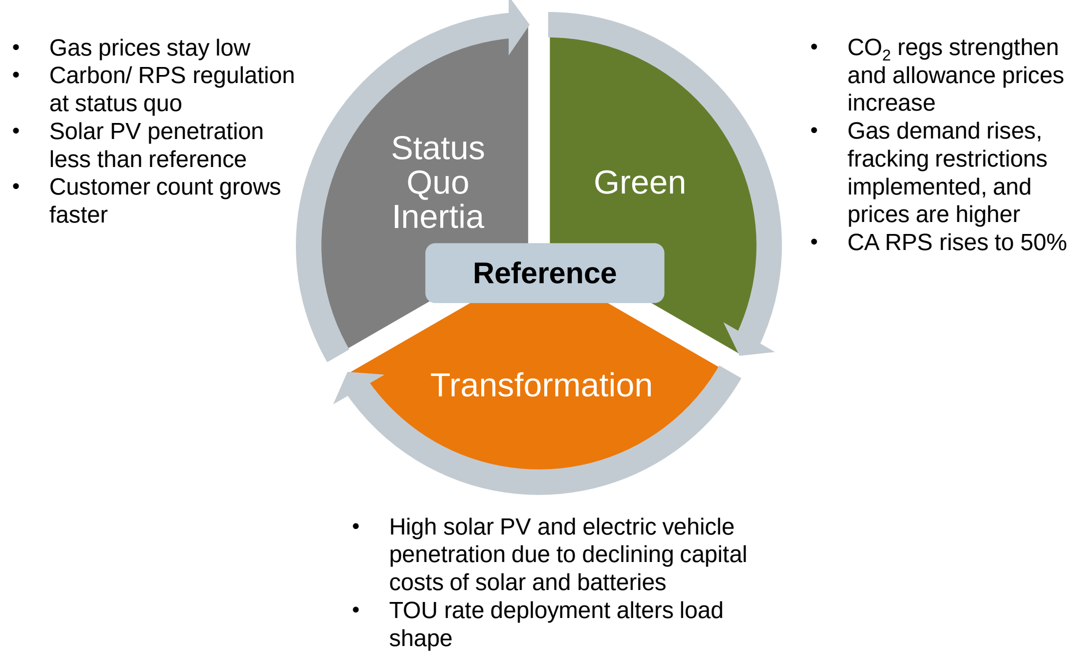
[15] Note that for simplicity, Exhibit 44 displays the portfolios that contain wind, solar, and geothermal additions.

MARKETLINK SCENARIOS – RISK ASSESSMENT

In order to evaluate the portfolios against a range of potential future conditions, Pace Global developed four distinct, but internally consistent scenarios within our MarketLink[16] process. The scenarios are designed around broad themes that stress the boundary conditions for many key drivers relevant to GWP's portfolio choices. The scenarios are summarized in Exhibit 45 and are defined as follows:

- Reference Case: A scenario that is based on current, central tendency expectations for the future. Market forwards and existing policies drive the major parameters, but long-term expected changes in carbon policy, natural gas markets, load growth, and resource technology development are included. Screening analyses are all performed with the Reference Case.
- Status Quo Inertia (SQI): A scenario based on the **dominance of prevailing market** conditions in the context of current (status quo) energy system dynamics. This includes sustained low natural gas prices, as production costs remain low; cost-effective declines in carbon emissions, mitigating the need for more stringent regulations in California; low electricity prices, limiting the penetration of new technologies; and higher customer counts and demand in GWP than the Reference case.
- Green: A scenario based on the **dominance of regulation** in the areas of CO_2 policy, renewable policy, and natural gas development. California's RPS rises to 50%, CO_2 regulations strengthen at the state and national levels, and fracking limitations contribute to high gas prices.
- Transformation: A scenario based on the **dominance of technical change** in re-shaping the traditional electric utility model. Costs for solar PV and batteries decline faster than in the Reference Case, driving distributed solar penetration and electric vehicle deployment upward, while time of use ("TOU") rate implementation alters customer load shapes.

Exhibit 45: MarketLink Scenario Summary



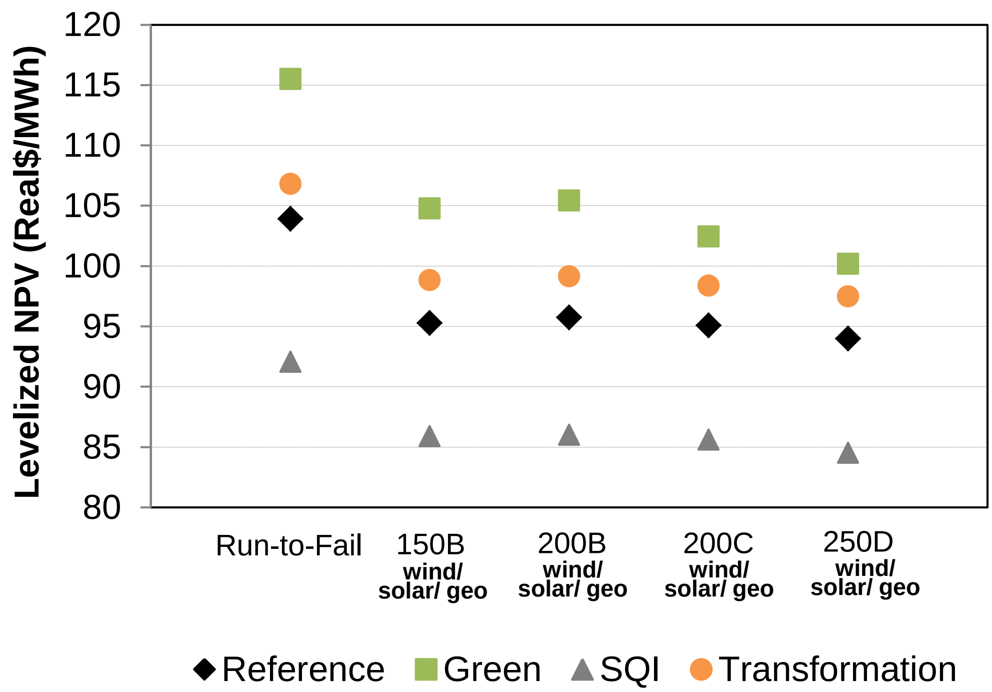
Source: Pace Global

[16] MarketLink refers to Pace Global's corporate scenario development process, which identifies global and national "states-of-the-world" for use in resource and strategic planning. See chapter on MarketLink Scenario Details for further information on the scenario descriptions.

Each of the integrated portfolios was evaluated against each of the MarketLink scenarios in order to assess the impact of changes in key external drivers on overall portfolio costs. Exhibit 46 summarizes the results of this analysis by plotting the levelized costs of each portfolio[17] across the 20-year evaluation period for each of the four market scenarios. The analysis shows that the general cost ordering of the portfolios across the various scenarios is relatively stable. It also indicates that 250D, the portfolio with two combined cycles, is able to protect against high cost outcomes through sales of excess energy into a high-priced market.

While the ability to sell excess energy is a likely benefit, the magnitude of sales can pose a risk without a contracted long-term energy or capacity off-taker. Therefore, the magnitude of net sales in relation to total portfolio costs has been recorded for all portfolios. While 150B and 200B have minimal net sales, the revenues from sales in the 250D case represent over 25% of total portfolio costs.

Exhibit 46: Summary of Levelized Portfolio Costs across MarketLink Scenarios



The cost of debt is assumed to be 4.5% nominal, 2.5% real.

Source: Pace Global

LOSS OF LOAD ANALYSIS – RELIABILITY ASSESSMENT

Separate from the hourly portfolio simulation analysis, Pace Global conducted a loss of load analysis, designed to assess the likelihood that GWP's generation and transmission system will be unable to meet load for any period of time. This study assesses the reliability of various portfolio options and is summarized in detail in the chapter on Loss of Load Equivalent Analysis. Overall, the analysis found that the "Run to Fail" portfolio has unacceptable risk and that the 150B portfolio marginally violates standard reliability criteria. The other portfolio options provide sufficient reliability for GWP's retail customers.

[17] Note that for simplicity, Exhibit 46 displays the portfolios that contain wind, solar, and geothermal additions.

ENVIRONMENTAL STEWARDSHIP ASSESSMENT

The portfolio analysis evaluated two key metrics for environmental stewardship – RPS percentage and CO_2 emissions. Each portfolio was constructed to meet the 33% renewable portfolio standard requirement (or 50% in the Green scenario), while the hourly simulation analysis recorded CO_2 emissions associated with GWP's owned resources and market purchases.[18] Portfolios with more energy generation (200C and 250D) also produce larger amounts of CO_2. However, this assessment does not account for displacement by a repowered Grayson of less efficient generation throughout the wider California region.

FINANCIAL STABILITY ASSESSMENT

As part of the integrated portfolio analysis, the total capital expenditures associated with Grayson repowering or life extension and construction of generation at Scholl Canyon for landfill gas were calculated. These totals represent the amount of debt that GWP would need to raise to fund the projects associated with the portfolio options. The larger capacity additions at Grayson require more capital and potentially pose a risk to GWP's financial stability. However, this IRP has not conducted further analysis on GWP's financial position or ability to raise additional debt at assumed interest rates.

SUMMARY OF PORTFOLIO ANALYSIS FINDINGS

The overall findings from the integrated portfolio analysis can be summarized according to each key metric. Exhibit 47 presents the details within each category along with a qualitative ranking of overall performance (green: positive; yellow: neutral; red: negative). The key findings can be summarized within each objective as follows:

- Cost: The "Run to fail" portfolio is highest cost, while 250D portfolio is lowest cost
- Risk: The 250D portfolio offers a hedge against high market prices, but relies heavily on market sales, suggesting that a long-term offtake agreement may be recommended.
- Reliability: The "Run to fail" portfolio violates reliability standards by 2019 and later; the 150B portfolio faces moderate reliability risks; the larger portfolios meet reliability guidelines.[19]
- Environmental Stewardship: Portfolios with more local generation have the highest CO_2 emission footprint.
- Financial Flexibility: The 250D portfolio requires the highest capital expenditures and new debt. However, a contract arrangement with an offtaker could provide security in future revenue.

Overall, the integrated portfolio analysis concludes the following:

- The "Run to Fail" option is not feasible due to high cost and unacceptable risk to local reliability.
- The 150 MW option has relatively low capital investment, but some reliability risk.
- The 250 MW option has the highest capital investment but lowest range of costs; it has highest reliance on off-system sales in order to keep costs down.
- The 200 MW option performs relatively well across all metrics, but doesn't "win" in any.
- Portfolios with diverse remote renewables (wind, solar, and geothermal) are slightly lower cost and have greater technological diversity than portfolios that just have wind and solar.

[18] Note that the portfolio analysis includes a price on carbon for each ton of CO_2 emitted. This impacts variable costs of dispatch and potential market prices for sales or purchases.

[19] Pace Global has performed a full loss of load equivalent analysis for all key portfolio options to quantitatively evaluate the reliability outcomes. This is summarized in the Loss of Load Equivalent Analysis chapter found later in this report.

Exhibit 47: Summary of Integrated Portfolio Results – All Metrics

Portfolios	Cost	Risk/ Rate Stability		Reliability		Environmental Stewardship	Manage Debt Levels
Study Period: 2016-35 All portfolios meet 33% RPS	Reference Case Levelized NPV* ($/MWh)	Worst Case Cost across Scenarios ($/MWh)	Reliance on market (Net Sales as a % of Total Portfolio Costs- 2020)	Total MWh of Lost Load over 10-year Period	Range Value of Lost Load (millions of 2013$)	Total CO_2 Emissions for owned resources plus purchases 2019-2035 average (000s tons)	Total Capital Investment at Grayson and LFG (millions of $)
Run to Fail	103.9	115.5	-7%	2019: 569 2027: 5,962	2019: 0.75-2.6 2027: 7.9-27.0	338.9	8.5
150B/ wind/ solar	95.4	105.6	0%	2019: 186 2027: 55	2019: 0.25-0.84 2027: 0.07-0.25	408.3	201.4
150B/ wind/ solar/ geo	95.3	104.8	0%	2019: 186 2027: 55	2019: 0.25-0.84 2027: 0.07-0.25	407.8	201.4
200B/ wind/ solar	95.8	106.3	1%	2019: 55	2019: 0.07-0.25	428.3	263.1
200B/ wind/ solar/ geo	95.7	105.4	1%	2019: 55	2019: 0.07-0.25	428.8	263.1
200C/ wind/ solar	95.2	103.3	14%	2019: 45	2019: 0.05-0.20	514.1	300.1
200C/ wind/ solar/ geo	95.1	102.5	14%	2019: 45	2019: 0.05-0.20	514.6	300.1
250D/ wind/ solar	94.1	101.1	27%	2019: 28	2019: 0.04-0.13	601.7	337.1
250D/ wind/ solar/ geo	94.0	100.2	27%	2019: 28	2019: 0.04-0.13	603.0	337.1

Source: Pace Global

MARKETLINK SCENARIO DETAILS

There are four major portfolio cost drivers that vary across the MarketLink scenarios. These include natural gas prices, carbon prices, the amount of distributed solar PV penetration in the GWP service territory, and load growth for GWP. Exhibit 48 summarizes how each of these variables changes across the three market scenarios in comparison to the Reference Case, while the remainder of this section describes the underlying assumptions in more detail.

Exhibit 48: MarketLink Summary of Key Variables vs. Reference Case across Scenarios

Variable	Status Quo Inertia	Green	Transformation
Natural Gas Price	↓ Lower production costs and prices	↑ Higher demand for gas and fracking ban	— Same as reference
Carbon Price	↓ Status quo policies remain in place	↑ Stricter regulations and higher compliance costs	— Same as reference
Solar PV Penetration	↓ Lower retail rates and longer payback economics	— Same as reference	↑ Lower technology costs and shorter payback economics
GWP Load Growth	↑ Customer count growth increases	— Same as reference	↓ Peak load declines due to TOU rates; ↑ Sales increase from PHEVs

Note: Red, down arrow (↓) means that the variable has lower values than the Reference Case; Green, up arrow (↑) means that the variable has higher values than the Reference Case; the black horizontal bar indicates no change for the variable in comparison to the Reference Case.

Source: Pace Global

NATURAL GAS PRICES

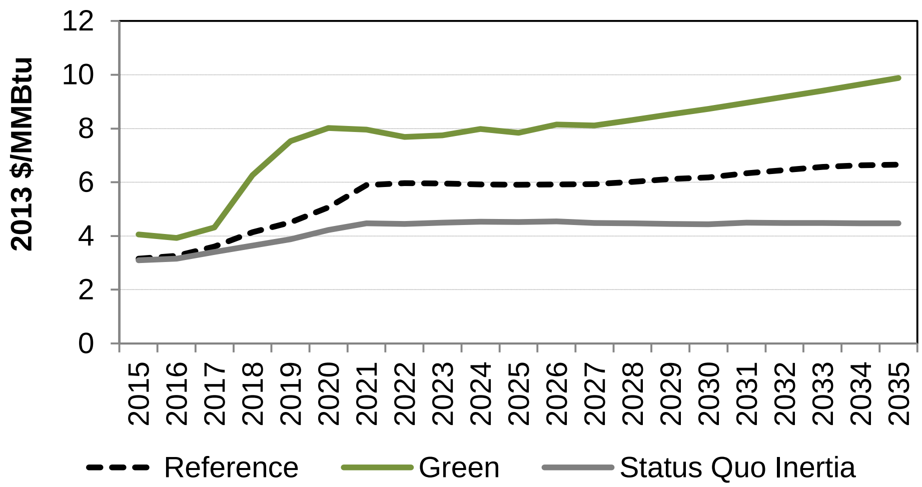
Natural gas prices are a key driver of power markets and portfolio costs for GWP. Exhibit 49 summarizes the projected price trajectories for natural gas prices at SoCal under the various scenarios, while the following section summarizes the key drivers for each.

Under Pace Global's Reference Case outlook, natural gas prices are expected to remain below \$4.00/MMBtu in the near term, as production from new sources of shale gas continues to outpace demand even as low oil prices curtail some associated gas production in places like the Permian Basin in West Texas and the Bakken shale play in North Dakota. In the mid- to long-term, LNG exports and mounting coal retirements will likely increase demand and place upward pressure on prices, driving them towards \$6/MMBtu (in real terms). Demand in the Southwest, including future exports to Mexico, is likely to drive a positive basis for the price in Southern California versus at the Henry Hub.

Under the Green scenario, natural gas demand is higher in the power sector than in the Reference Case, as a result of a very significant amount of coal retirements. In the early to mid-term, a spike in power sector gas demand above 30 bcf/day by the end of the decade, combined with LNG export demand of almost 10 bcf/day by the early 2020s, drives gas prices up above \$7/MMBtu. Over the longer term, demand pressures continue. While the Reference Case expects natural gas demand from the power sector to approach 40 bcf/day in the 2030s, the Green scenario pushes demand towards 50 bcf/day. This scenario also reflects higher production costs, especially in the post-2020 period as a result of fracking bans, and inefficient pipeline build-out in the face of rising baseload demand in the Gulf Coast. These factors keep natural gas prices sustained at a much higher level than the Reference Case.

Under Status Quo Inertia, abundant gas supplies are expected to be available and able to efficiently move to market demand regions. Marcellus and Utica production in particular contribute over 42 Bcf/d to U.S. supply by 2030, and optimistic production cost estimates are maintained even in the face of rising demand.

Exhibit 49: SoCal Natural Gas Prices by Scenario



*Note that the Transformation scenario uses the Reference Case gas price projections.

Source: Pace Global

CO_2 PRICES

Carbon policy and prices impact power market prices, dispatch costs for power plants, and portfolio costs for GWP. Exhibit 50 summarizes the projected price trajectories for CO2 in California under the various scenarios, while the following section summarizes the key drivers for each.

Under AB32, power plants operating in or delivering electricity to California began to incur a price for carbon emissions at the beginning of 2013. In Pace Global's Reference Case, carbon prices are expected to be between $10-20/tonne in line with auction reserve price levels and current market forwards. At the conclusion of AB32, which is currently scheduled to run through 2020, Pace Global projects that the start of a Federal[20] CO_2 price in 2020 will lead to some moderation in the California market, although long-term price growth is expected in line with more aggressive emission reduction goals.

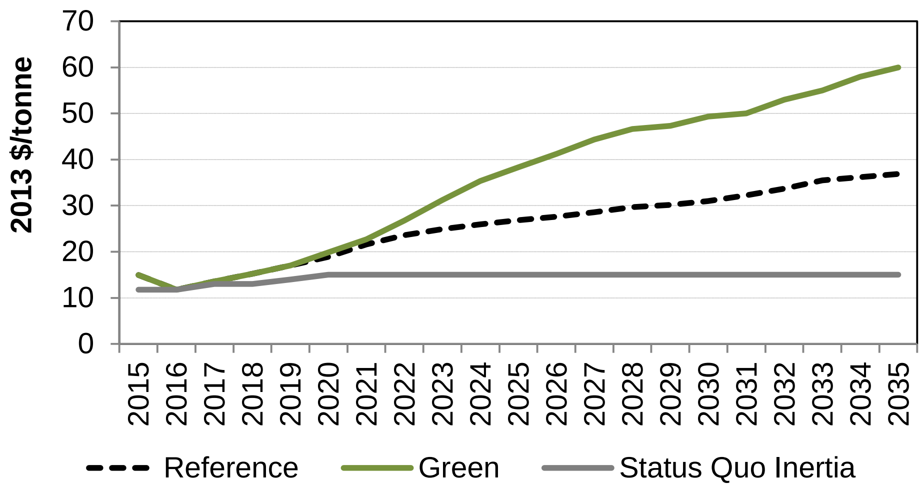
Under the Green scenario, two factors contribute to higher carbon prices. First, emission reduction targets are more stringent, with nationwide emission reduction goals between 40-50% of 2005 levels by the 2030 time period, with California similarly increasing reduction targets and being part of a nationwide trading program. Secondly, as a result of increased natural gas demand and fracking restrictions, natural

[20] The Reference Case federal CO_2 price may be a result of a federal tax or cap-and-trade program or national or regional programs in response to EPA's current draft Clean Power Plan. Pace Global's national Reference Case price projection is associated with emission reductions from the power sector of about 30% from 2005 levels by 2030.

gas prices are higher (as referenced in the previous section). This drives up the compliance costs associated with switching from coal generation to natural gas generation, raising CO_2 prices in the market.

Under Status Quo Inertia, no federal price on carbon is expected to materialize throughout the study period. In California, an extension of current policy is expected, with cost-effective reductions in emissions made possible by low natural gas prices and efficient changes in other sectors of the economy. The price of carbon is expected to remain at $15/tonne (in real terms) over the study period.

Exhibit 50: California CO_2 Prices by Scenario



*Note that the Transformation scenario uses the Reference Case carbon price projections.

Source: Pace Global

SOLAR PV PENETRATION

Distributed solar penetration is a significant driver of GWP's portfolio cost profile over the long term. Residential and commercial adoption of solar PV can impact the operations of GWP's remaining fleet and affect the costs borne by remaining customers. Exhibit 51 summarizes the projected solar PV penetration levels in MW under the various scenarios, while the following section summarizes the key drivers for each.

Pace Global's Reference Case is based on an analysis of expected retail rate changes, trajectories for capital costs for solar, and the expected penetration rates that are associated with the resulting payback periods for residential and commercial customers. The chapter entitled Solar Penetration Analysis provides additional detail on the methodology, analysis, and results, summarizing that the expectation in the Reference Case is for around 40 MW of solar PV by the 2030s.

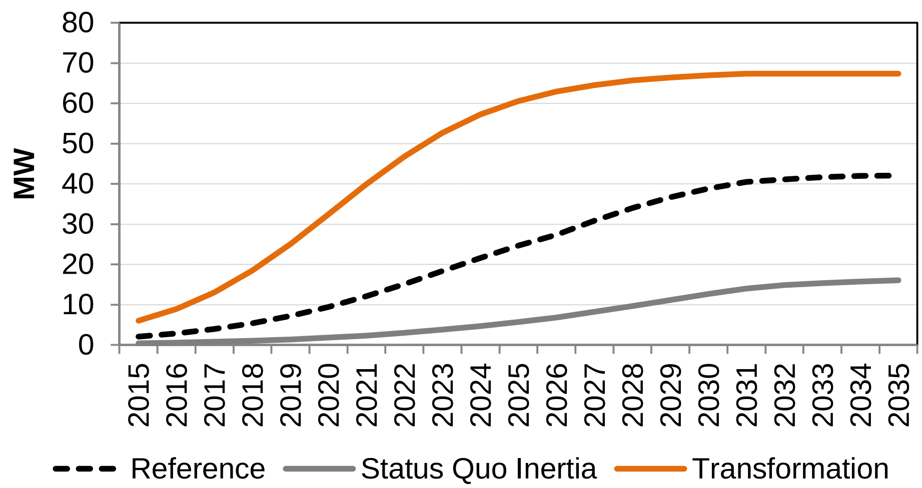
Under the Transformation scenario, a combination of technology drivers and customer responses lead to a higher penetration rate over time. Faster-than-expected declines in capital costs drive improved economics. Further, new market players and information platforms spread the potential opportunities to more customers. For example, companies such as EnergySage[21] have established an online solar marketplace designed to connect customers and solar installers. Customers are able to view multiple quotes and offers from installers and make a more educated decision on the solar purchase. Platforms

[21] http://www.energysage.com/

such as this can be a significant enabling force in driving demand for solar products by providing more price transparency to the customer. This can also induce more price competition amongst solar installers and bring down the overall price of solar installations, similar to what has been observed in Germany and Australia. Overall, under this scenario, the payback period for most customers improves to five years (vs. an average of seven years in the Reference Case), and the capacity of new distributed solar PV installations increases towards 70 MW.

Under Status Quo Inertia, costs of electricity are lower than the Reference Case due to flat natural gas and CO_2 prices. As a result, the expected payback period for new solar PV installations increases to ten years, driving a much more gradual penetration rate. Overall, by the 2030s, the total capacity of solar PV installations in GWP is only around 15 MW.

Exhibit 51: GWP Solar PV Penetration Levels by Scenario



*Note that the Green scenario uses the Reference Case solar PV levels.

Source: Pace Global

GWP LOAD GROWTH

Projections for load growth rates, load factors (the ratio between average and peak load), and hourly load profiles are all important drivers of GWP's portfolio costs. These variables change in the different MarketLink scenarios, with summary differences presented in Exhibit 52 and in the section below.

Pace Global's Reference Case load forecast was developed based on an econometric analysis of key economic and weather drivers, along with incorporation of customer count trajectories and energy efficiency and electric vehicle penetration rates over time. The details are explained in Appendix I: Load Forecast Details.

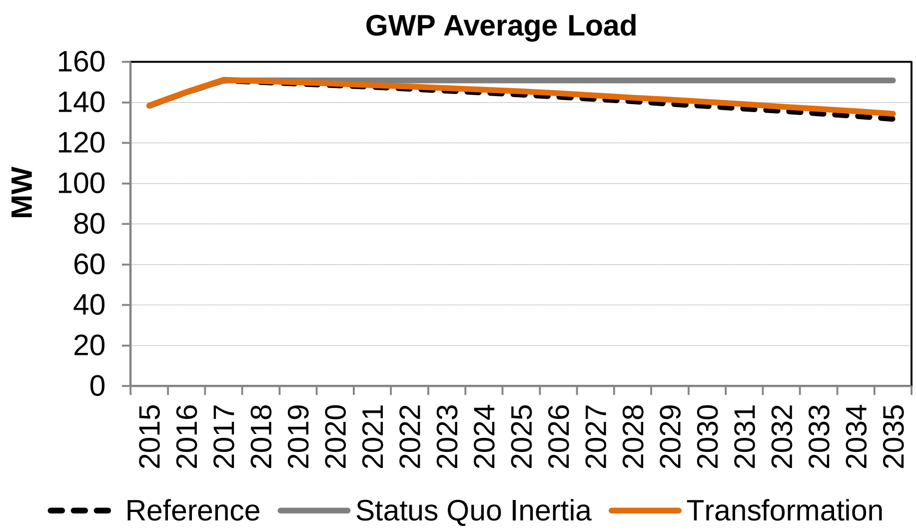
Under the Transformation scenario, two major changes are expected to drive a different load growth rate, load factor, and hourly load shape over time. These include:

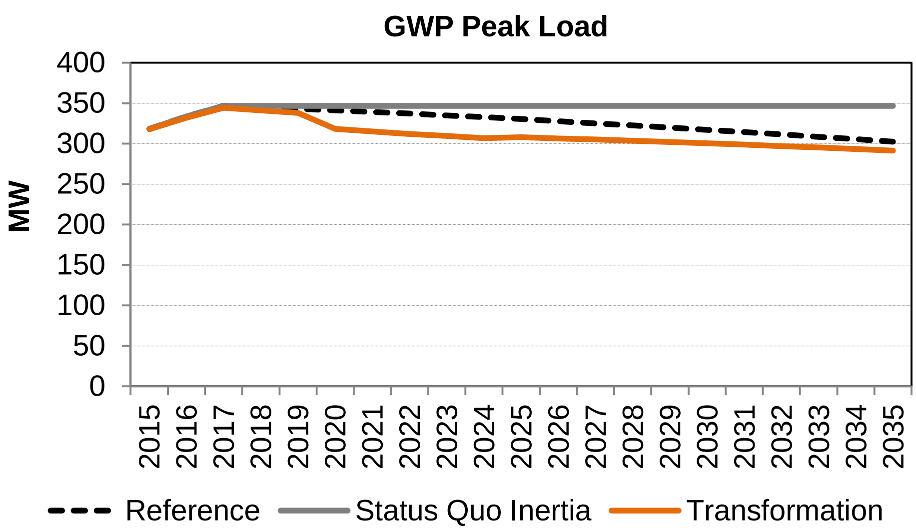
- Greater penetration of electric vehicles as a result of battery cost declines. Rather than the Reference Case assumption of 15% of new vehicle sales by 2025 coming from plug-in hybrid electric vehicles ("PHEVs"), the Transformation scenario expects 40% of new vehicle sales to be PHEV by 2025. This results in an average demand increase of about 2 MW by 2030 versus the Reference Case, with the load being heavily weighted to the off-peak hours.

- Shifting from peak to off-peak period consumption as a result of the effective deployment of time-of-use rates using GWP's existing smart meter infrastructure. As summarized in more detail in the Time of Use Rate Impact Analysis chapter, the introduction of a TOU rate structure is expected to lower peak demands, but keep overall energy sales and average load levels the same as the Reference Case.

Under Status Quo Inertia, continued customer count increases due to redevelopment and increased population density are expected to offset energy efficiency gains over time. Under this scenario, re-development in the City of Glendale drives customer count growth up at the rate of 0.82% (as opposed to 0.21% in the Reference Case), resulting in flat load growth after 2017 over the forecast horizon.

Exhibit 52**: GWP Load Growth Projections by Scenario**





*Note that the Green scenario uses the Reference Case load levels.

Source: Pace Global

LOSS OF LOAD EQUIVALENT ANALYSIS

As part of the assessment designed to screen candidate options for the ultimate portfolio review, Pace Global conducted an analysis of the reliability of each portfolio option. This analysis is referred to as a loss of load ("LOL") assessment and essentially tests the likelihood that GWP's generation and transmission system will be unable to meet load for any period of time. The analysis entails Monte Carlo-based simulations for outages in the generation and transmission system, as well as uncertainty in hourly loads for GWP's system. Monte Carlo methods involve random sampling across a distribution of possible outcomes, and this analysis has deployed such methods to evaluate future possible conditions for GWP's load and availability of supply resources in any given hour. The industry standard for loss of load events ("LOLE") is one event in ten years ("1-in-10 Standard").[22] Most jurisdictions define this as one single event (of indeterminate duration) in a ten year period. Pace Global has used this standard in benchmarking its analysis.

METHODOLOGY OVERVIEW

Aurora has the functionality to randomly "remove" power plants or other elements of GWP's system, such as transmission lines, from the available supply of resources for limited periods of time to simulate forced outage events. Pace Global coupled this random outage functionality with a set of load projections that was stochastically varied, providing both higher and lower load outlooks over one thousand different paths. Combining these two key elements of system uncertainty, Pace Global evaluated the frequency with which the various portfolio options would be unable to meet GWP load.

Definition of Loss-of-Load Event

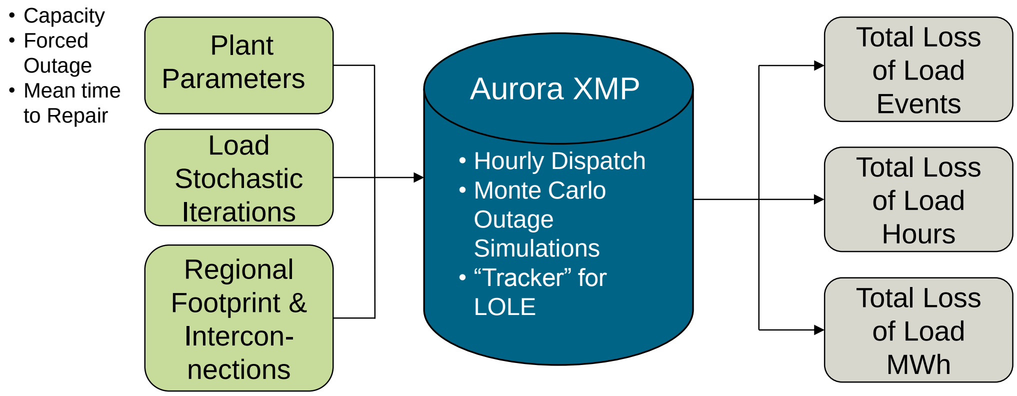
For the purposes of Pace Global's study, the following definitions are used:

- A LOL Event is defined as any hour or consecutive set of hours when the total available capacity in the GWP system (inclusive of import capability) is insufficient to meet GWP's load in that hour or set of hours;
- LOL Hours are defined as the total number of hours over the simulation period during which the total available capacity in the GWP system (inclusive of import capability) is insufficient to meet GWP's load.

For the analysis, Pace Global tracked the number of loss of load events, along with total loss of load hours and total loss of load MWh, for each portfolio. This is done through the tracking of a "dummy" resource in the GWP system that only operates when all other system resources (local capacity plus transmission imports) are unavailable to meet load. Exhibit 53 summarizes the key inputs and outputs for the assessment.

[22] The following sources provide an overview of the standard and its definition and applicability in the industry:
The Brattle Group and Astrape Consulting, "Resource Adequacy Requirements: Reliability and Economic Implications" prepared for FERC, September 2013. http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf
Hogan, William W., "Connecting Reliability Standards and Electricity Markets" presentation for Harvard Electricity Policy Group, December 8, 2005. http://www.hks.harvard.edu/fs/whogan/Hogan_hepg_120805.pdf
PJM Generation Adequacy Analysis: Technical Methods, October 2003.

Exhibit 53: LOLE Methodology Overview



Source: Pace Global

Test Years

Two test years were chosen for the LOLE study, 2019 and 2027, considered to be representative of critical points in time during the IRP study period. Since we assume that the Grayson Power Plant will be repowered no earlier than 2019, this test year allows a near-term comparison of the reliability implications of different repowering options, as well as a strategy where no significant action is taken at Grayson. The 2019 period also includes the loss of GWP's capacity from the San Juan Generating Station coal plant (assumed to be shut down by the end of 2017). By 2027, more significant changes will have occurred in GWP's system, including the possible replacement of IPP, additional evolution in energy efficiency, penetration, and the shutdown of most of the existing Grayson units if no repowering action is taken. The 2027 year is also closer to the end of the IRP study period. In consultation with GWP, Pace Global determined that these two years would be sufficient to capture the likely reliability impacts of different portfolios, and thus allow a clear ranking of the portfolios under consideration.

SYSTEM SUPPLY ELEMENTS AND ASSOCIATED UNCERTAINTY

Pace Global introduced random variation into the occurrence of plant forced outages using Aurora's Endogenous Risk Analysis. The random frequency and duration method takes into consideration the Forced Outage Rate ("FOR") of each plant/unit as well as the mean time to repair ("MTTR") required to bring the plant/unit back online. The FOR and MTTR values were developed in consultation with Stantec and GWP and are summarized in Exhibit 54.

Exhibit 54: Summary of FOR and MTTR for GWP System Elements

System Element	Forced Outage Rate (%)	Mean Time to Repair (hours)
Grayson Unit 3	20%*	720
Grayson Unit 4	10%**	720
Grayson Unit 5	10%^	720
Grayson Unit 8A	10%^^	720
Grayson Unit 8B	10%^^	720
Grayson Unit 9	2.5%	88
LM6000 Simple Cycle	1.9%	88
LM6000 Combined Cycle	2.7%	120
Victorville – LA Import Path	0.35%	72
NOB – Sylmar Import Path	0.35%	72
Magnolia Import Path	0.35%	72

*Initial rate is 20%. This increases by 5% per year until planned retirement in 2020.
**Initial rate is 10%. This increases linearly up to 20% until planned retirement in 2023.
^Note that this unit retires in 2017.
^^Initial rate is 10%. This increases linearly up to 20% until retirement in 2022.

FORs and MTTRs for Grayson reflect the current age and condition of the plant, as well as near-term planned life-extension investments that allow continued operations until planned retirement dates. FORs and MTTRs on import paths include both substations and transmission lines, including any contingency on the facilities that support delivery of energy at Air Way.

Sources: Stantec and GWP.

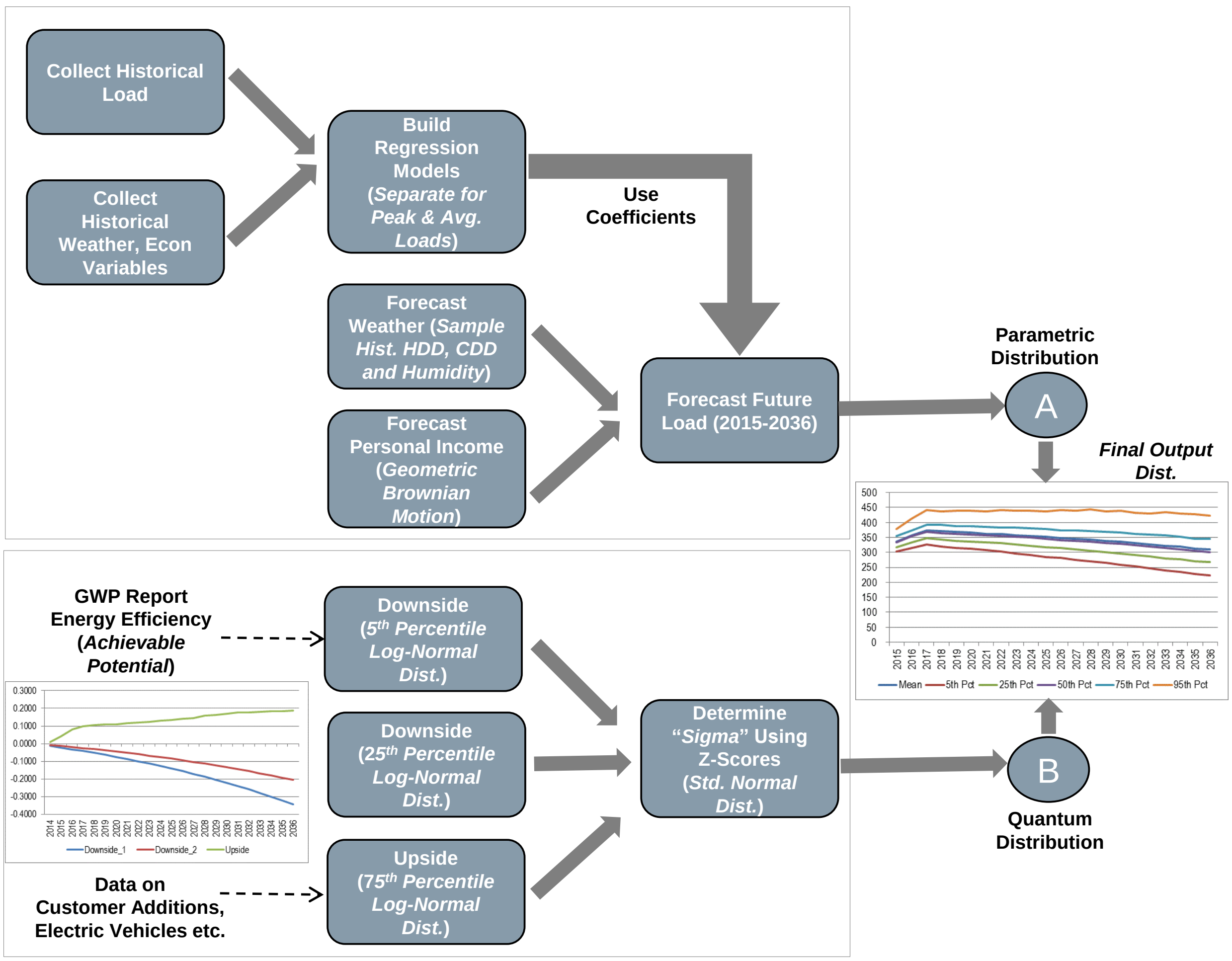
The analysis was performed for the four leading Grayson candidate portfolios (listed below), plus the run-to-fail scenario, along with a representation of the transmission capability for external resources. Since the key risk for external resources is transmission availability (other capacity could be imported through the transmission lines in the event external GWP-owned resources go down), the simulation does not need to incorporate remaining portfolio details, such as remote renewables or IPP renewal options. The five Grayson configurations include:

- 150B: three simple cycle LM6000 plants plus the existing unit 9;
- 200B: four simple cycle LM6000 plants plus the existing unit 9;
- 200C: three simple cycle LM6000 plants plus one 1x1 LM6000 combined cycle plus the existing unit 9;
- 250D: two simple cycle LM6000 plants plus two 1x1 LM6000 combined cycles plus the existing unit 9;
- "Run-to-fail": existing configuration with schedule of retirements for each unit.

SYSTEM LOAD UNCERTAINTY

Pace Global develops a distribution of potential load growth paths in order to perform the stochastic LOLE assessment. This is accomplished through assessment of the uncertainty in the key variables that drove our base load forecast. Pace Global produces a distribution of monthly average and peak loads using the methodology described below. The process to produce this distribution can be summarized by the flow chart in Exhibit 55. As is shown, the process includes the development of two distributions that are ultimately combined to create an integrated measure of uncertainty. The "parametric" distribution is based on statistical relationships between load, weather, and economic growth, and future uncertainty in these variables, guided by actual observations. The "quantum" distribution is based on fundamental projections of potential drivers of load uncertainty that have less historical data, such as energy efficiency penetration, electric vehicle penetration, and gains or losses of large customers.

Exhibit 55: Risk-Integrated Power Demand Modeling Overview



Source: Pace Global

Historical Driver Analysis

Similar to the baseline load forecast analysis, weather and economic data have historically explained GWP's monthly average and peak load fairly well. This relationship forms the basis for Pace Global's load uncertainty analysis. The historical weather data includes Heating Degree Days ("HDD"), Cooling Degree Days ("CDD") and Humidity. The basic premise of our stochastic model is that load can be expressed as follows:

$$Load_t = \alpha + (\beta_1 * HDD_t) + (\beta_2 * CDD_t) + (\beta_3 * HUM_t) + (\beta_4 * PI_t) + \xi_t$$

Where:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero. HDD is never negative.
- CDD (Cooling Degree Days): Average daily temperature - 65 in degrees Fahrenheit or zero. CDD is never negative.
- HUM (Humidity): Average daily percent humidity.
- PI: Personal Income

- ξ : A normally distributed error term with mean 0 and constant variance
- α : A constant derived from the regression analysis
- β_n: Estimated coefficients derived from the regression analysis

A stepwise regression then calibrates this model to historical data, yielding specific values for the estimated coefficients. Using the monthly historical data, Pace Global has obtained the following coefficients:

- Intercept : 116.79
- Coefficient for HDD : 0.0251
- Coefficient for CDD : 0.1249
- Coefficient for Personal Income : 0.0054

Load Stochastics Propagation

Step 1: Weather and Economic Variability

To produce our load stochastics, Pace Global propagates three independent random paths: weather data, personal income, and a residual.

Weather data includes heating and cooling degree days and humidity. To produce reasonable weather data projections, Pace Global samples actual yearly paths from history. For this analysis, 14 years of historical data (2000-2013) are used to perform the historical driver analysis. For every Monte Carlo iteration, the sampling of historical weather data is performed with "Equal-Weighted" probability for all historical years. This sampled historical weather for a year is considered as the forecast of weather for a specific year in the forecast time period. The same process is repeated for all forecast years, and for all iterations, with 2019 and 2027 as the test years in this analysis.

Pace Global has considered "Personal Income" as the independent economic variable. The evolution of personal income data is assumed to follow a Geometric Brownian Motion path. This means that there exists a normal distribution with constant mean and variance that describes how personal income will behave at any time. The trend in the growth rates of the personal income is estimated using the historical data. The two parameters used here are the drift rate and the variance to the drift. These two parameters are used in the Geometric Brownian Motion model to come with a distribution of personal income paths throughout the future years.

Finally, to account for unexplained variation in the observed data, Pace Global adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Pace Global treats the load distribution thus obtained as a "*Parametric Distribution*".

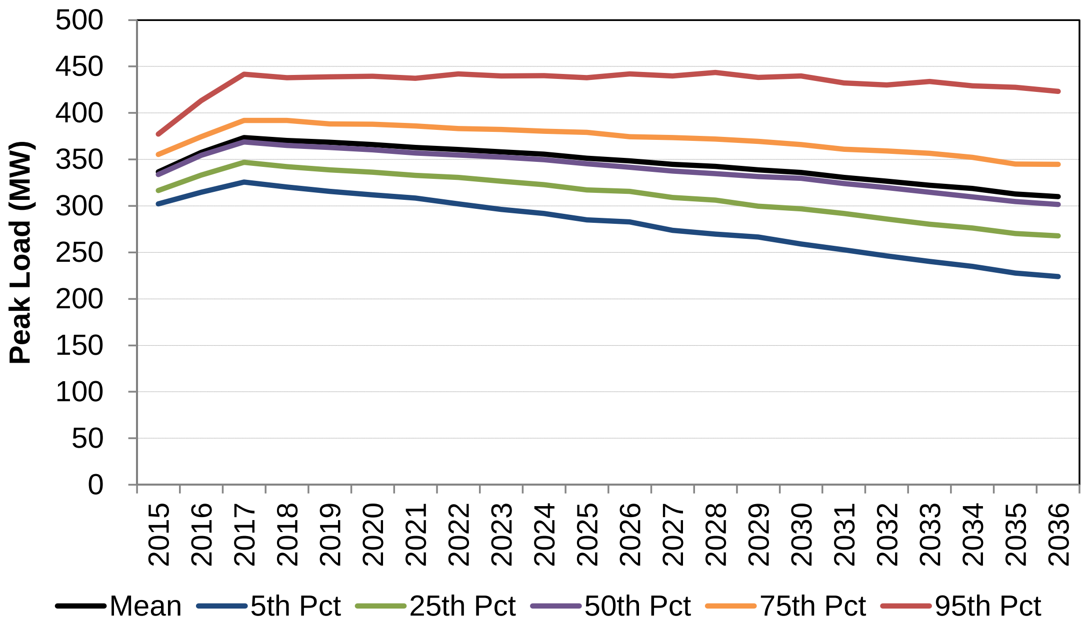
Step 2: Additional Variability

The determinants of future power demand have the potential to differ substantially from those explaining historical power demand, because of structural changes such as EV adoption and EE programs that differ from experience. To account for this, an additional "*Quantum (or Efficiency) Distribution*" is added to our empirically-derived distribution. The distribution is log-normally distributed. The 5th percentile case is treated as a downside and the 75th percentile case is treated as an upside.

The 5th percentile of this distribution is taken from GWP's data on expected potential for load reductions (DSM, energy efficiency and other measures). For example, these measures may include programs using advanced metering infrastructure, appliance efficiency standards, or other direct load control programs. The upper tail of this distribution is weighted to match Pace Global's analysis of historical high periods of load growth, along with upside drivers like new customers and sources of demand. Examples include increasing residential plug load and electric vehicles. Note that the "Quantum Distribution" incorporates the potential for limited or no penetration of the expected increases in the energy efficiency of the economy embedded in the Reference Case. Pace Global expects that changes attributable to the efficiency distribution will persist over time. Thus, the propagations have a high level of serial correlation and statistical consistency as well.

Exhibit 56 summarizes the peak load stochastic distribution over time for the GWP system. Note that each line is not a discrete path or load forecast, but a representation of the probability of being at or below that point across the entire distribution of potential outcomes.

Exhibit 56: Peak Load Stochastic Distribution



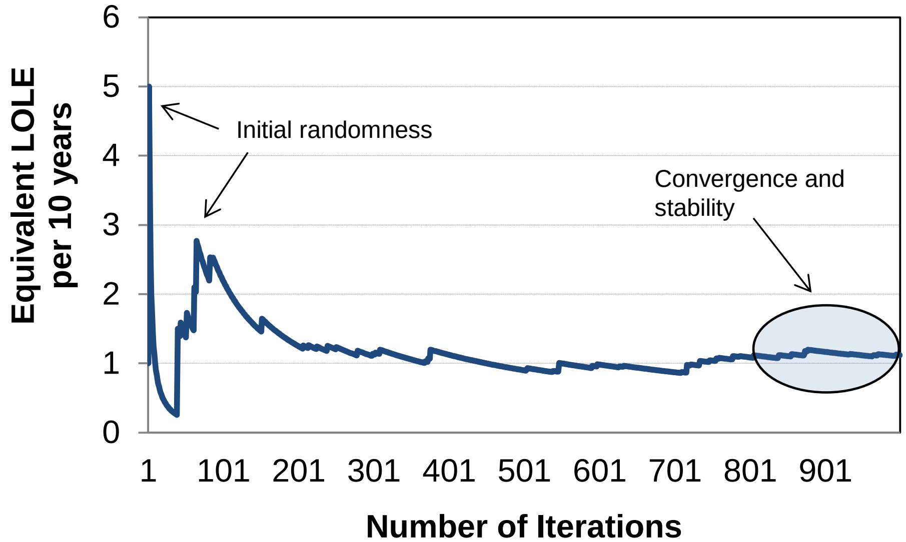
Source: Pace Global

USE OF 1,000 ITERATIONS

Monte Carlo methods are performed by running simulations repetitively, by sampling the input parameters every time the model is run. The accuracy of the results being estimated is proportional to the number of times the model is run. This relationship is thought to be exponentially increasing, so that at some point the repeated sampling of input parameters and operation of Aurora will yield a stable expected value of Loss of Load. In this context, we define convergence as "the optimal number of times the model needs to be run, in order to produce stability in the output parameter value being estimated, by fixing all input parameters."

Under Monte Carlo Analysis, the GWP simulation model is run for a series of iterations, each one providing a different number of LOL Events during the course of the 8760 hours that make up each year. Pace Global has performed test runs to determine the optimal number of runs (iterations) required for this study. Exhibit 57 shows the distribution of the measurement criteria (LOL Events/year) against the number of iterations. The vertical axis represents the equivalent LOLE per 10 year metric used in the industry, while the horizontal axis identifies the equivalent LOLE for the corresponding number of iterations. Exhibit 57 shows that the LOL Event equivalent value is initially volatile with a low number of iterations, as the frequency of an outage event is rare, but its impact on the ten year calculation can be significant. The value stabilizes around 1000 iterations. Therefore, for the purposes of the study, we set to 1000 the number of iterations to meet the convergence criteria for the Monte Carlo simulation.

Exhibit 57: LOL Equivalent by Iteration (sample 150B portfolio in 2019 shown)



Source: Pace Global analysis

LOLE FINDINGS

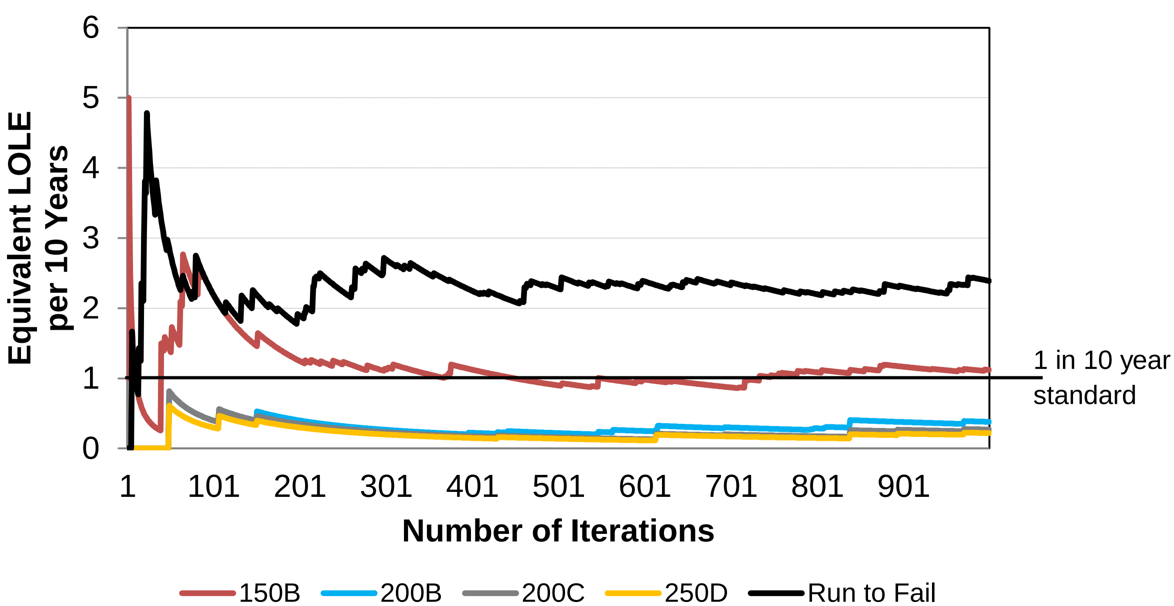
Pace Global simulated five Grayson configurations (four preferred local re-powering options plus the “run to fail” scenario) across 1,000 iterations under a 2019 simulation year. After observing the results from the 2019 year, two Grayson configuration portfolios were tested in 2027. The results of the analysis are summarized in Exhibit 58 with the LOLE summary by iteration for all five portfolios for 2019 summarized in Exhibit 59 and for two select portfolios in Exhibit 60. As is shown, the “run-to-fail” and 150B portfolios both violate the one event in ten year standard in 2019, although the 150B portfolio is only slightly above target. The other options meet the one-in-ten standard, with the larger local Grayson options having lower LOL events. In 2027, when GWP load is expected to be lower due to energy efficiency penetration, the 150B portfolio is within the one in ten year standard, while the “run-to-fail” faces significant reliability concerns due to the loss of all local Grayson elements, save unit 9. Note that two different axis scales are used in Exhibit 60to showcase the different LOLE levels.

Exhibit 58: Summary of Loss of Load Findings

Portfolio/ Year	Loss of load Events per 10 years	Loss of Load Hours per 10 year period	Loss of MWh per 10 year period
150B/ 2019	1.1	5.3	186
200B/ 2019	0.4	1.5	55
200C/ 2019	0.3	1.2	45
250D/ 2019	0.2	0.9	28
Run to Fail/ 2019	2.4	14.3	569
150B/ 2027	0.5	2.0	55
Run to Fail/ 2027	22.3	149.8	5,962

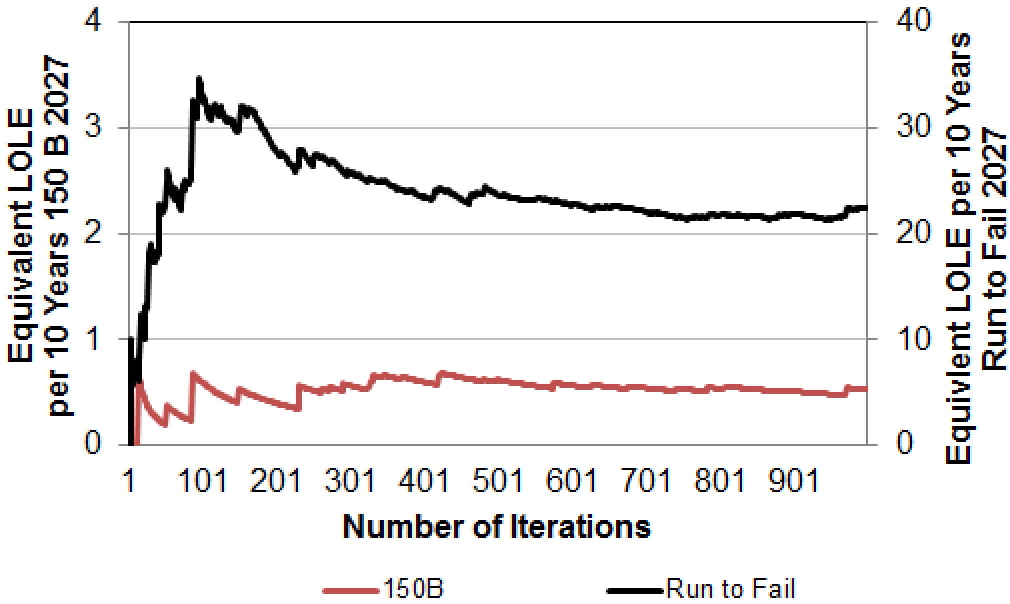
Source: Pace Global analysis

Exhibit 59: LOL Equivalent by Iteration for All Portfolios - 2019



Source: Pace Global analysis

Exhibit 60: LOL Equivalent by Iteration for Select Portfolios - 2027

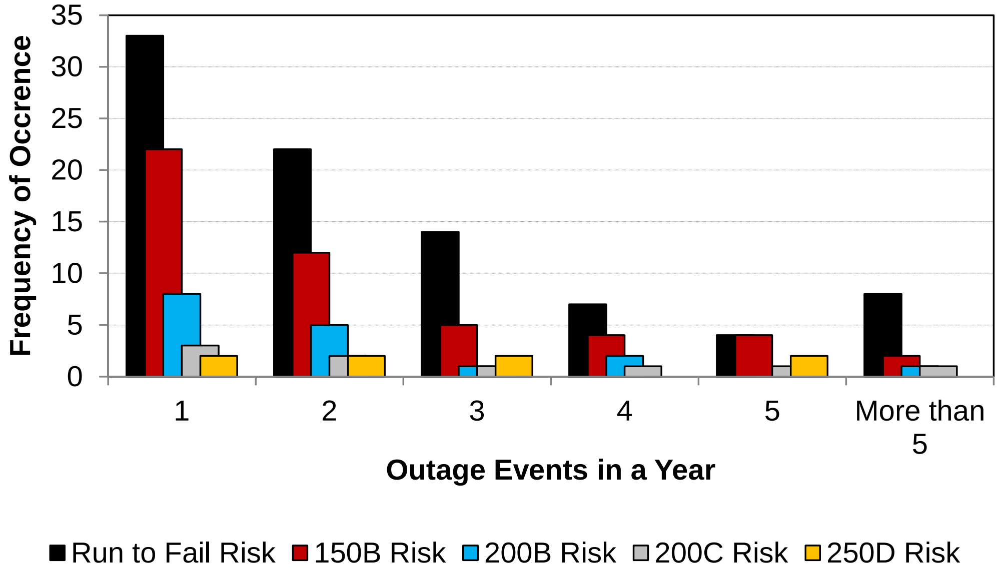


Source: Pace Global analysis.

LOLE Frequency Analysis

To better understand the LOLE under the Monte Carlo analysis performed, Pace Global performed a frequency analysis on the number of loss of load events (and hours) for every iteration. This analysis results in a frequency distribution plot or a histogram, which is simply the number of loss of load events or hours, summarized for all 1,000 iterations. As seen in Exhibit 61, the Run-to-Fail portfolio (black) and 150B portfolio (red) are the most prominent, indicating the cases with the most occurrences of loss of load events. The grouping of bars indicates how frequently each portfolio experienced a particular number of outage events in a given year. Hence the first grouping shows that the Run-to-Fail portfolio had thirty four iterations with one loss of load event. Subsequent groupings represent the frequency each portfolio experienced higher volumes of loss of load events. The frequency tends to decline over time, as the probability of greater loss of load events in one year decreases.

Exhibit 61: Frequency distribution of LOL Events across Iterations for 2019



Source: Pace Global analysis

CONVERSION TO TOTAL VALUE OF LOST LOAD

Pace Global performed a literature review to establish the economic Value of Lost Load ("VOLL"), which is a way of representing the cost of LOL events for end-use customers. Our primary source is a comprehensive report conducted by the U.S. Department of Energy ("DOE") in 2009. This was a nationwide survey of results from 28 customer "value of service" reliability studies conducted by 10 major U.S. electric utilities over the 16 year period from 1989 to 2005. It divided customer classes into Residential, Small Commercial/Industrial (less than 50,000 kWh of annual usage), and Large Commercial/Industrial.

Exhibit 62 summarizes the VOLL across various customer classes and regions, with the West highlighted. It should be noted that the value of lost load is estimated to be higher for small C/I customers than large C/I customers. This is because small C/I customers are less likely to prepare for operational risks, such as outages, by using interruptible contracts and back-up generation as hedges against outages, than are large C/I customers.

Exhibit 62: VOLL Summary from DOE Study by Class and Region

Region	Residential ($/MWh)	Large C/I ($/MWh)	Small C/I ($/MWh)
Nation - Winter	655	11,891	41,564
Nation - Summer	982	16,691	56,291
Nation - Weekend	1,855	2,400	35,127
Nation - Weekday	873	17,673	58,473
Midwest		13,200	55,964
Northwest	655	3,818	26,073
Southeast	1,418	25,527	61,091
Southwest	436	6,327	73,964
West	764	19,418	67,746
Agriculture		1,091	26,946
Mining		19,855	118,146
Construction		3,927	99,491
Manufacturing		44,618	69,818
Telco & Utilities		9,491	61,964
Trade & Retail		3,055	47,891
Fin., Ins. &R.E.		6,218	74,509
Services		5,127	40,582
Public Admin		13,091	23,673

Sources: Table adopted from "The Economic Ramifications of Resource Adequacy White Paper," a study from January 2013, performed by Astrape Consulting for EISPC and NARUC – p. 35.
http://www.naruc.org/grants/Documents/Economics%20of%20Resource%20Adequacy%20WhitePaper_Astrape_Final.pdf

Ultimate sources for values come from "Estimated Value of Service Reliability for Electric Utility Customers in the United States," by Berkeley National Laboratory under DOE. See tables 3-4, 4-4, and 5-4, which were adjusted for peak load assumptions.
http://certs.lbl.gov/pdf/lbnl-2132e.pdf

By combining the total MWh of projected lost load with the estimates of the value of lost load, Pace Global projected an economic impact for each of the portfolio options on the VOLL metric. This is summarized in Exhibit 63. Note that a range of values is shown for the industrial and commercial classes, since we have not assessed the specific breakdown of GWP's service territory into the small vs. large class sectors used in the DOE study.

Exhibit 63: GWP VOLL Estimates by Portfolio

Portfolio/ Year	Residential VOLL (2013$)	Industrial and Commercial VOLL (2013$)*	VOLL (Total 2013$)
150B/ 2019	$6,075	$239,617-$835,982	$245,692-$842,057
200B/ 2019	$1,796	$70,854-$247,199	$72,650-$248,995
200C/ 2019	$1,470	$57,972-$202,254	$59,442-$203,724
250D/ 2019	$914	$36,071-$125,847	$36,985-$126,761
Run to Fail/ 2019	$18,583	$733,022-$2,557,385	$751,605-$2,575,968
150B/ 2027	$1,796	$70,854-$24,7199	$72,650-$248,995
Run to Fail/ 2027	$194,714	$7,680,626-$26,796,358	$7,875,340-$26,991,072

*Range based on 100% of C + I load falling into small consumer category and 100% of C + I load falling into large consumer category; actual VOLL will fall within the stated range.

Source: Pace Global analysis

LOLE ANALYSIS CONCLUSIONS

The LOLE analysis concludes the following with regard to GWP's reliability objective, which has driven the ranking of each of the portfolio options summarized earlier in this report in Exhibit 47:

- The "Run to Fail" portfolio has unacceptable levels of reliability and potential costs associated with the value of lost load that total in the millions of dollars.
- The 150B portfolio slightly violates acceptable reliability standards in 2019, suggesting that the option poses reliability risk for GWP.
- The 200B, 200C, and 250D portfolio options all demonstrate acceptable levels of reliability.

TIME OF USE RATE IMPACT ANALYSIS

As part of the IRP assessment, Pace Global has performed an analysis to estimate the impact of potential deployment of time-of-use ("TOU") rates for residential and small commercial customers on GWP's load. The assessment required the following steps:

- Review existing TOU rate structures throughout the region to approximate a plausible on-peak/off-peak price period and ratio for GWP;
- Assess elasticity of demand estimates through research of existing studies and pilot programs, with a focus in Southern California;
- Assess potential participation in the TOU program over time based on assessments of opt-in and opt-out levels for similar utilities and an assumed roll-out of TOU rates at GWP;
- Apply the elasticity estimates to GWP's hourly load profiles by customer class to assess load shifting;
- Develop a revised peak and average load forecast with new hourly load profiles.

The results of this analysis are incorporated into the MarketLink Transformation scenario discussed in the MarketLink Scenario Details section of this report.

TOU RATE STRUCTURES AND PRICING

According to EIA-861, ten electric utilities (including GWP) in the state of California employ some kind of residential TOU pricing program, and all programs are offered on an opt-in basis. Pace Global has analyzed the standard and TOU rates of these entities through review of EIA filings and publicly available rate schedules. Most of the utilities price electricity based on consumption level (tiered rates), rather than at a single rate like GWP. However, within a tier, it is still appropriate to examine the ratio of flat rates to TOU rates in order to assess the appropriate ranges for GWP's study. Pace Global's review compared rates within the lowest demand tier (when relevant) by peak condition, season and sector.

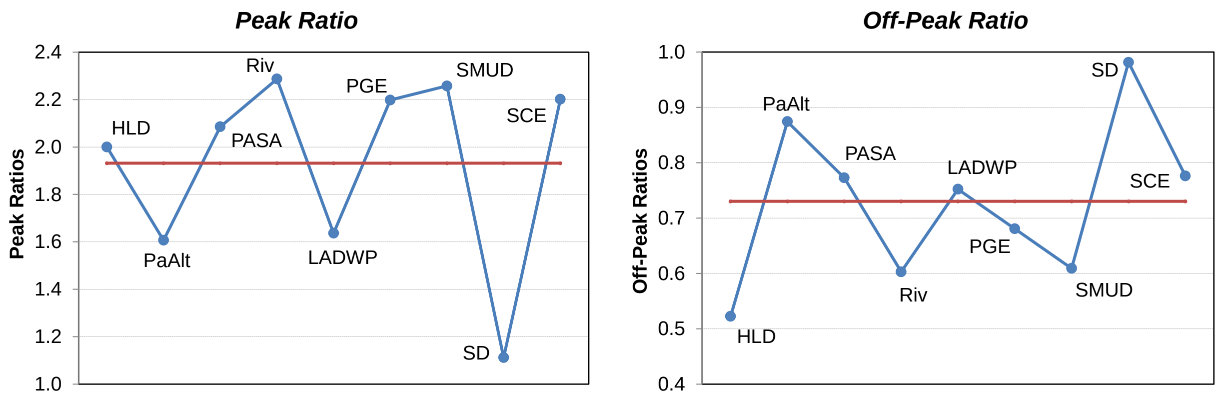
Based on the utilities surveyed, Pace Global has observed the following:

- Peak hours may reasonably be defined as noon – 8pm on weekdays, regardless of season. Although some programs only apply the peak period between noon and 6pm, growing concerns about the early evening "duck curve" would suggest that a period that extends to 8pm would be reasonable.
- Residential summer peak TOU rates may reasonably be set at a ratio of 1.93:1 relative to a traditional flat rate, with off-peak rates set at a ratio of 0.73:1.[23]

Exhibit 64 displays the range of ratios of TOU rates to flat rates for a variety of California utilities, along with recommendations (in red) for purposes of the assessment for GWP.

[23] Note that small commercial peak TOU rate ratios tend to be lower than those for residential customers. However, for simplicity, a single rate structure ratio will be assumed for this analysis.

Exhibit 64: Summary of Ratio of Peak to Flat Rates for California Utilities



HLD: City of Healdsburg, CA – TOU rate for residential customers vs. flat Tier 1 rate.
PaAlt: City of Palo Alto, CA – TOU rate for Tier I residential customers vs. flat Tier 1 rate.
PASA: City of Pasadena, CA – optional residential TOU rate vs. optional seasonal (summer) flat rate.
Riv: City of Riverside, CA – optional TOU rate vs. flat rate for lowest usage class.
LADWP: Los Angeles Department of Water & Power: Summer TOU rate for residential customers vs. flat summer Tier 1 rate.
PGE: Pacific Gas & Electric Co – TOU rate for Tier I residential customers vs. flat Tier 1 rate.
SMUD: Sacramento Municipal Utility District – TOU "Option I" for residential customers vs. flat Tier 1 rate.
SD: San Diego Gas & Electric Co – Summer TOU rate for Tier 1 residential customers vs. flat Tier 1 rate.
SCE: Southern California Edison Co – Summer TOU rate for Level I for residential customers vs. flat Tier 1 rate.

Sources: Pace Global, EIA, and individual utility rate schedules.

ELASTICITY OF DEMAND

Price Elasticity of Demand

Price elasticity of demand estimates vary considerably across the literature.[24] Price elasticity measures the percentage change in energy consumption due to a percentage change in the price or rate charged. For example, a price elasticity of -0.1 would mean that if prices doubled (increased by 100%), demand would decrease by 10%.[25] The literature on the subject often differentiates between short-run elasticity (often measured through experiments that take place over the course of a year or two), with long-run elasticity measurements that look at the relationships between price movements and demand over many years (reflecting additional time for behavior changes and enabling technology deployment).

In assessing the elasticity estimates to use for GWP's study, Pace Global has relied on two national studies that produced regional estimates of both short-run and long-run elasticities and the results of California's Statewide Pricing Pilot from 2003-2004 for the most relevant short-run elasticity experiment. In that program, nearly 2,500 customers of California's three investor owned utilities participated in a program that offered off-peak discounts in exchange for an on-peak price around twice the value of the off-peak price, along with an even higher rate during critical peak pricing events.

Exhibit 65 summarizes the relevant elasticity estimates that drive Pace Global's estimates. As is shown, short-run elasticities are lower than those for the long-run, reflecting the increases in customer response over time as a result of additional information and infrastructure or technology change. Notably, the

[24] See Faruqui, Ahmad and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence." January 10, 2009. http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf

[25] Elasticity is a unit-less concept, since it is a percentage divided by a percentage. Price elasticities are generally negative, and in the example provided, -10% (change in demand) divided by 100% (change in price) equals -0.1. Measurements closer to -1 would indicate a more elastic condition, while those closer to zero are considered inelastic.

California Statewide Pricing Pilot observed lower elasticities in the short-run than other assessments. Based on this review, Pace Global has used an elasticity of -0.054 in the first few years of the study for GWP, given that it is the most relevant study for a proposed TOU rate structure. Over the long-term, our analysis included an increasing elasticity to a level of -0.2 by 2031. This is due to an average increase in elasticity of 0.15 between short-run and long-run elasticities in the national surveys reviewed.

Exhibit 65: Summary of Elasticity Estimates for Demand

Study	Short-Run Elasticity	Long-Run Elasticity	Notes
California Statewide Pricing Pilot – TOU rates with critical peak pricing events	-0.054	N/A	California
RFF Study on U.S. Electricity Demand	-0.13	-0.37	Pacific Region
NREL Study on Regional Differences in Price Elasticity of Demand for Energy	-0.188	-0.254	Pacific Coast Region

Sources:

California Pilot results summarized in Faruqui, as cited above.
Paul, Anthony, Erica Myers, and Karen Palmer, "A Partial Adjustment Model of U.S. Electricity Demand by Region, Season, and Sector. Resources for the Future (RFF) Discussion Paper, April, 2009: http://www.rff.org/documents/rff-dp-08-50.pdf
Bernstein, M.A. and J. Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy" RAND report for NREL, February, 2006: http://www.nrel.gov/docs/fy06osti/39512.pdf

Substitution Elasticity

Another measure of the impact of electricity price changes on demand is the substitution elasticity, which is expressed as the change in peak to off-peak demand *ratio* for a given change in the peak to off-peak price *ratio*. Throughout the literature, substitution elasticities are generally in the -0.05 to -0.1 range, suggesting that for a doubling in the *ratio* of peak to off-peak price, the ratio of peak to off-peak demand would decline by five to ten percent. Pace Global performed testing in our hourly demand models on the implied substitution elasticities that are realized when peak prices are raised by a factor of 1.93 (as noted in Exhibit 64), when off-peak prices are lowered by a factor of 0.73 (as noted in Exhibit 64), and when all demand lost from the peak period is shifted in full to the off-peak period. Under these assumptions, the implied substitution elasticity starts below -0.01 in the early years, but grows to -0.13 and averages -0.069 over the full study period. Given that this analysis is consistent with estimates of substitution elasticity in the literature, Pace Global's assessment has made the assumption that lost load from the peak period will be completely shifted to off-peak hours under the implementation of a TOU rate program. In other words, total energy consumption will stay the same, but the time of consumption will shift.

PROGRAM PARTICIPATION

TOU programs have generally been offered as "opt-in" rate structures, meaning that customers must proactively sign up for the TOU program. If action is not taken, the customer will by default remain on the standard flat structure. Alternatively, an "opt-out" program would institute the TOU rate structure as the default program, with customers having to proactively decide to change back to a flat rate. Participation in residential TOU programs is generally much higher on an opt-out versus an opt-in basis. For example, Regulatory Assistance Project offers the general rule of thumb that expected opt-out program participation may be as high as 80%, compared to only 20% for opt-in programs.[26] This is consistent with PG&E's assumed 25% participation in its opt-in TOU program[27] and with the Department of Energy's

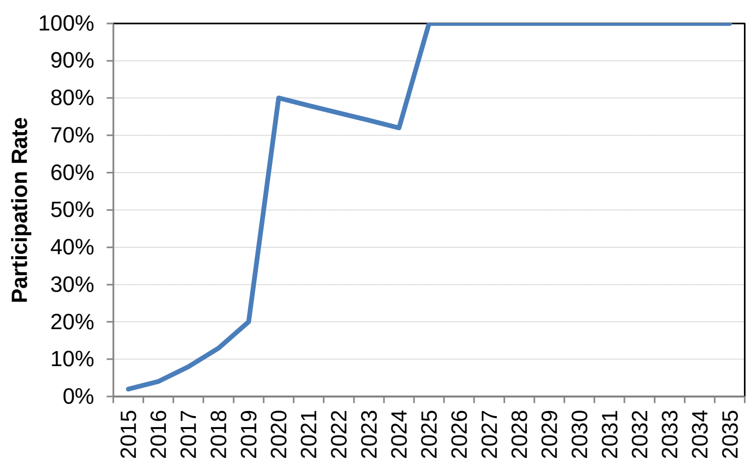
[26] Faruqui, Ahmad et. al. "Time-Varying and Dynamic Rate Design." Brattle Group, Regulatory Assistance Project., pg. 40

[27] Levin, Robert. "Time-Variant Pricing: Time-of-Use vs. Critical Peak Pricing." CPUC, 28 June 2012. https://www.pge.com/regulation/RateDesignWindow2010/Pleadings/DRA/2012/RateDesignWindow2010_Plea_DRA_20120703_242365Atch01_242366.pdf

estimated 17% opt-in participation rate across its 99 Smart Grid Investment Grant ("SGIG") projects.[28] Sacramento Municipal Utility District ("SMUD") noted that while 20% of participants left its SGIG pricing pilot over the two-year study, the actual opt-out rate was only 4 – 9% (with the rest attributable to moving).[29]

Given this information and guidance from GWP on the potential timing of opt-in, opt-out, and mandatory adoption regimes, Pace Global has developed an assumed participation rate over time. This is shown in Exhibit 66. As is shown, during the first five-year period, customers are assumed to have to opt-in through a voluntary participation program, driving participation rates up to 20% by 2019. For the next five years, an opt-out program is assumed to exist, with participation spiking to 80%, followed by gradual attrition over time. Attrition is generally attributed to real or perceived cost increases by customers after experiencing the new rate structure. In 2025 and beyond, the program is assumed to be mandatory, so there is no attrition.

Exhibit 66: TOU Rate Participation over Time



Source: Pace Global and GWP

TOU RATE IMPACTS ON LOAD

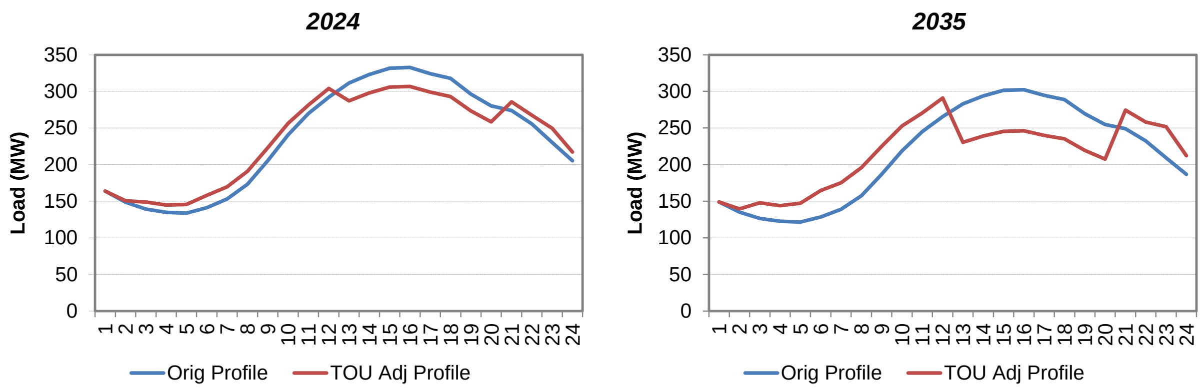
Pace Global's TOU rate impact analysis has found that the shape of hourly loads across the GWP system can be significantly impacted, with overall peak load levels likely to fall by 7% by 2020 and 5% by 2030. As shown in Exhibit 67, over time, as the price elasticity of demand increases and as program participation rates increase, the peak demand hours across GWP's system shift significantly from late afternoon to the mid-day or late evening hours. However, given that overall energy consumption is expected to remain the same, the overall peak demand requirements do not fall as much over time as a result of new peak hours forming during mid-day or late evening. In other words, over time, the shifting of load from the peak to off-peak periods becomes so significant that the new peak hours in the mid-day or late evening are nearly as high as the original peak expectations for late afternoon. As a result, system

[28] US Department of Energy, "Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies." July 2013, https://www.smartgrid.gov/sites/default/files/doc/files/DOE_CBS_report_final_draft-7-10-13.pdf

[29] Potter, Jennifer et. al. "SmartPricing Options Final Evaluation," US Department of Energy, 5 September 2014, https://www.smartgrid.gov/sites/default/files/doc/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf

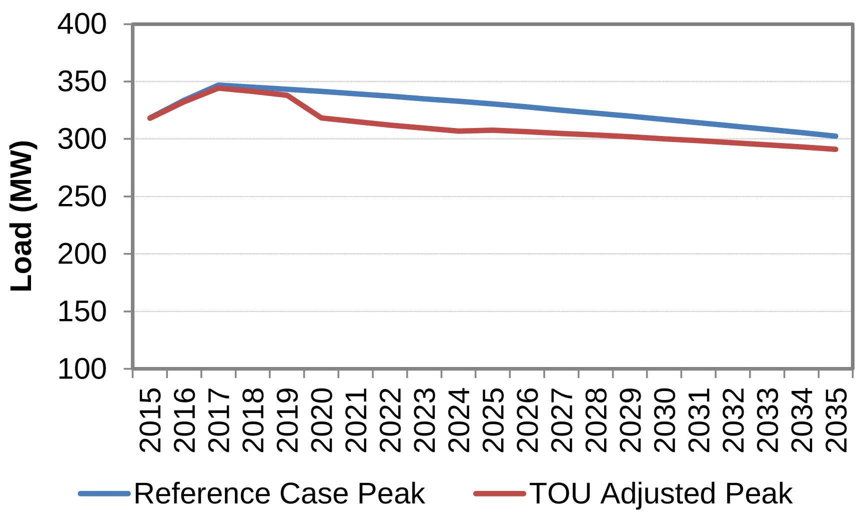
peak loads are projected to change by 23 MW in 2020, but only by 11 MW in 2035. This is shown in Exhibit 68.

Exhibit 67: Hourly Load Shape Changes under TOU Price Structure – Sample August Day



Source: Pace Global analysis

Exhibit 68: Peak Load Projections for Base Case and TOU Rate Impact Case



Source: Pace Global analysis

SOLAR PENETRATION ANALYSIS

As part of the GWP IRP assessment, Pace Global conducted a distributed solar penetration analysis. The solar penetration levels impact the cost to serve GWP's remaining load as well as the magnitude of the required renewable build-out to meet RPS, as customer-sited solar reduces retail sales, both peak load and total energy consumption.

METHODOLOGY OVERVIEW

Pace Global has developed solar penetration estimates based on established methodologies that have been used in the past and adopted by the National Renewable Energy Laboratory ("NREL"). This includes an estimation of the maximum market share and adoption rate as a function of the payback period. The payback period in turn is a function of module capital costs, retail rates, and financing assumptions.

The input assumptions were based on Glendale-specific customer demand levels, California-specific capital cost estimates, and Glendale Water and Power retail rate projections. The analysis is conducted separately for residential and commercial customers, with the solar PV module size being the key difference between the two customer classes. For sake of simplicity, the analysis is broken down into three discrete seven year periods[30] – early, mid, and late – with payback periods calculated for each period based on long term cash flows. The analysis uses these discrete periods because of expectations that the cost of solar PV will fall over time. Discrete periods are used in the IRP as a simplification from a continuous function that would reflect the cost reductions. The MWh reductions in demand due to solar penetration can be viewed in terms of energy reduction (MWh) and solar PV meter count over time.

INPUT ASSUMPTIONS

There are a number of input assumptions to the solar penetration analysis. The items listed below are the key assumptions underlying the analysis:

1) <u>Module Size</u>: A 3 kW module was chosen for the residential customer, while an 8 kW module was chosen for the commercial customer. The module size was based on peak consumption per customer as observed historically. The solar module capacity factor was assumed to be 15%, consistent with average fixed tilt rooftop systems in California.

2) <u>Technology Capital Costs</u>: Solar PV costs for customer-sited installations are currently in the $3,300/kW range. The costs are projected to decline to $2,600/kW by the end of the decade, with decline rates slowing thereafter, such that projected costs are $2,300/kW by 2030. The costs per kW were assumed to be the same for residential and commercial customers. Exhibit 69 shows the rooftop solar capital cost trajectory over time.

3) <u>Retail Rate Projections</u>: The retail rates projection was based on current rates, incremental changes in revenue requirements over time as a function of changes in operating costs (fuel and operating costs) on the supply side, investments in generation such as Grayson, and investments in transmission and distribution expenses over time. Exhibit 69 shows an average system rate trajectory over time in real dollars. The retail rates increase steadily over the next 5 years, primarily due to investments in Grayson repowering, but also due to capital investments to enhance transmission and distribution grid reliability funded from current revenues. Longer-term stability in real rate projections is a result of cost declines for remote renewables and the addition of efficient, natural gas-fired capacity at the IPP site.

[30] Early period is 2015-2021, mid period is 2022-2028, and late period is 2029-2035.

Exhibit 69: Retail Rate and Capital Cost Projections

Year	Retail Rate ($/KWh)	Capital Cost ($/KW)
2015	0.155	3,300
2016	0.165	3,169
2017	0.165	3,036
2018	0.163	2,905
2019	0.169	2,772
2020	0.176	2,641
2021	0.175	2,607
2022	0.177	2,574
2023	0.178	2,541
2024	0.178	2,508
2025	0.178	2,475
2026	0.178	2,443
2027	0.173	2,410
2028	0.170	2,376
2029	0.170	2,343
2030	0.170	2,310
2031	0.171	2,275
2032	0.172	2,238
2033	0.172	2,200
2034	0.172	2,160
2035	0.173	2,119

Source: Pace Global analysis and GWP rate information

4) Financing Assumptions: The solar module acquisition was assumed to be based on an ownership model with 20% down-payment, with the remaining investment being debt financed. A debt rate of 4.5% was used for the financing. This was largely based on 200 basis point spread over the 15 year T bond rate, assuming an average BBB credit rating. Below are summary points that support the soundness of our assumption:
    a. SolarCity's debt is rated at BBB+, close to the BBB assumption that we have used in our model. Under current market conditions, debt rated BBB (or equivalent to Moody's Baa) has a yield to maturity of roughly 4.5%. This is based on Federal Reserve's H15 data using corporate bonds rated at Moody's Baa rating[31].
    b. In Nov 2014, SolarCity issued solar bonds with a coupon rate of 4.0% for a 7 year term.
    c. SolarCity recently introduced a new product "MyPower" that allows customers to own the solar panel under a long term financing arrangement with a coupon rate of 4 - 4.9%.

5) Subsidies and Tax Credits: A solar investment tax credit of 30% was assumed for the early period, with tax credits declining to 10% for the mid and late periods. No other subsidies were assumed, as the GWP subsidy program is expected to expire soon.

[31] Based on Jan 2015 monthly data available at http://www.federalreserve.gov/releases/h15/update/

SOLAR PENETRATION CURVES

Pace Global conducted an analysis for Glendale with the objective of quantifying the total load reduction from solar PV installations in California. In developing the solar penetration levels, Pace relied on NREL documentation[32] in addition to its own experience and observations with developing penetration curves. There are three key components to this calculation: maximum market share, penetration or adoption rate, and energy available from PV installations[33]. The combination of these three variables results in the reduction in load from solar panel penetrations. Below is a more detailed outline of the assumptions that were used to estimate each variable.

The maximum market share is a function of the payback period, which represents the duration for the solar PV installation to break even (i.e., NPV of the cash flow = 0). The maximum market share is an exponentially declining function in relation to the payback period defined as follows:

$$Maximum\ Market\ Fraction = \mathrm{e}^{-Payback\ Sensitivity\ *\ Payback\ Time}$$

Pace Global assumed the payback sensitivity to be 0.3, an industry standard that was approximated by experts who have conducted research in this area.[34]

The penetration rate represents the cumulative adoption of a new technology since its introduction to the market. The curve is characterized by an "S" shape (S-curve), which shows a slower rate of growth in the initial and the late stages of the technology, but a faster adoption rate in the mid-stage.

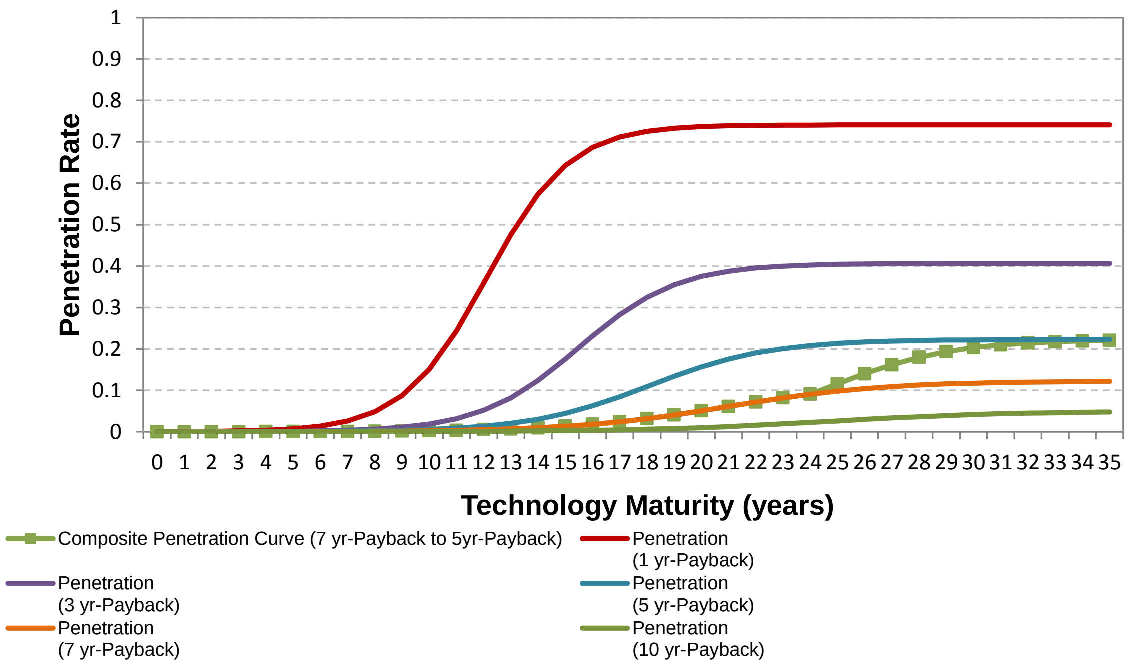
The "energy available from PV installations" is estimated by multiplying the kW module size assumed above by the expected capacity factor.

The initial observation from the simulated S-curves is that the adoption rate increases as the payback period decreases. Because the payback period may shift due to changes in capital costs or retail rates over time, Pace Global constructed a composite S-curve that represents the transition from one curve to another over time as payback period changes. This transition logic produces a more realistic rate of adoption and has implications for the maximum market share as time progresses. As noted above, the forecast horizon was split into three seven-year periods (early, mid, and late), with an average capital cost and retail rate representation for each period. Payback periods were developed for each period and the composite S-curve created over the forecast horizon by transitioning from one S-curve to another.

Exhibit 70 shows the S-curve employed in the analysis for various S-curves with a composite S-curve for the commercial class. The composite curve shows the switch from a 7 year payback to a 5 year payback in the "late" years due to declining capital costs and higher retail rates. This composite curve is used to project solar PV energy production over time.

[32] See NREL "The Solar Deployment System (SolarDS) Model: Documentation and Sample Results".
[33] Energy available from PV installations is a function of module size and capacity factor.
[34] See page 19 of the NREL report.

Exhibit 70: S-Curve Representation



Source: Pace Global analysis and NREL

SOLAR PENETRATION PROJECTIONS

Exhibit 71 shows the solar penetration projections over time for residential and commercial customers. As shown, by 2030 the solar energy production is estimated to be 3.8% of energy consumption for commercial customers and approximately 7.2% for residential customers. As explained above, the reduction to load or the energy available from PV installations is a function of module size, capacity factor, and penetration rate. Total PV installations by the early 2030s are expected to be between 35 MW and 40 MW. This level of installed distributed generation will require local generation or energy storage for integration into the GWP system.

In terms of meter count, this translates to 1,540 commercial meters and 8,900 residential meters by the early 2030s, or roughly 11% by 2030 for residential customers and 18% for commercial customers.

Exhibit 71: Solar PV Penetration Projections

Commercial	Reduction In Load (MWh)	Total Load (MWh)	Load Reduction (%)	Installed PV (kW)	PV Meter Count
2015	611	412,369	0.1%	465	58
2016	849	439,043	0.2%	646	81
2017	1,168	462,520	0.3%	889	111
2018	1,589	460,321	0.3%	1209	151
2019	2,128	458,048	0.5%	1619	202
2020	2,794	455,541	0.6%	2127	266
2021	3,585	452,889	0.8%	2728	341
2022	4,476	450,175	1.0%	3406	426
2023	5,426	447,405	1.2%	4129	516
2024	6,379	444,577	1.4%	4855	607
2025	7,283	441,672	1.6%	5542	693
2026	8,092	438,715	1.8%	6158	770
2027	10,331	435,708	2.4%	7862	983
2028	12,546	432,639	2.9%	9548	1193
2029	14,536	429,498	3.4%	11062	1383
2030	16,175	426,284	3.8%	12310	1539
2031	17,441	423,028	4.1%	13273	1659

Residential	Reduction In Load (MWh)	Total Load (MWh)	Load Reduction (%)	Installed PV (kW)	PV Meter Count
2015	2,094	475,241	0.4%	1593	531
2016	2,910	493,548	0.6%	2215	738
2017	4,009	509,686	0.8%	3051	1017
2018	5,458	508,733	1.1%	4154	1385
2019	7,315	507,752	1.4%	5567	1856
2020	9,616	506,591	1.9%	7318	2439
2021	12,347	505,341	2.4%	9396	3132
2022	15,430	504,091	3.1%	11743	3914
2023	18,721	502,848	3.7%	14247	4749
2024	22,013	501,190	4.4%	16752	5584
2025	25,127	499,481	5.0%	19123	6374
2026	27,888	496,869	5.6%	21224	7075
2027	30,228	494,163	6.1%	23004	7668
2028	32,155	491,759	6.5%	24471	8157
2029	33,673	489,250	6.9%	25627	8542
2030	34,839	486,632	7.2%	26514	8838
2031	35,717	483,951	7.4%	27182	9061

Source: Pace Global analysis

APPENDIX I: LOAD FORECAST DETAILS

METHODOLOGY OVERVIEW

Pace Global developed a deterministic reference case load forecast for GWP. The load forecasting process takes into consideration the historical relationship between demand growth and weather and economic variables, which are the key drivers of load growth, as well as adjustments for other drivers including customer additions, energy efficiency and DSM penetration, and electric vehicle usage. The forecast was performed according to the following process:

Step 1: Perform econometric analysis on core load drivers:

a) Build the relationship between demand and weather
b) Perform econometric assessment of the influence of economic variable(s) on demand growth
c) Incorporate customer count changes across each of the classes: namely residential, commercial and industrial

Step 2: Produce a load forecast based on the projections for each of the driver variables:

a) Use "Rank & Average" Technique to generate a normal weather projection
b) Use Moody's Analytics data for the GDP/Personal Income growth forecast for LA Metropolitan area
c) Incorporate known and unknown customer count additions in the service territory.

Step 3: Incorporate "one-off" developments such as:

a) Expected increase in Plug-in Hybrid Electric Vehicles (PHeV)
b) Degree of Energy Efficiency penetration levels and other DSM programs

These effects are not reflected in the historical data. Based on reports and publicly available data, the one-off development factors are quantified and used to adjust the forecasts from step 2.

Input Data

The following input data sets were used for building the models:

a) **Historical weather data** – Hourly temperature data from 1997-present for the Burbank airport weather station was used.

b) **Historical load data** – Hourly load data for GWP service territory from 1999-present was used for this analysis. GWP provided this data set to Pace Global (which also includes customer count data by customer class: residential, commercial and industrial).

c) **Historical energy and customer count** – GWP provided the monthly energy (MWh) and customer count by class (Res, Com and Ind) data set to Pace Global for the time period 2003-present. This data was useful in determining the energy use per customer data by class (*MWh/customer*).

d) **Historical economic data** – The source of this data is "Bureau of Economic Analysis (BEA)". From BEA's website, the LA metropolitan Personal Income (in '000s of dollars) data set and LA metropolitan GDP (in millions of current dollars) data set were downloaded and used for the analysis.

e) **Normal temperature data** – From the past 18-years of historical hourly data, Pace Global used the "Rank & Average" technique to generate a weather normal hourly temperature series.

f) **Economic forecast data** – The personal income forecast for LA metropolitan area was obtained from Moody's Analytics for the full study period. This data set is a quarterly forecast of personal income in current dollars.

g) **Customer count forecast data** – Pace Global extrapolated the trends in customer count for each of the classes (residential, commercial and industrial) for the forecast time period. On top of it, know customer count additions, shown in Exhibit 72 for the near term, were included. Pace Global obtained this information from GWP.

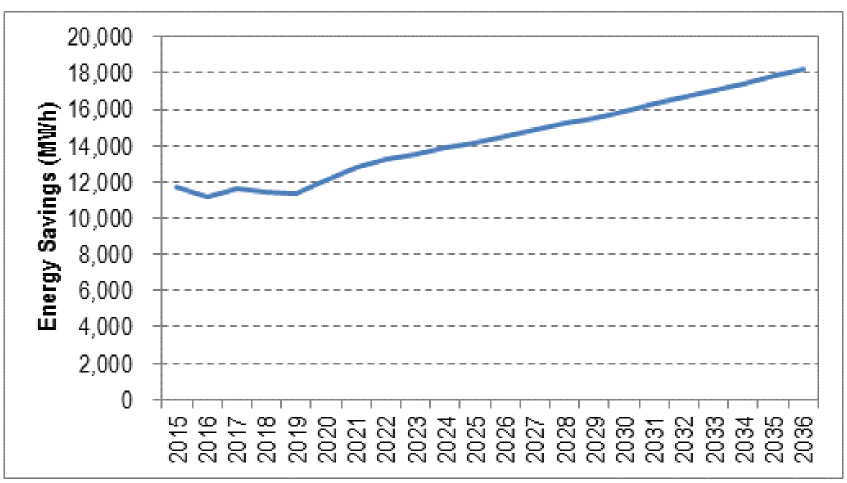
Exhibit 72: New Customer Additions in the Future

Year	Commercial Load	Mixed Use	Total Load
	MW	*MW*	*MW*
2014		1.25	1.25
2015	1.25	6.25	7.5
2016		7.25	7.25
2017		6.5	6.5
2018			
Total	1.25	21.25	22.5

Source: GWP

h) **Energy Efficiency data** – The data for energy efficiency is taken from a California report on the topic.[35] It denotes the adopted energy savings target by utility, each year from 2014-2023. Pace Global has extrapolated the data beyond this time period for this analysis, as shown in Exhibit 73.

Exhibit 73: Energy Efficiency Savings (MWh)

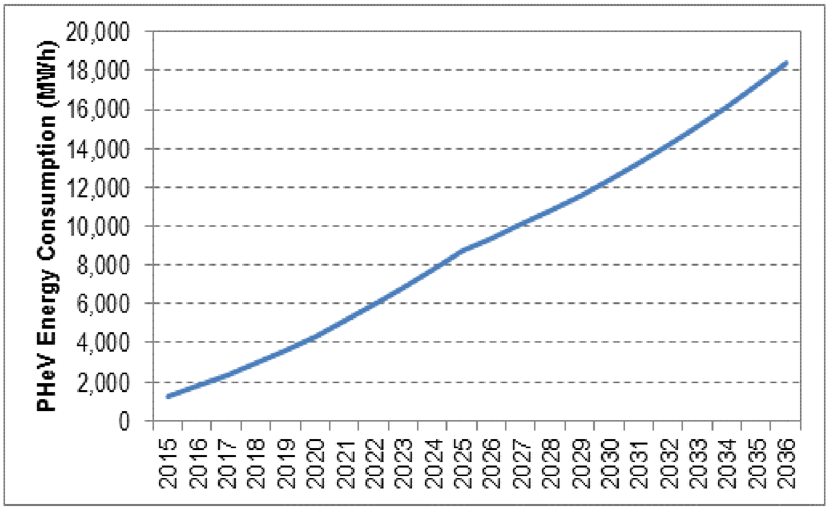


Source: GWP, Pace Global

[35] Energy Efficiency in California's Public Power Sector, a 2013 Status Report: Table 8

i) **PHeV data** – The data for PHeV penetration is taken from various public data sources and Executive Order B-16-12 of the Governor's ZEV action plan, which stipulates targets regarding new vehicle sales. Based on this information, the current electric vehicles in Glendale and the present consumption rating of an electric vehicle consuming 4.2 MWh of energy per year, Pace Global has generated a PHeV energy forecast shown in Exhibit 74 below.

Exhibit 74: PHeV Energy Consumption Projections

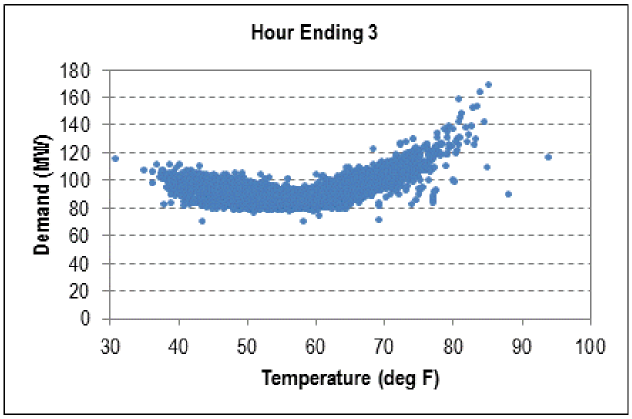


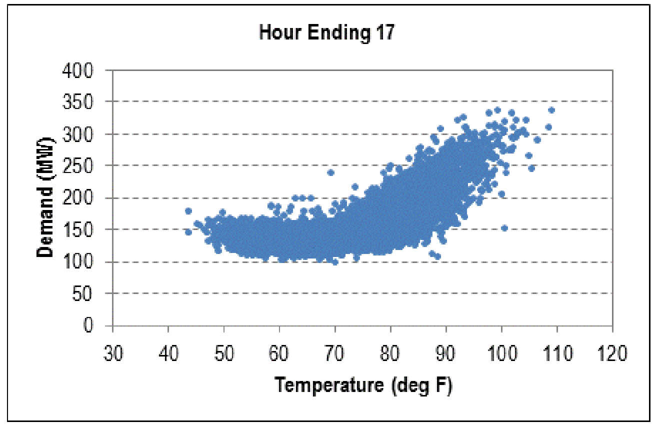
Source: Pace Global

WEATHER NORMALIZED LOAD FORECAST

Pace Global studied the load response to temperature changes using the historical hourly data sets. The response is different for different hours of the day. Typically, a weather response function looks like the plots shown in Exhibit 75 for sample hours 4 and 17. The response is non-linear with respect to temperature variations.

Exhibit 75: Weather Response Functions





Source: GWP, Pace Global

Hourly Weather Response Functions

In order to capture the load response satisfactorily, Pace Global has developed hourly weather response functions to capture the variation. The fundamental model is that load can be expressed as follows:

$$Load_{Hr_n} = f(Temperature, CumulativeHeat, CumulativeCold, Weekend)$$

Since the slopes are different for different temperature ranges, Pace Global has used cut-off temperature points and binary variables to fit the model response.

$$Load = \sum_{n=1}^{6} \alpha_n.Temp_n + \beta_1.Temp_{CumuHeat} + \beta_2.Temp_{CumuCold} + \beta_3.WeekendBinary + Constant + \varepsilon$$

Where,

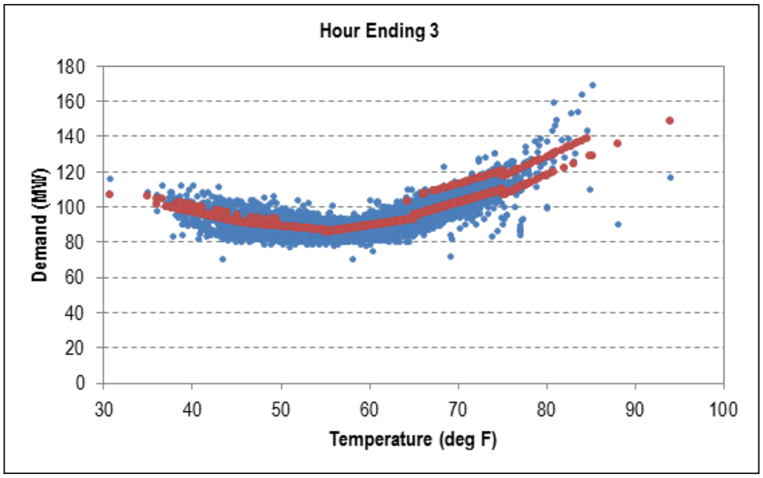
α_n - Slopes (coefficients) for different temperature ranges

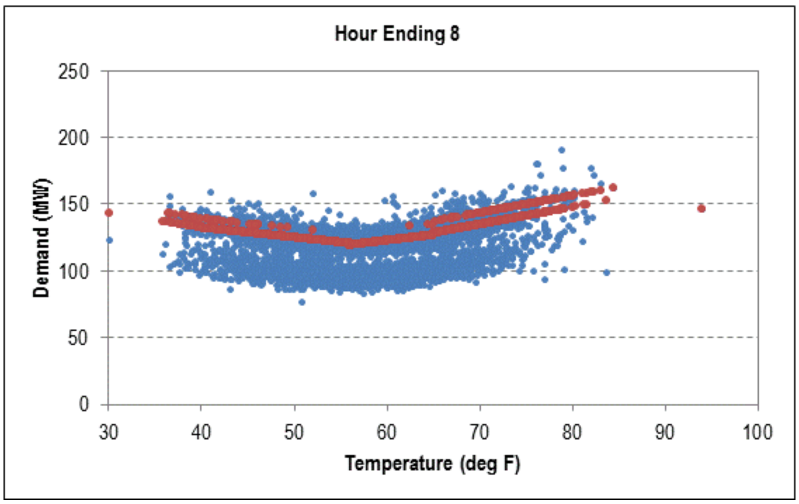
$\beta_1, \beta_2, \beta_3$ - Coefficients for Cumulative Heat effect, cumulative cold effect and weekend

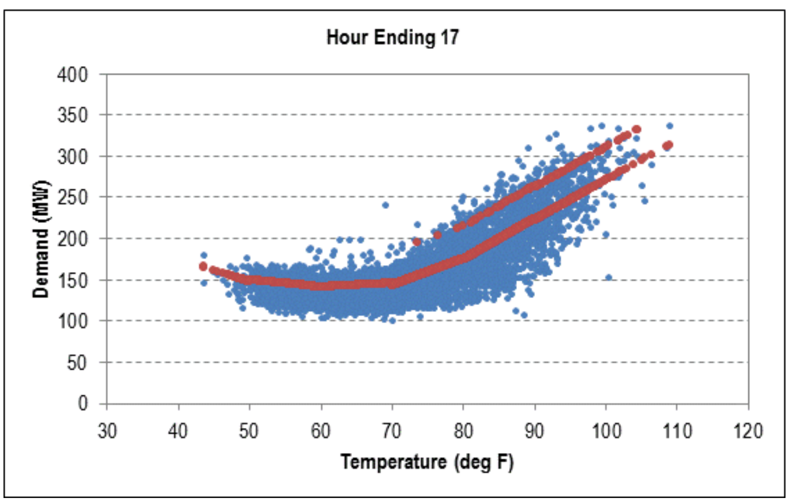
ε - Model error term

The non-linear responses to temperature are shown in Exhibit 76 below for sample hours (hour ending 3, 8 and 17).

Exhibit 76: Model Fit to Weather Response Functions



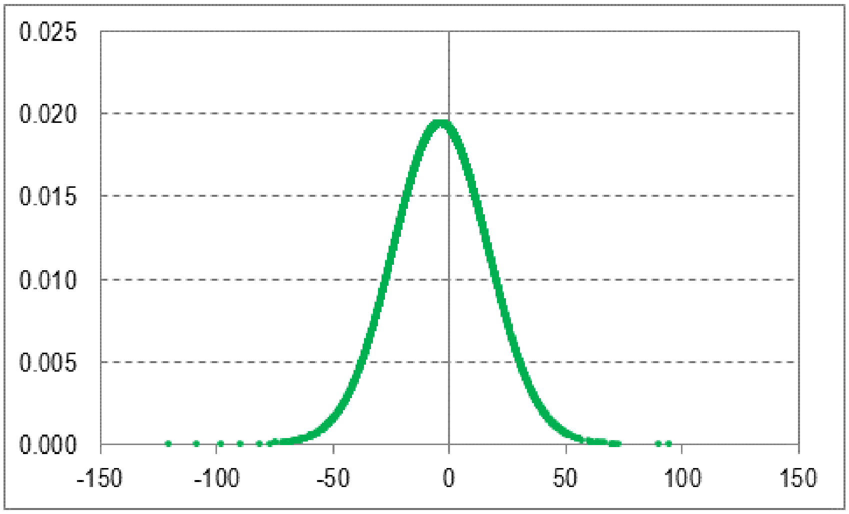




Source: Pace Global

The normally-distributed error term is shown below in Exhibit 77:

Exhibit 77: Normal Distribution of the Error-Term

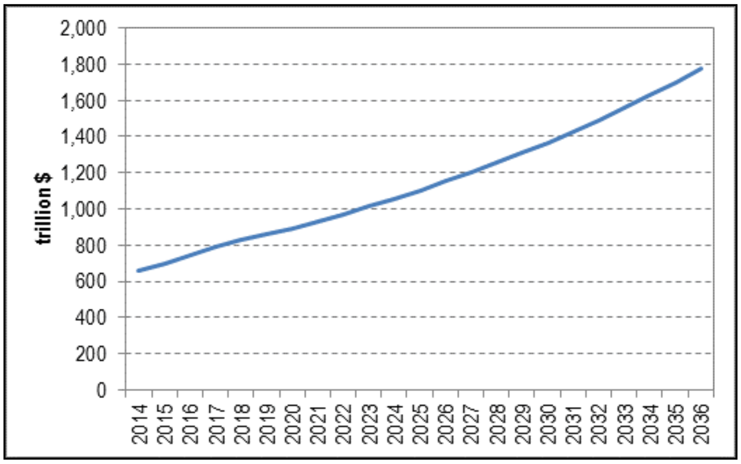


Source: Pace Global

ECONOMIC AND CUSTOMER COUNT FORECAST

Pace Global used the personal income forecast from Moody's analytics for the study period. The plot in Exhibit 78 shows the personal income data in current dollars.

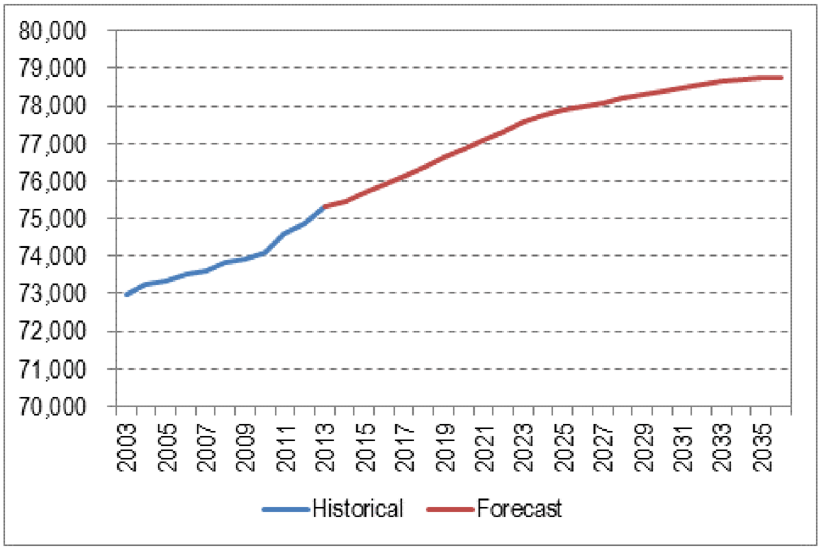
Exhibit 78: Personal Income Forecast for LA Metropolitan Area (in Current $)



Source: Moody's Analytics

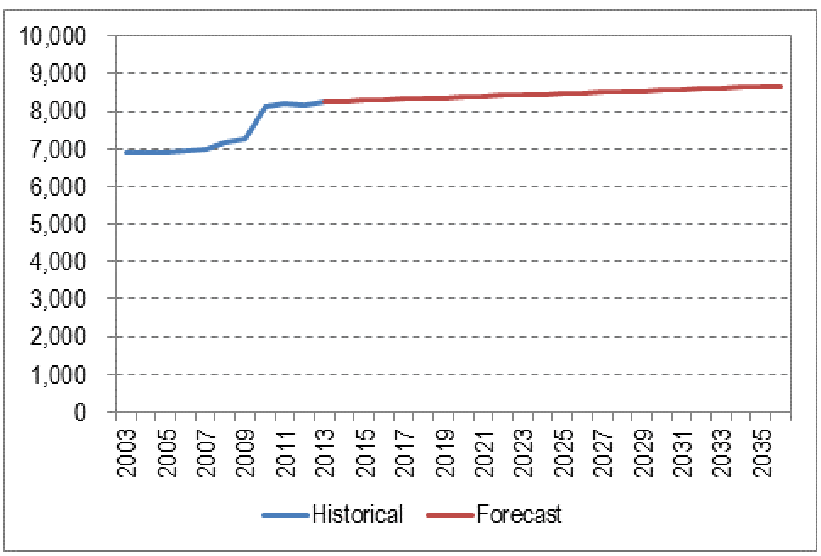
For the customer count forecast, Pace Global used an exponential model to fit the historical data and used it to come up with a forecast. This method was used for residential and commercial classes. For the industrial class, the customer count value is flat-lined based on the 2014 value. The customer count projections for all the classes are shown in Exhibit 79 to Exhibit 81 below.

Exhibit 79: Residential Customer Count



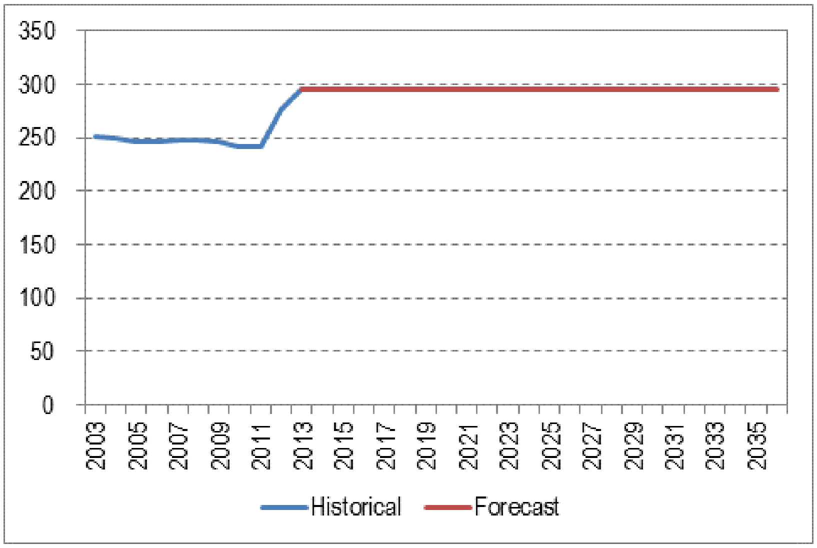
Source: Pace Global

Exhibit 80: Commercial Customer Count



Source: Pace Global

Exhibit 81: Industrial Customer Count



Source: Pace Global

REFERENCE CASE LOAD GROWTH FORECAST

The following steps are carried out to obtain the final reference case deterministic load forecast for GWP:

1) Use the weather response functions and normal weather to come up with a monthly weather normalized load forecast.

2) Year 2013 load shape is used to come up with hourly load forecast for the entire GWP service area.

3) Year 2013 class-wise hourly shape data is used to split the total load into residential, commercial and industrial classes.

4) Model the historical relationship between class-wise load and economic variable (personal income or GDP). This relationship is used to grow the weather normal load forecast for each customer class obtained in step 3. This forecast is done on a monthly *per_customer (MWh/customer)* basis.

5) Use the customer count growth projections for each class, and multiply the forecast from step 4 with the customer count values to get the total energy (MWh) for each customer class. This will be the weather normalized base forecast, not adjusted for DSM and upside potential.

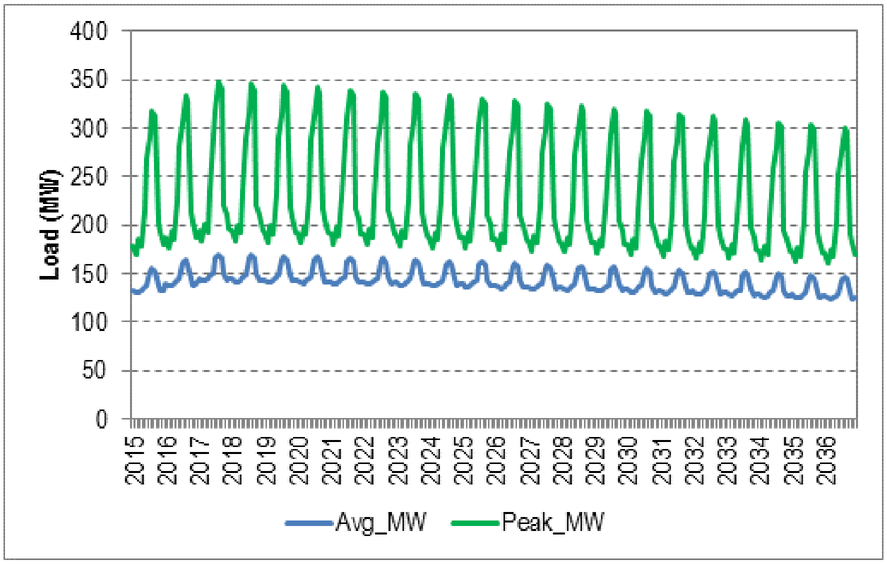
6) The PHeV upside potential energy (MWh) is added to the residential energy forecast in step 5.

7) Known MW additions (new customers), as shown in Exhibit 72, are added to the base forecasts in step 5 for each class.

8) The load in step 7 is then adjusted downwards for potential energy efficiency penetration effects to obtain the final load forecast for each class (MWh).

9) Exhibit 82 shows the final deterministic forecast of monthly average (MW) and peak (MW), with Compounded Annual Growth Rates (CAGR) of **-0.27%** and **-0.29%** respectively.

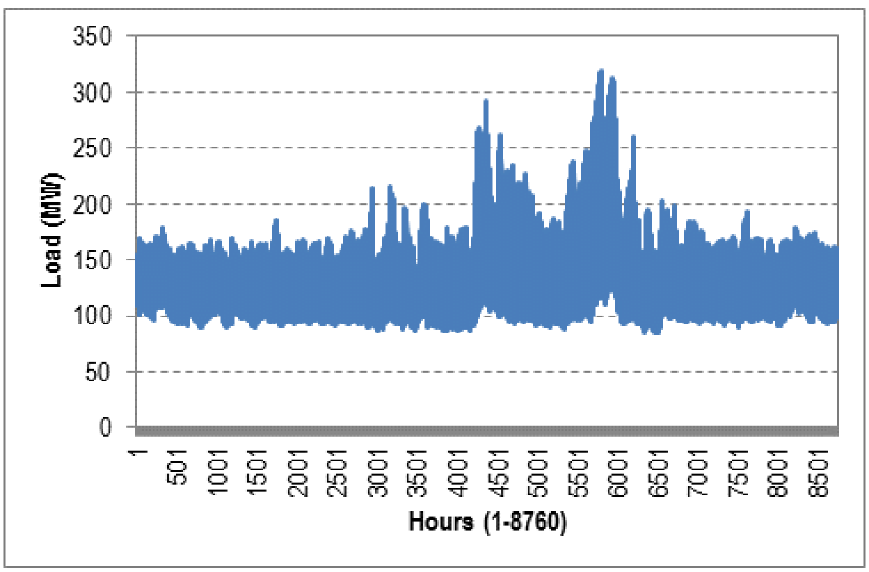
Exhibit 82: Monthly Average and Peak Load Forecast for GWP (MW)



Source: Pace Global

10) Exhibit 83 shows the final deterministic hourly forecast load profile:

Exhibit 83: Hourly Load Forecast Profile



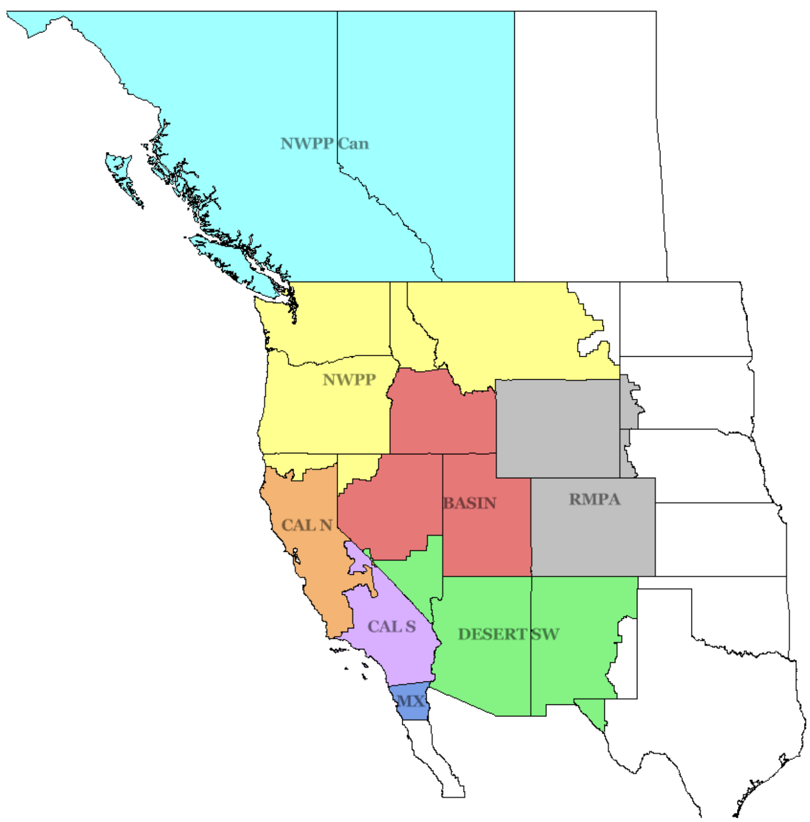
Source: Pace Global

APPENDIX II: REGIONAL POWER AND FUEL MARKETS

REGIONAL POWER MARKET STRUCTURE

The power market portfolio analysis for this IRP was conducted with an integrated regional model of the entire Western Electricity Coordinating Council ("WECC") region. GWP sits within the California-South region. Other WECC sub-regions include the Northwest Power Pool (NWPP), WECC-Canada-NWPP, the Basin region, the Desert Southwest, California-North, The Rocky Mountain Power Area (RMPA), and WECC-Mexico. Exhibit 84 illustrates the WECC footprint.

Exhibit 84: Western Power Market Regions



Source: Pace Global and Energy Velocity.

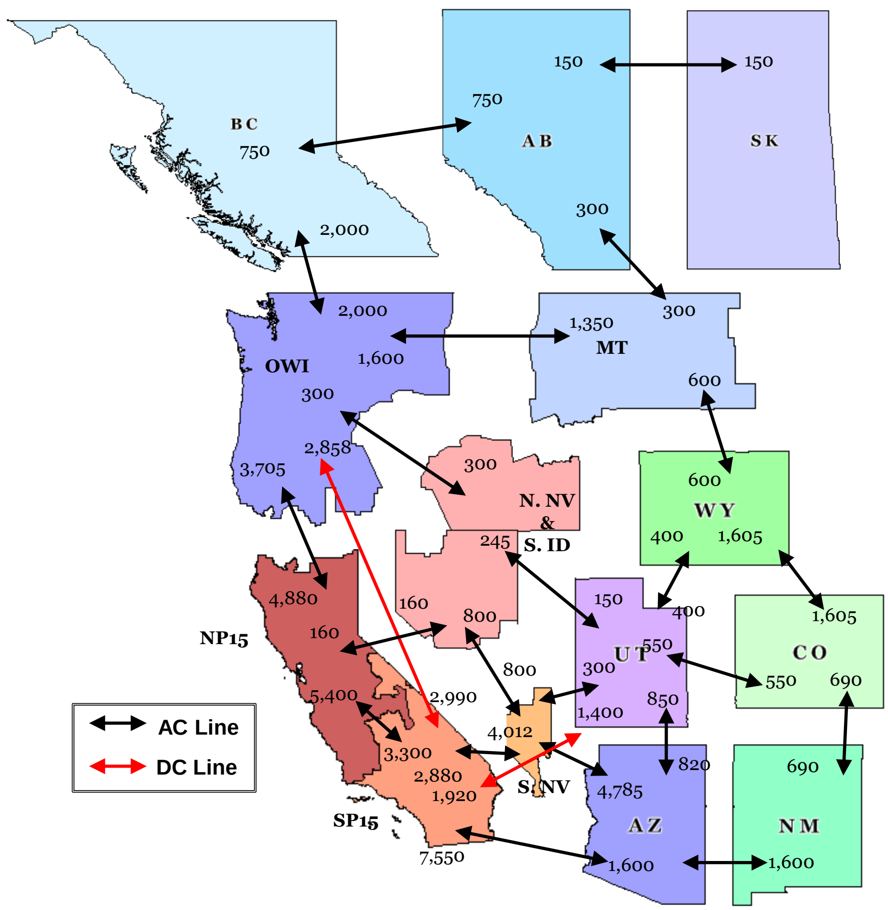
TRANSMISSION

Pace Global developed its regional power market analysis based on regional designations that represent areas with persistent and significant transmission congestion, which are the cause of long-term price divergence.

All electricity supply and demand within the WECC, including each transmission area's native load and capacity, as well as neighboring and interconnected regions are included in Pace Global's modeling systems. The transfer capabilities represented are based on data obtained from recent NERC Seasonal Reliability Assessments, the respective regional Reliability Assessments for the power market areas within the modeled regional consolidation, and historical wholesale transactions as reported to FERC.

Exhibit 85 provides a representation of Pace Global's modeling regions for WECC and the inter-regional transfer capability between California and the neighboring states/regions. For modeling purposes, Pace Global has explicitly evaluated GWP's service territory within the California-South region, with transmission interconnections to various external sources of energy. Details on GWP's system can be found in the GWP Situation Assessment chapter of this report.

Exhibit 85: WECC Inter-Regional Transfer Capability (MW)



Source: Pace Global.

NATURAL GAS MARKET DRIVERS

Since natural gas prices are a primary driver of regional power prices and GWP's portfolio costs, the following section outlines the key fundamental drivers underlying Pace Global's fuel market projections under the Reference Case. The scenario-based projections are outlined in the MarketLink Scenario Details chapter.

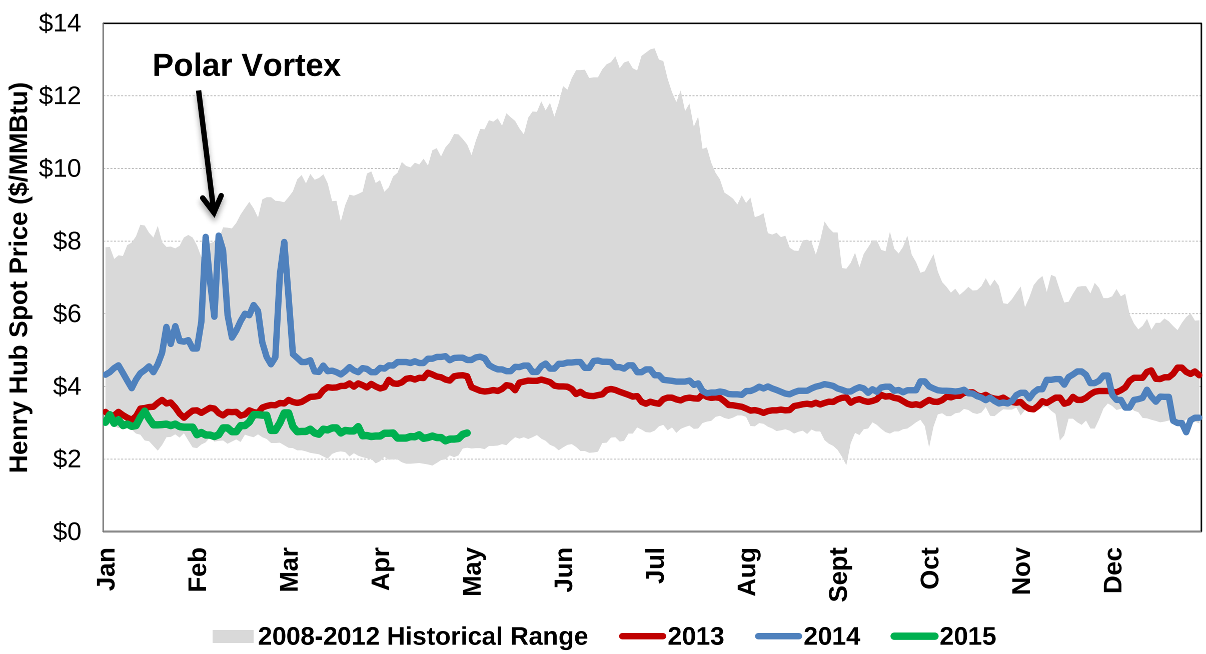
The principal location for natural gas trading in the United States is the Henry Hub near Erath, Louisiana. Due to the volume of physical trading at this location (over one billion MMBtu were traded in the day-ahead gas market at Henry Hub from 2010-2014) as well as its location in the traditional Gulf Coast production zone, Henry Hub has also become the location for financial market trading on the NYMEX. Regional gas prices are based on basis differentials from the Henry Hub to other delivery locations.

Supply and Demand Fundamentals

U.S. natural gas production has been increasing steadily over the last six years, which can be attributed to unconventional shale plays that now account for nearly 56 percent of the country's gas supply in March 2015, up from 1 percent in 2000. During this time period, unconventional gas production has changed the perception of gas markets and has been the primary driver of Henry Hub pricing since prices dropped from winter 2008 highs.

Since the end of 2012, prices at the Henry Hub have been at or below the previous five-year low. Exhibit 86 shows the range of prices from 2008 to 2012 as well as where prices have been over the last few years, highlighting the major changes that have occurred in the natural gas markets largely as a result of shale development.

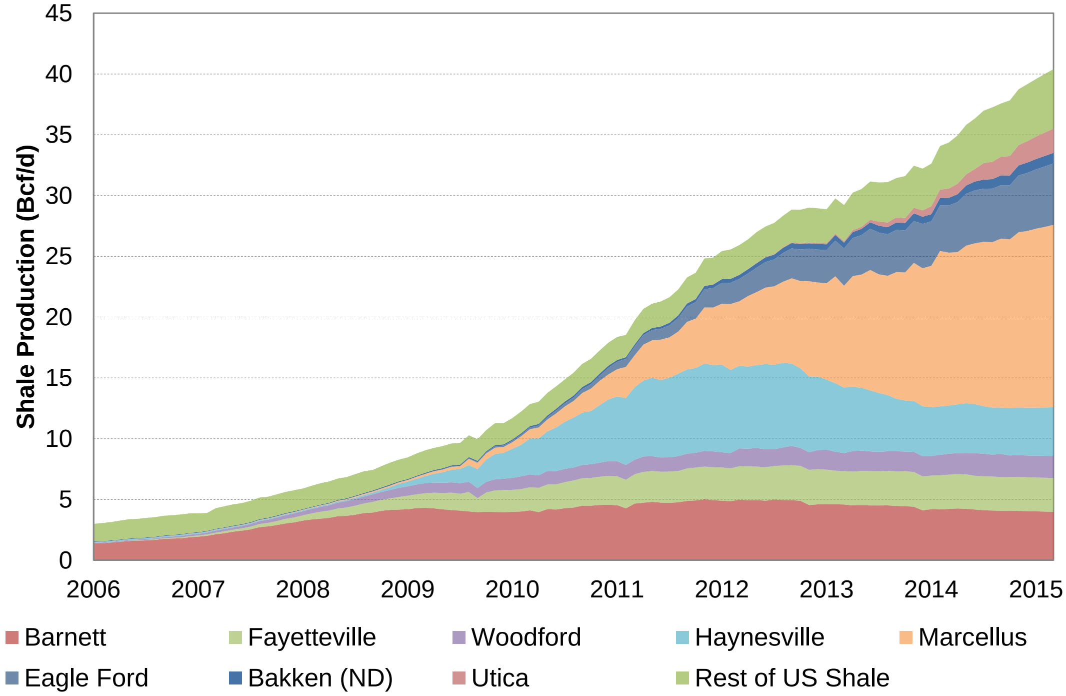
Exhibit 86: Historical Henry Hub Price Range (Nominal$/MMBtu)



Source: Pace Global and Platts

The major shale plays in North America collectively have seen a 750 percent increase in production since January 2008 (See Exhibit 87). The Marcellus shale play, with major drilling centered on northeastern Pennsylvania, southwestern Pennsylvania, and eastern Ohio, has dramatically changed the natural gas pricing dynamics across the country.

Exhibit 87: Historical Gas Production by Shale Play (Bcf/d)

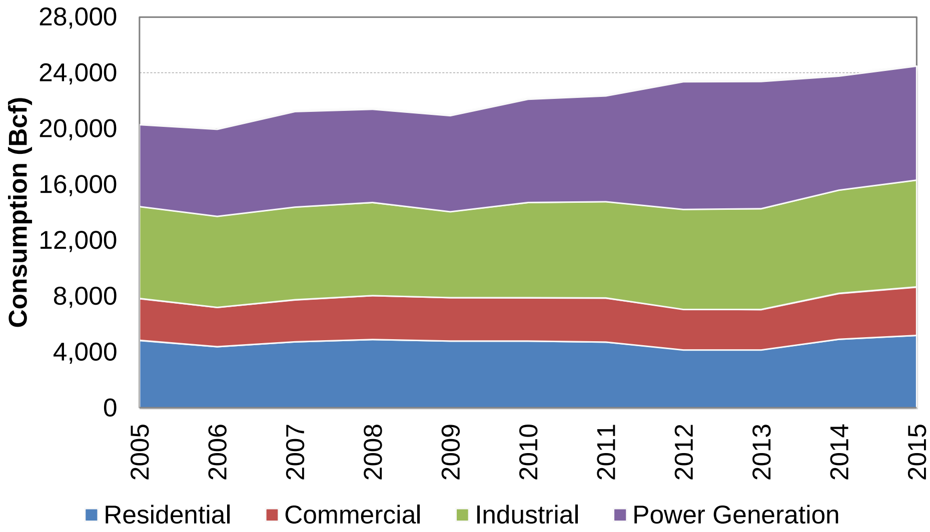


Source: Pace Global and EIA

On the demand side, according to the U.S. Energy Information Administration ("EIA"), in 2012, with low natural gas prices resulting in significant coal-to-gas switching, year-over-year consumption growth was significantly higher at 4.4 percent over 2011. Power sector demand for gas in 2012 rose 20.6 percent over 2011. The rebound in gas prices seen in 2013 significantly degraded the gas generation advantage resulting in a decline of gas consumption for power generation of 11 percent. 2014 proved to be very similar to 2013 in terms of power sector gas consumption. To date in 2015 (through mid-May), power sector gas consumption has been very close to the levels seen in 2012, mostly due to a return to a very low gas price environment.

Exhibit 88 shows total historical gas demand by sector. Outside of power generation, natural gas demand has been weak for quite some time. On the industrial front, gas usage has been slipping since the early 2000s, when demand was running well above 20 Bcf/d. Industrial gas consumption in the recent recessionary period in the U.S. dropped precipitously, hitting a low of 16.9 Bcf/d in 2009. The situation has since improved – industrial gas usage in the U.S. in 2014 averaged 20.8 Bcf/d – the highest consumption rate since 2004. Pace Global anticipates a continued increase of consumption from the industrial sector as consumers take advantage of sustainably low gas prices and as new industrial projects are commissioned, particularly in the Gulf Coast region.

Exhibit 88: Historical Natural Gas Consumption by Sector (Bcf/month)



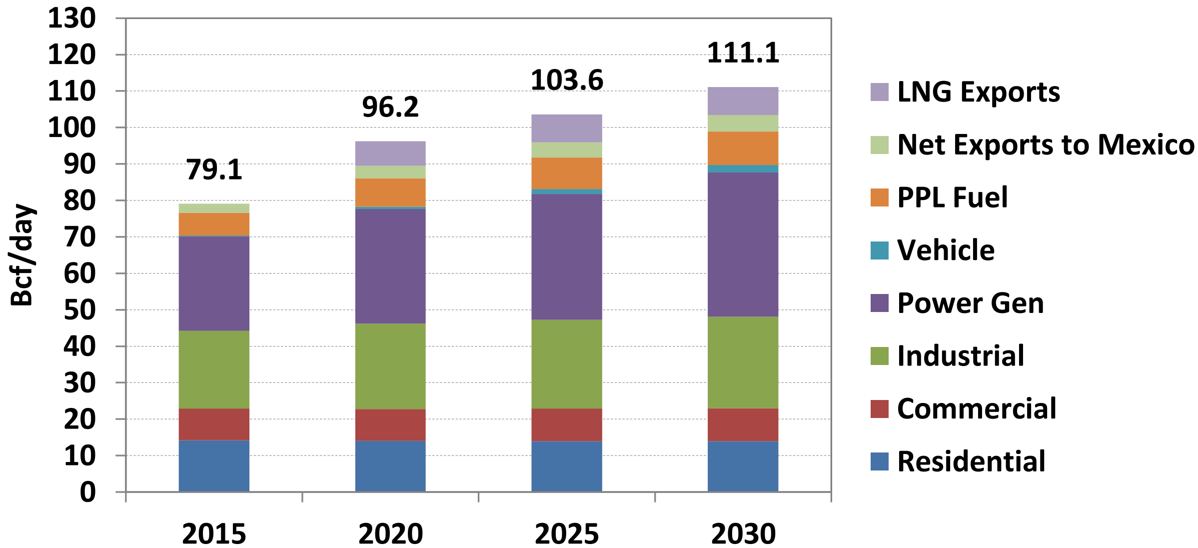
Source: Pace Global, EIA, Platts

Although North American gas markets are currently in a supply-driven environment, significant new demand is expected in the coming few years. On a national level, Pace Global expects the power generation sector to grow from 21.5 Bcf/d in 2014 to 31.4 Bcf/d by 2020 and 34.5 Bcf/d by 2025. U.S. LNG exports are expected to reach nearly 10 Bcf/d by 2025, exports to Mexico will exceed 4.2 Bcf/d by this same year, and industrial demand will add over 3 Bcf/d to reach 24.4 Bcf/d by 2025. Exhibit 89 provides Pace Global's Reference Case view of U.S. gas demand.

More regionally, a major potential driver of new demand in the West would come from greenfield liquefaction terminals in Oregon (Oregon LNG and Jordan Cove) as well as LNG export terminals in British Columbia. While Oregon LNG and Jordan Cove have both received approval for exports to non-Free Trade Agreement countries, they lack FERC approval, long-term contracts for liquefaction capacity, and they are greenfield projects with higher investment hurdles. In addition, they face significant environmental opposition, though U.S. Senator Ron Wyden (OR) has previously expressed support for these two Oregon projects and the jobs they would bring. Should one or both of these LNG export terminals be built (and Pace Global at this point does not believe they will be built), this would create upward price pressure for gas in the region and in California especially.

In California, gas demand growth in the residential and commercial sectors, and largely in the industrial sector, is expected to remain roughly level. Only power generation is expected to grow, largely spurred on by regulatory reform such as the U.S. EPA's proposed Clean Power Plan but also by relatively low gas prices. Exhibit 90 summarizes demand projections in the Western U.S.

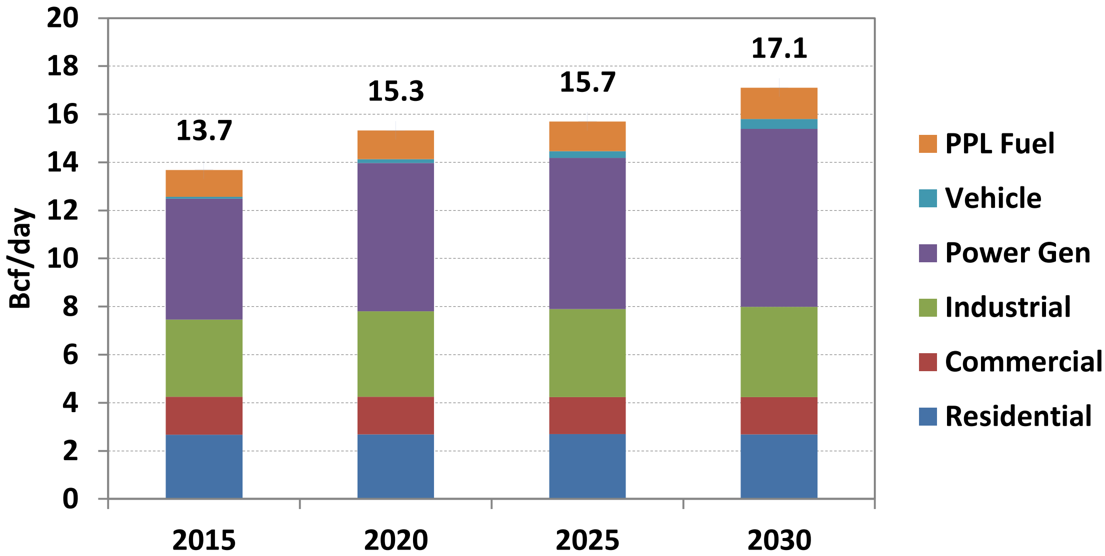
Exhibit 89: U.S Gas Demand Projections (Bcf/day)



Year	Residential	Commercial	Industrial	Power Gen	Vehicle	PPL Fuel	Net Exports to Mexico	LNG Exports	Total Demand
2015	14.2	8.7	21.3	26.0	0.2	6.2	2.5	-	79.1
2020	14.0	8.8	23.4	31.4	0.6	7.8	3.4	6.8	96.2
2025	14.0	8.9	24.4	34.5	1.4	8.6	4.2	7.7	103.6
2030	13.9	9.0	25.2	39.5	2.1	9.2	4.6	7.6	111.1

Note: PPL refers to pipeline fuel, gas plant processing fuel, and lease fuel, which together fuel the pipeline system.
Source: Pace Global

Exhibit 90: Western Gas Demand to 2030 (Bcf/day)



Year	Residential	Commercial	Industrial	Pow er Gen	Vehicle	PPL Fuel	Total Demand
2015	2.7	1.6	3.2	5.0	0.1	1.1	13.7
2020	2.7	1.6	3.6	6.2	0.2	1.2	15.3
2025	2.7	1.5	3.7	6.3	0.3	1.2	15.7
2030	2.7	1.5	3.8	7.4	0.4	1.3	17.1

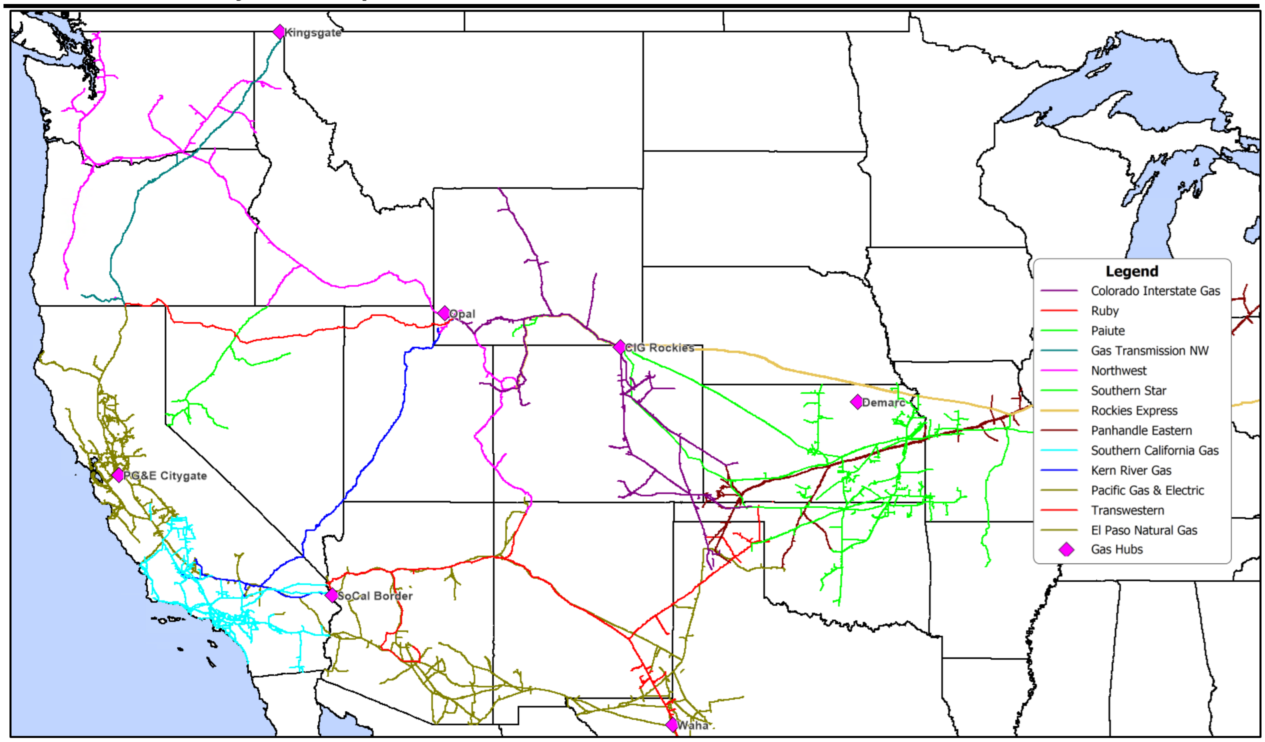
Note: PPL refers to pipeline fuel, gas plant processing fuel, and lease fuel, which together fuel the pipeline system.
*Note: Western U.S. is considered to be NM, CO, WY, MT and all states further to the West.

Source: Pace Global

Regional Drivers

Western United States gas markets are distinct from Gulf Coast or Northeastern gas markets. California is a major consumer of natural gas, with the PG&E Citygate gas hub acting as the most active market point for natural gas trading on the Intercontinental Exchange day-ahead market. Much of the gas that serves the California market comes from the Rockies production region or from Western Canadian Sedimentary Basin ("WCSB"). California receives gas supplies via several pipelines, including Ruby Pipeline and Kern River Pipeline from the Rockies Basin, Gas Transmission NW Pipeline from the WCSB, and El Paso Pipeline and Transwestern Pipeline from the Permian and San Juan Basins as well as the Mid-Continent region. Of course, gas from other regions like South Texas, the Gulf Coast, and even the Marcellus and Utica can and do impact western markets. Exhibit 91 shows major gas pipelines in the Western United States.

Exhibit 91: Major Gas Pipelines in the Western United States

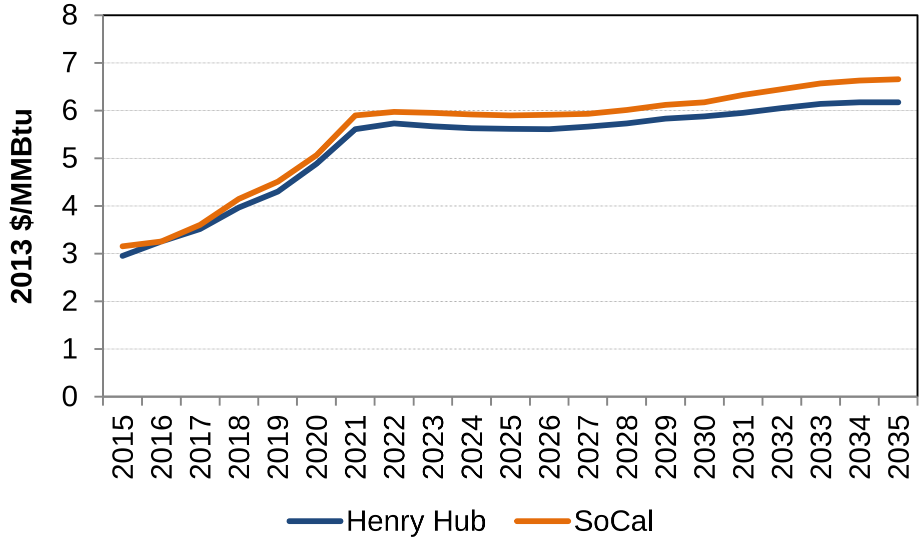


Source: Pace Global, Energy Velocity

Price Outlook

Pace Global's natural gas priceoutlook is developed through a fundamental assessment of supply and demand drivers across the interconnected North American markets. Given demand pressures from the power sector and exports expected towards the end of the decade, Pace Global expects real prices to rise above $5/MMBtu by the 2020s and then stabilize. Pricing in Southern California is generally at a premium to the Henry Hub due to demand pressures and pipeline constraints. Pipeline build-out in California is expected to remain difficult, much as it is in the U.S. Northeast, due largely to environmental issues and permitting hurdles. As a result, California is expected to maintain a positive basis to Henry Hub, in the range of 30 to 50 cents until 2027, growing to 70 cents by 2035. Exhibit 92 presents Pace Global's Reference Case natural gas price projections. The MarketLink Scenario Details chapter provides additional information on the price ranges evaluated in this IRP.

Exhibit 92: Natural Gas Price Projections (2013$/MMBtu)



Source: Pace Global

Glendale Water & Power Grayson Repowering 150 MW Options

28-Oct-14

Case	New / Existing	Engine Type	Model	Number of Machines	Configuration	Fuel	Increment	% of Full Load	Net Output kW	Heat Rate (LHV) Btu/kW	Heat Rate (HHV) Btu/kW	Available Spinning Reserve @ Minimum Load (Net kW)	Can Fire LFG without Btu upgrade?	Capital Cost TIC (unit only) mm$	Capital Costs ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Minimum Downtime hours	Minimum Uptime hours	Estimated Operation hours/yr	Controlled NOx emissions (tons/yr)	Controlled CO emissions (tons/yr)	Comments
150-1a	New	Reciprocating	Wartsila 18V50SG	7	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 150.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	20.0 (at 2.5 ppm NO) 3.619 E-05 lb/kW	74.6 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	128,331	7,607	8,368												
							Unit	28%	36,211	9,857	10,843	92,120											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
	Total New Generation								149,003					$ 194.7	$ 1,307								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
	Total Plant						Plant	100%	194,206	8,189	9,008												
							Plant	31%	59,713			134,493											
150-1b	New	Reciprocating	Wartsila 18V50SG	8	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 172.0	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	22.8 (at 2.5 ppm NO) 3.619 E-05 lb/kW	85.2 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	146,664	7,607	8,368												
							Unit	28%	41,384	9,857	10,843	105,280											
	Total New Generation								146,664					$ 172.0	$ 1,173								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
	Total Plant						Plant	100%	191,867	7,813	8,594												
							Plant	29%	54,884			136,983											
150-2a	New	Reciprocating	Wartsila 18V50SG	4	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 86.0	$ 1,173	$ 58.6	$ 2.50	0.5	3	8,400	11.4 (at 2.5 ppm NO) 3.619 E-05 lb/kW	42.6 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	73,332	7,607	8,368												
							Unit	28%	20,692	9,857	10,843	52,640											
	New	Gas Turbine	LM6000PG Sprint	1	SimpleCycle	PUC Gas		100%	53,886	8,931	9,824		No	$ 61.7	$ 1,145	$ 28.6	$ 4.50	0.5	3	3,000	4.6 (at 2.5 ppm NO) 5.492 E-05 lb/kW	17.1 (at 10 ppm CO) 2.051 E-04 lb/kW	
							Machine	29%	15,896	13,048	14,353	37,990											
								100%	53,886	8,931	9,824												
							Unit	29%	15,896	13,048	14,353	37,990											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.50	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
	Total New Generation								147,890					$ 191.9	$ 1,298								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
	Total Plant						Plant	100%	193,093	8,562	9,418												
							Plant	31%	60,090			133,003											
150-2b	New	Reciprocating	Wartsila 18V50SG	5	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 107.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	14.3 (at 2.5 ppm NO) 3.619 E-05 lb/kW	53.3 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	91,665	7,607	8,368												
							Unit	28%	25,865	9,857	10,843	65,800											
	New	Gas Turbine	LM6000PG Sprint	1	SimpleCycle	PUC Gas		100%	53,886	8,931	9,824		No	$ 61.7	$ 1,145	$ 28.6	$ 4.5	0.5	3	3,000	4.6 (at 2.5 ppm NO) 5.492 E-05 lb/kW	17.1 (at 10 ppm CO) 2.051 E-04 lb/kW	
							Machine	29%	15,896	13,048	14,353	37,990											
								100%	53,886	8,931	9,824												
							Unit	29%	15,896	13,048	14,353	37,990											
	Total New Generation								145,551					$ 169.2	$ 1,162								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
	Total Plant						Plant	100%	190,754	8,188	9,007												
							Plant	29%	55,261			135,493											

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Notes

Performance is given for Annual Avg Site Conditions (61°F, 66% RH, 465 ft elev MSL)

"PUC Gas" means pipeline quality

Capital costs are TIC costs derived from the Thermoflo Peace cost estimating module.

Not included in the capital costs above:

1) Owner's costs.
2) Demolition of existing facilities and site preparation costs.
3) Interconnection costs (studies and any resulting potential upgrades).
4) Switchyard expansion/reconfiguration/new switchyard equipment/upgrade costs.
5) Foundation piles, probably required based on experience with existing Unit 9.
6) Permitting costs and air emissions offset costs.
7) Natural gas fuel supply modifications/upgrades.
8) Makeup water supply and/or discharge modifications/upgrades.

Glendale Water & Power Grayson Repowering 200 MW Options

28-Oct-14

Case	New / Existing	Engine Type	Model	Number of Machines	Configuration	Fuel	Increment	% of Full Load	Net Output kW	Heat Rate (LHV) Btu/kW	Heat Rate (HHV) Btu/kW	Available Spinning Reserve @ Minimum Load (Net kW)	Can Fire LFG without Btu upgrade?	Capital Cost TIC (unit only) mm$	Capital Costs ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Minimum Downtime hours	Minimum Uptime hours	Estimated Operation hours/yr	Controlled NOx emissions (tons/yr)	Controlled CO emissions (tons/yr)	Comments
200-1a	New	Reciprocating	Wartsila 18V50SG	7	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 150.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	20.0 (at 2.5 ppm NO) 3.619 E-05 lb/kW	74.6 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	128,331	7,607	8,368												
							Unit	28%	36,211	9,857	10,843	92,120											
	New	Gas Turbine	LM6000PG Sprint	1	SimpleCycle	PUC Gas		100%	53,886	8,931	9,824		No	$ 61.7	$ 1,145	$ 28.6	$ 4.5	0.5	3	3,000	4.6 (at 2.5 ppm NO) 5.492 E-05 lb/kW	17.1 (at 10 ppm CO) 2.051 E-04 lb/kW	
							Machine	29%	15,896	13,048	14,353	37,990											
								100%	53,886	8,931	9,824												
							Unit	29%	15,896	13,048	14,353	37,990											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
						Total New Generation			202,889					$ 256.4	$ 1,264								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	248,092	8,350	9,185												
							Plant	30%	75,609			172,483											
200-1b	New	Reciprocating	Wartsila 18V50SG	8	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 172.0	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	22.8 (at 2.5 ppm NO) 3.619 E-05 lb/kW	85.2 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	146,664	7,607	8,368												
							Unit	28%	41,384	9,857	10,843	105,280											
	New	Gas Turbine	LM6000PG Sprint	1	SimpleCycle	PUC Gas		100%	53,886	8,931	9,824		No	$ 61.7	$ 1,145	$ 28.6	$ 4.5	0.5	3	3,000	4.6 (at 2.5 ppm NO) 5.492 E-05 lb/kW	17.1 (at 10 ppm CO) 2.051 E-04 lb/kW	
							Machine	29%	15,896	13,048	14,353	37,990											
								100%	53,886	8,931	9,824												
							Unit	29%	15,896	13,048	14,353	37,990											
						Total New Generation			200,550					$ 233.7	$ 1,165								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	245,753	8,058	8,864												
							Plant	29%	70,780			174,973											
200-2a	New	Reciprocating	Wartsila 18V50SG	10	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 215.0	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	28.5 (at 2.5 ppm NO) 3.619 E-05 lb/kW	106.5 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	183,330	7,607	8,368												
							Unit	28%	51,730	9,857	10,843	131,600											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
						Total New Generation			204,002					$ 259.2	$ 1,271								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	249,205	8,061	8,867												
							Plant	30%	75,232			173,973											
200-2b	New	Reciprocating	Wartsila 18V50SG	11	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 236.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	31.4 (at 2.5 ppm NO) 3.619 E-05 lb/kW	117.2 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	201,663	7,607	8,368												
							Unit	28%	56,903	9,857	10,843	144,760											
						Total New Generation			201,663					$ 236.5	$ 1,173								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	246,866	7,767	8,544												
							Plant	29%	70,403			176,463											
200-3a	New	Reciprocating	Wartsila 18V50SG	3	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 64.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	8.6 (at 2.5 ppm NO) 3.619 E-05 lb/kW	32.0 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	54,999	7,607	8,368												
							Unit	28%	15,519	9,857	10,843	39,480											
	New	Gas Turbine	LM6000PG Sprint	2	1 x 1 Combined Cycle	PUC Gas		100%	70,106	6,855	7,541		No	$ 197.4	$ 1,408	$ 49.3	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.373 E-05 lb/kW	86.4 (at 10 ppm CO) 1.574 E-04 lb/kW	
							Machine	34%	24,051	8,620	9,482	46,055											
								100%	140,212	6,855	7,541												
							Unit	34%	48,102	8,620	9,482	92,110											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
						Total New Generation			215,883					$ 306.1	$ 1,418								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	261,086	7,636	8,400												
							Plant	33%	87,123			173,963											
200-3b	New	Reciprocating	Wartsila 18V50SG	3	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 64.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	8.6 (at 2.5 ppm NO) 3.619 E-05 lb/kW	32.0 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	54,999	7,607	8,368												
							Unit	28%	15,519	9,857	10,843	39,480											
	New	Gas Turbine	LM6000PG Sprint	2	1 x 1 Combined Cycle	PUC Gas		100%	70,106	6,855	7,541		No	$ 197.4	$ 1,408	$ 49.3	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.373 E-05 lb/kW	86.4 (at 10 ppm CO) 1.574 E-04 lb/kW	
							Machine	34%	24,051	8,620	9,482	46,055											
								100%	140,212	6,855	7,541												
							Unit	34%	48,102	8,620	9,482	92,110											
						Total New Generation			195,211					$ 261.9	$ 1,342								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	240,414	7,333	8,066												
							Plant	32%	77,121			163,293											

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Notes

Performance is given for Annual Avg Site Conditions (61°F, 66% RH, 465 ft elev MSL)

"PUC Gas" means pipeline quality

Capital costs are TIC costs derived from the Thermoflo Peace cost estimating module.

Not included in the capital costs above:

1) Owner's costs.
2) Demolition of existing facilities and site preparation costs.
3) Interconnection costs (studies and any resulting potential upgrades).
4) Switchyard expansion/reconfiguration/new switchyard equipment/upgrade costs.
5) Foundation piles, probably required based on experience with existing Unit 9.
6) Permitting costs and air emissions offset costs.
7) Natural gas fuel supply modifications/upgrades.
8) Makeup water supply and/or discharge modifications/upgrades.

Glendale Water & Power Grayson Repowering 250 MW Options

28-Oct-14

Case	New / Existing	Engine Type	Model	Number of Machines	Configuration	Fuel	Increment	% of Full Load	Net Output kW	Heat Rate (LHV) Btu/kW	Heat Rate (HHV) Btu/kW	Available Spinning Reserve @ Minimum Load (Net kW)	Can Fire LFG without Btu upgrade?	Capital Cost TIC (unit only) mm$	Capital Costs ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Minimum Downtime hours	Minimum Uptime hours	Estimated Operation hours/yr	Controlled NOx emissions (tons/yr)	Controlled CO emissions (tons/yr)	Comments
270-1a	New	Reciprocating	Wartsila 18V50SG	7	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 150.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	20.0 (at 2.5 ppm NO) 3.619 E-05 lb/kW	74.6 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	128,331	7,607	8,368											
							Unit	28%	36,211	9,857	10,843	92,120											
	New	Gas Turbine	LM6000PC Sprint	1	2 x 1 Combined Cycle	PUC Gas		100%	130,000	7,000	7,700		No	$ 176.1	$ 1,355	$ 47.4	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.349 E-05 lb/kW	86.4 (at 10 ppm CO) 1.563 E-04 lb/kW	Performance and output not derived from GE or Thermoflow software
							Machine	25%	33,000	8,800	9,680	97,000											
								100%	130,000	7,000	7,700												
							Unit	25%	33,000	8,800	9,680	97,000											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
					Total New Generation				279,003					$ 370.8	$ 1,329								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	324,206	7,712	8,484												
							Plant	29%	92,713			231,493											
270-1b	New	Reciprocating	Wartsila 18V50SG	7	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 150.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	20.0 (at 2.5 ppm NO) 3.619 E-05 lb/kW	74.6 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	128,331	7,607	8,368												
							Unit	28%	36,211	9,857	10,843	92,120											
	New	Gas Turbine	LM6000PG Sprint	1	2 x 1 Combined Cycle	PUC Gas		100%	141,237	6,806	7,487		No	$ 178.0	$ 1,260	$ 44.1	$ 5.3	1	6	8,400	18.5 (at 2.0 ppm NO) 3.349 E-05 lb/kW	86.4 (at 10 ppm CO) 1.563 E-04 lb/kW	Spinning reserve is sufficient. Non-spinning reserve is adequate Run only 6 RICEs for spinning
							Machine	34%	48,712	8,512	9,363	92,525											
								100%	141,237	6,806	7,487												
							Unit	34%	48,712	8,512	9,363	92,525											
					Total New Generation				269,568					$ 328.5	$ 1,219								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	314,771	7,373	8,111												
							Plant	31%	98,423			216,348											
250-1a	New	Reciprocating	Wartsila 18V50SG	13	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 279.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	37.1 (at 2.5 ppm NO) 3.619 E-05 lb/kW	138.5 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	238,329	7,607	8,368												
							Unit	28%	67,249	9,857	10,843	171,080											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
					Total New Generation				259,001					$ 323.7	$ 1,250								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	304,204	7,979	8,777												
							Plant	30%	90,751			213,453											
250-1b	New	Reciprocating	Wartsila 18V50SG	14	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 301.0	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	39.9 (at 2.5 ppm NO) 3.619 E-05 lb/kW	149.1 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	256,662	7,607	8,368												
							Unit	28%	72,422	9,857	10,843	184,240											
					Total New Generation				256,662					$ 301.0	$ 1,173								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	301,865	7,738	8,512												
							Plant	28%	85,922			215,943											
250-2a	New	Reciprocating	Wartsila 18V50SG	5	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 107.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	14.3 (at 2.5 ppm NO) 3.619 E-05 lb/kW	53.3 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	91,665	7,607	8,368												
							Unit	28%	25,865	9,857	10,843	65,800											
	New	Gas Turbine	LM6000PG Sprint	2	1 x 1 Combined Cycle	PUC Gas		100%	70,106	6,855	7,541		No	$ 197.4	$ 1,408	$ 49.3	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.373 E-05 lb/kW	86.4 (at 10 ppm CO) 1.574 E-04 lb/kW	
							Machine	34%	24,051	8,620	9,482	46,055											
								100%	140,212	6,855	7,541												
							Unit	34%	48,102	8,620	9,482	92,110											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
					Total New Generation				252,549					$ 349.1	$ 1,382								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	297,752	7,633	8,396												
							Plant	33%	97,469			200,283											
250-2a	New	Reciprocating	Wartsila 18V50SG	6	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 129.0	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	17.1 (at 2.5 ppm NO) 3.619 E-05 lb/kW	63.9 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	109,998	7,607	8,368												
							Unit	28%	31,038	9,857	10,843	78,960											
	New	Gas Turbine	LM6000PG Sprint	2	1 x 1 Combined Cycle	PUC Gas		100%	70,106	6,855	7,541		No	$ 197.4	$ 1,408	$ 49.3	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.373 E-05 lb/kW	86.4 (at 10 ppm CO) 1.574 E-04 lb/kW	
							Machine	34%	24,051	8,620	9,482	46,055											
								100%	140,212	6,855	7,541												
							Unit	34%	48,102	8,620	9,482	92,110											
					Total New Generation				250,210					$ 326.4	$ 1,305								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	295,413	7,384	8,122												
							Plant	31%	92,640			202,773											
250-3a	New	Reciprocating	Wartsila 18V50SG	2	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 43.0	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	5.7 (at 2.5 ppm NO) 3.619 E-05 lb/kW	21.3 (at 10 ppm CO) 1.351 E-04 lb/kW	
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	36,666	7,607	8,368												
							Unit	28%	10,346	9,857	10,843	26,320											
	New	Gas Turbine	LM6000PG Sprint	1	SimpleCycle	PUC Gas		100%	53,886	8,931	9,824		No	$ 61.7	$ 1,145	$ 28.6	$ 4.5	0.5	3	3,000	4.6 (at 2.5 ppm NO) 5.492 E-05 lb/kW	17.1 (at 10 ppm CO) 2.051 E-04 lb/kW	This case requires the LM6000 to provide spinning reserve when a 1x1 combined cycle is at full load.
							Machine	29%	15,896	13,048	14,353	37,990											
								100%	53,886	8,931	9,824												
							Unit	29%	15,896	13,048	14,353	37,990											
	New	Gas Turbine	LM6000PG Sprint	2	1 x 1 Combined Cycle	PUC Gas		100%	70,106	6,855	7,541		No	$ 197.4	$ 1,408	$ 49.3	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.373 E-05 lb/kW	86.4 (at 10 ppm CO) 1.574 E-04 lb/kW	
							Machine	34%	24,051	8,620	9,482	46,055											
								100%	140,212	6,855	7,541												
							Unit	34%	48,102	8,620	9,482	92,110											
	New	Gas Turbine	Solar Mars	2	SimpleCycle	LFG	Machine	100%	10,336	11,163	12,279		Yes	$ 44.2	$ 2,138	$ 64.1	$ 4.5	1	6	8,400	29.5 (at 10 ppm NO) 3.193 E-04 lb/kW	41.3 (at 15 ppm CO) 4.471 E-04 lb/kW	Turbines dedicated to LFG Performance was run with PUC gas but LFG gas compression was reflected in auxiliary loads.
							Machine	48%	5,001	17,252	18,977	5,335											
							Unit	100%	20,672	11,163	12,279												
							Unit	48%	10,002	17,252	18,977	10,670											
					Total New Generation				251,436					$ 346.3	$ 1,377								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	296,639	7,873	8,661												
							Plant	33%	97,846			198,793											
250-3b	New	Reciprocating	Wartsila 18V50SG	3	Independent no heat recovery	PUC Gas	Machine	100%	18,333	7,607	8,368		No	$ 64.5	$ 1,173	$ 58.6	$ 2.5	0.5	3	8,400	8.6 (at 2.5 ppm NO) 3.619 E-05 lb/kW	32.0 (at 10 ppm CO) 1.351 E-04 lb/kW	LFG upgraded to PUC quality.
							Machine	28%	5,173	9,857	10,843	13,160											
							Unit	100%	54,999	7,607	8,368												
							Unit	28%	15,519	9,857	10,843	39,480											
	New	Gas Turbine	LM6000PG Sprint	1	SimpleCycle	PUC Gas		100%	53,886	8,931	9,824		No	$ 61.7	$ 1,145	$ 28.6	$ 4.5	0.5	3	3,000	4.6 (at 2.5 ppm NO) 5.492 E-05 lb/kW	17.1 (at 10 ppm CO) 2.051 E-04 lb/kW	This case does not require the LM6000 for spinning reserve when a 1x1 combined cycle is at full load.
							Machine	29%	15,896	13,048	14,353	37,990											
								100%	53,886	8,931	9,824												
							Unit	29%	15,896	13,048	14,353	37,990											
	New	Gas Turbine	LM6000PG Sprint	2	1 x 1 Combined Cycle	PUC Gas		100%	70,106	6,855	7,541		No	$ 197.4	$ 1,408	$ 49.3	$ 5.3	1	6	7,600	18.5 (at 2.0 ppm NO) 3.373 E-05 lb/kW	86.4 (at 10 ppm CO) 1.574 E-04 lb/kW	
							Machine	34%	24,051	8,620	9,482	46,055											
								100%	140,212	6,855	7,541												
							Unit	34%	48,102	8,620	9,482	92,110											
					Total New Generation				249,097					$ 323.6	$ 1,299								
	Existing	Gas Turbine	LM6000PC Sprint	1	SimpleCycle	PUC Gas	Machine	100%	45,203	8,482	9,330		No			$ 28.0	$ 4.5	0.5	3	3,000	4.1 (at 2.5 ppm NO) 5.865 E-05 lb/kW	15.3 (at 10 ppm CO) 2.190 E-04 lb/kW	
							Machine	30%	13,500	12,800	14,080	31,703											
							Unit	100%	45,203	8,482	9,330												
							Unit	30%	13,500	12,800	14,080	31,703											
					Total Plant			100%	294,300	7,626	8,388												
							Plant	32%	93,017			201,283											

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Notes

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Capital costs are TIC costs derived from the Thermoflo Peace cost estimating module.
Not included in the capital costs above:

1) Owner's costs.
2) Demolition of existing facilities and site preparation costs.
3) Interconnection costs (studies and any resulting potential upgrades).
4) Switchyard expansion/reconfiguration/new switchyard equipment/upgrade costs.
5) Foundation piles, probably required based on experience with existing Unit 9.
6) Permitting costs and air emissions offset costs.
7) Natural gas fuel supply modifications/upgrades.
8) Makeup water supply and/or discharge modifications/upgrades.

"PUC Gas" means pipeline quality

INTERIM SCREENING REPORT:
NEW INTERCONNECTION OPTIONS
FOR THE
CITY OF GLENDALE WATER & POWER

Prepared By Stantec, Inc.

PRIME CONTRACTOR	STANTEC, INC.
ELECTRICAL ENGINEERING CONSULTANT	Gary T. Rose, P.E.

December 11, 2014

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APPENDICES

1. EXECUTIVE SUMMARY

1.1 Introduction

The purpose of this Report is to present the results of an interim screening/analysis of sites identified by the City of Glendale Water and Power (GWP) and sites identified by Stantec to interconnect at transmission level voltages to the Southern California Edison (SCE)/ California Independent System Operator (**CAISO**) system. The Report provides an assessment for interconnection options and assesses the feasibility, providing conceptual cost estimates, schedule and constructability at each site. A more detailed analysis will be provided in Phase II Report. However, a final determination of the feasibility will be made after an Interconnection Application is submitted and accessed by SCE.

The Report considered GWP costs for the interconnection, including an estimate of SCE new facilities costs. In addition, impacts to existing facilities on the SCE System, BWP, LADWP and GWP Electrical Systems arising from the Interconnection were roughly estimated by preliminary short circuit studies of the electrical network, which included the proposed GWP-SCE Interconnection and Grayson Site Repowering and conservative contingencies, have been included in the cost estimates. The Interim Study has determined interconnection capacities and includes preliminary engineering drawings and one-line diagrams.

We anticipate no difficulty in meeting California General Orders and Federal Construction, Reliability and Safety Standards. We reviewed the National Electric Safety Code and the CA GO-128 which covers Underground Construction as part of this Report.

LADWP/GWP have phase rotation A-B-C counter clockwise while SCE has rotation A-C-B counter clockwise. Conductors can be swapped during installation to correct the phase rotation difference as it has been done at Sylmar and Lugo Substations.

We believe that three of the sites identified all may be feasible but the most viable based on this preliminary analysis is Option 1 which is a double circuit 69 kV underground line from GWP Kellogg Substation to a new GWP 69/220 kV Substation then overhead drop to SCE's Eagle Rock Substation . We estimate the cost to implement Option 1, including construction and facility impact contingencies is about $66,000,000.

1.2 Scope of Work

The Scope of the Interim Study as outlined in the GWP-Stantec Agreement requires that we assess the feasibility, cost and schedule for the identified sites. It was assumed that discussions with SCE would also be necessary.

Several options were examined, including considerations for connections to several different Southern California Edison (SCE) substations and to the 220 kV Eagle Rock-Sylmar Line at several locations. Site visits and assessments were performed at GWPs stations and at several possible interconnection locations, including the Eagle Rock substation near the Scholl Canyon Landfill. Additionally, system drawings and system data for GWP, Los Angeles Department of Water and Power (LADWP) and the City of Burbank Water and Power (BWP) were reviewed as part of this analysis.

The Report also includes the results of discussions with SCE's Transmission Engineering Group on the requirements for the 220 kV line transmission line interconnection options and requirements for interconnection into the Eagle Rock Substation.

A Short Circuit and Load Flow Analysis will be completed using model data from the Western Electricity Coordinating Council (WECC) including system drawings and data from GWP, Los Angeles Department of Water and Power (LADWP) and the City of Burbank Water and Power (BWP). GWP already interconnects with LADWP at Airway Substation and BWP at Western Substation. The Thevenin impedances and station short circuit duties at Eagle Rock will also be part of the information used for these studies. The work on these studies has begun and will be included in "Initial" Screening Report as part of the Phase I analysis of the interconnection study, not included herein.

1.3 Results and Recommendations

The Report identifies four site options for interconnection possibilities, including the ranking of the four sites investigated and the recommendation of the single best overall site. The sites were analyzed primarily in terms of electrical system feasibility, siting constraints, environmental factors and cost. Interconnections were then ranked based on these factors.

The most feasible interconnection is identified as Option 1 between GWP's Kellogg Substation and SCE's Eagle Rock Substation and this determination was based on engineering, constructability and environmental impact considerations. The stations would be interconnected through a double circuit underground line from Kellogg to a new substation with a 69/220 kV step-up transformer and circuit breakers; and extend an overhead line from a terminal structure into the Eagle Rock Substation. SCE would need to add two circuit breakers to accommodate the new line. The double circuit 69 kV lines from Kellogg would be run in an approximately ten (10) mile long single duct bank, run in Glendale streets until Scholl Canyon where it is proposed to have a three (3) mile overhead line to the new GWP 69/220 kV substation.

Option 2 and Option 3 involve interconnection to the Eagle Rock- Sylmar Line which runs roughly northwest through Glendale. These options require a 220/69 kV substation and in the case of Option 2 run a double circuit back to Kellogg. In the case of Option 3, we propose to run a new line back to Western from the new Substation near Cresenta Valley Park. As the Eagle Rock- Sylmar double circuit lines are balanced, SCE will require that interconnect to each circuit. These options each have issues and are considered less feasible than Option 1 because Option 2 has space limitations, which would require a 230 kV ring bus, which may not be acceptable to SCE, in order to accommodate the interconnection and Option 3 has environmental siting issues and possible ROW constraints which must be resolved. However Options 2 and 3 should be considered as possible alternatives to Option 1. All three Options would provide an interconnection with about 155 MW capacities.

Option 4 involved utilizing GWP's Rossmoyne Substation. Rossmoyne is fed by three 69 kV lines from Kellogg with total spare capacity of about 85 MW. This option would utilize 69 kV double circuit underground and overhead lines to interconnect at Eagle Rock Substation. However, Rossmoyne is built out and space for additional breakers would hamper maintenance access to the existing equipment and therefore, we did no further work on this Option.

Cost Estimates for the location options are proposed. The substation estimates are quite detailed. The transmission cost estimates relied primarily on cost data from GWP, Stantec and industry sources. The Cost Estimates include substantial contingencies to cover impacts new facilities required by SCE and potential breaker replacements on the GWP, SCE and BWP systems. Despite picking fairly high impedances for the step-up transformers in an effort to limit fault current, preliminary short circuit studies which included the 250 MW Grayson Repowering Option indicates several breakers at Airway, Rossmoyne and Kellogg will need to be replaced. The Phase II Report will include detailed short circuit and load flow analysis.

2. INTERCONNECTION OPTIONS

IDENTIFICATION & ANALYSIS OF SITES

2.1 SCE's 220kV Eagle Rock Line

GWP provided three possible interconnection sites with SCE. The suggested sites involved interconnection to SCE's double circuit 220 kV Eagle Rock to Sylmar line. The Eagle Rock line passes through Glendale in a north westerly direction from the SCE Eagle Rock Substation located in the vicinity of the Scholl Canyon Landfill. The electrical criteria assumed the interconnection would be made to SCE's 220 kV volt system and the minimum interconnection capacity would be 100 MW.

A meeting was held on November 6, 2014 at the offices of SCE in Pomona with SCE's Transmission Planning Group. SCE indicated that it was probably feasible to interconnect at the Eagle Rock 220 kV Substation, but that loop flows and certain line loss contingencies should be considered. SCE indicated that any interconnections at the 66 kV level could not be considered as the SCE 66 kV system is radial and SCE already connects to LADWP at Sylmar and at Lugo. Such a connection would parallel their 66 kV System. A preliminary study drawing was distributed to show a ring bus connection in and out of the 220 kV line. SCE would consider this approach but preferred to see a breaker and one-half schemes for each line. SCE will provide a drawing showing their interface requirements, but so far, it has not been received, including their system impedance diagrams, station one-lines or layout of the Eagle Rock Substation. The Interconnection Agreement process was also discussed briefly, but a detailed discussion will be held further on the subject.

Also identified were two other potential interconnection sites, but eliminated an interconnection at SCE McNeil because of length of the line, potential Safety Integrity Level (SIL) problems and difficulty finding a direct route. We eliminated a connection at Gould because of distance and difficulty in getting Right of Way (ROW).

The interconnection locations considered are as follows:

2.2 Option 1: Kellogg-Eagle Rock Substation

Option 1 is the GWP Kellogg to SCE's Eagle Rock interconnection. This Option is the most feasible option identified in this preliminary analysis. This option would utilize two existing spare breakers at Kellogg 69 kV Substation and would involve the installation of about 10 miles of double circuit underground duct bank installed in City streets and about three miles of double circuit OH 69 kV line to a new 69/220 kV substation located just west of the SCE Eagle Rock Substation.

The OH section of the interconnection would be run just north or just south of the Scholl Canyon Landfill. The exact routing of the OH line needs to be determined. Some Google Earth pictures and site pictures are included in Appendix B. A Short Circuit and Load Flow Analysis must be completed and further study is required on routing. SCE has indicated that the space for additional breakers will be tight. We are hoping for an opportunity to visit the Substation or receive some detailed site drawings. Examination of the site per Google Earth indicates there is enough space on the north end of the Eagle Rock Substation bus to accommodate additional breakers. The preliminary Option 1 one- line diagram is shown as Drawing 1 of Appendix A.

2.2 Option 2: 220kV SCE Eagle Rock-Sylmar Line near Glorietta Substation

Option 2 involves a connection to the Eagle Rock Sylmar line which runs roughly northwest through Glendale. Option 2 would require a ring bus connection to the SCE line and a new 220/69 kV substation. A double circuit 69 kV underground line would then be back to the Kellogg Substation. Option 2 would utilize open areas near the SCE ROW for locating the new equipment. SCE requires we connect into each of the circuits of the Eagle Rock Sylmar line to maintain balance. We submitted a preliminary layout to SCE but as yet have not received a response. Preliminary drawings showing the ring bus arrangement and the 220/69 kV substation are included in Appendix A

2.3 Option 3: 220kV Eagle Rock-Sylmar Line near Honolulu Avenue & Dunsmore Street

Under Option 3, we investigated the possible connection into the 220kV Eagle Rock -Sylmar Line which runs on the hillside south of Honolulu Ave. with a GWP overhead 69kV that runs over the Verdugo Hills and terminates in an underground transition near the park. The hillside has several wilderness area signs but includes an SCE service road and hiking trails. We surveyed the site using Google Earth and via a hiking trail. The hillside location is promising in that it appears to have the 4 acres necessary to complete a 220/69 kV Substation but would require substantial earthwork. The environment and land use aspects are discussed further in the Environmental Section of this Report. Option 3 would like, option 2, also require a ring bus connection for the 220 kV circuits and a 220/69 kV substation.

While a detailed estimate of the cost of this option was not performed, the cost should be very similar to the cost of Option 2. Apparently, the Western- Bel Aire and Bel Aire-Montrose lines are built for 69kV, but are operated at 34.5 kV. It may be possible to make a double circuit line out of the existing H-Frame overhead line and perhaps under build to accommodate the 34.5 kV, or build a new 69 kV double circuit line adjacent to the existing line using wood pole structures. The line from the interconnection point to Western Substation would, if possible, follow the existing path of the Bell Aire-Montrose Line through the Verdugo Hills. We need more detailed information and will need to do additional work on the route from vicinity of Bel Aire Station to Western Substation.

While it might be possible to locate a substation at the bottom of the hill in Cresenta Valley Park, it offers no significant advantage and would require even longer overhead lines. An interconnection with SCE, interconnection substation and a double circuit 69 kV to Western may prove more difficult to accommodate from a load flow and short circuit perspective. We originally thought environmental issues would eliminate Option 3, but it now appears it may be feasible from siting point of view but other issues remain.

Appendix a. contains preliminary drawings showing how the interconnection to the SCE lines could be accomplished. We have not received SCE comments on these drawings.

2.3 Option 4: Rossmoyne Substation to SCE Eagle Rock Substation

The Rossmoyne Substation site of Option 4 had some advantages in terms of reducing some of the costs for interconnection to Eagle Rock but utilizing the three circuits from Kellogg as the transmission source back to Grayson would limit interconnection capacity to around 100 MW. Additionally, SCE addressed concern about the installation of the two 69 kV breakers and bus modifications necessary to provide a tie to Eagle Rock. The additional breakers could not be accommodated in the existing bus and would have reduced access within the Substation. Sufficient space is not available to locate the breakers along the perimeter wall.

Table 1 outlines the 4 options:

Options	Description	Estimated Cost	Comments
1	Interconnection between GWP Kellogg Substation to step up transformer and connection to SCE Eagle Rock Substation Capacity about 150 MW	$65,853,000	The most straight forward and viable interconnection. Costly, depending on determination of mitigation measures required on existing facilities from Short Circuit Studies. Need space info from SCE on Eagle Rock Sub. Ranked1, based on engineering, constructability and environmental considerations.
2	Interconnection to SCE 220 kV Double circuit Eagle Rock- Sylmar Line Near Glorietta St and Oakmont. Capacity 150 MW	59,758,000	Interconnection facilities would be constructed on available land near Transmission line ROW. Space is limiting factor. Awaiting determination from SCE but may not be feasible.
3	Hillside above Cresenta Valley Park. A new Substation 220/69 kV, Similar to Option 2. 69 kV Overhead double circuit line from interconnection point to Western Substation.	$41,608,000	Space is available to meet SCE Bus Clearance Requirement. Environmental and Siting concerns. Mitigation of possible impacts to GWP and BWP Systems must be determined.
4	Rossmoyne Substation. Additional 69 kV breakers and 69 kV double circuit underground line in duct bank and step up transformer to connect SCE Eagle Rock Station	No Detailed Estimate Rough Estimate about $45,000,000	Additional breakers and Bus Connects would limit access to existing equipment in Rossmoyne Substation The three lines serving Rossmoyne from Kellogg are already loaded and would limit load Flow to SCE and back to Kellogg to about 100 MW

Table 2-1 Summary of the Interconnection Options

LINE ROUTING CONSIDERATIONS

Briefly, the preliminary routing of Option 1 is Kellogg Substation to Highland Ave., to Glen Oaks Blvd which follow Glenoaks east to the vicinity of Scholl Canyon Landfill, overhead via a double circuit 69 kV line to the GWP/69/220 Substation then into the SCE Eagle Rock Substation.

A more detailed routing will be provided in the Phase 1 analysis following input from SCE regarding best location for GWP 69/220 Substation and Termination structure. SCE prefers an overhead entrance into the Eagle Rock 220 kV Bus. It appears that there is sufficient space to accommodate breakers on the north end of the substation bus. We are hoping to get access to the Eagle Rock Substation and nearby area in the near future to make a determination of the best location for the 69/220 kV substation location and entrance termination structure.

The preliminary routing for Option 2 is from the Kellogg GIS substation property line go to Highland Ave, to Glenoaks Blvd., follow Glenoaks Blvd. all the way to Ethel St., to Las Flores Dr. follow the best route to Santa Rosa to 220/69kV Intertie Substation. Total distance is approximately 10 miles.

We investigated a number of GWP overhead lines in the vicinity of Glorietta Substation near Option 2 and could not find a suitable single circuit 69 kV lines for double circuiting. We believe finding easements or ROW back to Kellogg from the Option 2 site would be very difficult and so we propose to utilize double circuit underground duct banks to get circuits back to Kellogg. The same is essentially true for Option 1. Option 1 involves 10 miles of underground double circuit 69 kV and a 3.3 mile 69 kV double circuit overhead line to connect to the 69/220 kV substation near the Eagle Rock Substation.

Maps showing proposed line routings for Options 1 and 2 are shown in Appendix C. The preliminary routing for Option 3 is from an Interconnection Substation near Cresenta Valley Park, overhead following route of existing Bel Aire-Montrose line to vicinity of Bel Aire substation then double circuit underground south along Thompson Ave. to Western. The underground route has not been fully determined but the line would run in streets to Western Substation.

Appendix B contains photographs and Google Earth Screen Shots of Options 1, 2 and 3

No routing was determined for Option 4.

INTERCONNECTION IMPACTS

There are three categories of impacts that we might expect with a transmission project: Environmental, Construction and Facility impacts. Since the purpose would be interconnect to another large utility, we would expect impacts to GWP facilities and possibly to LADWP and BWP facilities since they are already interconnected with GWP.

2.4 Environmental Impacts

An environmental Survey was conducted by Stantec's Environmental Group, a copy of the report is included in the Appendices. The Report concluded that no critical environmental issues with any of the three options. Option 3 could potentially have the most environmental impact of all the options.
The underground ductbanks are not routed down any Glendale "Signature Streets". A more thorough analysis will be considered once an Option is selected.

2.5 Construction Impacts

We would expect that the major impact of Interconnection Project construction will be the installation of underground circuits in Glendale Streets which will cause noise, traffic problems and inconvenience to residents as the underground work proceeds. Construction will no doubt be limited to day time from around 8 am to 4 pm. Notifications to neighborhoods and perhaps informational meetings will be held. The use of metal plating should minimize street problems. We would expect any overhead portions of construction under Options 1 and 3 will be faster than the underground construction. The overhead construction is primarily in sparsely populated areas but usual noise and need for heavy equipment can be expected.

2.6 Facility Impacts

We expect that new facility and upgrade costs will be significant. This assessment is based upon the need for new upgraded breakers at Kellogg to terminate the proposed new 69 kV lines, a new GWP substation, plus required new breakers and bus at Eagle-Rock Substation or at Western, depending on the Option selected.

In addition, we know from the preliminary short circuit studies, we have performed, that it is likely that other upgrades to breakers at Kellogg and Airway may be required. It may also be necessary to install a phase shifting transformer to control load flow. The Load Flow Analysis should provide the answer.

3. Cost Analysis

We prepared fairly detailed estimates for the substations based on vendor quotes, estimating guides and recent costs for similar installations. We received transformer quotations from ABB and Prolec. We were able to get circuit breaker price quotes from PD and from ABB. We estimated transmission line costs using data from Burns and MacDonald, Black and Veatch and from recent experience on other Projects such as Anaheim's Canyon Project which had both overhead and underground 69 kV lines. Ductbanks are based on a design similar to GWP's double circuit design standard and the double circuit overhead is also based on a GWP design.

The preliminary design of the 69/220 kV substations were using low profile GIS breakers and bus.The initial conceptual estimates are show in Table 3-1. It should be noted that these are conceptual estimates approximately plus or minus 30% and include substantial contingencies for possible system impacts such as short circuit currents. Those breakers subject to short circuit currents which exceed 80% of the interrupting rating should be replaced if other methods to mitigate the short circuit currents such as transformer impedances or reactors cannot reduce currents below the 80%.

Options	**Total Cost**
Option1	$65,853,000
Option 2	$59,758,000
Option 3	$41,608,000
Option 4	No detailed Estimate prepared

Table 3-1 Preliminary Conceptual Cost Estimate

4. Schedule

Included is a milestone schedule for obtaining an Interconnection Agreement with SCE, which includes the interconnection application, feasibility study, impact study and facility study, performed by SCE/CAISO.

Typically, the expected estimated process is about a year. The Schedule also includes preparation of EPC contract including preliminary drawings, bid processing, evaluation and award of the contract, construction and testing of the installed system. We would expect the project to take about three years from application date. The preliminary milestone durations are shown in Table 4-1.

ACTIVITY	START	DURATION (MTHS)
Approval of City	1	2
Application for Interconnection	2	12
Prepare EPC Contract	12	5
Award Contract	13	2
Construction	15	14
Commissioning	30	2
COD	32	1
	Total	**38 Months**

Table 4-1 GWP-SCE Interconnection /Preliminary Milestone Schedule

5. Recommendations and Conclusions

Based upon our preliminary findings as presented in this Interim Report, we believe it is feasible to interconnect with SCE at the Eagle Rock Substation. We still need to confirm that there is space for bus extension and circuit breakers at the Eagle Rock Substation for terminating the 220 kV line from our proposed 69/220 kV substation near the Eagle Rock Substation. Further, there are other issues with Option 1 that need to be resolved such as Substation siting and ROW. Still, we are cautiously optimistic about Option 1.

We need further information on SCE bus separation requirements for Options 2 and 3. We believe it is possible to interconnect with the two SCE Eagle Rock- Sylmar Lines and meet the clearances of the National Electric Safety Code using two different open spaces under the SCE line, but the clearances will be tight. Option 3 may ultimately prove to be a better choice that Option 2 but Option 3 needs more environmental assessment.

Once we have completed the Short Circuit Studies and Load Flow Studies in Phase 1, we can better quantify the impact costs and cost for any necessary mitigation measures. Hopefully, the studies will not reveal any insoluble problems.

APPENDICES

A. DRAWINGS

1. Option 1, One-Line Diagram
2. Options 2 and 3, Interconnection Ring bus with SCE Line
3. Options 2 and 3 One-Line Diagram
4. Options 2 and 3 Equipment Layout per SCE Line
5. Section Drawings
6. Grayson Repowered One-Line Diagram for Short Circuit Study
7. GWP System One Line Diagram E1562
8. GWP Sub-transmission System Map
9. GWP Impedance Diagram
10. One-line Diagram Airway Receiving Station RA-1-EA1
11. Sketch LADWP-SCE Phase Sequence

B. SITE PHOTOGRAPHS AND GOOGLE EARTH PRINTS

1. Option 2 Site near Glorietta Substation
2. Eagle Rock Substation from Google Earth
3. Option 2 Site with Eagle Rock- Sylmar Line in Background
4. GWP 69 kV Overhead Lines and Flood Control Channel near Glorietta Substation
5. Option 3 Site near Cresenta Valley Park and GWP OH/UP Transition Tower
6. SCE Eagle Rock-Sylmar Line looking south from Cresenta Valley Park
7. Option 3, Hillside area near SCE Tower on Hillside above Cresenta Valley Park
8. Option 3, SCE Eagle Rock–Sylmar Line and GWP Bel Aire- Montrose 69 kV line
9. GWP Chlorination Station near Option 2 Site

C. LINE ROUTING MAPS

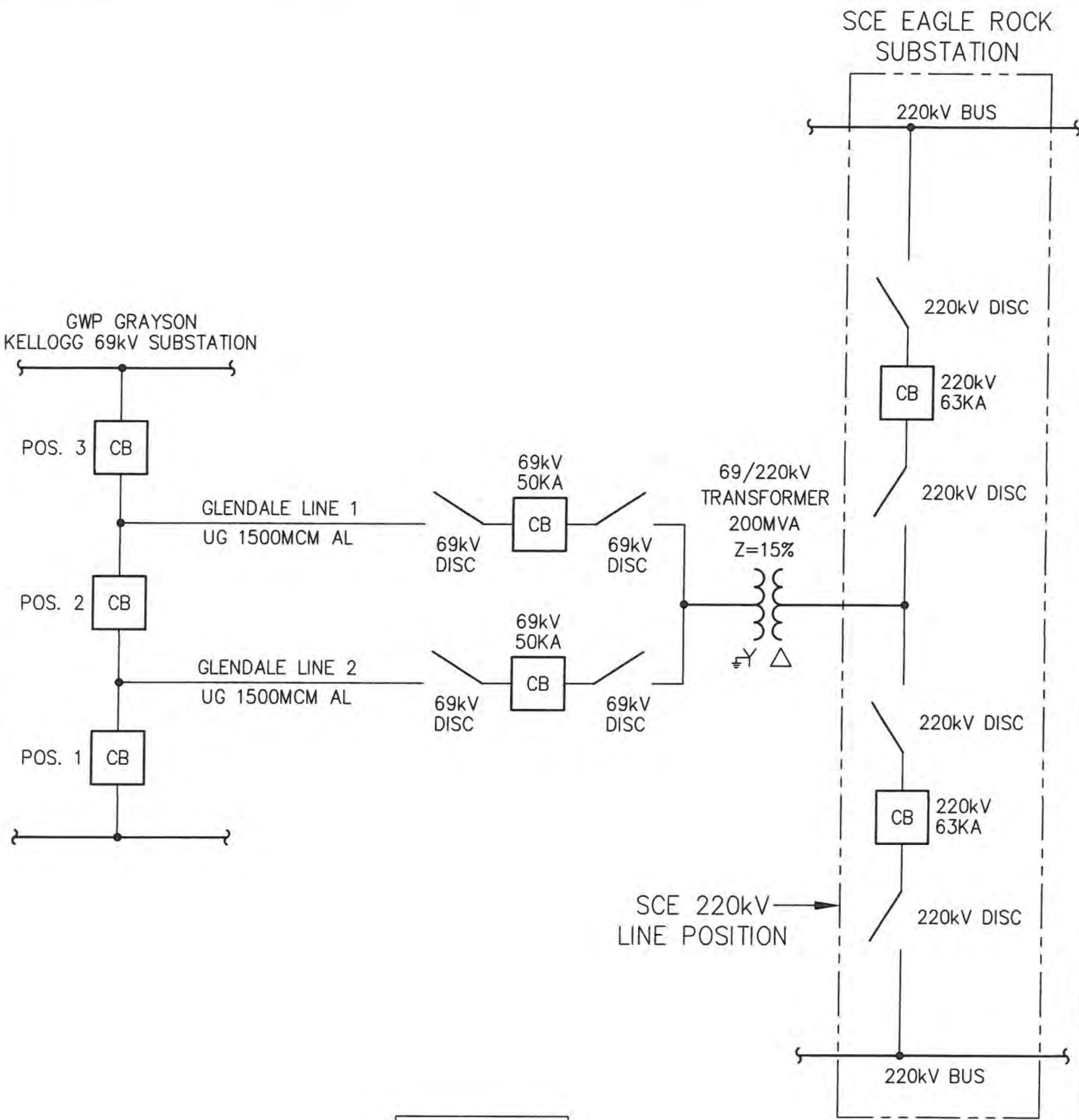
1. Option 1
2. Option 2
3. Option 3 follows Bel Aire- Montrose line toward Western, Exact routing TBD

D. DETAILED COST ESTIMATES

E. ENVIRONMENTAL REPORT

APPENDIX A

DRAWINGS



OPTION 1

Stantec

City of Glendale Water & Power
GWP
Your Trusted Community Utility

DRAWN BY: THH	DATE: 11/04/14	CITY OF GLENDALE GLENDALE, CA GWP–SCE INTERCONNECTION EAGLE ROCK SUBSTN OVERALL ONE LINE DIAGRAM
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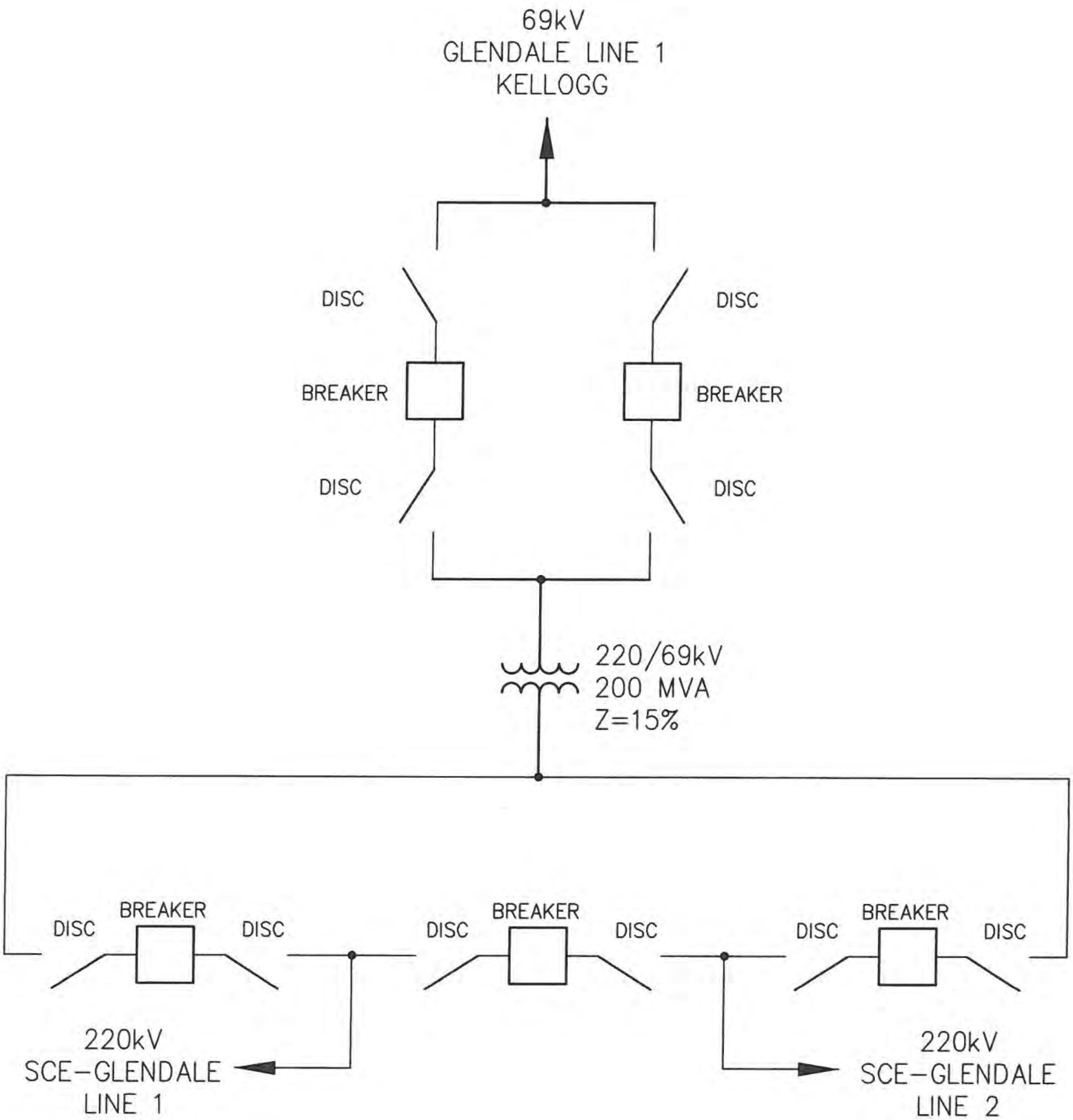

TYPICAL OPTIONS 2 AND 3

Stantec

City of Glendale Water & Power GWP Your Trusted Community Utility

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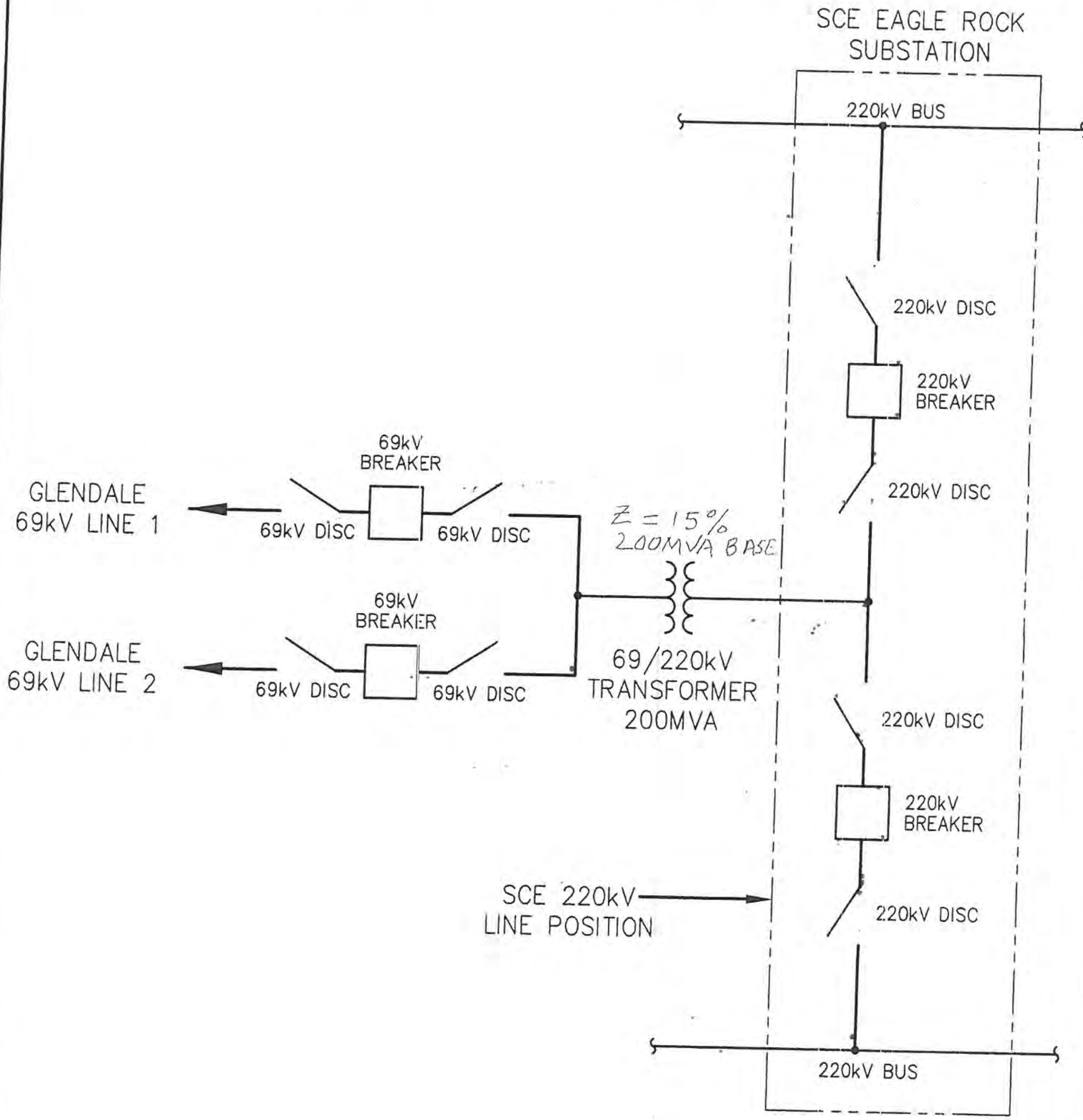

Stantec

City of Glendale Water & Power
GWP
Your Trusted Community Utility

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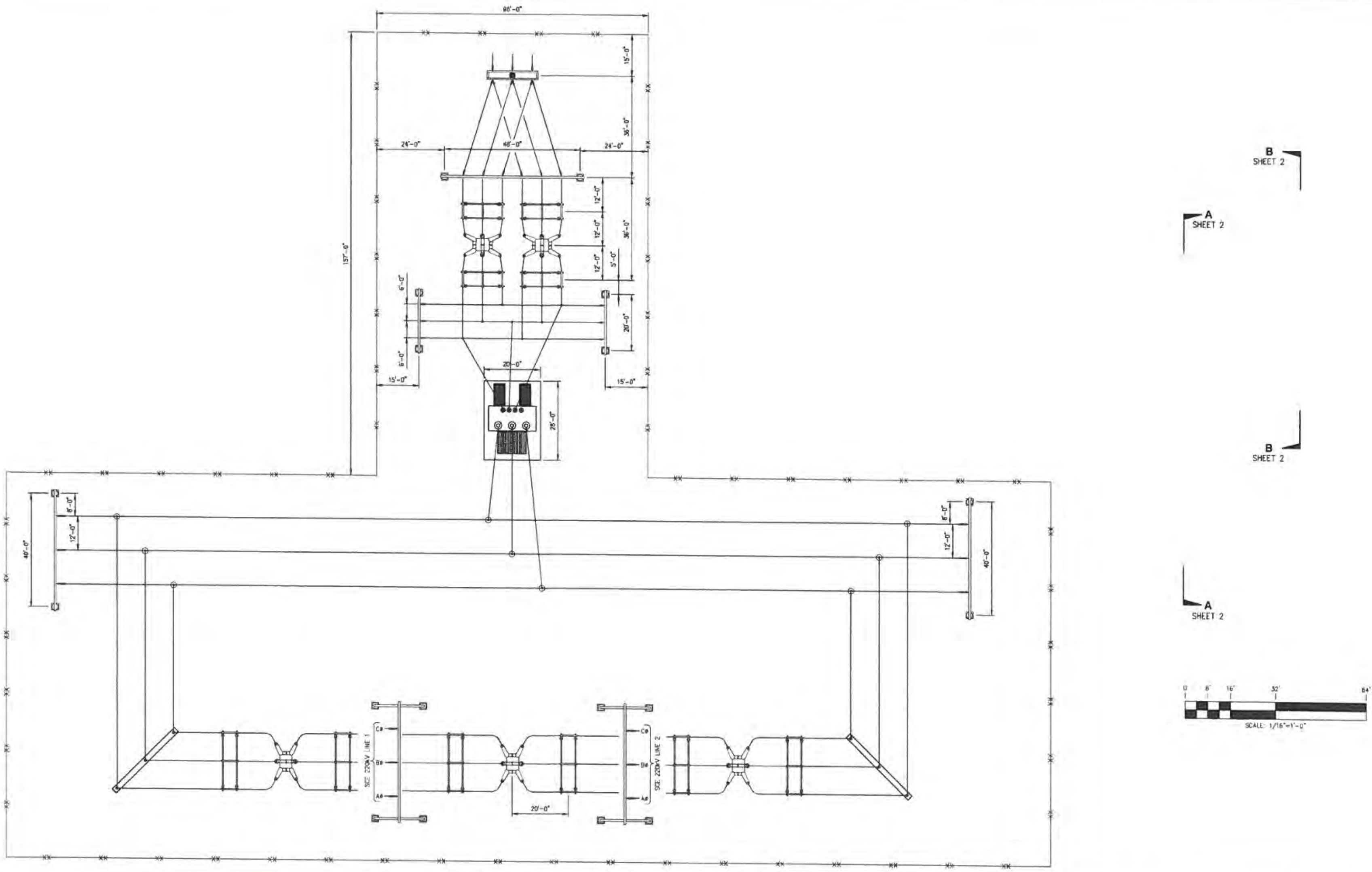

NUMBER	REFERENCE DRAWINGS

4

Stantec

CityofGlendaleSwitchYard

PRELIMINARY
FOR REVIEW ONLY

REV. NO.	DATE	REVISION	REV. BY	CKD. BY	APP'D
A		ISSUED FOR REVIEW	THH	GR	CDH

City of Glendale Water & Power — GWP — Your Trusted Community Utility

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APPROVED:	DATE:
APPROVED:	DATE:

CITY OF GLENDALE
GLENDALE, CA
SCE-GLENDALE INTERTIE
SWITCHYARD EQUIPMENT PLAN

SCALE:	DWG NO:	SHT:	REV. NO.
1/16"=1'-0"	SWITCHYARD	1	A

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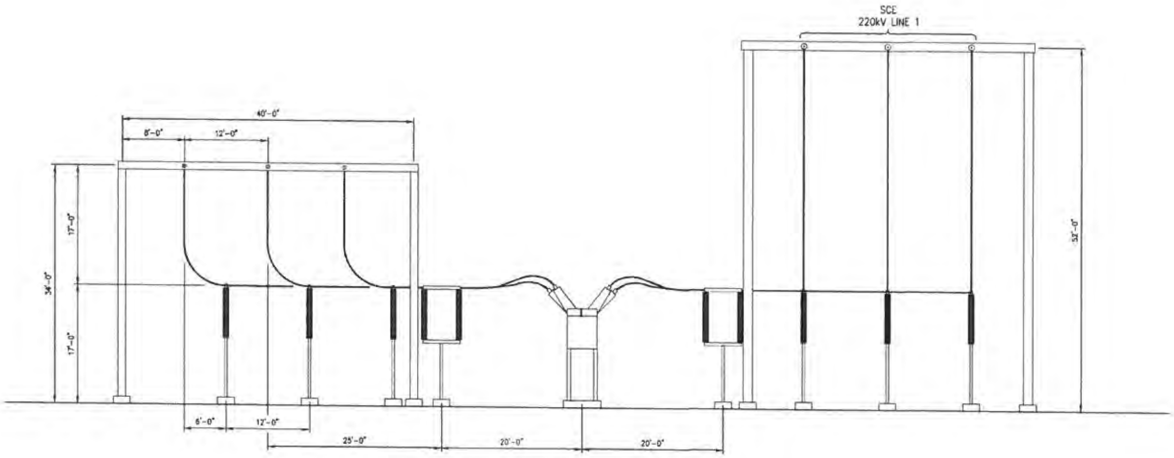
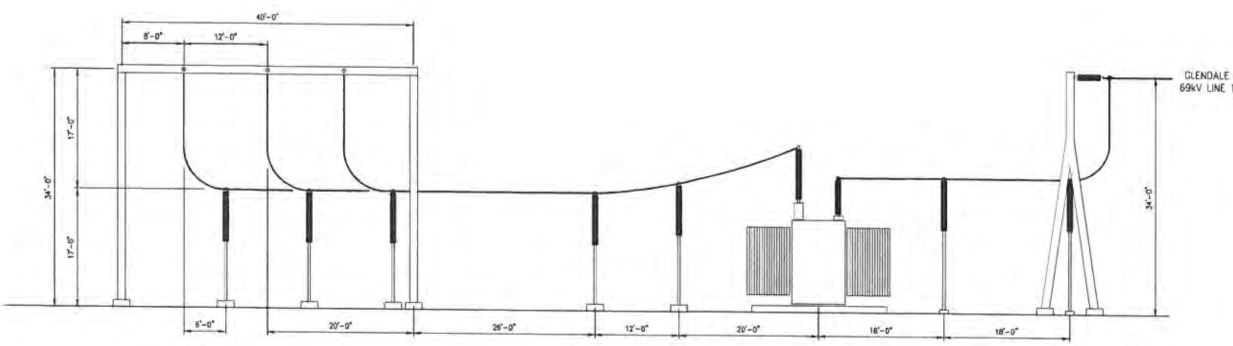


SECTION A-A



SECTION B-B

NOTES:

1. **THIS NOTES SECTION IS FORMATTED FOR PARAGRAPH AND AUTOMATICALLY NUMBERED MULTI-LINE TEXT TO FIT THE DESIGNATED AREA. SIMPLY USE THE ENTER KEY TO END A LINE AND START WITH THE FOLLOWING NUMBER. TO INSERT AN UNNUMBERED OR GRAPHIC ENTRY BETWEEN NUMBERED ITEMS, TYPE ENTER TWICE OR MORE THEN RIGHT CLICK "BULLETS AND LISTS/NUMBERED" TO CONTINUE FROM THE LAST NUMBER. THE ITEMS WILL EXPAND FROM THE BOTTOM UP TO RETAIN BOTTOM RIGHT JUSTIFICATION.

NUMBER	REFERENCE DRAWINGS

5

Stantec

GlendaleSwitchYardSections

PRELIMINARY
FOR REVIEW ONLY

A	DATE	ISSUED FOR REVIEW	THH	GR	CDH
		REVISION	REV. BY	CKD. BY	APPD

City of Glendale Water & Power
GWP
Your Trusted Community Utility

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CITY OF GLENDALE
GLENDALE, CA
SCE-GLENDALE INTERTIE
SWITCHYARD EQUIPMENT

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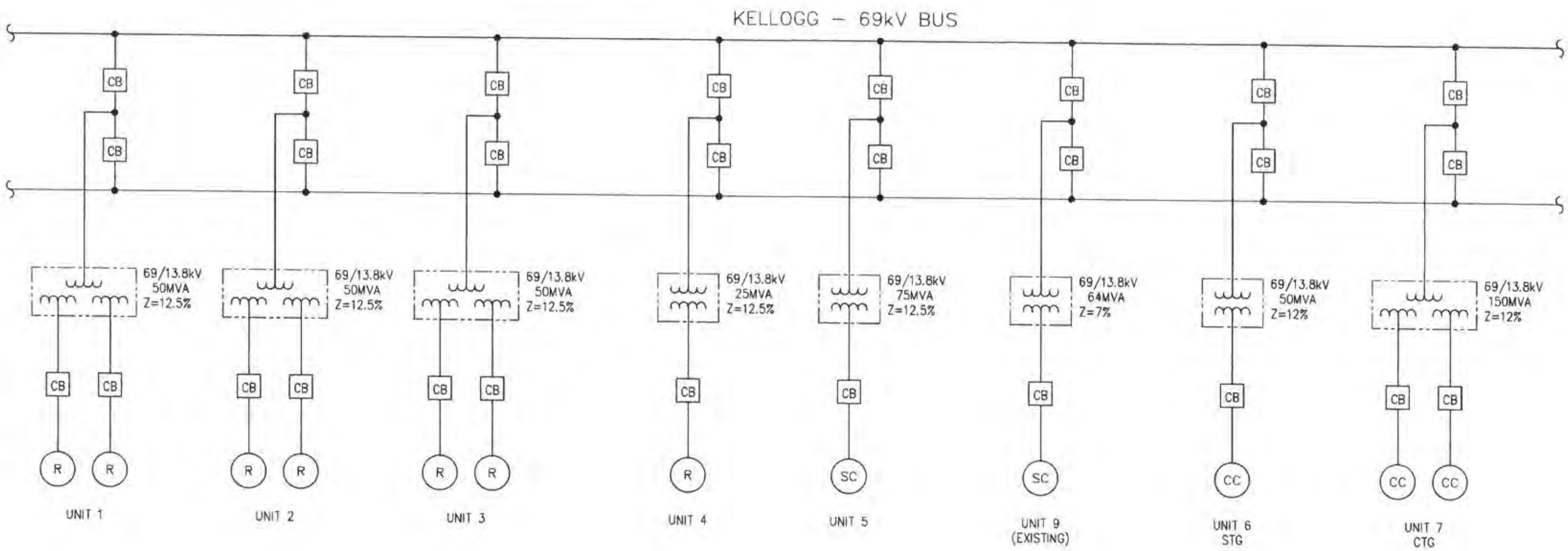

SYMBOLS

(R) RECIPROCATING ENGINES, 20.3MVA, 18.3MW, 13.8kW GENERATORS

(SC) SIMPLE CYCLE CT LM6000 62.8MVA, 50.4MW

(CC) COMBINED CYCLE 2-LM6000 62.8MVA, 50.4MW, 1-50MVA, 42MW ST

NOTE:

ONE LINE DIAGRAM IS FOR SHORT CIRCUIT STUDY ONLY.

NUMBER | REFERENCE DRAWINGS

Stantec

6 'GlendaleInterconnStudy

PRELIMINARY
FOR REVIEW ONLY

A | DATE | ISSUED FOR REVIEW | THH | GR | CDH
NO. | DATE | REVISION | REV BY | CHK BY | APP'D

City of Glendale Water & Power
Your Trusted Community Utility

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DESIGN: GR	DATE: 11/18/14
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APPROVED:	DATE:
APPROVED:	DATE:
APPROVED:	DATE:

CITY OF GLENDALE
GLENDALE, CA
INTERCONNECTION STUDY
GRAYSON REPOWER 270MW OPTION 270-1A

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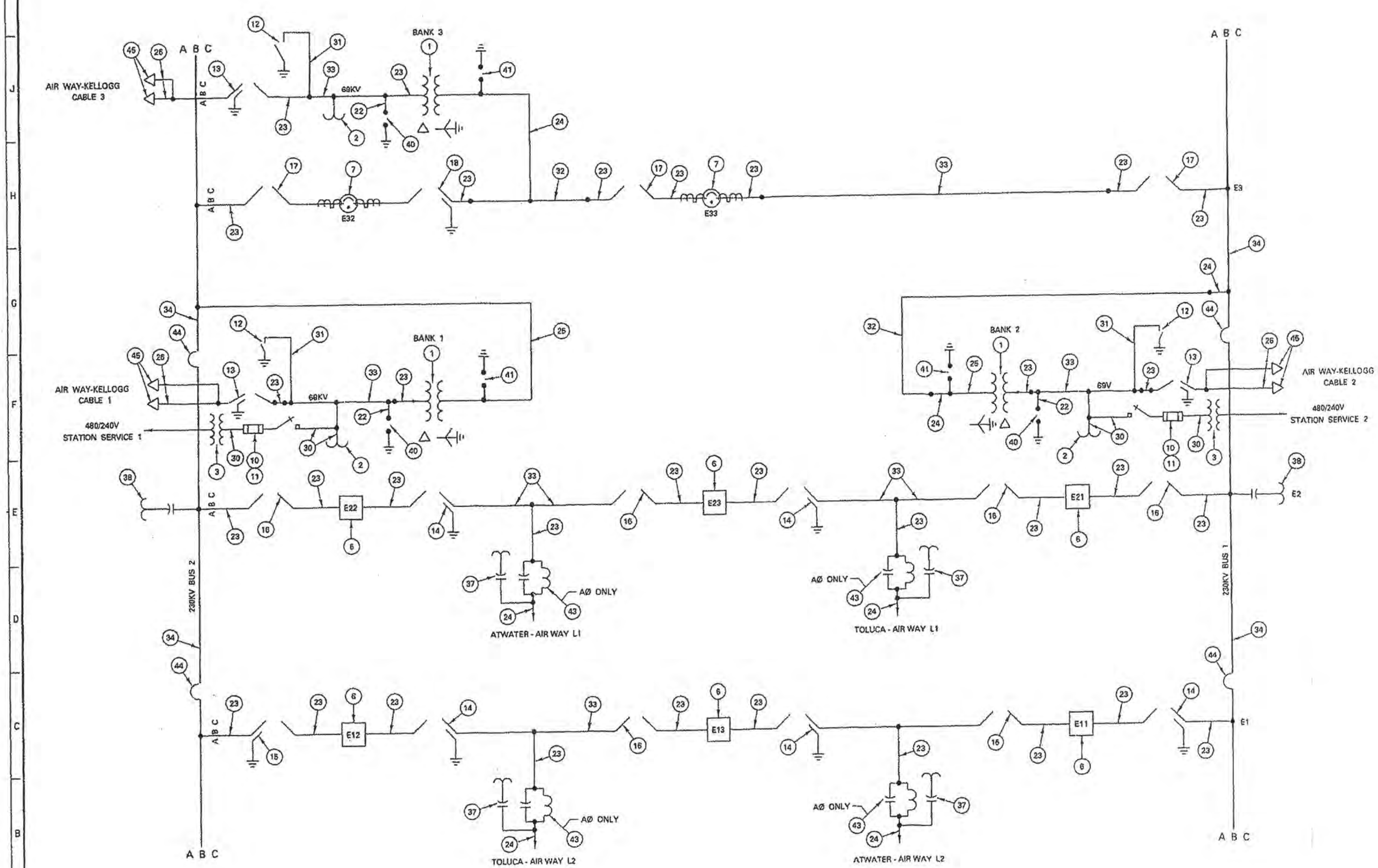


NO.	DESCRIPTION
1	XFMR, 3Ø,220-70KV, Y-△, LTC, 108/144/180MVA
2	XFMR, POT, 69KV - 115V (2)
3	XFMR, SINGLE PHASE, 69KV - 480/240V, 100KVA (3)
4	
5	
6	PCB, OIL 230KV, 2000A, 50KA
7	PCB, SF6 GAS, 230KV, 2000A, 60KA
8	
9	
10	SW, INTERRUPTIBLE FUSED DISC, 69KV INVERTED, S & C SMD-3 OUT[illegible]
11	FUSED, S & C, SMD-3 (3-E)
12	SWITCH, GROUND, 69KV, 80KA MOM
13	SWITCH, DISC, 69KV, 2000A, 3P W/GND SW
14	SWITCH, DISC, 230KV, 2000A, 3P W/RH GND OPR
15	SWITCH, DISC, 230KV, 2000A, 3P W/LH GND OPR
16	SWITCH, DISC, 230KV, 2000A, 3P W/LH OPR
17	SWITCH, DISC, 230KV, 3000A, 3P W/LH OPR
18	SWITCH, DISC, 230KV, 3000A, 3P W/LH GND OPR
19	
20	
21	
22	CABLE, CU, BARE, 4/0 SD, 19/S
23	CABLE, AL, BARE, 2500KCMIL, 2/Ø LUPINE 91S
24	CABLE, AL, BARE, 2500KCMIL, LUPINE 91S
25	CABLE, AL, BARE, 1590KCMIL, COREOPSIS 61S
26	CABLE, CU, BARE, 1000KCMIL, SD, 61S
27	
28	
29	
30	BUS, PIPE, CU, 3/4" IPS
31	BUS, PIPE, CU, 1" IPS
32	BUS, PIPE, AL, 2" IPS SCHED 80, 20
33	BUS, AL, 4" IPS SCHED 40
34	BUS, INTEGRAL WEB CHANNEL (IWCB) 4" X 4", AL
35	
36	
37	DEVICE, COUPLING CAP, POT W/CARR ACS REV METERING
38	DEVICE, COUPLING CAP, POT
39	
40	ARRESTER, LIGHTNING, 60KV
41	ARRESTER, LIGHTNING, 180KV
42	
43	TRAP, LINE, AIR CORE, 230KV, 2000A, 60HZ
44	CONNECTOR EXPANSION
45	POTHEAD, 69KV

NOTES:

1. CONTROL AND OPERATING VOLTAGE 125VDC.

DES. ENGR. L. HORTON
SUP. ENGR. L. KIME

REVISIONS		
NO.	DESCRIPTION	
3	AS INSTL	(3, 4-F) (9, 10-F) PT 8 WAS CONN TO PT 29, 4 BUS & ADD PT 16
4	81083; 8AH87	ADD POSN E3, TOL - AIR WAY L1 & ATW - TOL L2 TO POSN E2; REV BK 1 & BK 2 HS CONN
5	81083; 8AH87	(6,8-A,C) REV POSN E1 & E2 LINE NAMES
6	81083; 8AH87	(6,8-A,C) INTCHG TOL-AIR LINE NAMES
7	81083; 8AH87	(8, 9-G) REV BK 2 SEC CA

Revision Number 7
DRAFTING RELEASE
DRAWN BY T. I. MORRISON
CHECKED BY JRB
ENGINEERING APPROVAL
Everard K. Hinman E13412
John Brodo

OWNER/AGENT APPROVAL

DRAWING REVISION RELEASE APPROVAL

FINAL APPROVAL RELEASE SIGNATURE DATE

SCALE: (UNLESS NOTED) NONE
DRAFTING RELEASE
DRAWN BY NPJ
CHECKED BY RY
ENGINEERING APPROVAL
L. Horton
L. D. Kime E6165

OWNER/AGENT APPROVAL
William R. Hall, P.E.
CITY OF GLENDALE - P.S.D.
DRAWING RELEASE APPROVAL
Norman E. Nichols 7-20-83
FINAL APPROVAL RELEASE SIGNATURE DATE

ONE LINE DIAGRAM
AIR WAY RECEIVING STATION 820 AIR WAY, GLEN[illegible]

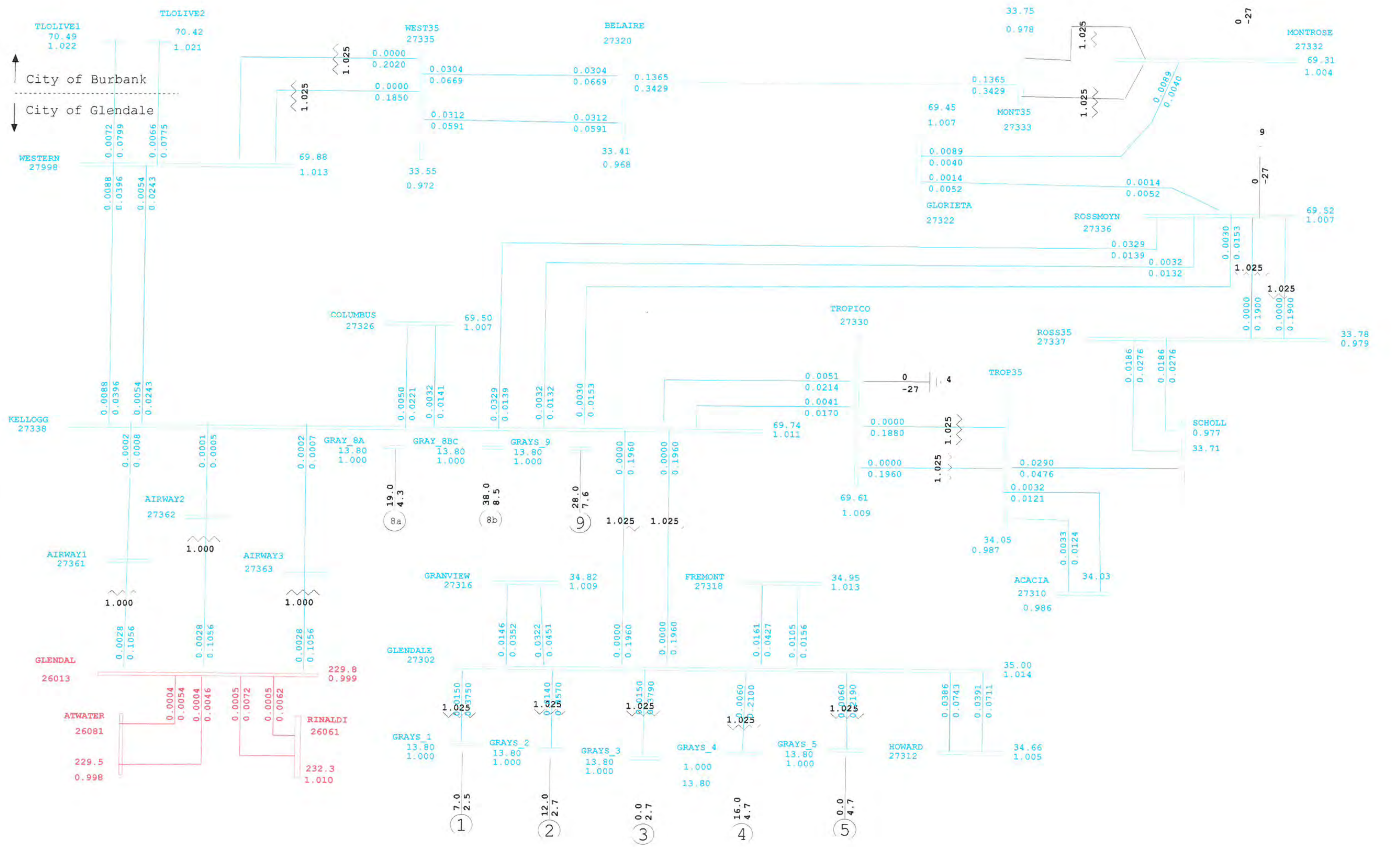
POWER SYSTEM
DEPARTMENT OF WATER AND POWER
CITY OF LOS ANGELES

DRAWING NUMBER RA1-EA1

3-E860868 4-E000003 5-E000146 6-E000174 7-E010001

DRA E830000, E830525, E930617

CITY OF GLENDALE POWER SYSTEM



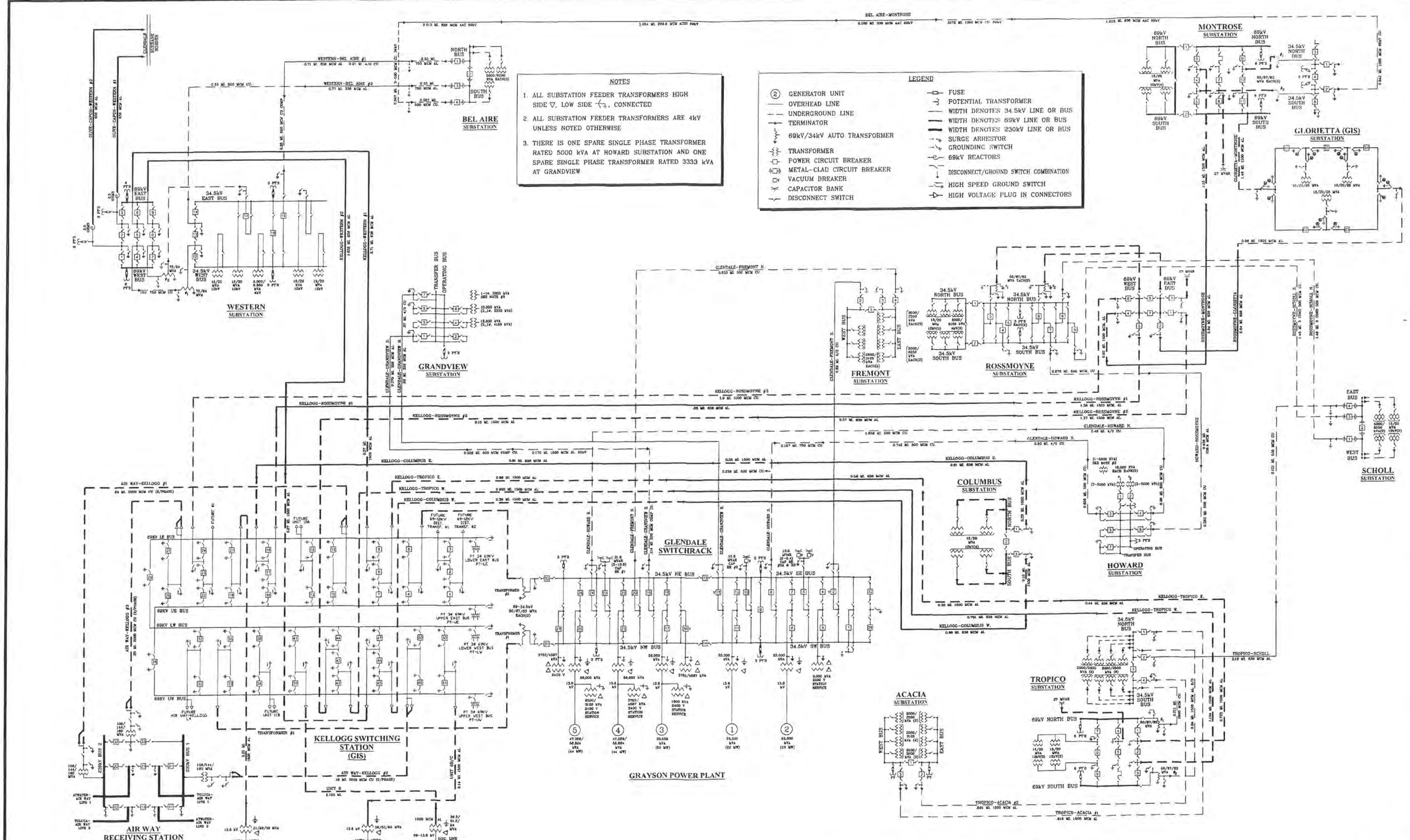
General Electric International, Inc. PSLF Program Tue Oct 28 14:15:04 2014 C:\Users\balshanti\Desktop\source impedance_v1.sav

040107 STEP1: STEP0 W/ LOAD 3247 FROM 04/04/07/14

ALL LINES IN

R/X

Rating = 1



NOTES

1. ALL SUBSTATION FEEDER TRANSFORMERS HIGH SIDE ▽, LOW SIDE ⅄, CONNECTED
2. ALL SUBSTATION FEEDER TRANSFORMERS ARE 4kV UNLESS NOTED OTHERWISE
3. THERE IS ONE SPARE SINGLE PHASE TRANSFORMER RATED 5000 kVA AT HOWARD SUBSTATION AND ONE SPARE SINGLE PHASE TRANSFORMER RATED 3333 kVA AT GRANDVIEW

LEGEND

- GENERATOR UNIT
- OVERHEAD LINE
- UNDERGROUND LINE
- TERMINATOR
- 69kV/34kV AUTO TRANSFORMER
- TRANSFORMER
- POWER CIRCUIT BREAKER
- METAL-CLAD CIRCUIT BREAKER
- VACUUM BREAKER
- CAPACITOR BANK
- DISCONNECT SWITCH
- FUSE
- POTENTIAL TRANSFORMER
- WIDTH DENOTES 34.5kV LINE OR BUS
- WIDTH DENOTES 69kV LINE OR BUS
- WIDTH DENOTES 230kV LINE OR BUS
- SURGE ARRESTOR
- GROUNDING SWITCH
- 69kV REACTORS
- DISCONNECT/GROUND SWITCH COMBINATION
- HIGH SPEED GROUND SWITCH
- HIGH VOLTAGE PLUG IN CONNECTORS

	DISTRIBUTION LIST	QTY.
1	GM OF WATER AND POWER	1
2	ASSISTANT GM OF WATER AND POWER	1
3	SENIOR ELECTRICAL ENGINEERS	2
4	WATER AND POWER YARD	20
5	ENGINEERING	2
6	MAPPING AND RECORDS	3
7	POWER PLANT	2
8	ENERGY CONTROL CENTER	2

REVISIONS

DATE	NO.	DESCRIPTION	BY	CH'K	APP
06-27-11	22	REROUTE & RECABLED PORTION OF WEST/BEL-A 1 UNDER PROJECT 14445-U-1	JL		
10-08-11	23	AS-BUILT: GLORIETTA SUBSTATION	SA	HB	EO
4-24-12	24	CORRECT CABLE LENGTH OF ROSS/GLOR LINE	SA	BA	BA
4-17-13	25	UPDATED DISTRIBUTION LIST	JP	EO	EO

REVISIONS

DATE	NO.	DESCRIPTION	BY	CH'K	APP
5-25-06	14	REMOVE KELLOGG SWITCHING STATION, ADD KELLOGG GIS STATION; REVISE LEGEND	GA	ER	FDF
5-1-08	15	REVISE ONE-LINE PER SUBSTATION ASBUILTS	AP		
3-30-10	16	RPLC. KELL-GIS/COLUMBUS W. XLPV CABLE FROM V906,V863,V2075 TO P34081A PRJ.12784-U-13	AP	JL	-
9-29-10	17	SHOW NEW GLORIETTA SUBSTATION UNDER CONSTRUCTION	SA	EO	EO
09-30-10	18	RPLC. PORTION OF GLENDALE/GRANDVIEW SOUTH FROM OH TO UG PRJ.[illegible]	JL		
09-30-10	19	MATERIAL CHANGED FROM AL TO CU ON THE UG GLENDALE/FREMONT NORTH	BA/JL		
04-25-11	20	REROUTE & RECABLED PORTION OF WEST/BEL-A 2 UNDER PROJECT 14258-U-2 & 14405-U-1	JL		
04-25-11	21	ROSS/MONT 2 TO ROSS/MONT & ROSS/MONT 1 TO ROSS/GLOR & GLOR/MONT 14200-U-1	JL		

DES:
DWN: CH'K:
APPROVED:
H. R. ABRARI
PRINCIPAL ELECTRICAL ENGINEER
DATE: 1-28-86
SCALE: NONE

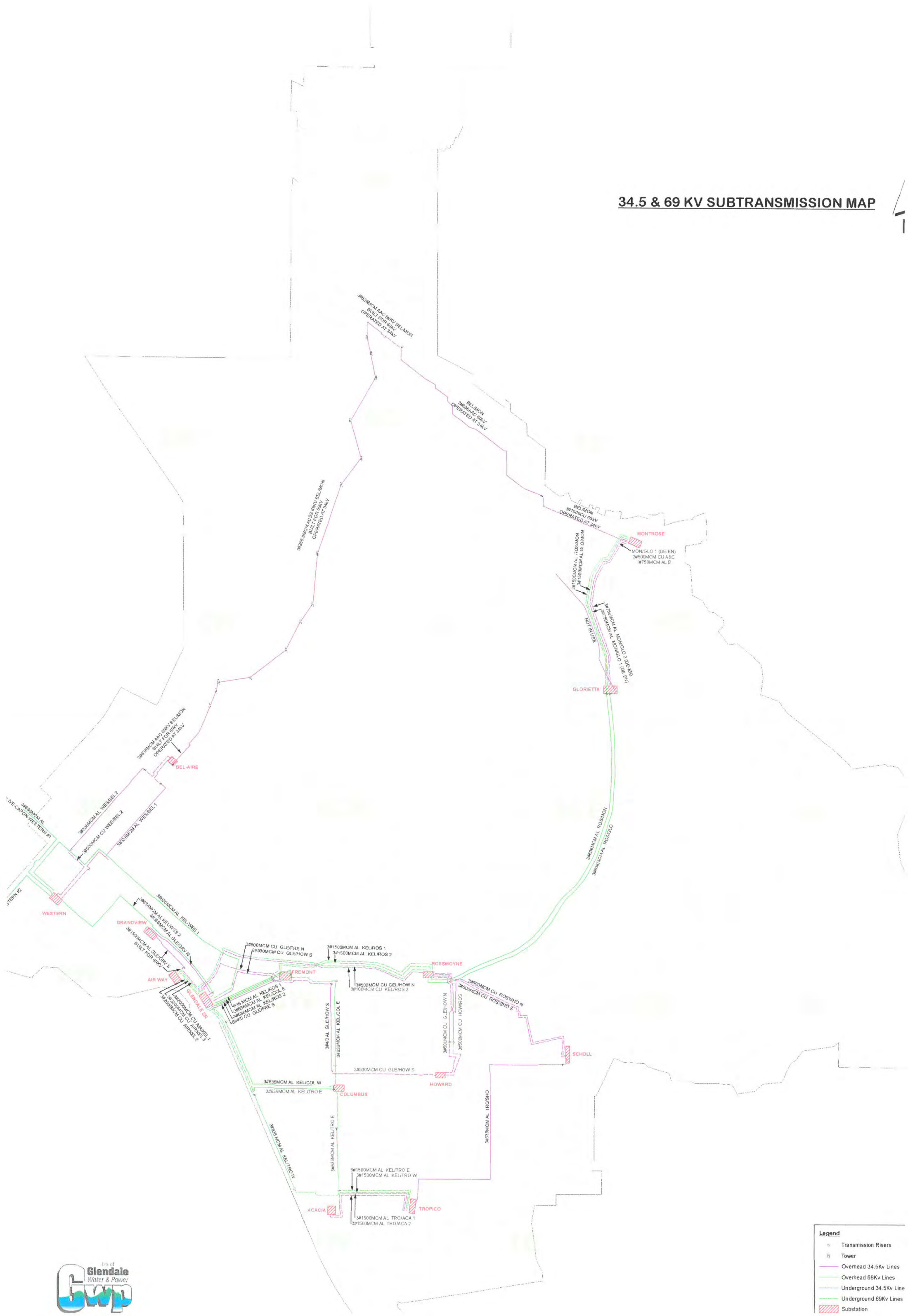
CITY OF GLENDALE
ONE LINE DIAGRAM
34.5 & 69kV DISTRIBUTION SYSTEM

GLENDALE WATER & POWER
CITY OF GLENDALE
CALIFORNIA

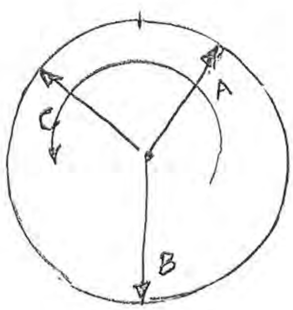
SHEET: E-1

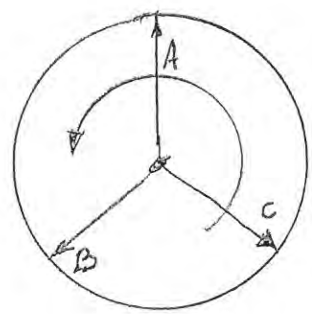
1562

34.5 & 69 KV SUBTRANSMISSION MAP



ENGINEERING DATA SHEET	Sheet No. 1 of 1	Date 9/25/14
Phase Rotation SCE- LADWP	Prepared GTR	
	Checked	
	Approved	





Phasor Diagram LADWP

LADWP ABC Counter Clockwise

Phasor Diagram SCE

SCE ACB Counter Clockwise

Sketch E-1

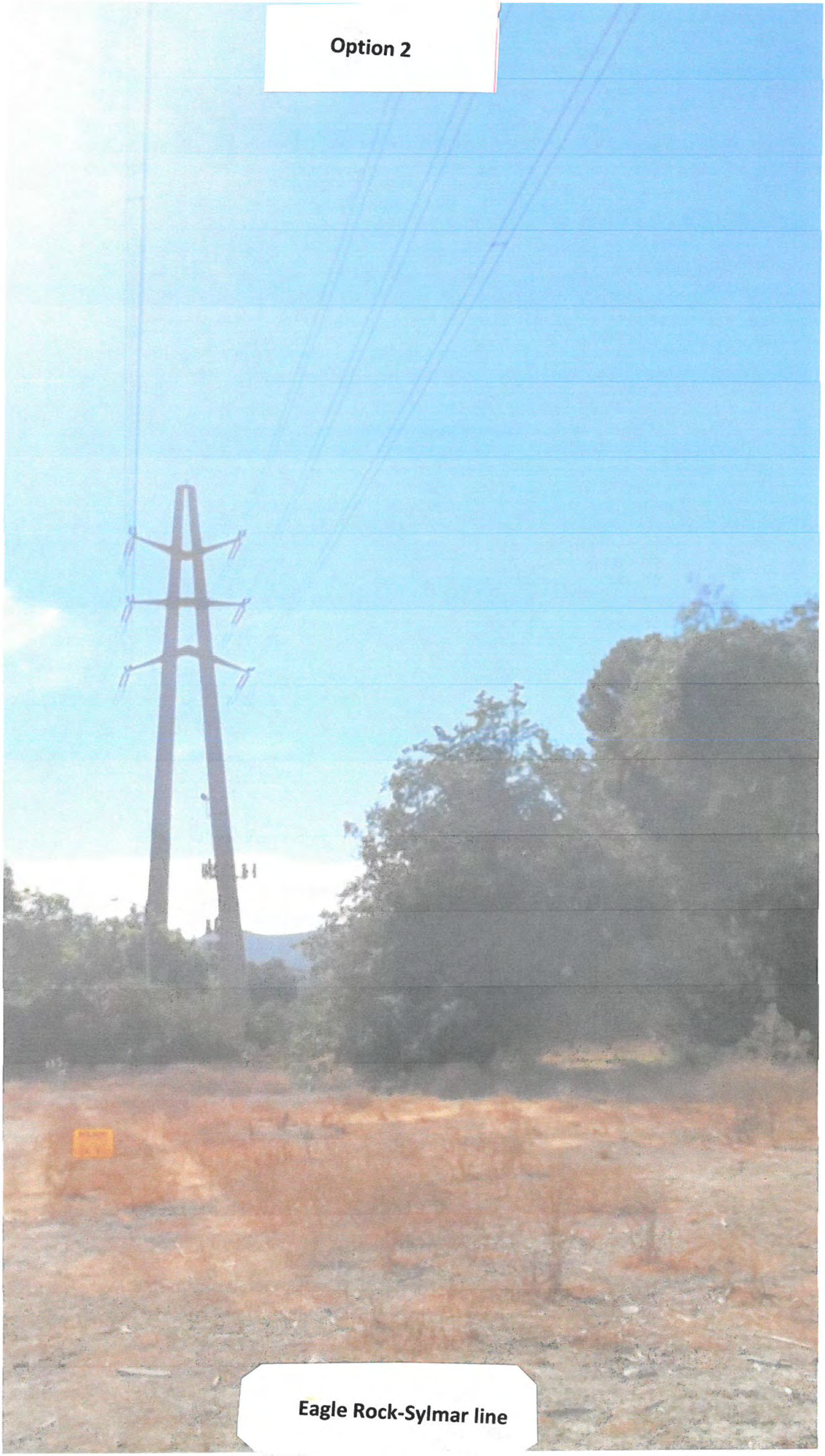
APPENDIX B

SITE PHOTOGRAPHS AND GOOGLE EARTH PRINTS

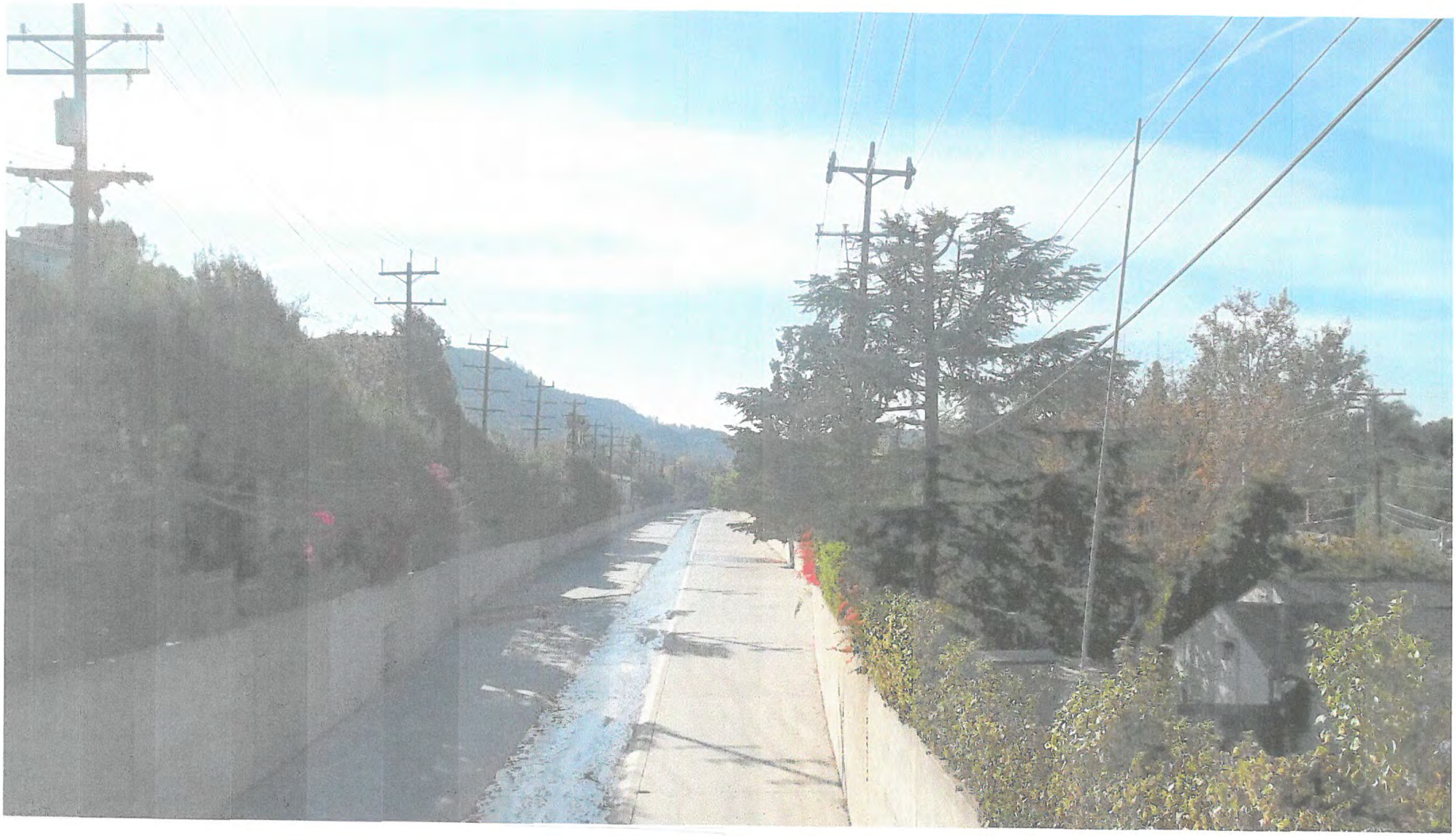
Option 1

Option 2

Option 2



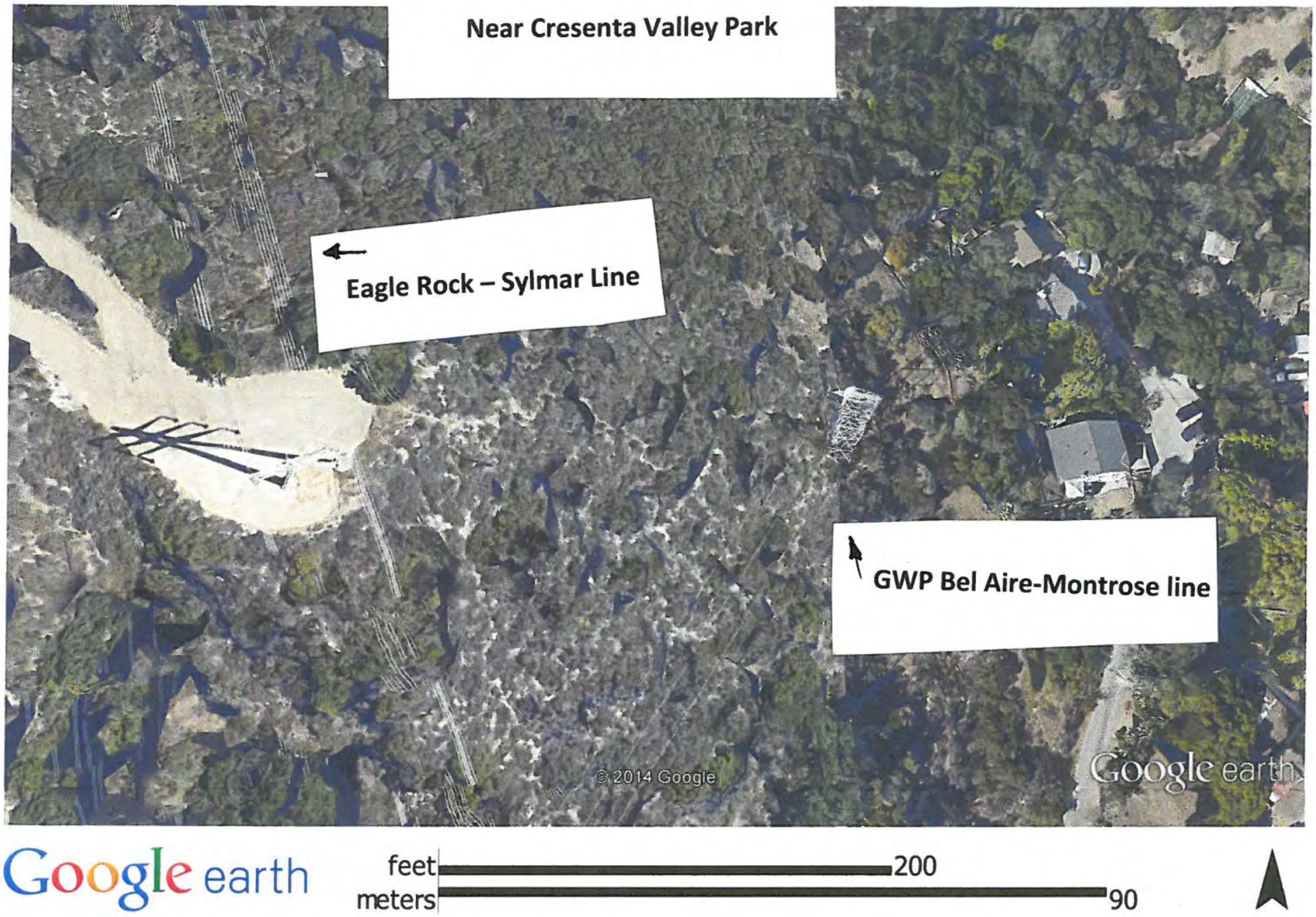
Eagle Rock-Sylmar line



Overhead 69 kV Circuit

Near Glorietta Substation+

Option 3


Near Cresenta Valley Park
Eagle Rock – Sylmar Line
GWP Bel Aire-Montrose line
© 2014 Google
Google earth
Google earth
feet
200
meters
90

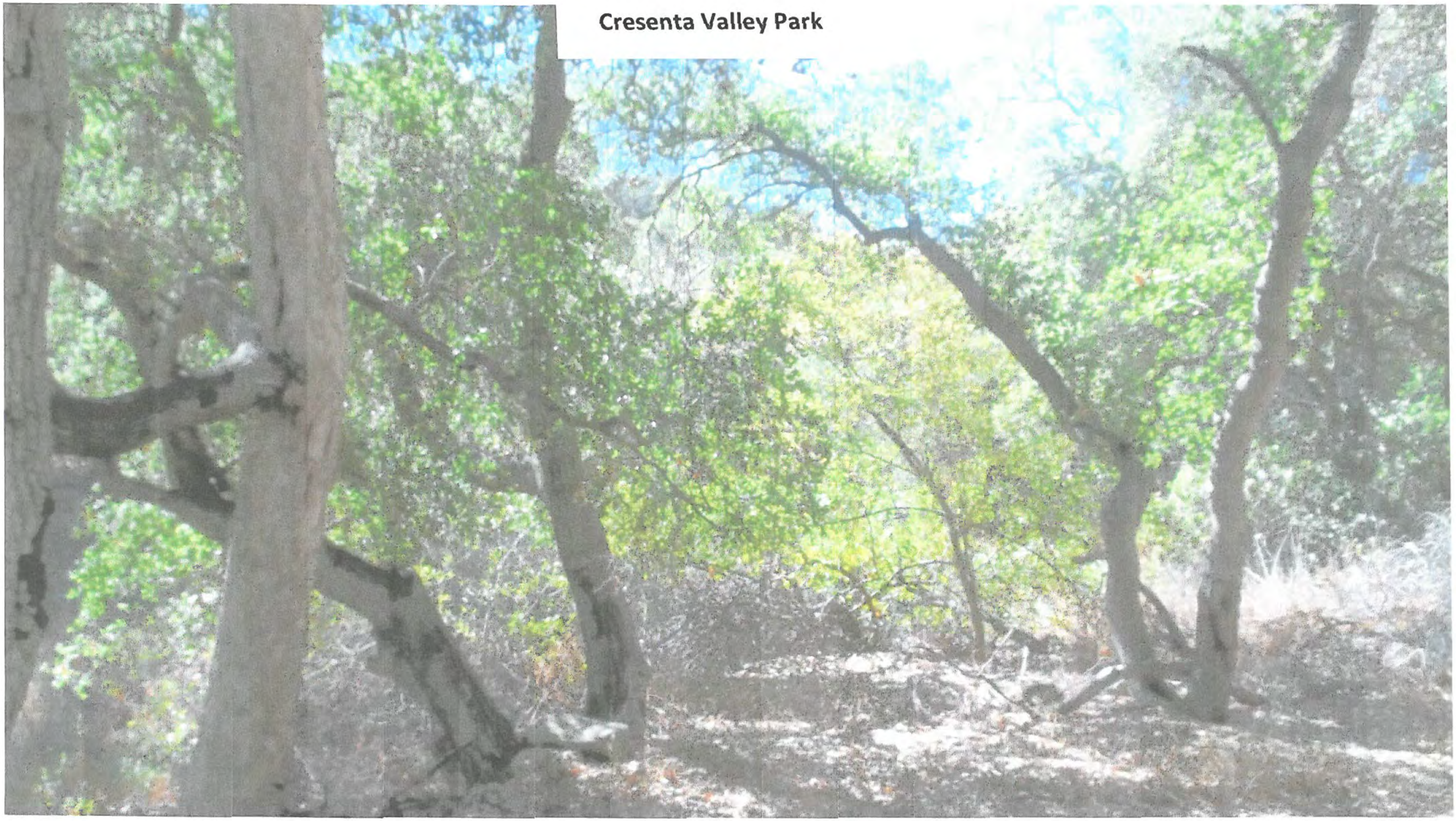

Transition Tower OH-UG
Bel Aire - Montrose
Google earth

Eagle Rock-Sylmar

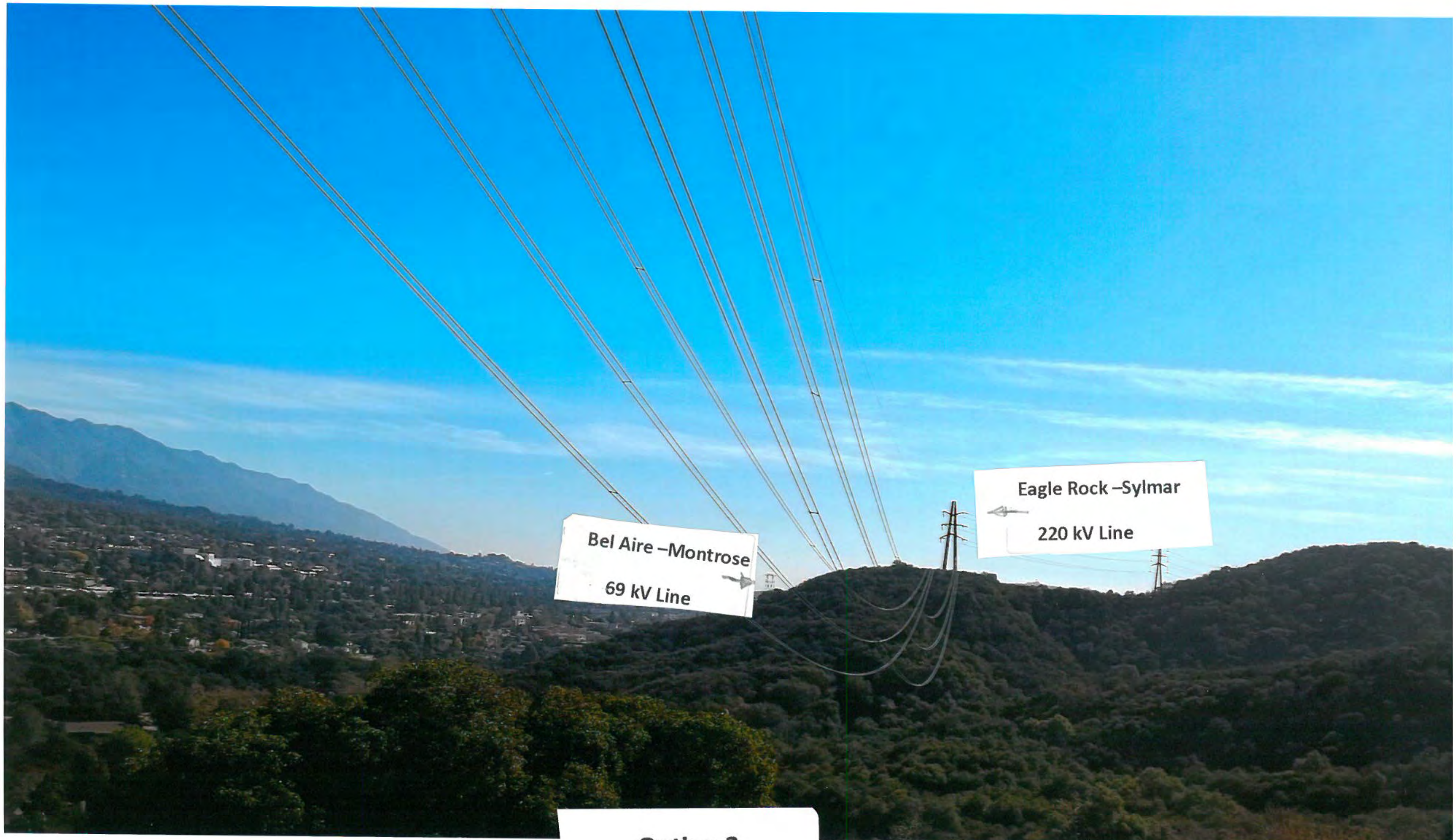
From Cresenta Valley Park

Hillside near SCE Tower

Cresenta Valley Park



Option 3



Option 3

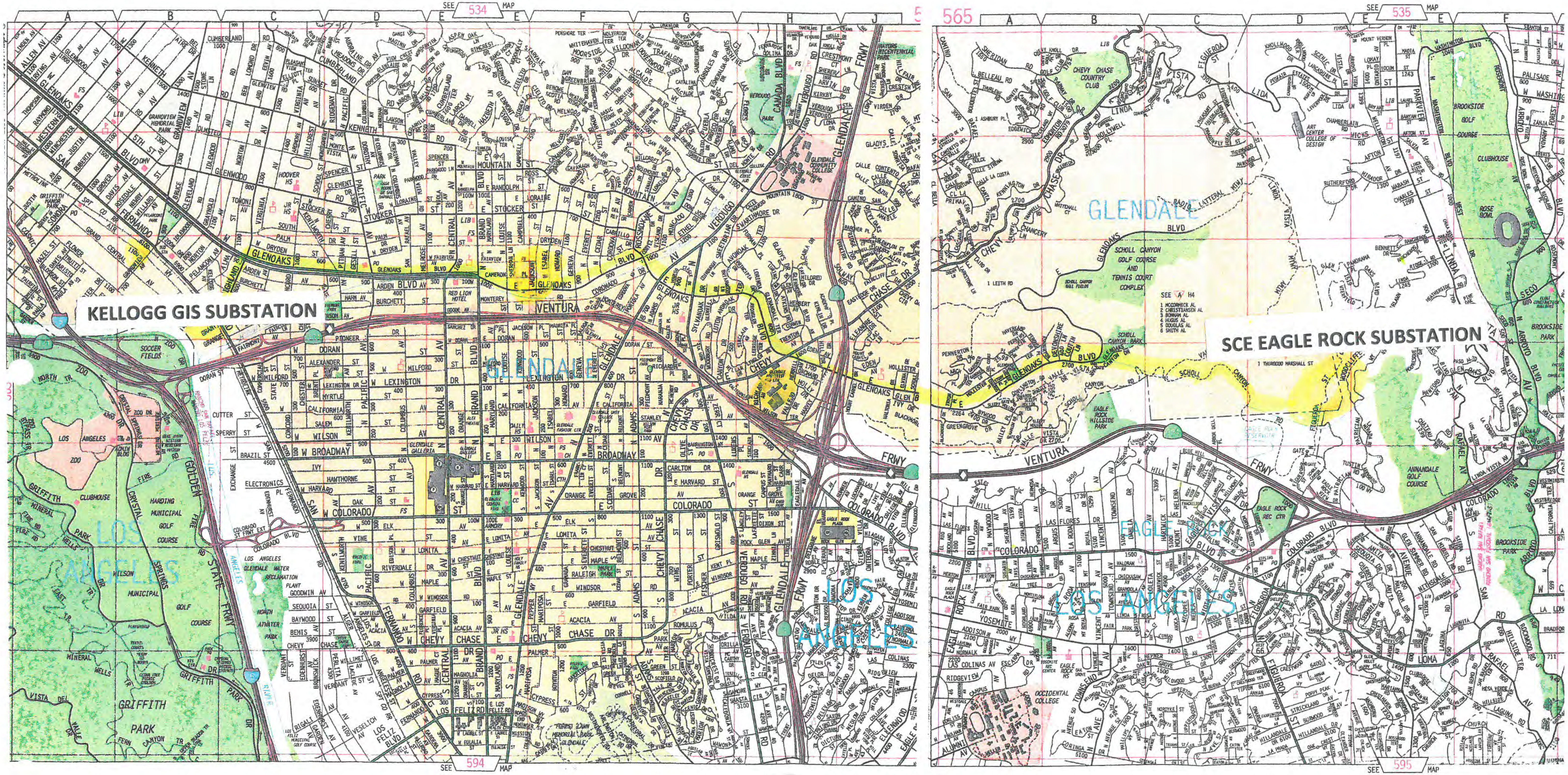
Cresenta Valley Park

GWP Clorination Station

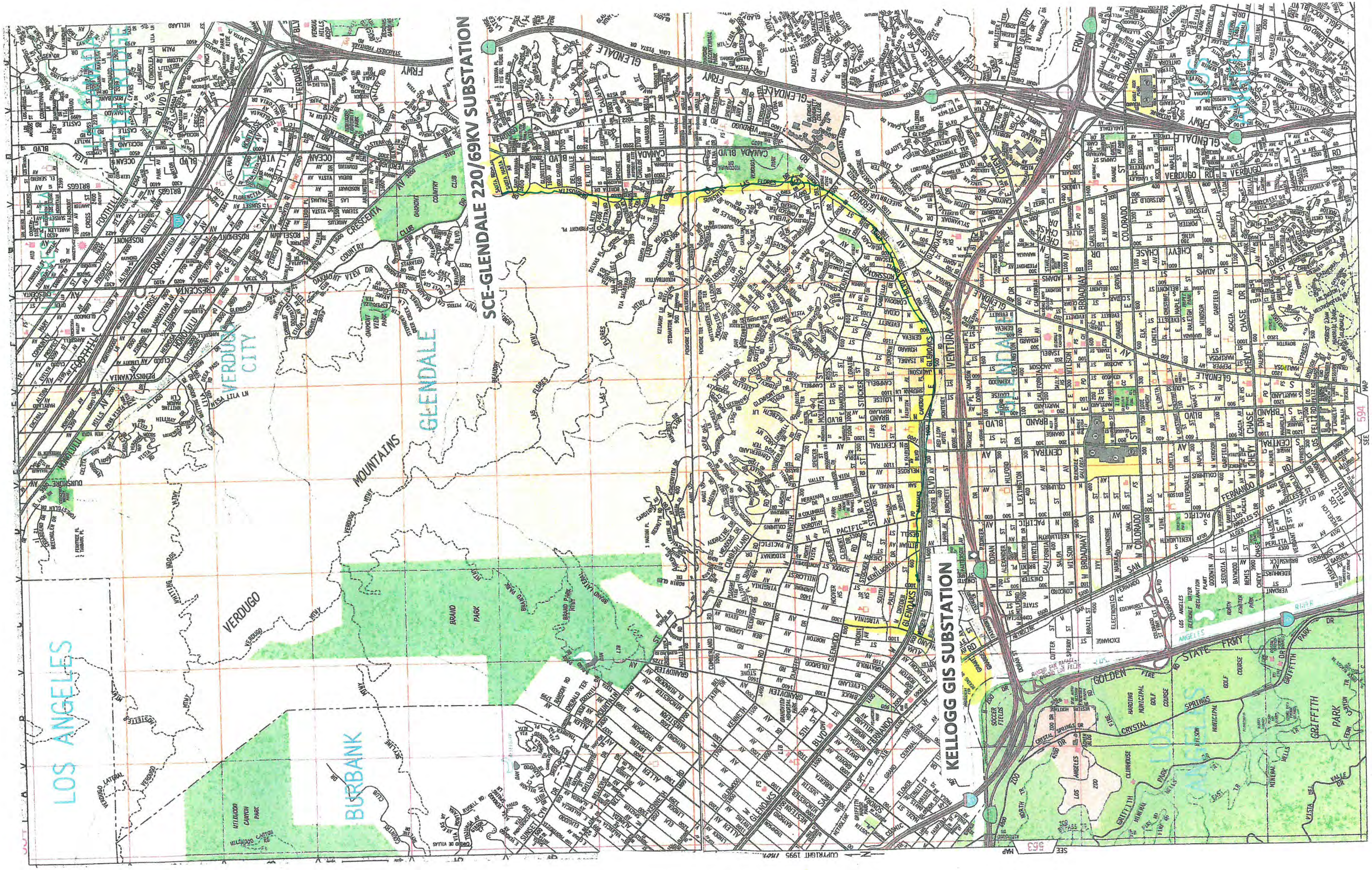
Near Option 2 Site

APPENDIX C

LINE ROUTING MAPS


KELLOGG GIS SUBSTATION
SCE EAGLE ROCK SUBSTATION
GLENDALE
LOS ANGELES
EAGLE ROCK
GRIFFITH PARK
VENTURA FRWY
GLENOAKS BLVD
SEE 534 MAP
SEE 594 MAP
565
SEE 535 MAP
SEE 595 MAP

Option 1


SCE-GLENDALE 220/69KV SUBSTATION
KELLOGG GIS SUBSTATION
GLENDALE
VERDUGO CITY
VERDUGO
MOUNTAINS
LOS ANGELES
BURBANK
BRAND PARK

Option 2

APPENDIX D

DETAILED COST ESTIMATES

Glendale – Southern Cal Edison Systems Interconnection

Option 2: Glendale GIS Substation to 220/69kV Intertie Substation

Suggested route :

Using two 69kV, 3phase underground cables in individual phase conductor per conduit with one spare conduit per circuit.

From the Kellogg GIS Substation property line go to Highland Ave, to Glenoaks Blv., on Glenoaks Blvd. go all the way to Ethel St., to Las Flores Dr. follow best route to Santa Rosa to 220/69kV Intertie Substation. Total distance, approximately 10 miles. A proposed routing is included in the Appendices.

The 220/69kV Interconnection Station and a 69kV Switching Station are to be installed at a now vacant lots apparently owned by the city of Glendale but which contain easements for SCE and AT&T.

Transmission $19,000,000

Transmission Line Contingency 30% $5,700,000

The estimated cost of this Interconnection Station and 69kV Switching Station is : $14,558,000

Estimated Impact Facilities Impact Costs and interconnection Fees $20,000,000

LGIA SCW/CAISO Applications and Studies $500,000

<u>The Total estimated cost for this Interconnection Option 2 is : $ 59,758,000</u>

Glendale – Southern Cal Edison Systems Interconnection

Option 2: Glendale 220/69kV Intertie Substation

Cost Estimate Breakdown :

Materials:

Six 230kV, 2000A, 63kA SF6 Circuit Breakers @ $100,000.00 EA $600,000

One 220kV to 69kV, 150MVA, OA, FA Transformer $1,100,000

Six 220kV Lighting Arrestors @ 15,000.00 EA $90,000

Six 69kV Lighting Arrestors @ 5,000.00 EA $30,000

Six 220kV,and three 69kV Arrestor Supports @$1500.00 EA .... $ 18,000

Twelve 230kV, 2000A, Vertical Break, Disc. Switches @ $40,000.00 EA $480,000

Four 52 FT. High, 40 FT. Wide Line termination Racks @50,000.00 EA .... $ 200,000

Four 34FT. High, 40 FT. Wide Bus Termination Racks @40,000.00 EA .... $ 160,000

Approx. 100 230kV post insulators @$2,000.00 EA $200,000

Approx. 100 post insulator supports @$1,000.00 EA $100,000

Aluminum conductor, string insulators, fittings & miscl.................................... . $200,000

Conduit and grounding and fittings .... $ 250,000

Relays and communications equipment $200,000

Other Miscellaneous $150,000

Materials Total: $3,778,000

Site Grading and Fencing $650,000

Control House $150,000

Installation and construction)..$1,600,000

Engineering and Drafting (25% of materials) $725,000

Testing and Commissioning $125,000

Administration, project & construction management $780,000

Sub Total Cost $7,800,000

Contingency (30 %) $2,350,000

Estimated Total Cost for this 220 to 69kV Substation $10,150,000

Adjacent to the 220/69kV Substation, a 69kV Switching Station needs to be built to terminate, switch and connect the two 69kV lines, coming from the Kellogg GIS, to the 220/69kV transformer. The estimate for this installation is as follows:

Materials:

Two 69kV, 2000A, 50kA interrupting duty @ $75,000 EA . ... $150,000.

Four 69kV, 2000A, vertical break disc. switches @ $25,000 EA........................ $100,000.

One 32Ft. high, 48Ft.wide double circuit steel rack .... $50,000.

Two 32Ft. high, 20Ft. wide steel racks @$30,000 EA .... $60,000.

Bus conductor, post and string insulators, miscel. fittings .... $40,000.

Conduit and grounding, other miscellaneous .... $ 50,000.

Relays and communications equipment $60,000

Other miscellaneous .... $40,000.

Materials Total : $550,000

Grading and fencing ....$ 30,000

Small Control House $50,000

Terminations, Relay Protection and CB controls.. $100,000

Installation and Construction .... $192,500.

Engineering and Drafting .... $137,500.

Testing and Commissioning .... $35,000.

Administration, project and construction management .... $ 99,000.

Sub Total Cost .... $1,194,000.

Contingency 30% of Sub Total Cost ....$360,000.

Total Estimated Cost for this 69kV switching station $1,554,000

Property Easement or Lease for Substations...$500,000

Kellogg Sub, three 50 KA Circuit breakers , Relay Protection and Controls $300,000

Total Costs for Substations $14,558,000

Transmission line Costs ....$ 19,000,000

Transmission Line Contingency 30%.. $5,700,000

LGIA Interconnection Application SCE/CAISO Studies $500,000

Contingency for Impact Mitigation Costs (GWP,SCE, CAISO, LADWP and BWP) ... $20,000,000

Total Project Cost.. $59,758,000

.

Revision A

Project Transmission Outline and Cost Estimate Summary

Glendale – Southern Cal Edison Systems Interconnection

Option 1: Glendale GIS Substation to SCE Eagle Rock Substation

Study Route :

Using two 69kV, 3phase underground cables in individual phase conductor per conduit with one spare conduit per circuit.

From the Kellogg GIS Substation property line go to Highland Ave, to Glenoaks Blvd., on Glenoaks Blvd. go all the way to vicinity of Scholl Canyon. Total distance, approximately 10 miles. See attached map.

From Scholl Canyon using two 69kV overhead circuits on single poles, following the best route , go to the SCE Eagle Rock Substation. Total distance, approximately 3.3 miles. Preliminary Routing map is enclosed.

The estimated cost of 69kV double circuit underground portion, 10 miles long: $19,400,000.

The estimated cost of 69kV double circuit overhead portion, 3 miles long : $1,800,000.

69 kV, Double Circuit Overhead 75 foot , Right of Way Costs for 9 acre miles : $2,000,000

In addition to the double circuit 69kV transmission lines, a small Interconnection Station needs to be installed at Eagle Rock Substation . Detailed Estimate is included in the Appedices.

A basic one- line diagram is shown in Figure 1

	SUMMARY
Transmission , including 30% Contingency	$30,200,000
The Estimated Cost of this Interconnection Substation is :	$ 15,153,000
Estimated Facilities Impact Costs Contingency	$ 20,000,000
LGIA SCE/CAISO Application and Studies	$500,000

The Total Estimated Cost for this Interconnection Option 1 is : $ 65,853,000

Revised 11-24

Glendale – Southern Cal Edison Systems Interconnection

Option 1: Glendale 69kV Eagle Rock Intertie Substation

Cost Estimate Breakdown:

Materials:

Four 69kV, 2000A, 50kA SF6 Circuit Breakers @ $75,000.00 EA	$300,000
One 69kV to 220kV, 200MVA, OA, FA Transformer.....	1,950,000
Three 69kV Lighting Arrestors @ 5,000.00 EA	15,000
Three 66kV Lighting Arrestors @ 5,000.00 EA	15,000
Six 69kV Arrestor Supports @$1000.00 EA	6 ,000.
Eight 69kV, 2000A, Vertical Break, Disc. Switches @ $25,000.00 EA	$200,000
One 32 FT. High, 48 FT. Wide 69kV Lines termination Rack	$50,000
Two 34FT. High, 40 FT. Wide Bus Racks @30,000.00 EA	$60,000
Approx. 30 69kV post insulators @$500.00 EA	$ 15,000
Approx. 30 post insulator supports @$500.00 EA	$ 15,000
Aluminum conductor, string insulators, fittings & miscl....................................	20,000
Conduit and grounding and fittings	$50,000
Steel Frame Transition Structure per SCE..	$375,000
Relays and communications equipment	$80,000
Other Miscellaneous	$ 150,000
Materials Total:	**$ 3,301,000**
Site Grading and Fencing	**$60,000**
Control House	**$80,000**
Substation Land 1.5 acres...	**$400,000**
Installation and construction	**$1,975,000**

Revised 11-24

Engineering and Drafting	**$ 410,000.**
Testing and Commissioning	**$50,000**
Administration, permits, project & construction management	**$ 292,000**
Sub Total Cost	**$ 4,193,000**
Contingency (30% of Sub Total cost)	**1,260,000**
<u>Estimated Total Cost for this 69kV to 220 kV Substation</u>	**<u>$5, 853,000</u>**
Kellogg Sub., Three 50 KA CB's, Terminations, Controls and Relay Settings ..	**$300,000**
Total Costs of GWP Substations	**$6,153,000**
SCE Facilities Cost:	
Two 220 kV GIS Circuit Breakers, 50 KA, including installation	**$1,950,00**
Bus Modifications	**$800,000**
Communications, RIG and Relay Protection	**$600,000**
Four Disconnect Switches, including installation	**$750,000**
Overhead Structures	**$400,000**
Engineering and Interconnection Studies	**$2,500,000**
Contingency 30%	**$2,000,000**
Total SCE Substation	**$9,000,000**
Total Substations Costs	**$15,153,000**
Transmission	**$23,200,000**
Transmission Contingency 30%	**$7,000,000**
LGIA Interconnection SCE/CAISO Studies and Agreement	**$500,000**
Contingency for Impact Costs for GWP, SCE, LADWP and BWP	**$20,000,000**
Total Cost	**$65,853,000**

Glendale – Southern Cal Edison Systems Interconnection

Option 3: Glendale La Crescenta 220/69kV Intertie Substation

Cost Estimate Breakdown :

Materials:

Six 230kV, 2000A, 63kA SF6 Circuit Breakers @ $100,000.00 EA $600,000

One 220kV to 69kV, 150MVA, OA, FA Transformer $1,100,000

Six 220kV Lighting Arrestors @ 15,000.00 EA $90,000

Six 69kV Lighting Arrestors @ 5,000.00 EA $30,000

Six 220kV,and three 69kV Arrestor Supports @$1500.00 EA .... $ 18,000

Twelve 230kV, 2000A, Vertical Break, Disc. Switches @ $40,000.00 EA $480,000

Four 52 FT. High, 40 FT. Wide Line termination Racks @50,000.00 EA .... $ 200,000

Four 34FT. High, 40 FT. Wide Bus Termination Racks @40,000.00 EA .... $ 160,000

Approx. 100 230kV post insulators @$2,000.00 EA $200,000

Approx. 100 post insulator supports @$1,000.00 EA $100,000

Aluminum conductor, string insulators, fittings & miscl..................................... . $200,000

Conduit and grounding and fittings .... $ 250,000

Relays and communications equipment $200,000

Other Miscellaneous $150,000

Materials Total: $3,778,000

Site Grading and Fencing $650,000

Control House $150,000

Installation and construction)..$1,600,000

Engineering and Drafting (25% of materials) $725,000

Testing and Commissioning $125,000

Administration, project & construction management	**$780,000**
Sub Total Cost	**$7,800,000**
Contingency (30 %)	**$2,350,000**
Estimated Total Cost for this 220 to 69kV Substation	**$10,150,000**

Adjacent to the 220/69kV Substation, a 69kV Switching Station needs to be built to terminate, switch and connect the two 69kV lines, coming from the Western, to the 220/69kV transformer. The estimate for this installation is as follows:

Materials:

Two 69kV, 2000A, 50kA interrupting duty @ $75,000 EA .	**$150,000**
Four 69kV, 2000A, vertical break disc. switches @ $25,000 EA	**$100,000**
One 32Ft. high, 48Ft.wide double circuit steel rack	**$50,000**
Two 32Ft. high, 20Ft. wide steel racks @$30,000 EA	**$60,000**
Bus conductor, post and string insulators, miscel. fittings	**$40,000**
Conduit and grounding, other miscellaneous	**$ 50,000**
Relays and communications equipment	**$60,000**
Other miscellaneous	**$40,000**
Materials Total :	**$550,000**
Grading and fencing	**$30,000**
Small Control House	**$50,000**
Terminations, Relay Protection and CB controls	**$100,000**
Installation and Construction	**$192,500**
Engineering and Drafting	**$137,500**
Testing and Commissioning	**$35,000**
Administration, Project and Construction Management	**$ 99,000**

Sub Total Cost .... $1,194,000.

Contingency 30% of Sub Total Cost ....$360,000.

Total Estimated Cost for this 69kV Switching Station $1,554,000

Western Sub, three 50 KA CB's , Bus modifications, Relay Prot. and Controls $700,000

Total Costs for Substations $14,858,000

Transmission line Costs $4,350,000

ROW and Substation Land $600,000
Transmission Line Contingency 30 % $1,300,000
LGIA Interconnection Application SCE/CAISO Studies $500,000

Contingency for Impact Mitigation Costs (GWP,SCE, CAISO, LADWP and BWP) $20,000,000

Total Project Cost.. $41,608,000

APPENDIX E

ENVIRONMENTAL REPORT

Stantec

Memo

To:	Carl Haase Stantec Pasadena	From:	Michael Weber Stantec Thousand Oaks
File:	185803354	Date:	December 2, 2014

Reference: Grayson Repowering Project, Interconnect Alternatives, Environmental Constraints Overview

Carl:

I met with Mr. Gary Rose on November 10, 2014 and we conducted a windshield survey of portions of three alternative interconnect alignments being considered for the City of Glendale Grasyon Repowering Project.

The three interconnect alternative alignments and potentially significant environmental constraints identified through a cursory desktop study are as follows:

Interconnect Alternative 1

Alignment Description: Underground from the Kellog GIS Substation in Glenoaks Boulevard transitioning to overhead from near Scholl Canyon Park to the SCE Eagle Rock Substation (Scholl Canyon Landfill).

Critical Environmental Constraints: No critical environmental issues were identified for the underground segment (avoids City of Glendale "Signature Streets", known historic resources, and significant ecological areas). The area near Scholl Canyon Landfill is located in the San Rafael Hills which contains oak woodland, southern oak riparian, and chaparral native vegetation communities. This area is also located in a high or moderate fire hazard zone.

Interconnect Alternative 2

Alignment Description: Completely underground from the Kellog GIS Substation in Glenoaks Boulevard, Ethel Street, Las Flores Drive, and Hermosita Drive to a connection with the SCE Glendale Substation. A new substation would be constructed either on the east or west side of Canada Boulevard.

Critical Environmental Constraints: No critical environmental issues were identified for the underground segment (avoids City of Glendale "Signature Streets", known historic resources, and significant ecological areas). The considered substation site on the west side of Canada Boulevard is limited in size and has a large oak tree in a location that would be difficult to avoid. The considered site on the east side of Canada Boulevard is larger and although does contain some oak trees, the trees are located on the periphery of the site and may be avoided. In comparison, a substation on the east side of Canada Boulevard appears to have less environmental constraints compared to the west side.

Interconnect Alternative 3

Reference: Grayson Repowering Project, Interconnect Alternatives, Environmental Constraints Overview

Alignment Description: Alternative 2 with an overhead extension to existing SCE overhead lines and a proposed new substation located in the northern Verdugo Mountains.

Critical Environmental Constraints: No critical environmental issues were identified for the underground segment (avoids City of Glendale "Signature Streets", known historic resources, and significant ecological areas). The proposed connection with existing SCE overhead lines and new substation is proposed for an area located in the northern Verdugo Mountains. This area of the Verdugo Mountains is a designated Significant Ecological Area. The Verdugo Mountains have the most important habitat areas in the City of Glendale and also support sensitive plant and animal species. Based on maps contained in the City of Glendale General Plan Open Space and Conservation Element, this interconnect alternative could impact oak woodland, southern oak riparian, and chaparral native vegetation communities. The Verdugo Mountains are also located in an extreme, high, and or moderate fore hazard zone.

Summary

In comparison, Alternative Alignment 2 has the least amount of environmental constraints, Alternative Alignment 3 has the most, and Alternative Alignment 1 has an intermediate amount.

Stantec Consulting Services Inc.

Michael P. Weber
Principal Scientist
Phone: (805)
Fax: (805) 719-9239
michael.weber@stantec.com

c. Gary Rose

AIR PERMITTING FEASIBILITY STUDY FOR GRAYSON POWER PLANT

PROJECT LOCATION:

Grayson Power Plant
800 Air Way
Glendale, California 91201

Scholl Canyon Landfill
3001 Scholl Canyon Road
Glendale, California 91206

FOR SUBMITTAL TO:

City of Glendale Water and Power (GWP) Department
141 North Glendale Avenue
Glendale, CA 91206

PREPARED BY:

SCEC
MONTROSE ENVIRONMENTAL
an affiliate of Montrose Environmental Group, Inc.

1631 East Saint Andrew Place
Santa Ana, California 92705

May 2015

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SECTION **PAGE**

LIST OF TABLES

LIST OF APPENDICES

LIST OF ACRONYMS

AER - Annual Emissions Report

AIP - Achieved in Practice

BACT - Best Available Control Technology

CEC - California Energy Commission

CEQA - California Environmental Quality Act

CO - Carbon Monoxide

CO_2 - Carbon Dioxide

EA - Environmental Assessment

EFG - Electrical Generating Facilities

EIR - Environmental Impact Report

EIS - Environmental Impact Statement

ERC - Emission Reduction Credits

GHG - Greenhouse Gas

GWP - Glendale Water and Power

HI - Hazard Indices

LFG – Landfill Gas

MICR - Maximum Individual Cancer Risk

ND - Negative Declaration

NESHAP - National Emission Standards

NO_X - Nitrogen Oxides

NSPS - New Source Performance Standards

NSR - New Source Review

OEHHA - Office of Environmental Health Hazard Assessment

PM_{10} - Particulate Matter Less than 10 Microns in Diameter

RECLAIM - Regional Clean Air Incentives Market

RICE - Reciprocating Internal Combustion Engine

SAC - Single Annular Combustor

SCAQMD - South Coast Air Quality Management District

SCFM - Standard Cubic Feet per Minute

SCR - Selective Catalytic Reduction

SIP - State Implementation Plan

SO_X - Sulfur Oxides

UHC - Unburned Hydrocarbons

VOC - Volatile Organic Compounds

SECTION 1.0

EXECUTIVE SUMMARY

South Coast Environmental Company (SCEC), an affiliate of Montrose Environmental Group, Inc., conducted an air permitting feasibility study to accompany the City of Glendale Water and Power Department's (GWP) 2015 Integrated Resource Plan (IRP). The air permitting study focusses on options for repowering equipment located at the Grayson Power Plant (Grayson). The proposed repower project consists of replacing the existing boilers (Boilers 3, 4, and 5) and combined cycle gas turbines (Turbines 8A and 8BC) with new power generating equipment. This report discusses an overview of the proposed equipment, a summary of the applicable regulations, potential emission inventory, and emission offset and permitting costs.

GWP and Stantec initially developed nine repower cases based upon GWP's current and expected loads, operating reserve requirements, and expected plant utilization. Screening analyses by Pace, reviewed by GWP and Stantec, led to four of the nine cases being identified as the most viable options, should the repower project be undertaken, to be included in the air permitting study. These four cases include equipment combinations of three simple cycle LM6000PG SPRINT turbines (Case 150-B), four simple cycle LM6000PG SPRINT turbines (Case 200-B), three simple cycle and one combined cycle LM6000PG SPRINT turbines (Case 200-C), or two simple cycle and two combined cycle LM6000PG SPRINT turbines (Case 250-D).

Local, state, and federal regulations were reviewed to determine their impact on equipment selection, the ability to permit the project, and air permit acquisition costs for each of the four cases. Emissions from the repowered equipment were also estimated pursuant to applicable regulations. Based upon the project size, possible equipment selection and applicable regulations, all four possible equipment configurations for Grayson would qualify for permits from the South Coast Air Quality Management District (SCAQMD). The net increase in plant capacity for all four configurations is less than 50 MW, so California Energy Commission (CEC) licensing can be avoided and the City of Glendale would serve as the lead agency for California Environmental Quality Act (CEQA) proceedings.

Air permit acquisition costs for the Grayson project are driven primarily by emission profiles and offset prices. Approximately 1% of air permit acquisition costs are in the form of application fees and professional service fees. Table 1-1 provides a summary of estimated permit acquisition costs. The range of costs for each equipment configuration case reflects variables such as market costs, eligibility of emission decreases from existing equipment, eligibility for exemption provisions of SCAQMD rules, and open market offset credit prices. The high range of permit acquisition costs is used in PACE's analyses for the IRP.

TABLE 1-1
AIR PERMIT ACQUISITION COSTS
GRAYSON POWER PLANT

Case	Estimated Air Permit Acquisition Costs (Millions $)
150B	12 – 23
200B	23 – 34
200C	18 – 31
250D	17 – 31

The existing boilers currently combust renewable landfill gas from the Scholl Canyon Landfill, as well as natural gas as required for blending. Rather than installing new equipment dedicated to burn landfill gas at the Grayson Power Plant, or clean up the landfill gas sufficiently to meet combustion turbine requirements, GWP proposes to install power generating equipment at the landfill facility. Relocating combustion equipment to the landfill will allow GWP to take advantage of emission offset exemptions and will greatly reduce permit acquisition costs for landfill gas combustion equipment.

Gas turbines and reciprocating internal combustion engines were considered for the landfill project. Two gas turbine models were initially considered – the Solar Mercury and the Solar Taurus. Because the Mercury turbine is a low-emissions unit, SCAQMD has allowed it to be installed without requiring add-on emission control devices such as selective catalytic reduction (SCR) or oxidization catalysts to reduce NO_X and CO. Four Mercury units would be required to accommodate the fuel produced at the landfill. Because of its ability to forego emission control devices, the Mercury option would result in a higher emissions profile than that of the Taurus option. Therefore, The Mercury is the only turbine model for which a detailed emissions profile was compiled. Analysis of the Mercury units effectively subsumes analysis of the Taurus option.

Although emissions for the Taurus model are not identified in this report, the permitting costs of the Taurus option are discussed. Those costs are also included in Pace's analysis of the Taurus option. The Taurus model would need to be equipped with SCR and oxidization catalysts to control NO_X and CO emissions and three Taurus units would be required to accommodate the fuel produced at the landfill. The Taurus would present no significant permitting implications beyond those of the Mercury model.

The Caterpillar CG260-16 internal combustion engine was also considered for the analysis. It would have to be equipped with SCR and an oxidization catalyst to meet SCAQMD requirements. Six units would be needed to accommodate the fuel produced at the landfill.

Gas turbines and reciprocating internal combustion engines would qualify for SCAQMD permits at Scholl Canyon. Because of the emission offset exemptions that SCAQMD offers for landfill operations, the permit acquisition costs for the Scholl Canyon project are much lower than the costs for Grayson. Air permit acquisition costs for Scholl Canyon are estimated to be $60,000 for the Solar Mercury, $80,000 for the Solar Taurus, and $120,000 for the Caterpillar CG260-16.

These acquisition costs include only the permit application fees and professional consulting service fees, not the emission offsets. SCEC has determined that there would be no costs for acquiring because landfill combustion at the Scholl site can make use of the essential public service exemption.

SECTION 2.0

INTRODUCTION

2.1 Feasibility Study Goal

The objective of this feasibility study is to address the air permitting considerations associated with alternative repowering strategies for replacing the existing boilers and gas turbines at the Grayson Power Plant (Grayson). The project is located within the jurisdictional boundaries of the South Coast Air Quality Management District (SCAQMD) and is subject to SCAQMD permitting requirements and regulations affecting the operation of emission sources at the facility. The project is also subject to various State of California and US EPA regulations.

2.2 Elements of the Analysis

The air quality permitting analysis for Grayson includes an overview of the technology proposed to replace boilers and gas turbines at Grayson; a summary of the applicable regulations potentially affecting the design, construction, and operation of the equipment, including a review of possible Best Available Control Technology (BACT) requirements; a preliminary inventory of potential emissions of criteria pollutants for each repowering strategy; and emission offset and permitting costs associated with the project.

The existing boilers at Grayson currently burn landfill gas (LFG) from the nearby Scholl Canyon Landfill, as well as natural gas. The replacement landfill gas combustion devices, likely reciprocating internal combustion engines or small gas turbines, are proposed to be located at Scholl Canyon, rather than the Grayson Plant. This report also includes a discussion of the proposed replacement equipment, applicable regulations, permitting strategy and associated permitting costs for the Scholl Canyon project.

SECTION 3.0

PROJECT BACKGROUND

3.1 Grayson Power Plant

The Grayson Power Plant located at 800 Air Way in Glendale, California. The facility is a municipal facility that generates electricity for customers residing in the City of Glendale and operates under SCAQMD Facility #800327. The facility is generally surrounded by commercial land use. Area and site maps are included in Appendix A.

The facility includes three boilers that support steam turbine generators, along with a 2x1 combined cycle gas turbine generator system and one simple cycle gas turbine generator. The boilers are known as Boiler 3 (20 MW), Boiler 4 (44 MW), and Boiler 5 (44 MW). The combined cycle turbine system (Unit 8) includes combustion turbines 8A (30 MW) and 8BC (60MW). The simple cycle gas turbine generator is Turbine 9 (50 MW). The boilers are permitted to burn natural gas, landfill gas, or fuel oil in case of emergency. The gas turbines operate on natural gas and fuel oil in case of emergency. Each of the gas turbine generators is equipped with an oxidization catalyst and selective catalytic reduction (SCR) system to control carbon monoxide (CO) and nitrogen oxides (NO_X) emissions.

GWP proposes to replace Boilers 3, 4, and 5 and Turbines 8A and 8BC with a combination of natural gas-fired turbines in simple or combined cycle configuration. Landfill gas combustion operations will be relocated from Grayson to the Scholl Canyon facility to minimize fuel transportation issues and to allow GWP to take advantage of cost saving permitting strategies allowed by SCAQMD for landfill operations. Gas Turbine No. 9 will not be replaced since it is a relatively new unit.

3.1.1 Proposed Equipment

Feasibility analyses conducted to date as part of GWP's resource management planning process indicate that gas turbine technology in simple cycle peaking operations and/or 1x1 combined cycle base load operations will likely be the most feasible repower opportunities for Grayson. The General Electric (GE), model LM6000PG SPRINT has been selected as the representative turbine for analysis. This turbine, equipped with single annular combustor (SAC), has the ability to produce power in the range of 54 – 56 MW with a Spray Inter-Cooled (SPRINT) system, which enhances power output and improves thermal efficiency.

TABLE 3-1
PROPOSED EQUIPMENT SPECIFICATIONS
GRAYSON POWER PLANT

Description	Specification
LM6000PG SPRINT®	
Power Output (kWe) – Simple Cycle	53,886
Power Output (kWe) – Combined Cycle	70,106
Thermal Efficiency (%)	40.8
Heat Rate HHV (Btu/kWe-Hr) – Simple Cycle	9,824
Heat Rate HHV (Btu/kWe-Hr) – Combined Cycle	7,541
Exhaust Flow (lbs/sec)	318
Exhaust Temperature (°F – prior to heat exchange)	897

3.1.2 Equipment Cases and Utilization

Nine equipment combinations (cases) were initially reviewed by Pace. Table 3-2 shows the initial nine proposed equipment combinations. Based upon its initial analysis, Pace and GWP, with Stantec, then identified four most likely potential equipment configurations for optimal power generation, cost effectiveness, and minimal environmental impact. The four cases are listed in Table 3-3 and include one 150 MW, two 200 MW and one 250 MW equipment configurations.

TABLE 3-2
INITIAL REPOWER PROJECT STUDY CASES
GRAYSON POWER PLANT

Case	Net Output (kW)	Equipment Type	Quantity	Proposed Average Annual Plant Capacity Utilization
150-A	162,771	RICE – WARTSILA 18V50SG	3	84 – 85%
		SCCT – LM6000PG SPRINT	2	26 – 28%
150-B	161,658	SCCT – LM6000PG SPRINT	3	29 – 31%
200-A	216,657	RICE – WARTSILA 18V50SG	3	84 – 85%
		SCCT – LM6000PG SPRINT	3	23 – 25%
200-B	215,544	SCCT – LM6000PG SPRINT	4	28 – 29%
200-C	231,764	SCCT – LM6000PG SPRINT	3	20 – 23%
		CCCT – LM6000PG SPRINT	1	63 – 75%
250-A	270,543	RICE – WARTSILA 18V50SG	3	85%
		SCCT – LM6000PG SPRINT	4	20 – 22%
250-B	269,430	SCCT – LM6000PG SPRINT	5	24 – 25%
250-C	285,650	SCCT – LM6000PG SPRINT	4	17 – 20%
		CCCT – LM6000PG SPRINT	1	64 – 81%
250-D	247,984	SCCT – LM6000PG SPRINT	2	9 – 13%
		CCCT – LM6000PG SPRINT	2	62 – 76%

TABLE 3-3
FINAL REPOWER PROJECT STUDY CASES
GRAYSON POWER PLANT

Parameters	Case 150-B	200-B	200-C	250-D
Net Output (kW)	161,658	215,544	231,764	247,984
Quantity of Proposed Turbines				
SCCT – LM6000PG SPRINT	3	4	3	2
CCCT – LM6000PG SPRINT	0	0	1	2
Avg. Annual Utilization:				
SCCT – LM6000PG SPRINT	29 – 31%	28 – 29%	20 – 23%	9 – 13%
CCCT – LM6000PG SPRINT	N/A	N/A	63 – 75%	62 – 76%
Max. Number of Starts per Month:				
SCCT – LM6000PG SPRINT	60	60	60	60
CCCT – LM6000PG SPRINT	N/A	N/A	5	5
Max. Number of Starts per Year:				
SCCT – LM6000PG SPRINT	360	360	360	360
CCCT – LM6000PG SPRINT	N/A	N/A	40	40
Est. Max. Monthly Operating Hour:				
SCCT – LM6000PG SPRINT	360	347	277	176
CCCT – LM6000PG SPRINT	N/A	N/A	612	630
Est. Max. Annual Operating Hour:				
SCCT – LM6000PG SPRINT	2,682	2,507	1,987	1,116
CCCT – LM6000PG SPRINT	N/A	N/A	6,602	6,618

3.2 Landfill Gas Combustion Facility

The existing boilers (Boilers 3, 4, and 5) at the Grayson Power Plant currently combust LFG from the Scholl Canyon Landfill, located approximately five miles away, at 3001 Scholl Canyon Road in Glendale, California. Scholl Canyon Landfill equipment includes landfill gas treatment system, condensate collection system, and flare.

GWP plans to install landfill gas combustion power generation equipment at the Scholl Landfill site in lieu of developing new landfill gas combustion systems at Grayson. By eliminating landfill gas combustion at Grayson and placing the system at the Scholl Canyon Landfill, GWP can take full advantage of SCAQMD regulations that allow landfill operators to draw emission offset credits from the SCAQMD Priority Reserve offset account for essential public services. Access to the Priority Reserve will allow GWP to avoid significant emission offset costs. Relocating LFG operations will also allow GWP to avoid costs associated with managing the five-mile gas transmission system.

Section 7.0 of this report provides additional details regarding the equipment, emissions and emission offset strategy for the development of the Scholl Canyon Landfill combustion units.

SECTION 4.0

APPLICABLE REGULATIONS

The following local, state, and federal regulations will affect the design and operation of proposed equipment. Other regulations may be applicable to the project; however, those regulations are not included in this report because they do not significantly influence the proposed equipment selection.

4.1 SCAQMD Regulations

Rule 1110.2 – Emissions from Gaseous and Liquid-Fueled Engines

Rule 1110.2(d)(1)(K) requires new natural gas non-emergency engines driving electrical generators to meet 0.070 lbs/MW-hr for nitrogen oxides (NO_X), 0.20 lbs/MW-hr for carbon monoxide (CO), and 0.10 lbs/MW-hr volatile organic compounds (VOC). The averaging time used to determine compliance with the compliance standard is 15 minutes.

Several RICE options for Grayson have been considered in the initial study; however, GWP has decided not to use RICE technology at Grayson because engine manufacturers have determined that compliance with Rule 1110.2 emission limits, when demonstrated over a 15-minute averaging period, would result in limiting the engine operations to high and fixed loads. GWP has determined that flexible operations are an important criterion in order to address uncertain future conditions.

Rule 1110.2 also includes emission standards for engines that combust landfill gas. Those standards include 11 ppmv NO_X, 30 ppmv VOC, and 250 ppmv CO (all at 15% O_2). Emission control systems such as selective catalytic reduction (SCR) and CO oxidization are needed in order for landfill gas engines to meet these emission standards.

Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems

Rule 1135 applies to electric power generating systems, which are defined as boilers and their replacement units. The rule restricts NO_X emissions from all affected units (combined) at Grayson to 35 tons per year. Boilers 3, 4, and 5 (108 MW) are affected by the Rule 1135 annual NO_X limit. The annual emission limit will also carry over to an equivalent 108 MW of the turbines that that would replace Boilers 3, 4, and 5. Rule 1135 will not apply to new turbines that would replace turbines 8A and 8BC, nor does it apply to Turbine 9. Because the turbines that would replace Boilers 3, 4 and 5 have lower NO_X emission rates than the existing boilers, continued compliance with Rule 1135 can be expected.

Regulation XIII – New Source Review

The SCAQMD regulatory framework includes two options for implementing new source review. Certain facilities included in the Regional Clean Air Market (RECLAIM) cap and trade program for NO_X and SO_X are subject to the new source review requirements of Regulation XX. Facilities that are not part of RECLAIM are subject to the NO_X and SO_X new source review requirements of Regulation XIII. New source review for VOC, CO and PM is administered through Regulation XIII for all facilities. GWP opted out of RECLAIM and is therefore subject to the new source review requirements of Regulation XIII for all criteria pollutants.

Rule 1303 – NSR Requirements: Best Available Control Technology (BACT)

Rule 1303(a) requires any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia to meet the BACT requirement. As it relates to the Grayson project, any new emission source would present an emissions increase and would be subject to BACT, even if it replaces an existing emissions source.

BACT also affects the way in which emission reductions due to replacing existing sources are calculated for NSR demonstrations. Generally, emission reductions from the removal of an existing source can be netted against emission increases for some NSR demonstrations, such as emission offset requirements. Those emission reductions, however, must be discounted to levels that can be achieved when BACT is applied to determine eligible emission reductions from the project.

BACT is the most stringent emission limitation or control technology which has been achieved in practice (AIP), is contained in any state implementation plan (SIP) approved by the USEPA, or is another technology that has been found to be technologically feasible and cost effective by the Air District. Table 4-1 provides a summary of recent BACT determinations for both existing and proposed equipment at the Grayson facility.

TABLE 4-1
BACT DETERMINATIONS

Equipment Type	Pollutant	BACT Emission Rate
Simple Cycle Combustion Turbine (SCCT) [Fuel: Natural Gas]	NO_X	2.5 ppmvd @ 15%O_2
	VOC	2.0 ppmvd @ 15%O_2
	CO	4.0 ppmvd @ 15%O_2
Combined Cycle Combustion Turbine (CCCT) [Fuel: Natural Gas]	NO_X	2.0 ppmvd @ 15%O_2
	VOC	2.0 ppmvd @ 15%O_2
	CO	2.0 ppmvd @ 15%O_2
Boiler [Fuel: Natural Gas]	NO_X	5.0 ppmvd @ 3%O_2
	CO	5.0 ppmvd @ 3%O_2
Boiler[1] [Fuel: Landfill Gas]	NO_X	9.0 ppmvd @ 3%O_2

[1]SCAQMD currently uses 20 ppmv as BACT emission limit for NO_X; however, the San Joaquin Valley APCD (SJVAPCD) is in the process of issuing a permit for a landfill gas boiler that will include a 9 ppmv emission limit for NO_X as guaranteed by the manufacturer. Therefore, 9 ppmv was used to reflect BACT for this analysis.

Rule 1303 – NSR Requirements: Air Quality Modeling

Rule 1303(b)(1) requires an analysis to demonstrate compliance with ambient air quality standards. Based upon analyses conducted for similar projects, emissions from the proposed equipment are not expected to cause a violation or significantly add to an existing violation of ambient air quality standards.

Rule 1303 – NSR Requirements: Emission Offsets

Rule 1303(b)(2) requires that an emission increase of nonattainment air contaminants is to be offset by either Emission Reduction Credits (ERC) approved pursuant to Rule 1309, allocations from the Priority Reserve pursuant to Rule 1309.1, or allocations from the Offset Budget pursuant to Rule 1309.2. In most cases, SCAQMD regulations require an emission offset ratio of 1.2:1 to be applied to Emission Reduction Credits (ERCs) purchased in the open market. An offset ratio of 1:1 is applied to allocations from the Priority Reserve or SCAQMD offset budgets. The additional offset ratio applied to open market purchases allows SCAQMD to demonstrate new emission reductions throughout the region.

Exceptions to typical offset ratios may apply to offsets provided through Rule 1304.1, which is summarized later in this report. The emission offset calculation is based on the new emission source's potential to emit, less eligible emission reductions from existing equipment would be removed from service. For the purpose of determining emission offset requirements, emissions are calculated on a 30-day average (total monthly emissions, divided by 30 days per month).

Rule 1304 – New Source Review Exemptions

Rule 1304 provides scenarios in which a project can be granted exemption from modeling and offset requirements pursuant to Rule 1303. The following scenarios may be applicable for this project:

- *Rule 1304(a)(1) – Replacements*

  Based on Rule 1304(a)(1), the proposed gas turbine LM6000PG-SPRINT in either a simple or combined cycle mode is eligible for an exemption from modeling and emission offset requirements if it used to replace existing gas turbines 8A and 8BC because of the following reasons:

  - The proposed equipment is functionally identical to the existing turbines;
  - The maximum rating of the proposed turbine (MMBtu/hr) is not higher than the maximum rating of the existing turbines;
  - The potential to emit air contaminants from the new turbines is not greater than emissions from the replaced turbines, if they were operated at the same conditions and if current BACT were applied.

- *Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement*

  Pursuant to Rule 1304(a)(2), modeling and offset exemptions are granted for replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbines(s), solar, geothermal, wind energy or other equipment to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The exemption applies only to the extent that the new equipment has a maximum electrical power rating (in megawatts) that does not allow any increase in electricity generating capacity on a per-utility basis. Emissions attributed to the difference between existing and new generating capacity must be offset with ERCs.

  In the case where the proposed gas turbine LM6000PG-SPRINT operates in combined cycle mode, it is eligible for the modeling and offset exemption described in this provision. In using this exemption, an electrical generating facility like GWP is required to pay fees to SCAQMD, which are estimated using Rule 1304.1 calculation methodology.

Rule 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption

SCAQMD adopted Rule 1304.1 to require that facility owners who utilize the provisions of Rule 1304(a)(2) pay a mitigation fee to SCAQMD. The fees are calculated based upon the new unit's potential to emit in pounds per day, multiplied by the ratio of (a) maximum permitted annual megawatt hour generation of the new unit(s) to (b) the average annual megawatt hour generation of the existing unit(s) during the last 24 month period immediately prior to issuance of the permit to construct. This rule provides the applicant options to pay the offset fees in a single payment lump sum or an annual payment.

Rule 1306 - Emission Calculations

Rule 1306 specifies methods for calculating daily emission increases and decreases used to determine BACT and air impact modeling applicability as well as emission offset requirements.

The proposed repower cases involve installing new equipment and removing existing boilers and gas turbines; therefore, offset requirements other than those calculated pursuant to Rule 1304.1 are calculated based on the net difference between emission increases from the new equipment and eligible emission decreases from the replaced equipment pursuant to Rule 1306. Emissions increases from the proposed new equipment are calculated using proposed maximum calendar monthly emissions divided by 30 days/month to determine offset requirements. BACT and air impact modeling applicability is based upon the existence of a simple daily increase in potential emissions.

Pursuant to Rule 1306(c), eligible emission decreases from the removal of existing equipment are calculated using the actual historical emissions, adjusted for current BACT. The eligible emission reductions from the replaced boilers and gas turbines were calculated as follows:

1. The sum of actual emissions as reported to SCAQMD in a representative 2-year period, during the most recent five years. Emissions as reported in the 2012 and 2013 Annual Emission Reports were selected for this study.
2. The actual emissions were reduced by applying the current BACT standards to the equipment being removed from service. The adjusted annual emissions were divided by the estimated operating days in each of those two years to obtain daily emissions.
3. The BACT adjusted daily emissions were multiplied by the following usage factors according to the usage of replaced equipment in each of those two years:
    a. 1.0 when operated 180 days or more,
    b. 0.5 when operated 30 to 179 days, and
    c. 0.0 when operated less than 30 days.

Rule 1309.1 – Priority Reserve

In limited cases, emission increases can be offset with allocations from the SCAQMD Priority Reserve account. Credits from the Priority Reserve can only be used for specific priority emission sources, such as research operations and essential public services (e.g., landfills, wastewater treatment facilities, hospitals, and schools).

Since construction and operation of an LFG control or processing facility is considered to be an essential public service, credits from the Priority Reserve can be granted for this project. SCAQMD policy dictates, however, that access to the Priority Reserve is granted for LFG combustion, only if the emission source is located at the landfill itself. The existing Grayson boilers currently combust LFG supplied by the landfill located at School Canyon Road. In order to be eligible for Priority Reserve credits, GWP plans to install new LFG combustion equipment at Scholl Canyon, rather than Grayson.

Rule 1401 – New Source Review of Toxic Air Contaminants (TACs)

Rule 1401 establishes allowable risk thresholds for permit units that emit TACs. Depending on the pollutant, the rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and/or non-cancer acute and chronic Hazard Indices (HI).

The proposed equipment at Grayson combusts natural gas; therefore, emissions of toxic air contaminants listed in Table I of Rule 1401 are expected. A health risk assessment is required to calculate the levels of MICR, cancer burden, acute and chronic HI at residential and worker receptor locations surrounding the facility.

Rule 1401 amendments are expected in the near future to incorporate revised California Office of Environmental Health Hazard Assessment (OEHHA) risk calculation guidelines. The revised guidelines will result in higher estimated cancer risks for residential and worker receptors in most cases. Based upon assessments conducted for similar gas turbine projects, the Grayson project is expected to comply with Rule 1401, even when the revised calculation methods are implemented, due to the relative low level of hazardous pollutants associated with natural gas turbine combustion and the way in which gas turbine exhaust is dispersed.

Regulation XVII – Prevention of Significant Deterioration (PSD)

Regulation XVII sets forth requirements when a significant increase of attainment air contaminants occurs at an existing major stationary source of criteria pollutants. PSD applies when the region is in attainment with federal ambient air quality standards for a pollutant. In the South Coast Basin, attainment has been reached for CO and NO_2. Attainment with federal PM10 standards is also to be expected within the next one to two years, based upon air quality and emission trends that are monitored by SCAQMD.

For the purpose of PSD, a major source is generally defined as a facility that emits more than 250 tons per year of an attainment pollutant. Certain listed emission sources, including fossil-fueled steam electric plants with a rating of more than 250 MMBtu/hr, are considered to be major sources if they emit more than 100 tons per year of an applicable pollutant.

The potential net emission increases of CO and NO_2 for the proposed equipment at Grayson Power Plant are shown in Section 5 of this report and are expected to be below the threshold limit of 100 tons per year. Although the potential CO emissions from the existing and proposed new sources at the Scholl Canyon Landfill shown in Section 7 exceed 250 tons per year, it appears that higher oxidization catalyst efficiencies for CO is achievable, and PSD permitting for the landfill may also be avoided.

PSD permitting requires an additional level of public and related agency notice, review and comment above what would be required under typical NSR permitting. It also can result in expanded air quality impact analyses beyond what is required under NSR. While PSD permitting can lead to extended permit processing timeframes and additional costs, it would not likely affect the successful issuance of a permit for the subject facility.

4.2 California Environmental Quality Act (CEQA)

The purpose of California Environmental Quality Act (CEQA) is to inform governmental decision makers and the public about potential significant environmental impacts of a project; to identify ways to reduce the environmental impacts, including potential alternatives to the project; and to disclose to the public the reasons why a project has been approved. CEQA can require various degrees of environmental analysis, reporting and determinations that must be conducted in a transparent fashion and in accordance with prescribed methodologies and schedules.

CEQA is administered by a lead agency, which is typically a local government agency with jurisdiction over general land uses where the project is located. An exception is generally made for large power plant projects. The California Energy Commission (CEC) assumes lead agency authority if a power plant project results in an increase in plant capacity of 50 megawatts or larger. The increase in capacity resulting from the proposed Grayson project will not exceed 50 megawatts when new generating capacity is netted against existing generating capacity of the units that will be removed from the plant; therefore, CEC will not have CEQA authority. The City of Glendale will instead assume the lead agency role for the Grayson project.

4.3 Federal Regulations

40 CFR 60, Subpart KKKK
New Source Performance Standards (NSPS) for Stationary Combustion Turbines

The existing NSPS subpart KKKK sets emission standards and compliance schedules for NO_X and SO_X from the stationary gas turbines. Because the Grayson and Scholl Landfill projects will be permitted to meet BACT standards, they are expected to comply with the NSPS for NO_X and SO_X.

USEPA is in the process of amending NSPS Subpart KKKK to incorporate emission standards and compliance schedules for the greenhouse (GHG) emissions from stationary gas turbines. USEPA published the proposed amendment section of this rule, dated January 8, 2014, to establish emission standards and compliance schedules for greenhouse gas (GHG) emissions from stationary combustion gas turbines. This amendment is also known as Clean Air Act Section 111(b). The proposed rule requires new base load gas turbines to meet a carbon dioxide (CO_2) emission limit of 1,000 pounds per megawatt-hour of gross output on a 12-operating month rolling average for units with heat input greater than 850 MMBtu/hr, and 1,100 pounds per megawatt-hour of gross output on a 12-operating month rolling average per unit with heat input equal to or less than 850 MMBtu/hr.

A stationary combustion gas turbine is subject to the Subpart KKKK GHG standards if it meets all of the following conditions:

- Has a design heat input greater than 250 MMBtu/hr;
- Combusts fossil fuels for more than 10% of average annual heat input for 3 consecutive calendar years;
- Combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis;
- Operates one-third or more of its potential electrical output and more than 219,000 MWh net electrical output on a 3 year rolling average basis.

In the Grayson cases where the proposed gas turbine is constructed and operated in simple cycle mode, the proposed equipment is not subject to this regulation since it will be operated less than one-third of its potential utilization or less than 219,000 MWh per year. If the proposed unit is a combined cycle combustion gas turbine, it will be required to meet the CO_2 emission limits because the expected utilization of the turbine will exceed 33%.

USEPA is planning to issue the final Subpart KKKK rule in the summer of 2015, and the final version of the rule may reflect slight changes to applicability thresholds and even the GHG emission standards. Any changes to the final regulation, however, are expected to provide greater flexibility in complying with the selected emission standards.

40 CFR 63, Subpart YYYY
National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Combustion Gas Turbines

NESHAP Subpart YYYY establishes national emission and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines. NESHAP Subpart YYYY is typically less stringent than the policies and rules enforced by SCAQMD to manage emissions of organic and hazardous air pollutants. As a result, the project is expected to comply with federal emission standards by complying with SCAQMD regulations.

SECTION 5.0

EMISSION PROFILE

5.1 Criteria Pollutant Emissions

5.1.1 Proposed Equipment

LM6000PG SPRINT gas turbines are proposed to replace the existing boilers and gas turbines in the four selected cases. The emission rates of NO_X, VOC, and CO are based on BACT emission limits for natural gas turbines. For a major source facility like Grayson, BACT generally reflects the lowest achievable emission rate without consideration of cost-effectiveness as demonstrated anywhere, including permitting agencies other than SCAQMD. The following tools were used to determine the most stringent BACT emission limits based upon permitting activity throughout the United States:

- SCAQMD BACT Guidelines
- SCAQMD BACT New Source Review Clearinghouse
- CAPCOA BACT Clearinghouse
- USEPA BACT Clearinghouse
- Bay Area AQMD BACT Guidelines
- San Joaquin Valley APCD BACT Clearinghouse and Guidelines

As a result, the following BACT determinations were used to calculate the emission rates of NO_X, VOC, and CO for the new turbines:

- 2.0 ppmv at 15% O_2 for NO_X, VOC, and CO for combined cycle units
- 2.5 ppmv at 15% O_2 for NO_X, 2 ppmv at 15% O_2 for VOC, and 4 ppmv at 15% O_2 for CO for simple cycle units.

The sulfur oxide (SO_X) emission factor of 0.6 pounds per million standard cubic foot of natural gas (lbs/mmscf) is based on the default emission factors from SCAQMD Annual Emissions Reporting (AER) program. The particulate matter (PM10 and PM2.5) emission factor of 1.7 pounds per hour (lbs/hour) is based on the SCAQMD approved PM10 emission factor for a recently permitted LM6000 gas turbine.

As shown in Table 3-3 of this report, four different repower cases have been selected for final evaluation. The highest monthly and annual equipment utilizations of each case have been selected to estimate potential emissions. The gas turbines will emit higher emission rates of NO_X, VOC, CO, SO_X, and PM10/2.5 during startup, shutdown, and maintenance activity because emissions would be partially uncontrolled during these events. Table 5-1 provides estimated emission factors for these operating conditions.

TABLE 5-1
EMISSIONS RATES LM6000 GAS TURBINE

SIMPLE CYCLE CONFIGURATION

Pollutant	Lbs./Hour Normal Hour	Lbs./ Startup[1]	Lbs./ Shutdown[1]	Lbs./Hour Maintenance
NO_X	4.95	10.09	0.69	43.64
CO	4.82	11.6	0.62	14
VOC	1.38	0.79	0.27	1.38
PM10/2.5	1.70	0.75	0.18	1.70
SO_X	0.30	0.14	0.02	0.30

[1] 35 minutes for startup and 10 minutes for shutdown in simple cycle.

COMBINED CYCLE CONFIGURATION

Pollutant	Lbs./Hour Normal Hour	Lbs./ Startup[1]	Lbs./ Shutdown[1]	Lbs./Hour Maintenance
NO_X	3.95	28.68	11.78	43.64
CO	2.40	23.61	9.9	14
VOC	1.37	0.79	0.27	1.38
PM10/2.5	1.70	0.75	0.18	1.70
SO_X	0.30	0.14	0.02	0.30

[2]It is assumed to take 120 minutes for startup and 60 minutes for shutdown in combined cycle.

Table 5-2 summarizes daily, monthly and annual emissions of NO_X, CO, VOC, CO, PM10/2.5 and SO_X for individual cases. Detailed emissions profiles for the proposed equipment are included in Appendix C.

TABLE 5-2
NEW EQUIPMENT
CRITERIA POLLUTANT POTENTIAL EMISSIONS

CASE 150-B: 3 SIMPLE CYCLE COMBUSTION TURBINES

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	7,779	259	24.31
CO	7,030	234	24.18
VOC	1,495	50	5.57
PM10/2.5	1,774	59	6.65
SO_X	312	10	1.17

CASE 200-B: 4 SIMPLE CYCLE COMBUSTION TURBINES

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	10,114	337	30.68
CO	9,123	304	30.55
VOC	1,921	64	6.94
PM10/2.5	2,277	76	8.28
SO_X	401	13	1.46

CASE 200-C: 3 SIMPLE CYCLE COMBUSTION TURBINES AND 1 COMBINED CYCLE COMBUSTION TURBINE

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	9,504	317	32.72
CO	7,546	252	27.46
VOC	1,974	66	8.58
PM10/2.5	2,370	79	10.41
SO_X	418	14	1.83

CASE 250-D: 2 SIMPLE CYCLE COMBUSTION TURBINES AND 2 COMBINED CYCLE COMBUSTION TURBINES

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	9,421	314	36.14
CO	6,432	214	25.62
VOC	2,184	73	10.49
PM10/2.5	2,657	89	12.86
SO_X	468	16	2.27

5.1.2 Replaced Equipment

Boilers 3, 4, and 5 and Turbines 8A and 8BC will be replaced as part of the project. Removal of these units will result in emission reductions that can be applied to emission increases from the new equipment to reduce offset requirements.

The eligible emission reductions from the removal of existing equipment are shown in Table 5-3. The annual emissions of these units as reported in 2012 and 2013 SCAQMD Annual Emission Reports (AER) were adjusted by applying the current BACT emission limits and usage factors to calculate the average hourly emission decrease due to removal pursuant to Rule 1306(c).

Eligible daily emission reductions (30-day average) were then calculated by multiplying the adjusted hourly emissions by 24 hours per day.

Boilers 3, 4 and 5 burned both natural gas and LFG in the years 2012 and 2013. For natural gas combustion, the BACT emission limit of 5 ppmv at 3% O_2 was used to calculate the NO_X and CO emissions. The BACT emission limit of 9 ppmv at 3% O_2 NO_X and approximately 27 ppmv @ 3% O_2 was used to calculate CO emissions for LFG combustion. VOC, SO_X and PM10 emissions were calculated using emission factors from the 2012 and 2013 AERs.

The current BACT emission limit of 2 ppmv at 15% O_2 for NO_X, CO and VOC was used to calculate the emissions from turbines 8A and 8BC. The SO_X emission factor of 0.6 pounds per million standard cubic foot of natural gas (lbs/mmscf) reflects the default emission factors from SCAQMD Annual Emissions Reporting (AER) program. The particulate matter (PM10) emission factor of 1.7 pounds per hour (lbs/hour) reflects SCAQMD approved PM10 emission factor for a recently permitted LM6000 gas turbine.

Detailed emissions profiles for the replaced equipment are included in Appendix D.

TABLE 5-3
EXISTING EQUIPMENT
ELIGIBLE CRITERIA POLLUTANT EMISSION REDUCTIONS

	NSR-Eligible Emission Reductions (lbs/day)							
Pollutant	**Boiler 3 (NG)**	**Boiler 3 (LFG)**	**Boiler 4 (NG)**	**Boiler 4 (LFG)**	**Boiler 5 (NG)**	**Boiler 5 (LFG)**	**Gas Turbine 8A (NG)**	**Gas Turbine 8BC (NG)**
NO_X	6	14	11	26	9	17	0	0
CO	4	27	7	47	6	31	0	0
VOC	5	15	9	26	8	17	0	0
PM10/2.5	7	30	13	52	11	35	0	0
SO_X	0.55	5	0.99	10	0.84	6	0	0

5.1.3 Net Emission Increase

The net emission increase reflects the net difference between the potential emissions from the new equipment and the eligible emission reductions from the equipment to be taken out of service. This net emission increase is used to determine the offset requirements. Table 5-4 shows the net emission increase for each case considered in the analysis.

TABLE 5-4
NET EMISSION INCREASE

CASE 150B: 3 SIMPLE CYCLE GAS TURBINES

Pollutant	New Potential Emissions (lbs./day)	Emission Decrease from Existing Equipment (lbs./day)	Net Emission Increase (lbs./day)
NO_X	259	82	177
CO	234	120	115
VOC	50	80	(31)
PM10/2.5	59	147	(88)
SO_X	10	24	(13)

CASE 200B: 4 SIMPLE CYCLE GAS TURBINES

Pollutant	New Potential Emissions (lbs./day)	Emission Decrease from Existing Equipment (lbs./day)	Net Emission Increase (lbs./day)
NO_X	337	82	255
CO	304	120	184
VOC	64	80	(16)
PM10/2.5	76	147	(72)
SO_X	13	24	(10)

CASE 200C: 3 SIMPLE CYCLE & 1 COMBINED CYCLE GAS TURBINES

Pollutant	New Potential Emissions (lbs./day)	Emission Decrease from Existing Equipment (lbs./day)	Net Emission Increase (lbs./day)
NO_X	317	82	235
CO	252	120	132
VOC	66	80	(15)
PM10/2.5	79	147	(68)
SO_X	14	24	(10)

CASE 250D: 2 SIMPLE CYCLE & 2 COMBINED CYCLE GAS TURBINES

Pollutant	New Potential Emissions (lbs./day)	Emission Decrease from Existing Equipment (lbs./day)	Net Emission Increase (lbs./day)
NO_X	314	82	232
CO	215	120	95
VOC	73	80	(8)
PM10/2.5	89	147	(59)
SO_X	17	24	(8)

5.2 Toxic Pollutant Emissions

Toxic pollutant emissions from the proposed gas turbines are expected. Based upon the emission profiles of gas turbine power plants of similar size, including any plant permitted by SCAQMD, however, toxic pollutant emissions are not expected to significantly affect permitting strategy. Therefore, toxic pollutant emissions were not considered in the initial study.

SECTION 6.0

AIR PERMIT COSTS

6.1 Emission Offset Costs

Pursuant to SCAQMD Rule 1303(b)(2), any net emissions increase of nonattainment air contaminants is required to be offset by Emission Reduction Credits (ERC) that are either allocated from the Priority Reserve or purchased on the open market. Since carbon monoxide (CO) is an attainment air pollutant in the South Coast Air Basin, ERCs are not required to offset CO emissions.

Emission offset costs for each of the possible Grayson repower cases are dependent upon the net emission increase from the project; changes in technology standards (BACT) that may occur between now and the time permit applications are submitted to SCAQMD; the ability to qualify for discounted offsets from SCAQMD internal accounts for turbines that would replace Boilers 3, 4 and 5; the ability to qualify for offset exemptions for functionally equivalent replacements of Turbines 8A and 8BC; and the market prices for any residual ERCs that must be purchased in the open market.

The extent to which each of these variables will affect total offset costs may not be fully known until permit applications are submitted to SCAQMD. Few applications have been processed by SCAQMD under Rule 1304.1 for boiler replacements and the use of landfill gas in the boilers may pose additional unknowns. Initial calculations based upon SCAQMD guidance for Rule 1304.1 appear to result in higher estimated offset costs than would be incurred if GWP waived access to SCAQMD-provided offsets pursuant to Rule 1304.1 and instead purchased offsets in the open market. SCAQMD will not fully evaluate the differences in offset requirements or costs until applications are submitted. Additionally, market prices for ERCs can fluctuate based upon changes in supply and demand. Even though prices have remained stable since 2014, future permitting activity in the District can affect future ERC prices.

To account for the variables that would affect emission offset costs, each of the four Grayson repower cases was evaluated using three options:

- Option 1 - Concurrent facility modification

  The emission offset costs were calculated pursuant to Rule 1306 without claiming any emission offset exemptions or access to Rule 1304.1 boiler repower credits. In this option, all applicable net emission increases are offset by purchasing ERCs in the open market. The results of Option 1 reflect the expected upper bound on emission offset costs for each repower case. They also reflect what costs would be if SCAQMD offset exemptions did not exist or access to Rule 1304.1 is not cost effective. Since Option 1 presents upper bound offset costs, those costs were used by PACE to assess the overall feasibility of each repower case (even though Option 2 or 3 costs are considered more likely to be representative of the final offset strategy).

- Option 2 - Functionally identical replacement offset exemption on turbines and concurrent facility modification on the boilers

  In this option, emission offset exemptions are claimed for new turbines replacing gas turbines 8A and 8BC due to the functionally identical replacement provisions of Rule 1304(a)(1). Although the existing permit for Turbines 8 A-C limits daily fuel consumption to approximately 33% capacity, the SCAQMD engineering report shows no restrictions for the purpose of new source review offset calculations. It is also unclear if the permit limit is truly applicable, since it was initially drafted to restrict CO emissions when the permit was modified to burn natural gas in 1980. The limit initially allowed GWP to avoid installing a CO oxidization catalyst. However, GWP did install a CO oxidization catalyst in 2000 and that action resulted in a decrease in CO emissions. For this analysis, eligibility for the offset exemption for functionally equivalent replacements was assumed to be based upon the full utilization of the existing units, rather than the fuel consumption limits listed in the permit. This calculation method results in greater offset exemptions than if the permit limit were considered. The offset costs for turbines replacing Boilers 3, 4 and 5 are calculated based upon the net emission increase of the proposed equipment replacing the existing boilers pursuant to Rule 1306 and open market prices, without consideration of Rule 1304.1.

- Option 3 - Functionally identical replacement offset exemption on turbines and electric steam boiler replacement offset exemption on the boilers

  Similar to Option 2, there will be no emission offset costs for Gas Turbines 8A and 8BC due to functionally identical replacement. Pursuant to SCAQMD implementation policy for Rule 1304(a)(2), access to discounted emission offsets pursuant to Rule 1304.1 is granted when electric utility steam boilers are replaced with combined cycle gas turbines, but not when the replacement is made with most simple cycle gas turbines. Therefore, cases 200C and 250D were assessed under this Option 3 because they incorporate combined cycle turbine technology. In each case, only a portion of the emission increase from the turbines replacing Boilers 3, 4 and 5 can be offset pursuant to Rule 1304.1 because the new turbines are expected to have higher power production capacity than the existing boilers. Additional emissions from the turbines that are not accommodated by 1304.1 are offset through the purchase of ERCs in the open market.

Except for offsets that would be provided pursuant to Rule 1304.1, ERC prices for VOC, SO_X and PM10 reflected in the cost analyses are based upon published market “seller offer” prices by Western US Environmental Markets dated October 31, 2014 for the Coastal Zone in the South Coast Market, plus an additional 10% to allow for future price increases. Market prices for ERCS have remained stable throughout 2014 and 2015. The current NO_X ERC market prices were not used for the analysis. Instead, high NO_X prices from prior years were used to reflect the assumption that the demand for NO_X ERCs for the Grayson project, under offset Option 1, could drive market prices upward to historical levels. Table 6-1 provides the summary of estimated offset cost ranges for each repower case. Detailed emission offset costs calculations are included in Appendix E.

TABLE 6-1
EMISSION OFFSET COSTS SUMMARY

Case	Proposed Equipment	Estimated Emission Offset Costs (Millions $)[1] Option 1	Option 2	Option 3
150B	3 SCCT	23	12	N/A
200B	4 SCCT	34	23	N/A
200C	3 SCCT & 1 CCCT	31	18	27
250D	2 SCCT & 2 CCCT	31	17	23

[1]Costs include the offset ratio of 1.2 to 1.0 for NO_X, VOC, PM10, and SO_X as applied pursuant to Regulation XIII.

As shown in Table 6-1, Option 1 imposes a higher cost than any other option. Option 2 shows the lowest offset costs by utilizing the identical replacement offset exemption. Option 3 presents the mid-range cost and reflects the uncertainties of Rule 1304.1 calculation methods.

6.2 Additional Permitting Costs

Table 6-2 shows the estimated permitting and professional service fees for the Grayson permitting project. Permitting fees are based upon SCAQMD fee schedules for fiscal year 2015-2016. Additional costs include professional consulting fees for air quality analysis, limited CEQA support related to air quality, SCAQMD application report preparation, and agency coordination. Permitting costs, including consulting fees, reflect the assumption that PSD permitting will not be required.

TABLE 6-2
ADDITIONAL PERMITTING COSTS

Fees type:	Case 150B	Case 200B	Case 200C	Case 250D
Permit Unit Fees[1]:				
Base Fees	$50,000	$65,000	$75,000	$75,000
Expedited Fees (50%)	$25,000	$33,000	$38,000	$38,000
Title V Facility Fees[2]:	$4,000	$5,000	$5,000	$5,000
Misc. Air Quality Consulting Fees[3]:	$100,000	$100,000	$100,000	$100,000
Total Permitting Fees:	$179,000	$203,000	$208,000	$208,000

[1]50% discount of permit unit fees applied to identical equipment. Additional 10% of the cost is applied to count the increase permit fees in the future.
[2]Additional 10% of the cost is applied to count the increase permit fees in the future.
[3]Misc. Air quality consulting fees include activities, such as permit applications write-up, and CEQA support.

SECTION 7.0

LANDFILL GAS FACILITY

Boilers 3, 4, and 5 combust renewable landfill gas produced from the Scholl Canyon Landfill in Glendale, which is located approximately five miles to the west of Grayson. GWP initially considered the installation of replacement gas turbines or reciprocating internal combustion engines to burn landfill gas at the Grayson Power Plant, but has since chosen to propose locating the replacement units at the landfill, rather than Grayson due to SCAQMD policies and fuel transportation issues.

SCAQMD often allows permit applicants to draw emission offset credits from the District's priority reserve account for landfill operations, including landfill combustion sources pursuant to Rules 1304 and 1309.1. However, SCAQMD implementation policy for these rules restricts priority reserve access to operations that exist only at the landfill itself. It is estimated that the value of emission offset credits needed to accommodate landfill gas combustion at Grayson could be $27 million to $38 million. The potential emissions offset cost avoidance that would result from relocating LFG combustion operations to the landfill warranted reconsideration of GWP's initial proposal. Relocating the LFG combustion operations to Scholl Canyon also allows GWP to avoid costs and management activities associated with the five mile gas transmission line.

7.1 Proposed Equipment

The Scholl Canyon Landfill is currently producing approximately 7,500 SCFM of landfill gas. The current study includes two alternative classes of electrical generation equipment – gas turbines and reciprocating internal combustion engines.

7.1.1 Gas Turbines

Gas turbine options for landfill operation include either four Solar Mercury™ 50 (Mercury) units or three Solar Taurus™ 60 (Taurus) units. Both turbines are manufactured by Solar Turbines, Inc., a subsidiary of the Caterpillar Company.

Based on unblended landfill gas fuel, the manufacturer guarantees 42 ppmv uncontrolled NO_X emissions for the Solar Taurus. Installing the Taurus units will require the use of enhanced landfill gas treatment systems to remove siloxanes combined with selective catalytic reduction (SCR) and CO oxidization units. Siloxane removal prolongs turbine life, and enhanced siloxane removal systems are necessary to also protect the SCR and oxidization units from masking and damage.

The Solar Mercury™ 50 is considered to be the more technologically feasible equipment, since it can achieve a much lower uncontrolled NO_X emission concentration of 15 ppmv. In addition, the Solar Mercury is more easily permitted than the Solar Taurus due to lower emission rates of NO_X, CO, and VOC. In fact, LA County has recently permitted a Solar Mercury unit without the use of SCR and oxidization catalysts, based upon demonstrations that such emission control systems are not cost effective due to the low uncontrolled emission rates of the units. Even without the use of SCR and oxidization catalysts, however, a notable level of siloxane removal is needed to protect the turbine itself from damage.

Emissions from the Mercury turbines were calculated for this analysis. SCAQMD has recently allowed the Mercury to be installed without SCR or oxidization catalysts due to its relatively low uncontrolled emission rates. Those emission rates, however, are higher than the rates of the Taurus when equipped with SCR and an oxidization catalyst. As such, the Taurus poses no significant permitting consideration beyond that of the Mercury. Permitting costs for both the Taurus and Mercury options are identified in this report and integrated into Pace's analysis.

The Mercury has the ability to produce 4.6 MW electrical output. The fuel consumption rate of the unit is estimated to be 1,950 SCFM operating at full load; therefore, 4 turbines will be required to burn the available landfill gas. Table 7-1 shows a summary of the equipment specifications. Additional equipment information is included in Appendix F.

TABLE 7-1
SOLAR MERCURY™ 50 EQUIPMENT SPECIFICATIONS

Description	Specification
Power Output (kWe)	4,853
Dimensions	36'6" L X 10'5" W X 12'3" H
Heat Rate LHV (Btu/kWe-Hr)	8,951
Heat Rate HHV (Btu/kWe-Hr)	9,926
Exhaust Flow (lbs/hr)	143,473
Exhaust Temperature (°F)	728°F
Fuel Consumption Rate (SCFM)	2,067

7.1.2 IC Engines

The Caterpillar model CG260-16 (Caterpillar) has the ability to burn LFG to produce 3.37 MW electrical output. SCAQMD BACT policy and local regulations dictate that the Caterpillar engine would need to be fitted with SCR and CO oxidization units. As with gas turbines, the landfill gas supplied to the Caterpillar must be treated to remove siloxanes to protect the emission control devices and to extend engine life.

The fuel consumption rate of the Caterpillar engine is estimated at 1,350 SCFM, operating at full load; therefore, six engines will be required to burn the all of the gas produced at the Scholl

Canyon Landfill. Table 7-2 shows a summary of the equipment specifications. Additional equipment information is included in Appendix F.

TABLE 7-2
CATERPILLAR CG260-16 EQUIPMENT SPECIFICATIONS

Description	Specification
Power Output (kWe)	3,370
Engine Rating (bhp)	4,657
Dimensions	30’11” L X 8’10” W X 11’1” H
Heat Rate LHV (Btu/kWe-Hr)	8,378
Heat Rate HHV (Btu/kWe-Hr)	9,290
Fuel Consumption Rate (SCFM)	1,350

7.2 Emissions Inventory

7.2.1 Solar Mercury™ 50 Gas Turbine

Solar Mercury™ 50 will emit criteria air pollutants due to the landfill gas combustion. The following emission factors are used to calculate these emissions:

- 15 ppmv (uncontrolled) at 15% O_2 for NO_X per manufacturer warranty
- 25 ppmv (uncontrolled) at 15% O_2 for CO per manufacturer warranty
- 5 ppmv (uncontrolled) at 15% O_2 for VOC per manufacturer warranty emission level (25 ppmv for unburned hydrocarbons (UHC) and VOC is estimated to be 20% of UHC per manufacturer.)
- 9.2 lbs/mmscf PM10 based on AP-42, Table 3.1-2b: Landfill Gas Fired Turbines
- 1.45 lbs/mmscf for SO_X based on the facility emission factors reported in SCAQMD AER for 2009 through 2013 reporting year.

An operating schedule of 24 hours per day, 720 hours per month, and 8,294 hours per year is assumed. The annual operating hours are based upon total landfill gas availability to be combusted in 4 gas turbines (approximately 96% annual utilization per turbine).

Table 7-3 provides a summary of the pollutant emissions on daily, monthly, and yearly bases. Additional information on the emission inventory is included in Appendix F. If Solar Taurus units are selected in place of the Solar Mercury units, they will be equipped with SCR and oxidization catalysts and their emissions profile will be lower than that of the uncontrolled Solar Mercury units. Likewise, if SCAQMD’s permitting policy for the Solar Mercury unit changes and SCR / oxidization units are required, the controlled emissions from the Solar Mercury turbine units will be lower than the emissions reflected in Table 7-3.

TABLE 7-3
CRITERIA POLLUTANT EMISSION SUMMARY
SOLAR MERCURY™ 50 GAS TURBINE BURNING LANDFILL GAS

SINGLE UNIT

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	2,160	72	11.79
CO	2,196	73	11.99
VOC	252	8	1.38
PM10/2.5	821	27	4.48
SO_X	130	4	0.71

FOUR SOLAR MERCURY™ 50 GAS TURBINES (PROJECT)

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	8,640	288	47.17
CO	8,784	293	47.96
VOC	1,008	34	5.50
PM10/2.5	3,283	109	17.93
SO_X	518	17	2.83

7.2.2 Caterpillar CG260-16 IC Engine

The following emission factors are used to calculate the emissions from the IC Engine:

- 11 ppmv (controlled) at 15% O_2 for NO_X per emission limit pursuant to Rule 1110.2
- 128 ppmv (controlled) at 15% O_2 for CO per manufacturer specifications
- 30 ppmv (controlled) at 15% O_2 for VOC per emission limit pursuant to Rule 1110.2
- 9.2 lbs/mmscf PM10 based on AP-42, Table 3.1-2b: Landfill Gas Fired Turbine
- 1.45 lbs/mmscf for SO_X based on the emission factors reported in SCAQMD AER for 2009 through 2013 reporting year.

The NO_X, CO, and VOC emission limits pursuant to Rule 1110.2 reflect BACT and are based on controlled emissions from IC engine equipped with air pollution control equipment. The IC engine requires up to 30 minutes for startup to allow SCR to reach operating temperatures. The maximum number of startups for the engine will be 2 startups per day, 10 startups per month and 120 startups per year; with an operating schedule of 24 hours per day, 720 hours per month, and 6,307 hours per year. The annual operating hours is adjusted based on the landfill gas availability to be combusted in 3 engines. Table 7-4 provides a summary of the pollutant emissions on daily, monthly, and yearly bases. Additional information on the emission inventory is included in Appendix F.

TABLE 7-4
CRITERIA POLLUTANT EMISSION SUMMARY
CATERPILLAR CG260-16 IC ENGINE BURNING LANDFILL GAS

SINGLE UNIT

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	1,303	43	6.67
CO	8,543	285	45
VOC	1,013	34	5.59
PM10/2.5	544	18	3.04
SO_X	87	3	0.49

SIX CATERPILLAR CG260-16 IC ENGINES (PROJECT)

Pollutant	Monthly Maximum Emission (lbs)	30-Day Average Emission (lbs)	Annual PTE (tons)
NO_X	7,819	261	40.03
CO	51,255	1,709	270
VOC	6,079	203	33.56
PM10/2.5	3,263	109	18.21
SO_X	522	17	2.91

7.3 Emissions Offset Value

The value of emission offsets that are expected to be provided (i.e., costs avoided) through access to the SCAQMD Priority Reserve for the landfill operation is summarized in Table 7-5. As shown in Table 7-5, a total of $59 million for a turbine project and $57 million for an engine project would be incurred if GWP obtained offsets in the open market instead of the Priority Reserve. It must be emphasized that the values in Table 7-5 are the costs that can be avoided due to the ability to access priority reserve credits. It is not expected that GWP will have to pay these costs to obtain offset credits.

Costs are calculated based on the daily emissions, 30-day monthly average and the published market price by Western US Environmental Markets, dated October 31, 2014, for the Coastal Zone in the South Coast Market, plus an additional 10%. As previously discussed, installation of 4 Solar Mercury gas turbines or 6 Caterpillar CG260-16 IC engines is required to combust 100%

of available landfill gas. Additional information regarding the emission inventory and value of costs foregone is provided in Appendix F.

TABLE 7-5
EMISSION OFFSET COSTS SUMMARY
SCHOLL CANYON LANDFILL

Pollutant	Solar Mercury Net Increase Emissions (lbs./day)	Caterpillar Net Increase Emissions (lbs./day)	Market Price ($/lb.)	Solar Mercury Estimated Emission Offset Cost (Million $)[1]	Caterpillar Estimated Emission Offset Cost (Million $)[1]
NO_X	288	261	$110,000	38	34
CO	293	3,335	$0	0	0
VOC	34	203	$5,170	0.2	1.3
PM10	109	109	$143,000	19	19
SO_X	17	17	$110,000	2	3
Total Costs Avoided through Priority Reserve (Million $):				59	57

[1] Costs include the offset ratio of 1.2 to 1.0 for NO_X, VOC, PM10, and SO_X.

7.4 Permitting Costs

Permitting costs for the Scholl Canyon project include SCAQMD permit application fees, expedited application fees, and professional service fees. The total permitting costs are estimated to be approximately $60,000 for four Mercury gas turbines, $80,000 for three Taurus gas turbines and $120,000 for six IC engines. These costs reflect the assumption that PSD permitting can be avoided.

SECTION 8.0

OUTSTANDING ISSUES/ FUTURE OPPORTUNITIES

Several outstanding issues were discovered during the air quality permitting analysis that may impact the emission offsets and permitting costs of the project. These issues may not be fully resolved until applications for permits to construct the repower project are submitted to SCAQMD.

8.1 Implications of Rule 1304.1

Access to SCAQMD emission offsets is available pursuant to SCAQMD Rule 1304.1 for electrical generating facilities which elect to use the offset exemption to replace electric utility steam boilers pursuant to Rule 1304(a)(2). The purpose of Rule 1304.1 is to ensure that applicants who replace existing boilers have access to emission offset credits at reasonable costs when low emission technology such as combined cycle turbines is utilized. While one would generally expect that fees calculated per Rule 1304.1 would result in lower costs than would be incurred by purchasing credits on the open market, Rule 1304.1 relies upon existing boiler utilization rates, rather than actual historical emissions, to determine the amount of new emissions that must be offset. The apparent result in the case of Grayson is a higher cost under Rule 1304.1 than would be expected. SCAQMD has been advised of the apparent cost inequity and is willing to consider the impacts of its policies when compared to the language in Rule 1304.1, but may not be equipped to identify whether a resolution is warranted until a permit application is submitted. Additionally, GE is assessing the ability of the LM6000 turbine in simple cycle mode to meet SCAQMD requirements for Rule 1304.1 eligibility. Regardless of Rule 1304.1 resolution, the air quality analysis utilizes the most conservative estimated offset costs that would be incurred if no access to Rule 1304.1 is available for all four cases, and boiler replacement offsets are calculated pursuant to SCAQMD Rule 1306 for concurrent modifications.

8.2 Future Role of Gas Turbine 9

According to the SCAQMD engineering evaluation of permit application #407834, dated March 9, 2003, Turbine 9 emission limits described in the permit are calculated based on a monthly operating schedule of 720 hours, which includes 60 startup and shutdown sequences. Based upon historical utilization, Turbine 9 has operated much less than 720 hours per month; hence, the monthly emissions are well below the permit limits.

Based on the permitted operating hours, GWP should be able to operate Turbine 9 more hours than it has operated historically. Significant potential increases in Turbine 9 utilization should consider that long-term continuous operation of the unit may cause SCAQMD to consider rulemaking actions to require enhanced SCR. Still, a temporary increase in operations over a period of a few years appears to be achievable.

Turbine 9 may also be a candidate for retrofit to a combined cycle unit. Since Turbine 9 has been through New Source Review (Regulation XIII), the modification would result in a net emission decrease. Unlike a new combined cycle turbine that would trigger emission offset requirements, a modified combined cycle Turbine 9 would likely result in an emissions reduction and minimal offset costs.

8.3 Throughput Limits of Gas Turbines 8a and 8b-c

Permit condition C1.2 in the permit dated 8/29/2014 shows a natural gas throughput limit of 8.6 mmscf/day for the combined fuel consumption of gas turbines 8a and 8b-c. The throughput limit was originally put in place to avoid triggering BACT on CO emissions when the units were converted to burn natural gas, based on the SCAQMD engineering evaluation dated 12/3/1992. In 2000, GWP proposed to install an SCR and an oxidization unit to control NO_X and CO emissions. The emission calculations reflected in the SCAQMD engineering evaluation of permit application #344955, dated 12/12/2000, suggest that the permitted throughput limit should have been removed. During the SCAQMD permit application process, GWP will propose that SCAQMD investigate past permitting activity and exclude the existing operating limit from its NSR calculations, if appropriate.

8.4 New Health Risk Assessment Guidelines

The California Office of Environmental Health Hazard Assessment (OEHHA) has revised its Risk Assessment Guidelines to incorporate recent studies on childhood sensitivity and new data on exposure impacts. As a result, the calculated cancer risk for residential receptors may increase significantly (3 to 6 times). There is no significant change for the worker exposures. SCAQMD plans to amend Rule 1401 to incorporate the revised guideline.

Although estimated cancer risks of the Grayson project will be greater due to the new calculation methods, they are expected to remain below significance thresholds based upon similar projects and should not affect permitting strategy.

Although the proposed Solar Mercury™ 50 units for the Scholl Canyon Landfill project are not required to have catalytic oxidization units as BACT for CO or VOCs, the implications of new cancer risk assessment guidelines on the project are less certain. It is possible that health risk assessments may suggest that oxidization catalysts will be required to limit organic toxic pollutants, even though they would not be required as BACT.

APPENDIX A

FACILITY MAPS AND DIAGRAMS

GLENDALE WATER & POWER PLANT (FACILITY ID 800327)
800 AIR WAY, GLENDALE, CA 91201

AREA MAP

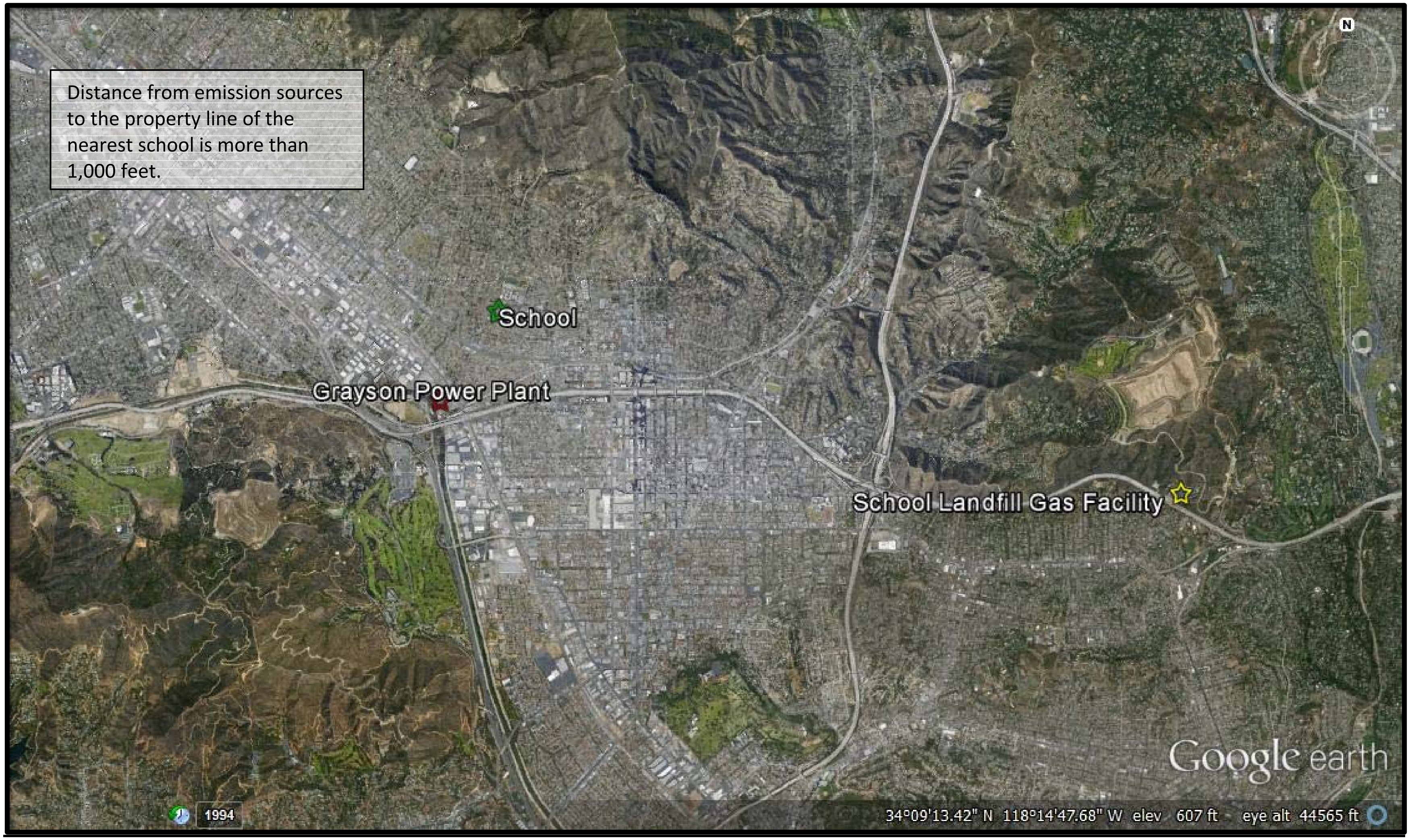
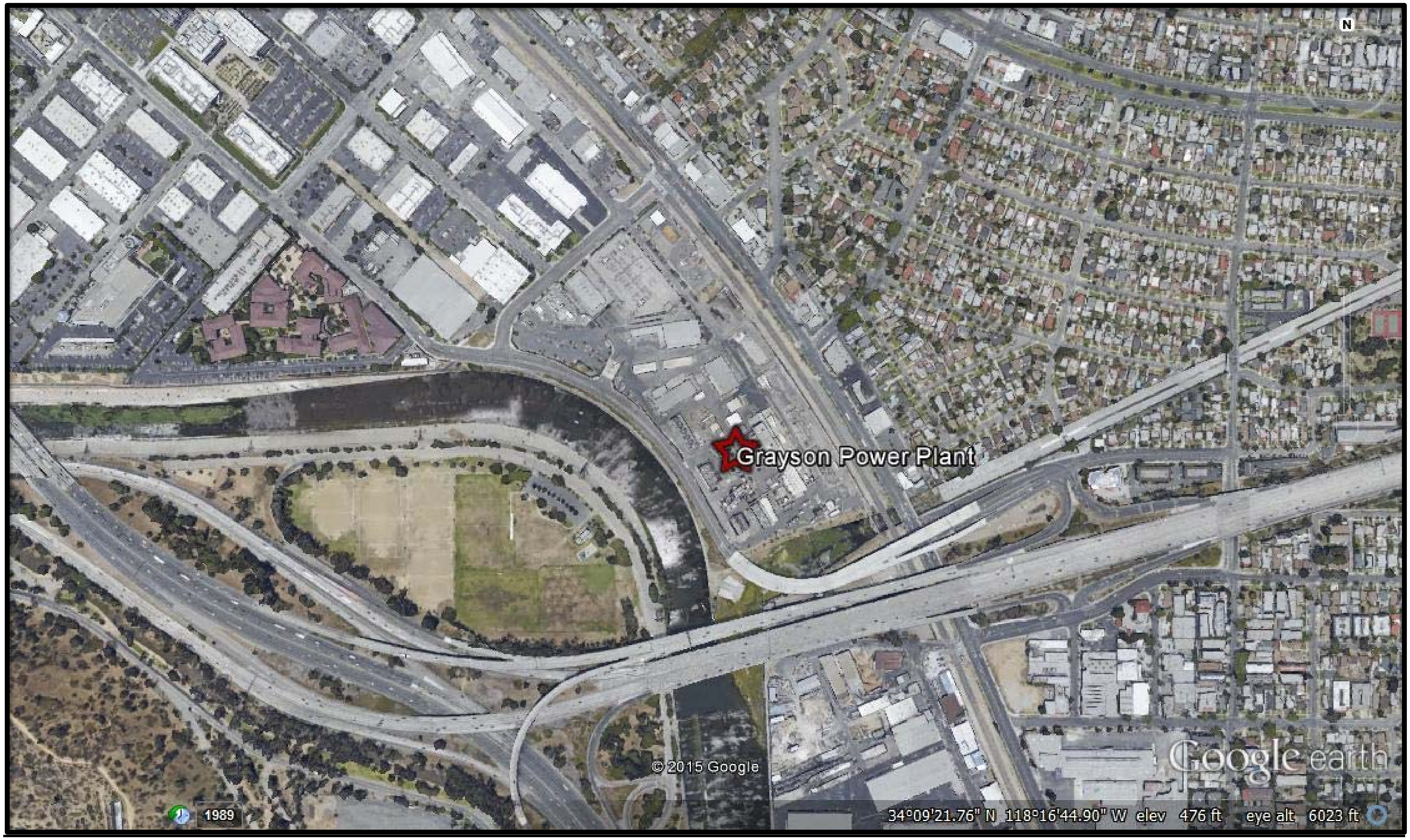


Image courtesy of Google ©2015 (www.google.com)

GLENDALE WATER & POWER PLANT (FACILITY ID 800327)
800 AIR WAY, GLENDALE, CA 91201

SITE MAP



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APPENDIX B

EQUIPMENT SPECIFICATIONS

GE Power & Water
Distributed Power

More Power – Total Flexibility

GE's LM6000-PG* (SAC)

Adding technology advancements to deliver greater value.

In its quest to push the limits of gas power and performance, GE Power & Water continues to innovate available gas turbine offerings that improve power capability and enhance customer operations.

Offering a 25% simple cycle power increase and an 18% boost in exhaust energy for cogeneration applications, GE introduces one of the latest enhancements of its proven LM6000® aeroderivative gas turbine product line: the LM6000-PG with single annular combustor (SAC).

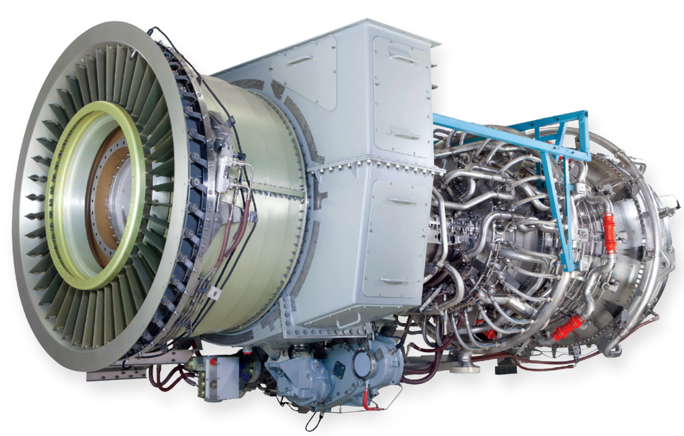
The LM6000-PG will provide combined cycle power in the range of 66 megawatts (MW) with efficiencies ranging from 50 to 52%, depending on selected emissions control methods. The power increase comes from the same 4.5 m X 21.5 m package footprint as existing 50 Hz LM6000 technology, yielding a power density improvement of nearly 20%.

GE's LM6000 has a product heritage of over 1,000 units shipped and +21 million operating hours with over 99% reliability. The improved combined cycle efficiency of the LM6000-PG can reduce fuel consumption by the equivalent of 33,000 barrels of oil per year, when compared to other similar aeroderivative solutions in its class. The LM6000 uprate also reduces carbon dioxide emissions by 6,500 tons over the course of a typical operating year—the same emissions reduction achieved by removing 2,500 cars from the road annually.

Material and technology upgrades previously demonstrated on the CF6-80E and GE90 aircraft engine, and the LMS100® were key to the improvements on the LM6000. The LM6000-PG has been designed with specific attention to commonalities between the 50 Hz and 60 Hz offerings, allowing operators to benefit from a global experience base. The 60 Hz packages will be assembled in GE's Houston, Texas facility, while the 50 Hz packages will be manufactured in GE's Hungary facility.

ISO Performance based on natural gas at ISO conditions, zero losses

NO_x Control Method/Sprint®	Unabated/-	Water/-	Water/Sprint®
Power Output (kWe)	52,784	55,617	58,036
Thermal Efficiency (%)	43.2%	41%	40.8%
Heat Rate LHV (Btu/kWe-Hr)	7,898	8,324	8,355
Exhaust Flow (lbs/sec)	310	320	324
Exhaust Temperature (°F)	878	858	867
NO_x Emissions (ppmvd)	—	25	25
Water Injection for NO_x (lbs/hr)	—	27,965	26,519
Power Turbine Speed (rpm)	3,930	3,930	3,930
No. of Compressor Stages	19	19	19
No. of Turbine Stages	7	7	7



The LM6000-PG provides more power and total flexibility. Built upon the heritage of an industry leader, the LM6000-PG is ready to meet your power needs.

STANDARD 60/50 Hz LM6000-PG (SAC) Package Configuration

Gas Turbine

- Cold-end drive
- Single Annular Combustor (25 ppm NO_X, 50 mg/Nm^3) combustor
- Horizontally split casing
- Variable inlet guide vanes
- Gas turbine familiarization training

Generator

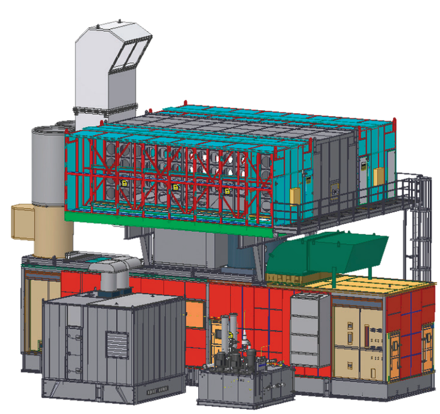
- 13.8 kV, 0.85 PF brushless 2-pole exciter (60 Hz)
- 11.5 kV, 0.8 PF brushless 2-pole exciter (50 Hz)
- WPII weather protected
- Voltage regulator/neutral side protection CTs
- NEMA Class F insulation and B temperature rise
- Integrated protective relay panel
- Vertical offset gearbox

Package

- Auxiliary module containing turbine lube oil, water wash, hydraulic start, and water injection systems
- Fully enclosed gas turbine and generator system meeting 85 dBA near field design
- Direct drive generator fans
- Guard inlet air filters
- Electro-hydraulic start/shutdown system
- Class I Div 2 Group D/Zone 2 class electrical system
- Digital control system with duplex key reliability sensors and instrumentation
- Simplex shell and tube coolers for the lube oil system
- Axial exhaust collector
- Fire protection system with gas detectors, and optical flame and thermal detectors

Options

- Dual igniter
- Integrated piping, cable trays, and wiring
- Enhanced walkway (60 Hz units only)
- Control Module
- Generator options
  - Voltages from 12.47 kV to 13.8 kV (60 Hz)
  - Voltages from 10.5 kV to 11.5 kV (50 Hz)
- Fuel systems
  - Gas with water or steam for NO_X control – 25 ppm, 50 mg/Nm^3
  - Liquid with water for NO_X control – 42 ppm, 86 mg/Nm^3
  - Dual fuel
- Control system
  - Black start for island operation
  - Continuous Emission Monitoring
  - Remote display to control or monitor the unit
  - Power & Control Module fully wired
  - Motor control center
- Lube oil system
  - Oil/water coolers
  - First fill lubricants
- Winterization interval packages down to -39°F, -39°C
- Pulse air filter for less maintenance
- 80 dBA capability
- Inlet conditioning for optimized efficiency
  - Evaporative cooling
  - Mechanical chilling
  - Heating



LM6000-PG/PH*
Enhanced Packaging

Key Characteristics

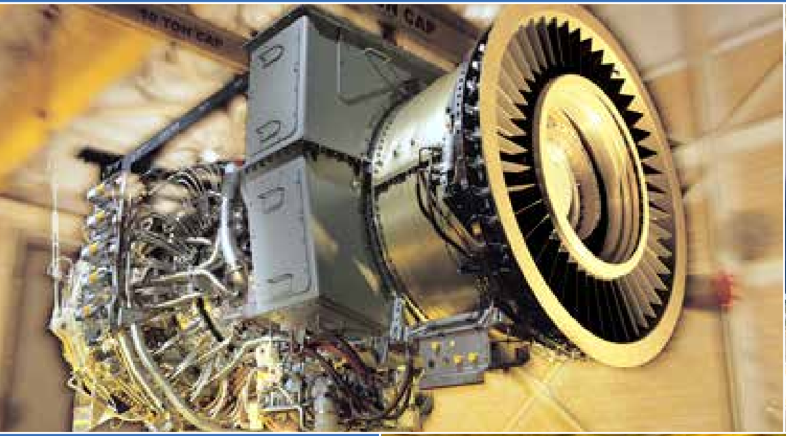
- Universal aux skid reduces footprint
- Minimizes field connections
- Main base has same footprint
- Mark VIe and Woodward Controls
- Same inlet air filter house
- Same chiller coils

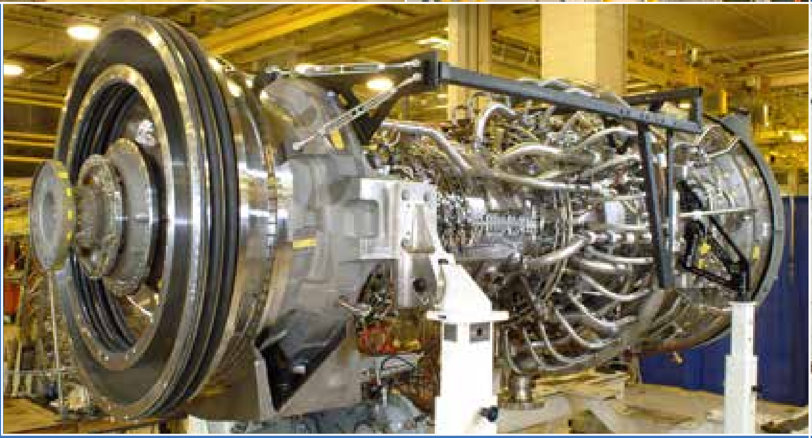
For more information, contact your GE representative or visit www.ge-aero.com.

GEA17012D (06/2013)

GE Power & Water
Distributed Power

Fast, Flexible Power
Aeroderivative Product and Service Solutions






imagination at work











GE Power & Water's Distributed Power business is a leading supplier of aeroderivative gas turbines and packaged generator sets for industrial and marine applications. Our products and services help power the potential of customers across a wide range of operational profiles and industries by increasing efficiency while reducing environmental impact.

GE's continued investment in research and development of aircraft engine technology enables the LM series of gas turbines to maintain a leadership position in technology, performance, operational flexibility and value to the customer. With power output from 18 to 100 MW and the ability to operate with a variety of fuels and emission control technologies, GE's aeroderivative gas turbines have gained wide acceptance in the industry, with total operating experience surpassing 100 million hours.

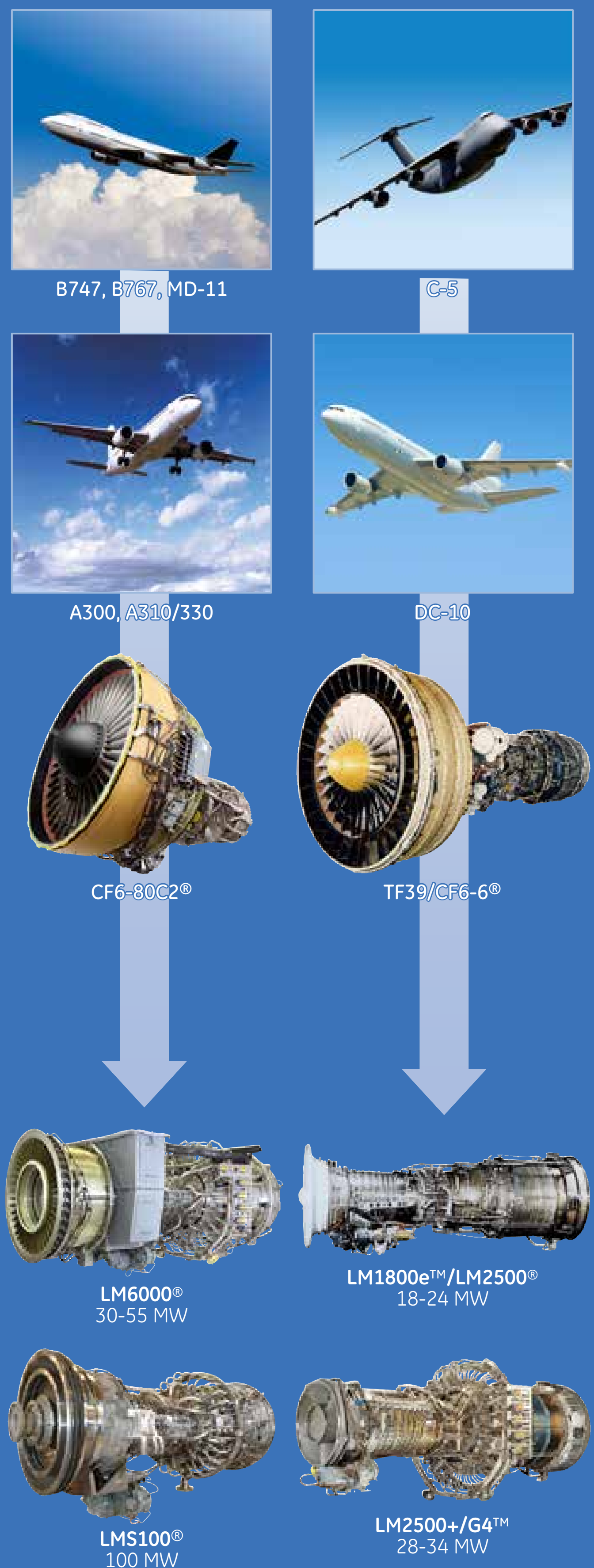
Products known for...

- *Operational flexibility*
- *High efficiency*
- *Superb reliability*
- *Fast installations*

Providing diverse solutions for...

- *FPSO*
- *Grid Stability*
- *Utilities*
- *Oil and Gas*
- *Industrial*
- *Pipeline*
- *Temp Power*
- *Marine*

Aeroderivative Heritage



Fast, Flexible Power

At GE, we recognize the individual operating schemes of our customers are vast and varied. That is why we are committed to providing a flexible portfolio of products to support a full spectrum of operating needs: from fast starts and load following to get peak customers on the grid quickly, to high availability and reliability to keep base load customers online for the long haul. Whatever your scenario, we can tailor a solution to meet your needs.

Operational flexibility is inherent to GE's portfolio of aeroderivative gas turbines and a critical component of our customers' success. We understand the importance of speed and flexibility when it comes to responding to power demands. Our gas turbines are designed to meet these challenges with efficiency and cost effectiveness.

Fast Installation with Less Interruption

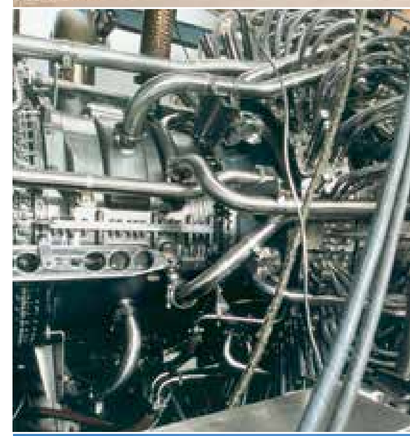
GE is committed to maintaining short manufacturing cycles supported by dependable, predictable delivery times and a robust supply chain. Our modular package designs and on-going interconnect innovation allow for shorter manufacturing cycles and faster installation times with less installed and operational costs than field erected units. All of our units undergo rigorous factory testing after assembly and are ready for operation soon after arriving on site—translating into lower installation costs, shorter project schedules, and reduced financial risk for our customers.

The integration of skid-mounted support systems requires less installation work, time and expense. Fewer materials are shipped directly to the site, reducing the amount of civil works, utilizing package support systems and less foundation work than alternate generation. Our compact, lightweight package design allows for installation flexibility and less process interruption.

Products known for operational flexibility, high efficiency, superb reliability and fast installations

Providing diverse solutions for various industries

- Utilities – peak power, combined cycle, distributed generation, grid stability
- Oil & Gas – mechanical drive, power generation
- FPSO – offshore power with our compact 538 and 538e packages
- Industrial – combined heat and power
- Mobile power – emergency power, peak demand, mining and O&G applications
- Marine – power and propulsion


Fast Starts and Cycling Capability

The ability to go from cold iron to full power in just 10 minutes and the ability to start and stop in short, 15-minute cycles (several times per day if necessary) without impacting maintenance intervals make GE's aeroderivative gas turbines exceptionally adept at accommodating fluctuating demand with increasing efficiency across multiple industry segments. GE's aeroderivative gas turbines can be the first to respond to a peak power demand opportunity, without the costs of a spinning reserve.

Load Following

Thanks to a two-rotor design, GE's aeroderivative portfolio provides higher part power efficiency and faster response to load changes than other similar gas turbines in the industry. This load matching allows for greater grid stability of voltage and frequency, and provides greater starting torque for mechanical drive applications.

High Availability/Reliability

By utilizing aircraft experience and design, our aeroderivative design approach incorporates features such as split casings, modular construction, individual replacement of internal and external parts, and GE's "lease pool" engine program. Our extensive use of high quality components common with parent aircraft engines validates engine reliability and offers reduced parts cost.

Various inspections and hot section repairs can be performed on the gas turbine at site within the turbine enclosure. The "Hot Section," HPT and combustor can be removed/replaced in the field within 72 hours, allowing for greater availability during planned maintenance. Greater availability is achieved by the on-condition maintenance program, which inspects and repairs only as necessary to desired operational condition.

Wide Fuel Range

At GE, we understand flexibility in fuel choices is a high priority. Our Alternate Fuels Center of Excellence is leading the industry in identifying, designing, and delivering fuel flexibility options—all with the high reliability, availability, and maintainability standards you expect from GE.

Our experience on liquid biofuels is proven and growing. In addition to conventional turbine fuels such as #2 diesel, jet fuel, and kerosene, aeroderivative gas turbines are designed to run on a range of alternates—from light distillates like naphtha, to greener fuels such as biodiesels and ethanol derived from various feedstocks. Our package and engine systems have over 450,000 hours of successful operations on naphtha fuel, and over 23,000 hours of operation using biodiesel.

Examples of fuel versatility for our gas turbine and package products include:

Gaseous fuel

- Pipeline and liquefied natural gas (LNG)
- Syngas (low and medium BTU)
- Propane, high hydrocarbon gas
- Wellhead, associated gas
- Coal bed methane (CBM)
- Landfill gas (LFG)
- Coke oven gas (COG)
- Refinery/process flare gas
- LNG for marine propulsion

Liquid fuel

- #2 Diesel
- Jet fuel, kerosene
- Naphtha
- Biodiesel
- Ethanol
- Liquid blends
- Butane

Aero Energy Services

GE customers benefit from a wellspring of operating experience and service expertise that is unmatched in the industry. Our service offerings are designed to help customers meet their operational goals, utilizing field expertise and unique technologies to deliver key results. From simple maintenance services to sophisticated technology upgrades to end-to-end outage services, we can help you keep your equipment operating reliably and efficiently.

Reduced Maintenance Costs

GE's on-condition maintenance philosophy allows the condition of your engine to dictate maintenance activities. Our aeroderivative packages are designed with a high degree of accessibility for easy maintenance including:

- Modular construction permits component inspection/replacement without total disassembly
- Approximately 40 different ports for conclusive on-site borescope inspections
- High pressure compressor split case design
- Individually replaceable compressor blades, stator vanes, and HPT rotor blades
- Horizontally split casings allow detailed inspection and partial blade replacement on-site
- Externally replaceable gearbox and seals
- Externally mounted accessories for easy replacement
- Lightweight aeroderivative design allows fast, on-site engine exchange
- Pre-installed cranes to handle the lightweight aeroderivative gas turbines, allowing for fast engine exchanges

Engine Repair Capability

Our world-class and worldwide network of Service Centers provides our customers with quick turnarounds and convenience. Our Centers of Excellence have the capability to overhaul and repair GE units with quick turnarounds. We are the only LM service centers globally certified to the Aerospace Quality Standard AS9100.

Re-energize Your Plant with GE's Repower Program

GE's Repower program provides the option of replacing older gas and steam turbine equipment with new LM gas turbine technology as an alternative to purchasing a completely new gas turbine package and balance of plant equipment.

Repowering existing gas turbine equipment allows retention of existing plant infrastructure to reduce costs while achieving substantial improvements in thermal efficiency, power output, availability, emissions, fuel efficiency and capital cost savings.

Contractual Service Agreements (CSAs)

Our contractual service agreements (CSAs) create a customized maintenance solution by integrating OEM technical knowledge and remote monitoring and diagnostics with field service, parts, and repairs to protect your investment, improve operational productivity and reduce costs. The CSA is a highly customizable product designed for the wide range of aeroderivative applications, packaging designs, operational demands and geographic locations. Options include full or partial maintenance cost risk transfer, engine-only up to full plant coverage, thermal and operational performance guarantees, integrated access to lease and rotable assets, onsite technical support, comprehensive maintenance planning and a full range of remote services support.

Field Services

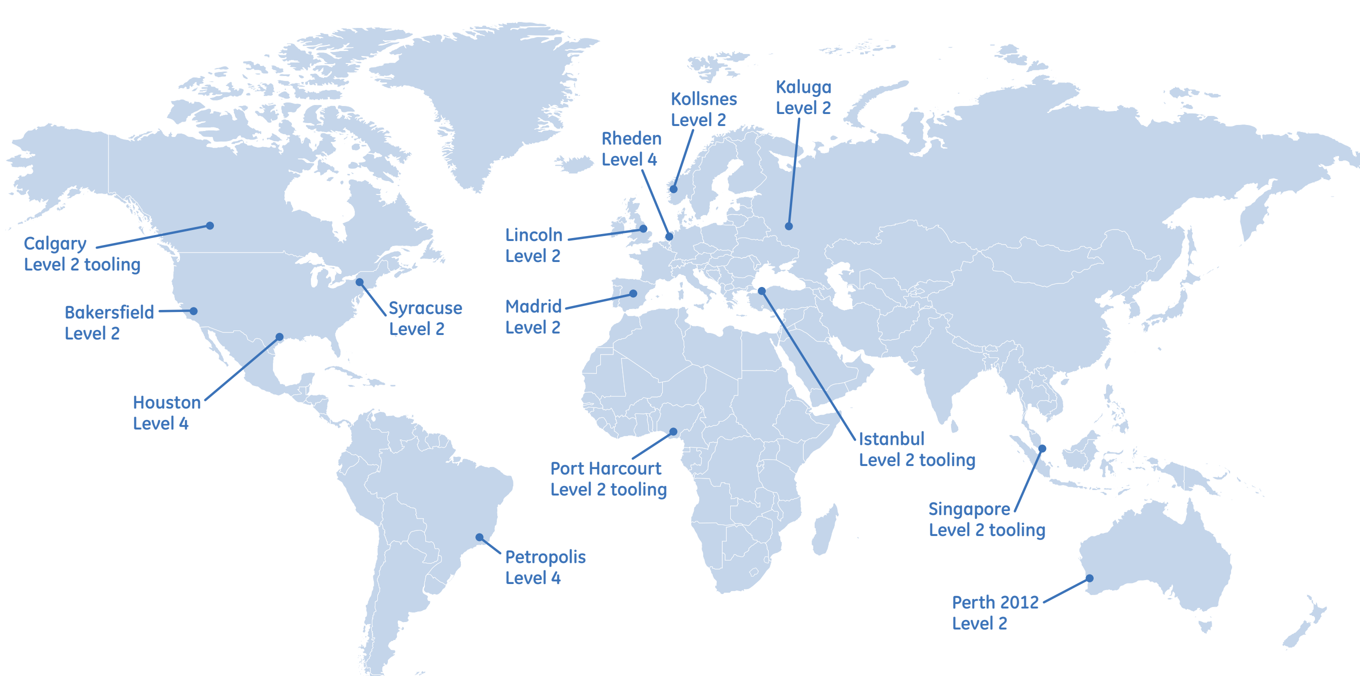
GE's aeroderivative Global Field Services network offers world-class service and support that can anticipate and respond to customer needs throughout the product life of their GE LM engines and packages. Offering the highest quality parts, tools and technical support, these teams are dedicated to reducing downtime and achieving a lower cost of operation. Field Service offerings include periodic inspections of the engine and package, hot sections, generator test and inspection, trim balances, vibration surveys, performance testing, controls calibration, and all Level 1 and 2 maintenance.

Asset Management

GE's aeroderivative lease pool program is designed to help customers reduce overall life cycle costs and provide a low cost method for maintaining unit availability. Customers can improve site availability by leasing equipment from GE when their own equipment is at a depot for repair, or when equipment is being repaired on site. This program allows lease customers to continue operations to serve their customers and meet their business objectives.

Lease assets are provided under member or non-member lease agreement concepts. Member and non-member rates and options are structured to cover the actual and opportunity costs to GE for every operating and non-operating hour.

Aeroderivative Field Services Locations



Level 2: A center that performs basic field and module repairs
Level 4: A center that performs component repairs

Product Directory

LM6000®

GE's LM6000 gas turbine family employs proven advanced emissions technology, package flexibility and diverse fuel capabilities that differentiate its ability to serve a broad spectrum of energy users. The LM6000 offers 40 MW to over 50 MW with up to 42% efficiency and 99% fleet reliability in a flexible, compact package design for utility, industrial and oil and gas applications. With fast ramp rates, 10-minute starts, cycling and load following capability, high efficiency and modular maintenance, the LM6000 has been one of the top selling gas turbines in its class for the last 10 years.

Expanding global heritage

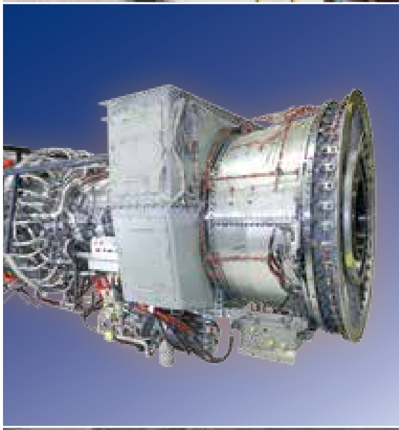
Based on the CF6-80C2® aircraft engine, the LM6000 has achieved over 21 million operating hours with over 1,000 units shipped to customers globally—over *four times more experience* than all other competing gas turbines in its class combined. A global network of over 240 LM6000 owners paired with GE's broad energy solutions portfolio yields an expansive source of operating expertise and experience unique to GE.

Imagination at work

GE's aeroderivative gas turbine business invests in diversified, efficient, reliable products and services that enhance customer operability and availability while addressing global energy concerns. Since its commercial introduction in 1992, the LM6000 engine and package design has continued to grow in its capacity to meet a broad spectrum of customer needs through technology developments like 15 ppm Dry Low NO_X combustion, spray intercooling for power enhancement, fiber optic distributed controls and off-gas/liquid fuel flexibility.

GE introduced the latest enhancement of its proven LM6000 product line in June of 2008 with the launch of the LM6000-PG with single annular combustor (SAC) and its dry low emissions equivalent, the LM6000-PH. The enhancements include increased power and exhaust energy in the same size gas turbine. The power increase comes from the same 4.5 m X 21.5 m package footprint as existing 50 Hz LM6000 technology, yielding a power density improvement of nearly 20%. The LM6000-PG and LM6000-PH provide combined cycle power in the range of 65 MW to 125 MW (2-on-1 combined cycle configuration) with efficiencies ranging from 52% to close to 55%, depending on selected emissions control methods.

The improved combined cycle efficiency of the LM6000-PG and LM6000-PH can reduce fuel consumption by the equivalent of 33,000 barrels of oil per year, when compared to other similar aeroderivative solutions in its class. GE's LM6000 uprate also reduces carbon dioxide emissions by 6,500 tons over the course of a typical operating year—the same emissions reduction achieved by removing 2,500 cars from the road annually.



MODEL	Output MW	Heat Rate Btu/kWh	Heat Rate kJ/kWh	Pressure Ratio	Power Turbine Speed (RPM)	Exhaust Flow lb/sec	Exhaust Flow kg/sec	Exhaust Temp. °F	Exhaust Temp. °C
60 HZ									
LM6000-PC™	43.8	8,519	8,988	29.0	3,600	283	129	809	432
LM6000-PC™ Sprint®†	50.3	8,466	8,932	31	3,600	296	134	839	448
LM6000-PD™	43	8,180	8,630	29.1	3,600	275	125	851	455
LM6000-PD™ Sprint®	47.3	8,170	8,620	30.8	3,600	290	132	838	448
LM6000-PF™	43	8,180	8,630	29.1	3,600	275	125	851	455
LM6000-PF™ Sprint®	47.3	8,170	8,620	30.8	3,600	290	132	838	448
LM6000-PG™	54.1	8,546	9,017	33.1	3,905	318	144	861	461
LM6000-PG™ Sprint®	56.2	8,580	9,052	33.8	3,905	322	146	868	464
LM6000-PH™	49.4	8,217	8,669	31.9	3,905	303	138	885	474
LM6000-PH™ Sprint®	51.7	8,205	8,657	32.6	3,905	306	139	880	471
50 HZ									
LM6000-PC™†	43.3	8,571	9,043	29.1	3,627	285	129	803	428
LM6000-PC™ Sprint®†	50.6	8,485	8,952	31.3	3,627	299	136	835	446
LM6000-PD™	42.7	8,222		29.3	3,627	277	126	843	451
LM6000-PD™ Sprint®	47.5	8,198	8,649	31.1	3,627	293	133	835	446
LM6000-PF™	42.7	8,227	8,675	29.3	3,627	277	126	843	451
LM6000-PF™ Sprint®	47.5	8,198	8,649	31.1	3,627	293	133	835	446
LM6000-PG™	54.1	8,543	9,013	33.2	3,911	318	144	860	460
LM6000-PG™ Sprint®	56.3	8,577	9,049	33.8	3,911	322	146	867	464
LM6000-PH™	48.8	8,321	8,779	32	3,911	304	138	885	474
LM6000-PH™ Sprint®	51.2	8,306	8,763	32.7	3,911	307	139	879	471
Mechanical Drive									
MODEL	Power Rating ISO Baseload (hp)	Heat Rate Btu/kWh	Heat Rate kJ/kWh	Pressure Ratio	Power Turbine Speed (RPM)	Exhaust Flow lb/sec	Exhaust Flow kg/sec	Exhaust Temp. °F	Exhaust Temp. °C
LM6000-PF™	58,969	5,981	8,469	29.1	3,600	275	125	851	455
LM6000-PC™	59,914	5,944	8,409	28.8	3,600	278	126	848	453
LM6000-PG™	*	*	*	*	*	*	*	*	*
LM6000-PH™	64,698	6,057	8,381	30.3	3,743	282	128	917	492

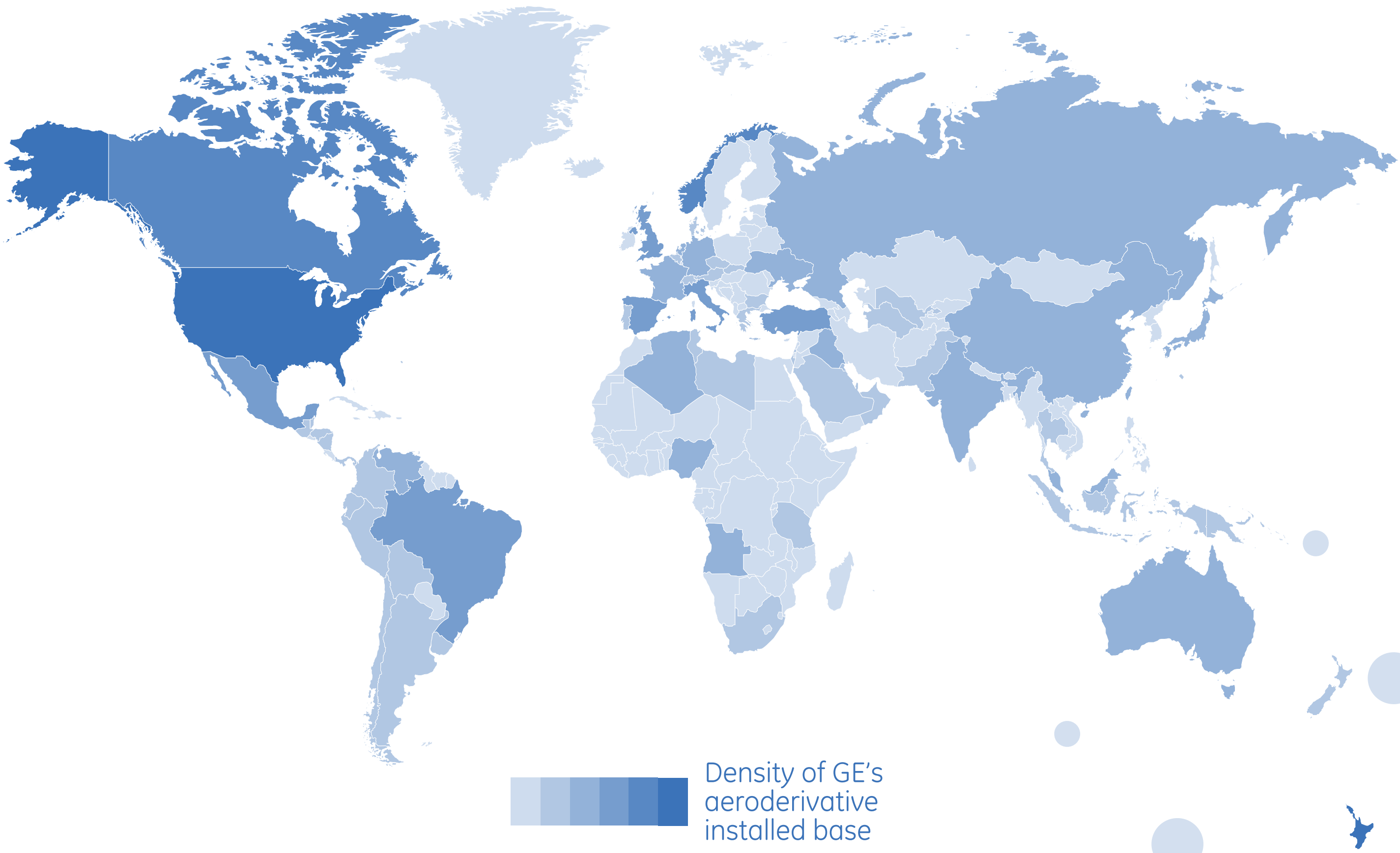
Notes: Performance based on 59°F ambient temperature, 60% RH, sea level, no inlet/exhaust losses on natural gas fuel with no NO_x media, unless otherwise specified. Turbine inlet temperature, exhaust flow and exhaust temperature at ISO rating conditions.

† With water injection for NO_x control to 25 ppm.

* Please contact your local GE representative for additional information.

Facts and Figures

- Headquarters in Houston, Texas
- Major manufacturing facilities: Houston, Texas and Veresegyhaz, Hungary
- Number of employees worldwide: ~1,600
- Applications in over 55 countries
- Total turbines manufactured: 3,700
- Total operating hours: over 100 million



GE Power & Water
1333 West South Loop
Houston, Texas, USA

www.ge-energy.com/aero

GEA18249B (06/2013)

APPENDIX C

EMISSION PROFILES FOR THE PROPOSED EQUIPMENT

APPENDIX C - EQUIPMENT PROFILES FOR THE PROPOSED EQUIPMENT
CRITERIA POLLUTANT EMISSION FACTORS
GRAYSON POWER PLANT

	POLLUTANT CONCENTRATION										POLLUTANT EMISSION FACTOR				
Equipment Type	NO_X		CO		VOC		PM10/2.5		SO_X		NO_X, LBS/HR	CO, LBS/HR	VOC, LBS/HR	PM10/2.5, LBS/HR	SO_X, LBS/HR
LM6000PG SPRINT® Gas Turbine (Simple Cycle)[1]	2.5	PPMV	4	PPMV	2	PPMV	1.7	LBS/HR	0.6	LBS/MMCF	4.95	4.82	1.38	1.7	0.3
LM6000PG SPRINT® Gas Turbine (Combined Cycle)[2]	2	PPMV	2	PPMV	2	PPMV	1.7	LBS/HR	0.6	LBS/MMCF	3.95	2.4	1.37	1.7	0.3
Wartsila 18V50SG IC Engine[3]	0.07	LBS/ MW-HR	0.2	LBS/ MW-	0.1	LBS/ MW-HR	7.71E-05	LBS/ MMBTU	0.6	LBS/MMCF	1.31	3.75	1.88	0.01	0.09

Equipment Type	Electric Output, $KW_{(NET)}$	Heat Rate (LHV), Btu/kWh	Heat Rate (HHV), Btu/kWh	Fuel Type	Fuel LHV, Btu/SCF	Fuel HHV, Btu/SCF	Dry Fuel Factor (Fd), dscf/mmbtu	Fuel Flow MMCF/hr
LM6000PG SPRINT® Gas Turbine (Simple Cycle)[1]	53,886	8931	9824	Natural Gas	914	1050	8710	0.504
LM6000PG SPRINT® Gas Turbine (Combined Cycle)[2]	70,106	6855	7541	Natural Gas	914	1050	8710	0.503
Wartsila 18V50SG IC Engine[3]	18,759	7356	8157	Natural Gas	914	1050	8710	0.146

NOTES:

[1]LM6000PG SPRINT® Gas Turbine (Simple Cycle)
- NO_X, CO, and VOC emission concentration based on BACT Emission Limits
- SO_X emission factor based on SCAQMD Annual Emissions Reporting (AER) Program
- PM10/2.5 emission factor is estimated based using LM6000 PM emission factor in Canyon Power Plant, Anaheim

[2]LM6000PG SPRINT® Gas Turbine (Combined Cycle)
- NO_X, CO, and VOC emission concentration based on BACT Emission Limits
- SO_X emission factor based on SCAQMD Annual Emissions Reporting (AER) Program
- PM10/2.5 emission factor is estimated based using LM6000 PM emission factor in Canyon Power Plant, Anaheim

[3]Wartsila 18V50SG IC Engine
- NO_X, CO, and VOC emission factor based on SCAQMD Rule 1110.2
- SO_X emission factor based on SCAQMD Annual Emissions Reporting (AER) Program
- PM10/2.5 emission factor based on AP-42, Table 3.2-2 (PM10, PM2.5) - Natural Gas-Fired Reciprocating Engines

- Electric outputs and heat rates of equipmentare based on the information provided by Stantec

APPENDIX C - EQUIPMENT PROFILES FOR EACH CASE
DAILY, MONTHLY, ANNUAL POTENTIAL EMISSIONS
GRAYSON POWER PLANT

THE SELECTED SCENARIO AFTER THE INITIAL STUDY

	250D - 2 SCCT & 2 CCCT				200B - 4 SCCT				200C - 3 SCCT & 1 CCCT				150B - 3 SCCT			
Pollutant	**Daily Maximum Emissions (Lbs)**	**Monthly Maximum Emissions (Lbs)**	**30-Day Average Emissions (lbs)**	**Annual PTE (tons)**	**Daily Maximum Emissions (Lbs)**	**Monthly Maximum Emissions (Lbs)**	**30-Day Average Emissions (lbs)**	**Annual PTE (tons)**	**Daily Maximum Emissions (Lbs)**	**Monthly Maximum Emissions (Lbs)**	**30-Day Average Emissions (lbs)**	**Annual PTE (tons)**	**Daily Maximum Emissions (Lbs)**	**Monthly Maximum Emissions (Lbs)**	**30-Day Average Emissions (lbs)**	**Annual PTE (tons)**
NOx	2094.43	9,421	314	36.14	2107.61	10,114	337	30.68	2101.02	9,504	317	32.72	1580.71	7,779	259	24.31
CO	866.41	6,432	214	25.62	933.18	9,123	304	30.55	899.80	7,546	252	27.46	699.89	7,030	234	24.18
VOC	126.05	2,184	73	10.49	132.78	1,921	64	6.94	129.42	1,974	66	8.58	99.59	1,495	50	5.57
PM10/PM2.5	152.79	2,657	89	12.86	159.06	2,277	76	8.28	155.93	2,370	79	10.41	119.30	1,774	59	6.65
SOx	26.93	468	16	2.27	28.02	401	13	1.46	27.48	418	14	1.83	21.02	312	10	1.17

NOTES:
1) Case 250D consists of 2 LM6000PG® SPRINT in simple cycle and 2 LM6000PG® SPRINT in combined cycle.
2) Case 200B consists of 4 LM6000PG® SPRINT in simple cycle.
3) Case 200C consists of 3 LM6000PG® SPRINT in simple cycle and 1 LM6000PG® SPRINT in combined cycle.
4) Case 150B consists of 3 LM6000PG® SPRINT in simple cycle.

APPENDIX C - EQUIPMENT PROFILES FOR THE PROPOSED EQUIPMENT (SINGLE UNIT)
DAILY, MONTHLY, ANNUAL POTENTIAL EMISSIONS
GRAYSON POWER PLANT

Simple Cycle	LM6000PG SPRINT® Gas Turbine - 35 min. startup; 10 min. shutdown							SCENARIO:	250D	200B	200C	150B
Pollutant	No. of Normal Operating Hours per Day	Normal Operating Hour Emission Rate	No. of Startups Per Day	lb / Startup	No. of shutdowns per Day	Lb / Shutdown	No. of Maintenance Operating Hours per Day	Maintenance Operating Hour Emission Rate	Number of Normal Operating Hours Per Month	Number of Normal Operating Hours Per Month	Number of Normal Operating Hours Per Month	Number of Normal Operating Hours Per Month
NOx	11.75	4.95	3	10.09	3	0.69	10	43.64	121	292	222	305
CO	11.75	4.82	3	11.6	3	0.62	10	14	121	292	222	305
VOC	11.75	1.38	3	0.79	3	0.27	10	1.38	121	292	222	305
PM10/2.5	11.75	1.70	3	0.75	3	0.18	10	1.70	121	292	222	305
SOx	11.75	0.30	3	0.14	3	0.02	10	0.30	121	292	222	305

Starts/stops =	2.25	hours/day
Maintenance =	10	hours/day
Daily = 24 hours with 3 starts		

Scenario:	250D	200B	200C	150B
Number of Startups/Shutdowns per Month:	60	60	60	60
Hours of Startups/Shutdowns per Month:	45	45	45	45
Number of Startups/Shutdowns per Year:	360	360	360	360
Hours of Startups/Shutdowns per Year:	270	270	270	270
Hours of Maintenance (Daily, Monthly, Annually):	10	10	10	10

NOTES:
1) Emission rates during startup, shutdown, and maintenance are based on permitted LM6000 simple cycle in Canyon Power Plant, Anaheim.
2) Operating hours and number of startups monthly and annually for the proposed equipment per scenario are provided by Pace Global.
3) Startup, shutdown, and maintenance hours are based on permitted LM6000 simple cycle operated in Canyon Power Plant, Anaheim.

APPENDIX C - EQUIPMENT PROFILES FOR THE PROPOSED EQUIPMENT (SINGLE UNIT)
DAILY, MONTHLY, ANNUAL POTENTIAL EMISSIONS
GRAYSON POWER PLANT

Combined Cycle LM6000PG SPRINT® Gas Turbine - 120 minutes startup, 60 minutes shutdown — **SCENARIO:**

Pollutant	No. of Normal Operating Hours per Day	Normal Operating Hour Emission Rate	No. of Startups Per Day	lb / Startup	No. of shutdowns per Day	Lb / Shutdown	No. of Maintenance Operating Hours per Day	Maintenance Operating Hour Emission Rate	250D Number of Normal Operating Hours Per Month	200B Number of Normal Operating Hours Per Month	200C Number of Normal Operating Hours Per Month	150B Number of Normal Operating Hours Per Month
NOx	11.00	3.95	1	28.68	1	11.78	10	43.64	605	0	587	0
CO	11.00	2.40	1	23.61	1	9.9	10	14	605	0	587	0
VOC	11.00	1.37	1	0.79	1	0.27	10	1.37	605	0	587	0
PM10/2.5	11.00	1.70	1	0.75	1	0.18	10	1.70	605	0	587	0
SOx	11.00	0.30	1	0.14	1	0.02	10	0.30	605	0	587	0

Starts/stops =	3.00	hours/day
Maintenance =	10	hours/day
Daily = 24 hours with 1 start		

Scenario:	250D	200B	200C	150B
Number of Startups/Shutdowns per Month:	5	0	5	0
Hours of Startups/Shutdowns per Month:	15	0	15	0
Number of Startups/Shutdowns per Year:	40	0	40	0
Hours of Startups/Shutdowns per Year:	120	0	120	0
Hours of Maintenance (Daily, Monthly, Annually):	10	0	10	0

NOTES:
1) NO_X and CO Emission rates during startup and shutdown are based on permitted LM6000 combined cycle operated in Pasadena Power Plant.
2) VOC, PM10, and SO_X Emission rates during startup and shutdown are based on permitted LM6000 simple cycle in Canyon Power Plant, Anaheim.
3) Emission rates during maintenance are based on permitted LM6000 simple cycle in Canyon Power Plant, Anaheim.
4) Operating hours and number of startups monthly and annually for the proposed equipment per scenario are provided by Pace Global.
5) Startup, shutdown, and maintenance hours are based on permitted LM6000 simple cycle operated in Canyon Power Plant, Anaheim.

LM6000PG SPRINT® Gas Turbine - 35 min. startup; 10 min. shutdown

Simple Cycle	250D	200B	200C	150B	250D				200B			
Pollutant	Number of Normal Operating Hours Per Year	Number of Normal Operating Hours Per Year	Number of Normal Operating Hours Per Year	Number of Normal Operating Hours Per Year	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)
NOx	836	2227	1707	2402	526.90	1,682	56.07	8,455	526.90	2,529	84.29	15,341
CO	836	2227	1707	2402	233.30	1,456	48.55	8,569	233.30	2,281	76.02	15,273
VOC	836	2227	1707	2402	33.20	244	8.15	1,549	33.20	480	16.01	3,469
PM10/2.5	836	2227	1707	2402	39.77	279	9.28	1,773	39.77	569	18.97	4,138
SOx	836	2227	1707	2402	7.01	49	1.63	311	7.01	100	3.34	729

LM6000PG SPRINT® Gas Turbine - 120 minutes startup, 60 minutes shutdown

Combined Cycle	250D	200B	200C	150B	250D				200B			
Pollutant	Number of Normal Operating Hours Per Year	Number of Normal Operating Hours Per Year	Number of Normal Operating Hours Per Year	Number of Normal Operating Hours Per Year	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)
NOx	6488	0	6472	0	520.31	3,028	100.95	27,682	0.00	0	0.00	-
CO	6488	0	6472	0	199.91	1,760	58.65	17,052	0.00	0	0.00	-
VOC	6488	0	6472	0	29.83	848	28.26	8,945	0.00	0	0.00	-
PM10/2.5	6488	0	6472	0	36.63	1,050	35.01	11,084	0.00	0	0.00	-
SOx	6488	0	6472	0	6.46	185	6.18	1,956	0.00	0	0.00	-

LM6000PG SPRINT® Gas Turbine - 35 min. startup; 10 min. shutdown

Simple Cycle	200C				150B			
Pollutant	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)
NOx	526.90	2,182	72.74	12,767	526.90	2,593	86.43	16,207
CO	233.30	1,943	64.77	12,767	233.30	2,343	78.11	16,117
VOC	33.20	384	12.79	2,751	33.20	498	16.61	3,710
PM10/2.5	39.77	450	15.01	3,254	39.77	591	19.71	4,435
SOx	7.01	79	2.64	573	7.01	104	3.47	781

LM6000PG SPRINT® Gas Turbine - 120 minutes startup, 60 minutes shutdown

Combined Cycle	200C				150B			
Pollutant	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)
NOx	520.31	2,957	98.58	27,148	0.00	0	0.00	-
CO	199.91	1,716	57.21	16,617	0.00	0	0.00	-
VOC	29.83	823	27.44	8,912	0.00	0	0.00	-
PM10/2.5	36.63	1,020	33.99	11,049	0.00	0	0.00	-
SOx	6.46	180	6.00	1,950	0.00	0	0.00	-

APPENDIX D

EMISSION PROFILES FOR THE EXISTING EQUIPMENT

APPENDIX D - EQUIPMENT PROFILES FOR THE EXISTING EQUIPMENT
CRITERIA POLLUTANT EMISSION FACTORS
GRAYSON POWER PLANT

		BACT POLLUTANT CONCENTRATION			EMISSION FACTOR				
DEVICE DESCRIPTION	FUEL	NOX (PPMV)	CO (PPMV)	VOC (PPMV)	NO_X (LBS/MMSCF)	CO (LBS/MMSCF)	VOC (LBS/MMSCF)	PM10/2.5 (LBS/MMSCF)	SO_X (LBS/MMSCF)
GAS TURBINE 8A,8B,8C	Natural Gas	2	2	2	7.85	4.78	2.73	5.10	0.60
BOILER 3,4,5	Natural Gas	5	5		6.47	3.94	5.50	7.60	0.60
BOILER 3,4,5	Landfill Gas	9			3.84	7.10	4.00	8.00	1.45

NOTES:

Natural Gas heating value: 1050 Btu/scf. F factors for natural gas: 8,710 dscf/mmbtu.
BACT Emission Factor Unit Conversion:
(lbs/mmscf) = PPMV * MW * 1050 * 8710/379.5 * (20.9/(20.9 - %O2)

Landfill Gas heating value: 310 Btu/scf. F factors for natural gas: 9,713 dscf/mmbtu.
BACT Emission Factor Unit Conversion:
(lbs/mmscf) = PPMV * MW * 310 * 9713/379.5 * (20.9/(20.9 - %O2)

Gas Turbine 8A, 8B, and 8C:
- NO_X, CO, and VOC emission concentration based on BACT emission limits
- SO_X emission factors are based on SCAQMD Annual Emissions Reporting (AER) Program
- PM emission factor based is estimated based on LM6000 PM emission factor in Canyon Power Plant, Anaheim although the District used a different emission factor on the engineering evaluation for prior permit application A/N 344955.

Boiler 3, 4, and 5 during natural gas combustion:
- NO_X and CO concentration based on BACT emission limits
- VOC, SO_X, and PM emission factors are based on AER emission factors used in the reporting year 2009 - 2013.

Boiler 3, 4, and 5 during landfill gas combustion:
- NO_X concentration based on the BACT emission limit. This limit is guaranteed by the manufacturer of a landfill gas boiler that is going to be permitted by San Joaquin Valley APCD.

APPENDIX D - EQUIPMENT PROFILES FOR THE EXISTING EQUIPMENT
2009 - 2013 SCAQMD ANNUAL EMISSION REPORT (AER)
GRAYSON POWER PLANT

				AER EMISSIONS, LBS/YEAR					OPERATING HOURS	AER EMISSIONS, LBS/DAY					POWER PRODUCTION, MWH	
YEAR	DEVICE DESCRIPTION	FUEL	USAGE, MMCF	NO_X	CO	VOC	PM10	SO_X		NO_X	CO	VOC	PM10	SO_X	GROSS	NET
2009	BOILER UNIT 3	NG	47.90	1472	723	423	120	30	573	61.67	30.29	17.72	5.02	1.26	5482	4956
2009	BOILER UNIT 3	LFG	105.20	1460	747	421	842	153		61.16	31.28	17.63	35.25	6.39		
2009	BOILER UNIT 4	NG	369.80	13660	5584	3265	925	233	4346	75.44	30.84	18.03	5.11	1.29	70155	65032
2009	BOILER UNIT 4	LFG	1,583.90	13542	11246	6336	12671	2297		74.79	62.10	34.99	69.97	12.68		
2009	BOILER UNIT 5	NG	520.00	13083	7852	4592	1300	328	4200	74.76	44.87	26.24	7.43	1.87	76169	70302
2009	BOILER UNIT 5	LFG	1,416.10	12971	10054	5664	11329	2053		74.12	57.45	32.37	64.74	11.73		
2009	GAS TURBINE UNIT 8A	NG	45.70	1349	998	1907	654	27	167	193.88	143.44	274.00	93.92	3.94	2891	2882
2009	GAS TURBINE UNIT 8B/C	NG	119.30	3683	7399	4977	1706	72	217	407.31	818.32	550.47	188.68	7.92	7276	7214
2009	GAS TURBINE UNIT 9	NG	189.30	4695	765	416	1287	114	561	200.84	32.72	17.82	55.07	4.86	18158	17386
2010	BOILER UNIT 3	NG	4.16	138	349	23	32	3	45	73.66	186.37	12.20	16.86	1.33	365	333
2010	BOILER UNIT 3	LFG	4.60	52	33	18	37	7		27.82	17.42	9.81	19.63	3.56		
2010	BOILER UNIT 4	NG	345.05	11456	28984	1898	2622	207	3855	71.32	180.45	11.81	16.33	1.29	62939	58558
2010	BOILER UNIT 4	LFG	1,229.95	13948	8733	4920	9840	1783		86.83	54.37	30.63	61.26	11.10		
2010	BOILER UNIT 5	NG	706.72	23463	59364	3887	5371	424	5353	105.20	266.16	17.43	24.08	1.90	107955	100746
2010	BOILER UNIT 5	LFG	1,801.06	20424	12788	7204	14408	2612		91.57	57.33	32.30	64.60	11.71		
2010	GAS TURBINE UNIT 8A	NG	22.86	680	311	954	327	14	84	194.31	88.76	272.49	93.40	3.92	1337	1332
2010	GAS TURBINE UNIT 8B/C	NG	31.75	945	431	1325	454	19	57	397.71	181.68	557.73	191.17	8.02	1886	1873
2010	GAS TURBINE UNIT 9	NG	209.81	6242	2851	462	1427	126	673	222.59	101.68	16.46	50.88	4.49	19603	18751
2011	BOILER UNIT 3	NG	2.79	452	234	15	21	2	25	433.66	224.99	14.74	20.35	1.60	207	186
2011	BOILER UNIT 3	LFG	0.89	556	6	4	7	1		533.73	6.07	3.42	6.84	1.24		
2011	BOILER UNIT 4	NG	195.57	6612	16428	1076	1486	117	1754	90.48	224.78	14.72	20.34	1.61	31214	28889
2011	BOILER UNIT 4	LFG	515.24	8141	3658	2061	4122	747		111.39	50.06	28.20	56.40	10.22		
2011	BOILER UNIT 5	NG	728.64	21495	61206	4008	5538	437	7148	72.17	205.50	13.46	18.59	1.47	125685	116666
2011	BOILER UNIT 5	LFG	2,753.91	26465	19553	11016	22031	3993		88.86	65.65	36.99	73.97	13.41		
2011	GAS TURBINE UNIT 8A	NG	19.27	906	617	804	276	12	68	319.72	217.70	283.74	97.26	4.08	1181	1177
2011	GAS TURBINE UNIT 8B/C	NG	85.43	3785	4865	3564	1222	51	152	597.56	768.20	562.76	192.89	8.09	4938	4890
2011	GAS TURBINE UNIT 9	NG	111.20	3241	558	245	756	67	328	237.18	40.85	17.90	55.33	4.88	10521	10096

APPENDIX D - EQUIPMENT PROFILES FOR THE EXISTING EQUIPMENT
2009 - 2013 SCAQMD ANNUAL EMISSION REPORT (AER)
GRAYSON POWER PLANT

				AER EMISSIONS, LBS/YEAR					OPERATING HOURS	AER EMISSIONS, LBS/DAY					POWER PRODUCTION, MWH	
YEAR	DEVICE DESCRIPTION	FUEL	USAGE, MMCF	NO_X	CO	VOC	PM10	SO_X		NO_X	CO	VOC	PM10	SO_X	GROSS	NET
2012	BOILER UNIT 3	NG	59.28	2615	4980	326	451	36	876	71.64	136.43	8.93	12.34	0.97	9764	8858
2012	BOILER UNIT 3	LFG	285.65	3208	2028	1143	2285	414		87.89	55.56	31.30	62.61	11.35		
2012	BOILER UNIT 4	NG	468.77	13693	39377	2578	3563	281	5045	65.14	187.32	12.27	16.95	1.34	81329	75320
2012	BOILER UNIT 4	LFG	1,856.66	16784	13182	7427	14853	2692		79.85	62.71	35.33	70.66	12.81		
2012	BOILER UNIT 5	NG	398.13	10861	33443	2190	3026	239	3334	78.18	240.74	15.76	21.78	1.72	56886	52512
2012	BOILER UNIT 5	LFG	1,268.04	13314	9003	5072	10144	1839		95.84	64.81	36.51	73.02	13.24		
2012	GAS TURBINE UNIT 8A	NG	87.39	3425	5781	3646	1250	52	309	266.00	449.00	283.18	97.06	4.07	5439	5423
2012	GAS TURBINE UNIT 8B/C	NG	189.74	6210	17282	7916	2713	114	332	448.93	1249.27	572.24	196.14	8.23	11505	11399
2012	GAS TURBINE UNIT 9	NG	117.81	3804	536	247	801	71	360	253.61	35.74	16.49	53.41	4.71	10897	10387
2013	BOILER UNIT 3	NG	67.93	3090	5706	374	516	41	810	91.56	169.07	11.07	15.30	1.21	9397	8560
2013	BOILER UNIT 3	LFG	242.80	3433	1724	971	1942	352		101.72	51.08	28.78	57.55	10.43		
2013	BOILER UNIT 4	NG	382.62	11230	32140	2104	2908	230	4232	63.69	182.27	11.93	16.49	1.30	63957	59181
2013	BOILER UNIT 4	LFG	1,510.66	12478	10726	6043	12085	2190		70.76	60.83	34.27	68.54	12.42		
2013	BOILER UNIT 5	NG	462.43	13780	38844	2543	3514	277	4085	80.96	228.22	14.94	20.65	1.63	71061	65784
2013	BOILER UNIT 5	LFG	1,409.84	15311	10010	5639	11279	2044		89.95	58.81	33.13	66.26	12.01		
2013	GAS TURBINE UNIT 8A	NG	3.84	260	223	160	55	2	16	390.30	334.65	240.30	82.37	3.45	164	164
2013	GAS TURBINE UNIT 8B/C	NG	117.11	4787	11935	4886	1675	70	214	536.91	1338.47	547.94	187.81	7.88	6666	6600
2013	GAS TURBINE UNIT 9	NG	132.20	4159	706	291	899	79	428	233.22	39.59	16.31	50.41	4.45	12048	11494

APPENDIX D - EQUIPMENT PROFILES FOR THE EXISTING EQUIPMENT
RULE 1306 EMISSION REDUCTIONS
GRAYSON POWER PLANT

			ACTUAL EMISSIONS, LBS/DAY					BACT ADJUSTED EMISSIONS, LBS/DAY						USAGE FACTOR ADJUSTED EMISSIONS, LBS/DAY				
YEAR	DEVICE DESCRIPTION	FUEL TYPE	NO_X	CO	VOC	PM10	SO_X	NO_X	CO	VOC	PM10	SO_X	USAGE FACTOR	NO_X	CO	VOC	PM10	SO_X
2012	BOILER UNIT 3	NG	71.64	136.43	8.93	12.34	0.97	10.51	6.40	8.93	12.34	0.97	0.5	5.25	3.20	4.47	6.17	0.49
2012	BOILER UNIT 3	LFG	87.89	55.56	31.30	62.61	11.35	30.05	55.56	31.30	62.61	11.35		15.03	27.78	15.65	31.30	5.67
2012	BOILER UNIT 4	NG	65.14	187.32	12.27	16.95	1.34	14.43	8.79	12.27	16.95	1.34	1	14.43	8.79	12.27	16.95	1.34
2012	BOILER UNIT 4	LFG	79.85	62.71	35.33	70.66	12.81	33.92	62.71	35.33	70.66	12.81		33.92	62.71	35.33	70.66	12.81
2012	BOILER UNIT 5	NG	78.18	240.74	15.76	21.78	1.72	18.54	11.29	15.76	21.78	1.72	0.5	9.27	5.65	7.88	10.89	0.86
2012	BOILER UNIT 5	LFG	95.84	64.81	36.51	73.02	13.24	35.05	64.81	36.51	73.02	13.24		17.53	32.40	18.26	36.51	6.62
2012	GAS TURBINE UNIT 8A	NG	266.00	449.00	283.18	97.06	4.07	53.28	32.44	18.53	34.62	4.07	0	0.00	0.00	0.00	0.00	0.00
2012	GAS TURBINE UNIT 8BC	NG	448.93	1249.27	572.24	196.14	8.23	107.67	65.56	37.45	69.95	8.23	0	0.00	0.00	0.00	0.00	0.00
2013	BOILER UNIT 3	NG	91.56	169.07	11.07	15.30	1.21	13.02	7.93	11.07	15.30	1.21	0.5	6.51	3.97	5.54	7.65	0.60
2013	BOILER UNIT 3	LFG	101.72	51.08	28.78	57.55	10.43	27.63	51.08	28.78	57.55	10.43		13.81	25.54	14.39	28.78	5.22
2013	BOILER UNIT 4	NG	63.69	182.27	11.93	16.49	1.30	14.04	8.55	11.93	16.49	1.30	0.5	7.02	4.27	5.97	8.25	0.65
2013	BOILER UNIT 4	LFG	70.76	60.83	34.27	68.54	12.42	32.90	60.83	34.27	68.54	12.42		16.45	30.41	17.13	34.27	6.21
2013	BOILER UNIT 5	NG	80.96	228.22	14.94	20.65	1.63	17.58	10.70	14.94	20.65	1.63	0.5	8.79	5.35	7.47	10.32	0.82
2013	BOILER UNIT 5	LFG	89.95	58.81	33.13	66.26	12.01	31.81	58.81	33.13	66.26	12.01		15.90	29.40	16.57	33.13	6.01
2013	GAS TURBINE UNIT 8A	NG	390.30	334.65	240.30	82.37	3.45	45.22	27.53	15.72	29.38	3.46	0	0.00	0.00	0.00	0.00	0.00
2013	GAS TURBINE UNIT 8BC	NG	536.91	1338.47	547.94	187.81	7.88	103.10	62.78	35.86	66.98	7.88	0	0.00	0.00	0.00	0.00	0.00

AVERAGE OF THE TWO YEARS EMISSIONS

		POTENTIAL EMISSION REDUCTION, LBS/DAY				
DEVICE DESCRIPTION	FUEL TYPE	NO_X	CO	VOC	PM10	SO_X
BOILER UNIT 3	NG	5.88	3.58	5.00	6.91	0.55
BOILER UNIT 3	LFG	14.42	26.66	15.02	30.04	5.44
BOILER UNIT 4	NG	10.72	6.53	9.12	12.6	0.99
BOILER UNIT 4	LFG	25.18	46.56	26.23	52.46	9.51
BOILER UNIT 5	NG	9.03	5.5	7.68	10.61	0.84
BOILER UNIT 5	LFG	16.71	30.9	17.41	34.82	6.31
GAS TURBINE UNIT 8A	NG	0	0	0	0	0
GAS TURBINE UNIT 8BC	NG	0	0	0	0	0

NOTES:

The following usage factors pursuant to Rule 1305 are used:
- Usage factor is equal to 1 for equipment is operating for 180 days or more
- Usage factor is equal to 0.5 for equipment is operating between 30 days to 179 days

APPENDIX E

EMISSION OFFSET COSTS

APPENDIX E - EMISSION OFFSET COSTS
SUMMARY OF EMISSION OFFSET COSTS
GRAYSON POWER PLANT

CASE	EQUIPMENT	EMISSION OFFSET OPTION	Net Emission Increase based on 30 day average: NO_X, lbs/day	CO, lbs/day	VOC, lbs/day	PM10/2.5, lbs/day	SO_X, lbs/day	EMISSION OFFSET COST
150B	3 SCCT	OPTION 1	177	115	(31)	(88)	(13)	$23,400,000
		OPTION 2	91	36	(47)	(108)	(17)	$12,000,000
200B	4 SCCT	OPTION 1	255	184	(16)	(72)	(10)	$33,700,000
		OPTION 2	171	108	(32)	(91)	(14)	$22,600,000
200C	3 SCCT & 1 CCCT	OPTION 1	235	132	(15)	(68)	(10)	$31,000,000
		OPTION 2	136	75	(42)	(102)	(16)	$18,000,000
		OPTION 3	145	130	26	30	5	$26,600,000
250D	2 SCCT & 2 CCCT	OPTION 1	232	95	(8)	(59)	(8)	$30,600,000
		OPTION 2	131	36	(36)	(94)	(14)	$17,300,000
		OPTION 3	102	75	21	25	4	$22,700,000

NOTES:
1) The net increase CO emission does not contribute to offset costs since CO is an attainment air pollutant.
2) In option 3, the total offset cost is estimated based on the net increase emission of non-attainment air pollutants and the Rule 1304.1 fee to use boiler replacement offset exemption.
3) Scenario 200B and 150B are not eligible for boiler replacement exemption because both scenarios do not have LM6000 combined cycle as the proposed equipment. The Air District confirms LM6000 in combined cycle not simple cycle is eligible for the boiler replacement offset exemption.
4) The emission reductions of VOC, PM10/2.5 and SO_X occur due to the following factors:
   a) The landfill gas emissions from the existing boilers
   b) Different PM10/2.5 emission factors used in the new turbines and existing boilers
   c) The actual fuel consumption of the exisitng boilers

APPENDIX E - EMISSION OFFSET COSTS
CASE 150B - OPTION 1
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment Type	Emissions Calculated Based On	**NOx** 30 day Average, lbs/day	**CO** 30 day Average, lbs/day	**VOC** 30 day Average, lbs/day	**PM10/2.5** 30 day Average, lbs/day	**SOx** 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	86	78	17	20	3
LM6000PG SCCT 2	PTE	86	78	17	20	3
LM6000PG SCCT 3	PTE	86	78	17	20	3
POST MODIFICATION EMISSIONS		259	234	50	59	10
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 1: CONCURRENT FACILITY MODIFICATION

	NOx 30 day Average, lbs/day	**CO** 30 day Average, lbs/day	**VOC** 30 day Average, lbs/day	**PM** 30 day Average, lbs/day	**SOx** 30 day Average, lbs/day	
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS						
SCCT 1 - 3	259	234	50	59	10	
TOTAL	259	234	50	59	10	
ELIGIBLE EMISSIONS REDUCTIONS FROM EXISTING SOURCES (CALCULATED PURSUANT TO RULE 1306(C))						
BOILER 3 - 5	82	120	80	147	24	
CCCT 8ABC	0	0	0	0	0	
TOTAL	82	120	80	147	24	
NET INCREASE EMISSIONS TO OFFSET						
DELTA	177	115	-31	-88	-13	
OFFSET PRICE CALCULATION						
OFFSET RATIO APPLIED	213	138	-37	-106	-16	
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000	
TOTAL PRICE	$23,410,860	$0	$0	$0	$0	$23,410,860

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment

APPENDIX E - EMISSION OFFSET COSTS
CASE 150B - OPTION 2
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment Type	Emissions Calculated Based On	**NOx** 30 day Average, lbs/day	**CO** 30 day Average, lbs/day	**VOC** 30 day Average, lbs/day	**PM10/2.5** 30 day Average, lbs/day	**SOx** 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	86	78	17	20	3
LM6000PG SCCT 2	PTE	86	78	17	20	3
LM6000PG SCCT 3	PTE	86	78	17	20	3
POST MODIFICATION EMISSIONS		259	234	50	59	10
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 2: FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(A)(1)) ON GAS TURBINES 8ABC AND CONCURRENT ON THE BOILERS 3,4,5

FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC

	NOx 30 day Average, lbs/day	**CO** 30 day Average, lbs/day	**VOC** 30 day Average, lbs/day	**PM** 30 day Average, lbs/day	**SOx** 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 1	86	78	17	20	3
ELIGIBLE EMISSIONS REDUCTIONS FROM GAS TURBINES 8ABC (CALCULATED PURSUANT TO RULE 1306(C))					
CCCT 8ABC	0	0	0	0	0
NET INCREASE EMISSIONS TO OFFSET					
DELTA	86	78	17	20	3
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	104	94	20	24	4
ERC PRICE, $/(LBS/DAY)	$0	$0	$0	$0	$0
TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00

APPENDIX E - EMISSION OFFSET COSTS
CASE 150B - OPTION 2
GRAYSON POWER PLANT

CONCURRENT MODIFICATION ON BOILER 3,4,5

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 2 & 3	173	156	33	39	7
TOTAL	173	156	33	39	7
ELIGIBLE EMISSIONS REDUCTIONS FROM BOILERS 3,4,5 (CALCULATED PURSUANT TO RULE 1306(C))					
BOILER 3 - 5	82	120	80	147	24
NET INCREASE EMISSIONS TO OFFSET					
DELTA	91	36	-47	-108	-17
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	109	44	-57	-130	-20
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$12,001,880	$0	$0	$0	$0

OFFSET PRICE SUMMARY

	NOx	CO	VOC	PM	SOx	
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	
TOTAL OFFSET PRICE FROM FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC						
	$0.00	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM CONCURRENT MODIFICATION ON BOILER 3,4,5						
	$12,001,880	$0	$0	$0	$0	
TOTAL PRICE	$12,001,880	$0	$0	$0	$0	**$12,001,880**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment
3) LM6000PG SCCT1 is eligible for functionally identical equipment with Gas turbine 8ABC based on the potential to emit reflects the District engineering evaluation on prior permit application A/N 344955.

APPENDIX E - EMISSION OFFSET COSTS
CASE 200B - OPTION 1
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_X 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	84	76	16	19	3
LM6000PG SCCT 2	PTE	84	76	16	19	3
LM6000PG SCCT 3	PTE	84	76	16	19	3
LM6000PG SCCT 4	PTE	84	76	16	19	3
POST MODIFICATION EMISSIONS		337	304	64	76	13
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 1: CONCURRENT FACILITY MODIFICATION

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day	
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS						
SCCT 1 - 4	337	304	64	76	13	
TOTAL	337	304	64	76	13	
ELIGIBLE EMISSIONS REDUCTIONS FROM EXISTING SOURCES (CALCULATED PURSUANT TO RULE 1306(C))						
BOILER 3 - 5	82	120	80	147	24	
CCCT 8ABC	0	0	0	0	0	
TOTAL	82	120	80	147	24	
NET INCREASE EMISSIONS TO OFFSET						
DELTA	255	184	-16	-72	-10	
OFFSET PRICE CALCULATION						
OFFSET RATIO APPLIED	306	221	-20	-86	-12	
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000	
TOTAL PRICE	$33,687,280	$0	$0	$0	$0	$33,687,280

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment

APPENDIX E - EMISSION OFFSET COSTS
CASE 200B - OPTION 2
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_X 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	84	76	16	19	3
LM6000PG SCCT 2	PTE	84	76	16	19	3
LM6000PG SCCT 3	PTE	84	76	16	19	3
LM6000PG SCCT 4	PTE	84	76	16	19	3
POST MODIFICATION EMISSIONS		337	304	64	76	13
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 2: FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(A)(1)) ON GAS TURBINES 8ABC AND CONCURRENT ON THE BOILERS 3,4,5

FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EM POST PROJECT (PTE) EMISSIONS					
SCCT 1	84	76	16	19	3
ELIGIBLE EMISSIONS REDUCTIONS FROM GAS TURBINES 8ABC (CALCULATED PURSUANT TO RULE 1306(C))					
CCCT 8ABC	0	0	0	0	0
NET INCREASE EMISSIONS TO OFFSET					
DELTA	84	76	16	19	3
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	101	91	19	23	4
ERC PRICE, $/(LBS/DAY)	$0	$0	$0	$0	$0
TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00

APPENDIX E - EMISSION OFFSET COSTS
CASE 200B - OPTION 2
GRAYSON POWER PLANT

CONCURRENT MODIFICATION ON BOILER 3,4,5

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 2 - 4	253	228	48	57	10
TOTAL	253	228	48	57	10
ELIGIBLE EMISSIONS REDUCTIONS FROM BOILERS 3,4,5 (CALCULATED PURSUANT TO RULE 1306(C))					
BOILER 3 - 5	82	120	80	147	24
NET INCREASE EMISSIONS TO OFFSET					
DELTA	171	108	-32	-91	-14
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	205	130	-39	-109	-16
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$22,561,440	$0	$0	$0	$0

OFFSET PRICE SUMMARY

	NOx	CO	VOC	PM	SOx	
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	
TOTAL OFFSET PRICE FROM FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC						
	$0.00	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM CONCURRENT MODIFICATION ON BOILER 3,4,5						
	$22,561,440	$0	$0	$0	$0	
TOTAL PRICE	$22,561,440	$0	$0	$0	$0	**$22,561,440**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment
3) LM6000PG SCCT1 is eligible for functionally identical equipment with Gas turbine 8ABC based on the potential to emit reflects the District engineering evaluation on prior permit application A/N 344955.

APPENDIX E - EMISSION OFFSET COSTS
CASE 200C - OPTION 1
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_X 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	73	65	13	15	3
LM6000PG SCCT 2	PTE	73	65	13	15	3
LM6000PG SCCT 3	PTE	73	65	13	15	3
LM6000PG CCCT 1	PTE	99	57	27	34	6
POST MODIFICATION EMISSIONS		317	252	66	79	14
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 1: CONCURRENT FACILITY MODIFICATION

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day	
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS						
SCCT 1 - 3	218	194	38	45	8	
CCCT 1	99	57	27	34	6	
TOTAL	317	252	66	79	14	
ELIGIBLE EMISSIONS REDUCTIONS FROM EXISTING SOURCES (CALCULATED PURSUANT TO RULE 1306(C))						
BOILER 3 - 5	82	120	80	147	24	
CCCT 8ABC	0	0	0	0	0	
TOTAL	82	120	80	147	24	
NET INCREASE EMISSIONS TO OFFSET						
DELTA	235	132	-15	-68	-10	
OFFSET PRICE CALCULATION						
OFFSET RATIO APPLIED	282	158	-18	-82	-12	
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000	
TOTAL PRICE	$30,999,980	$0	$0	$0	$0	$30,999,980

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%

APPENDIX E - EMISSION OFFSET COSTS
CASE 200C - OPTION 2
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_X 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	73	65	13	15	3
LM6000PG SCCT 2	PTE	73	65	13	15	3
LM6000PG SCCT 3	PTE	73	65	13	15	3
LM6000PG CCCT 1	PTE	99	57	27	34	6
POST MODIFICATION EMISSIONS		317	252	66	79	14
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 2: FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(A)(1)) ON GAS TURBINES 8ABC AND CONCURRENT ON THE BOILERS 3,4,5

FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
CCCT 1	99	57	27	34	6
ELIGIBLE EMISSIONS REDUCTIONS FROM GAS TURBINES 8ABC (CALCULATED PURSUANT TO RULE 1306(C))					
CCCT 8ABC	0	0	0	0	0
NET INCREASE EMISSIONS TO OFFSET					
DELTA	99	57	27	34	6
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	118	69	33	41	7
ERC PRICE, $/(LBS/DAY)	$0	$0	$0	$0	$0
TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00

APPENDIX E - EMISSION OFFSET COSTS
CASE 200C - OPTION 2
GRAYSON POWER PLANT

CONCURRENT MODIFICATION ON BOILER 3,4,5

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 1 - 3	218	194	38	45	8
TOTAL	218	194	38	45	8
ELIGIBLE EMISSIONS REDUCTIONS FROM BOILERS 3,4,5 (CALCULATED PURSUANT TO RULE 1306(C))					
BOILER 3 - 5	82	120	80	147	24
NET INCREASE EMISSIONS TO OFFSET					
DELTA	136	75	-42	-102	-16
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	164	90	-51	-123	-19
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$17,987,640	$0	$0	$0	$0

OFFSET PRICE SUMMARY

	NOx	CO	VOC	PM	SOx	
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	
TOTAL OFFSET PRICE FROM FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC						
	$0.00	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM CONCURRENT MODIFICATION ON BOILER 3,4,5						
	$17,987,640	$0	$0	$0	$0	
TOTAL PRICE	$17,987,640	$0	$0	$0	$0	**$17,987,640**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment
3) LM6000PG CCCT1 is eligible for functionally identical equipment with Gas turbine 8ABC based on the potential to emit reflects the District engineering evaluation on prior permit application A/N 344955.

APPENDIX E - EMISSION OFFSET COSTS
CASE 200C - OPTION 3
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_x 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_x 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	73	65	13	15	3
LM6000PG SCCT 2	PTE	73	65	13	15	3
LM6000PG SCCT 3	PTE	73	65	13	15	3
LM6000PG CCCT 1	PTE	99	57	27	34	6
POST MODIFICATION EMISSIONS		317	252	66	79	14
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

OPTION 3: FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC, BOILER 3,4,5 REPLACEMENT (1304(a)(2) AND 1304.1) WITH CCCT 1, PTE ON SCCT 2 & 3

FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 1	73	65	13	15	3
ELIGIBLE EMISSIONS REDUCTIONS FROM GAS TURBINES 8ABC (CALCULATED PURSUANT TO RULE 1306(C))					
CCCT 8ABC	0	0	0	0	0
NET INCREASE EMISSIONS TO OFFSET					
DELTA	73	65	13	15	3
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	87	78	15	18	3
ERC PRICE, $/(LBS/DAY)	$0	$0	$0	$0	$0
TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00

APPENDIX E - EMISSION OFFSET COSTS
CASE 200C - OPTION 3
GRAYSON POWER PLANT

BOILER 3,4,5 REPLACEMENT (1304(a)(2) AND 1304.1) WITH CCCT 1

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMI POST PROJECT (PTE) EMISSIONS					
CCCT 1 (70 MW)	99	57	27	34	6
ELIGIBLE EMISSIONS REDUCTIONS FROM BOILERS 3,4,5 (CALCULATED PURSUANT TO RULE 1306(C))					
BOILER 3 - 5 (108 MW)	82	120	80	147	24
1304.1 OFFSET PRICE (PTE) ANALYSIS					
1304.1 SINGLE OFFSET PRICE ($/(LBS/DAY)) UP TO 100 MW REPOWERED	$16,643	$0	$1,159	$24,911	$19,816
1304.1 SINGLE OFFSET PRICE ($/(LBS/DAY)) IN EXCESS OF 100 MW REPOWERED	$66,571	$0	$4,635	$99,643	$79,262
1304.1 OFFSET RATIO FACTOR	1.20	0.00	0.00	0.00	0.00
MAXIMUM PERMITTED ANNUAL POWER OF CCCT 1, MWH	532,000	532,000	532,000	532,000	532,000
AVERAGE ANNUAL POWER OF BOILER 3,4,5, MWH (GROSS)	146,197	146,197	146,197	146,197	146,197
TOTAL PRICE	$1,427,737	$0	$0	$0	$0

POTENTIAL TO EMIT ON REMAINING PROPOSED EQUIPMENT (SCCT 2 &3)

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 2 & 3	145	130	26	30	5
NET INCREASE EMISSION TO OFFSET	145	130	26	30	5
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	175	155	31	36	6
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$19,202,480	$0	$158,723	$5,150,288	$696,960

OFFSET PRICE SUMMARY

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day	
TOTAL OFFSET PRICE FROM FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC						
	$0.00	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM BOILER 3,4,5 REPLACEMENT (1304(a)(2) AND 1304.1) WITH CCCT 1						
	$1,427,737	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM NET INCREASE EMISSIONS ON SCCT 2 & 3						
	$19,202,480	$0	$158,723	$5,150,288	$696,960	
TOTAL PRICE	$20,630,217	$0	$158,723	$5,150,288	$696,960	**$26,636,188**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment
3) LM6000PG SCCT1 is eligible for functionally identical equipment with Gas turbine 8ABC based on the potential to emit reflects the District engineering evaluation on prior permit application A/N 344955.
4) The required fees to use the Rule 1304(a)(2) offset exemption are based on a single payment offset fee rate option.

APPENDIX E - EMISSION OFFSET COSTS
CASE 250D - OPTION 1
GRAYSON POWER PLANT

EMISSION PROFILES

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_X 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	56	49	8	9	2
LM6000PG SCCT 2	PTE	56	49	8	9	2
LM6000PG CCCT 1	PTE	101	59	28	35	6
LM6000PG CCCT 2	PTE	101	59	28	35	6
PROPOSED EQUIPMENT EMISSIONS		314	214	73	89	16
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
EXISTING EQUIPMENT EMISSIONS		81.94	119.73	80.46	147.44	23.64

OFFSET COSTS CALCULATION - OPTION 1: CONCURRENT FACILITY MODIFICATION

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day	
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS						
SCCT 1 & 2	112	97	16	19	3	
CCCT 1 & 2	202	117	57	70	12	
TOTAL	314	214	73	89	16	
ELIGIBLE EMISSIONS REDUCTIONS FROM EXISTING SOURCES (CALCULATED PURSUANT TO RULE 1306(C))						
BOILER 3 - 5	82	120	80	147	24	
CCCT 8ABC	0	0	0	0	0	
TOTAL	82	120	80	147	24	
NET INCREASE EMISSIONS TO OFFSET						
DELTA	232	95	-8	-59	-8	
OFFSET PRICE CALCULATION						
OFFSET RATIO APPLIED	279	114	-9	-71	-10	
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000	
TOTAL PRICE	$30,637,200	$0	$0	$0	$0	$30,637,200

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment

APPENDIX E - EMISSION OFFSET COSTS
CASE 250D - OPTION 2
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_X 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	56	49	8	9	2
LM6000PG SCCT 2	PTE	56	49	8	9	2
LM6000PG CCCT 1	PTE	101	59	28	35	6
LM6000PG CCCT 2	PTE	101	59	28	35	6
PROPOSED EQUIPMENT EMISSIONS		314	214	73	89	16
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
EXISTING EQUIPMENT EMISSIONS		81.94	119.73	80.46	147.44	23.64

OFFSET COSTS CALCULATION - OPTION 2: FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(A)(1)) ON GAS TURBINES 8ABC AND CONCURRENT ON THE BOILERS 3,4,5

FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
CCCT 1	101	59	28	35	6
ELIGIBLE EMISSIONS REDUCTIONS FROM GAS TURBINES 8ABC (CALCULATED PURSUANT TO RULE 1306(C))					
CCCT 8ABC	0	0	0	0	0
NET INCREASE EMISSIONS TO OFFSET					
DELTA	101	59	28	35	6
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	121	70	34	42	7
ERC PRICE, $/(LBS/DAY)	$0	$0	$0	$0	$0
TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00

APPENDIX E - EMISSION OFFSET COSTS
CASE 250D - OPTION 2
GRAYSON POWER PLANT

CONCURRENT MODIFICATION ON BOILER 3,4,5

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 1 & 2	112	97	16	19	3
CCCT 2	101	59	28	35	6
TOTAL	213	156	45	54	9
ELIGIBLE EMISSIONS REDUCTIONS FROM BOILERS 3,4,5 (CALCULATED PURSUANT TO RULE 1306(C))					
BOILER 3 - 5	82	120	80	147	24
NET INCREASE EMISSIONS TO OFFSET					
DELTA	131	36	-36	-94	-14
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	157	43	-43	-113	-17
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$17,312,020	$0	$0	$0	$0

OFFSET PRICE SUMMARY

	NOx	CO	VOC	PM	SOx	
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	
TOTAL OFFSET PRICE FROM FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC						
	$0.00	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM CONCURRENT MODIFICATION ON BOILER 3,4,5						
	$17,312,020	$0	$0	$0	$0	
TOTAL PRICE	$17,312,020	$0	$0	$0	$0	**$17,312,020**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment
3) LM6000PG CCCT1 is eligible for functionally identical equipment with Gas turbine 8ABC based on the potential to emit reflects the District engineering evaluation on prior permit application A/N 344955.

APPENDIX E - EMISSION OFFSET COSTS
CASE 250D - OPTION 3
GRAYSON POWER PLANT

EMISSION SUMMARY

Equipment	Emissions Calculated Based On	NO_x 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM10/2.5 30 day Average, lbs/day	SO_x 30 day Average, lbs/day
LM6000PG SCCT 1	PTE	56	49	8	9	2
LM6000PG SCCT 2	PTE	56	49	8	9	2
LM6000PG CCCT 1	PTE	101	59	28	35	6
LM6000PG CCCT 2	PTE	101	59	28	35	6
POST MODIFICATION EMISSIONS		314	214	73	89	16
BOILER 3 (NG)	ACTUAL	5.88	3.58	5.00	6.91	0.55
BOILER 3 (LFG)	ACTUAL	14.42	26.66	15.02	30.04	5.44
BOILER 4 (NG)	ACTUAL	10.72	6.53	9.12	12.6	0.99
BOILER 4 (LFG)	ACTUAL	25.18	46.56	26.23	52.46	9.51
BOILER 5 (NG)	ACTUAL	9.03	5.5	7.68	10.61	0.84
BOILER 5 (LFG)	ACTUAL	16.71	30.9	17.41	34.82	6.31
GAS TURBINE 8A	ACTUAL	0	0	0.00	0	0
GAS TURBINE 8BC	ACTUAL	0	0	0.00	0	0
PRE MODIFICATION EMISSIONS		81.94	119.73	80.46	147.44	23.64

EMISSION SUMMARY - OPTION 3: FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC, BOILER 3,4,5 REPLACEMENT (1304(a)(2) AND 1304.1) WITH SCCT 1 AND PTE ON SCCT 2 AND THE REMAINING CAPACITY OF CCCT 2

FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC

	NOx 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SOx 30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 1	56	49	8	9	2
ELIGIBLE EMISSIONS REDUCTIONS FROM GAS TURBINES 8ABC (CALCULATED PURSUANT TO RULE 1306(C))					
CCCT 8ABC	0	0	0	0	0
NET INCREASE EMISSIONS TO OFFSET					
DELTA	56	49	8	9	2
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	67	58	10	11	2
ERC PRICE, $/(LBS/DAY)	$0	$0	$0	$0	$0
TOTAL	$0.00	$0.00	$0.00	$0.00	$0.00

APPENDIX E - EMISSION OFFSET COSTS
CASE 250D - OPTION 3
GRAYSON POWER PLANT

BOILER 3,4,5 REPLACEMENT (1304(a)(2) AND 1304.1) WITH CCCT 1 & 2

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
CCCT 1&2 (140 MW)	202	117	57	70	12
ELIGIBLE EMISSIONS REDUCTIONS FROM BOILERS 3,4,5 (CALCULATED PURSUANT TO RULE 1306(C))					
BOILER 3 - 5 (108 MW)	82	120	80	147	24
1304.1 OFFSET PRICE (PTE) ANALYSIS					
1304.1 SINGLE OFFSET PRICE ($/(LBS/DAY)) UP TO 100 MW REPOWERED	$16,643	$0	$1,159	$24,911	$19,816
1304.1 SINGLE OFFSET PRICE ($/(LBS/DAY)) IN EXCESS OF 100 MW REPOWERED	$66,571	$0	$4,635	$99,643	$79,262
1304.1 OFFSET RATIO FACTOR	1.20	0.00	0.00	0.00	0.00
MAXIMUM PERMITTED ANNUAL POWER OF CCCT 1 & 2, MWH	1,064,000	1,064,000	1,064,000	1,064,000	1,064,000
AVERAGE ANNUAL POWER OF BOILER 3,4,5, MWH (GROSS)	146,197	146,197	146,197	146,197	146,197
TOTAL PRICE	$4,251,072	$0	$0	$0	$0

POTENTIAL TO EMIT OF THE REMAINING CAPACITY (34 MW)

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
INCREASE 34 MW	45	26	13	16	3
NET INCREASE EMISSION TO OFFSET	45	26	13	16	3
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	55	32	15	19	3
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$6,005,715	$0	$79,024	$2,707,316	$367,468

POTENTIAL TO EMIT ON SCCT 2

	NOx	CO	VOC	PM	SOx
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day
PROPOSED EQUIPMENT POTENTIAL TO EMIT (PTE) EMISSIONS					
SCCT 2	56	49	8	9	2
NET INCREASE EMISSION TO OFFSET	56	49	8	9	2
OFFSET PRICE CALCULATION					
OFFSET RATIO APPLIED	67	58	10	11	2
ERC PRICE, $/(LBS/DAY)	$110,000	$0	$5,170	$143,000	$110,000
TOTAL	$7,401,460	$0	$50,538	$1,593,020	$215,160

APPENDIX E - EMISSION OFFSET COSTS
CASE 250D - OPTION 3
GRAYSON POWER PLANT

OFFSET PRICE SUMMARY

	NOx	CO	VOC	PM	SOx	
	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	30 day Average, lbs/day	
TOTAL OFFSET PRICE FROM FUNCTIONALLY EQUIVALENT REPLACEMENT (1304(a)(1)) ON GAS TURBINES 8ABC						
	$0.00	$0.00	$0.00	$0.00	$0.00	
TOTAL OFFSET PRICE FROM BOILER 3,4,5 REPLACEMENT (1304(a)(2) AND 1304.1) WITH CCCT 1 & 2						
	$4,251,072	$0.00	$0.00	$0	$0.00	
TOTAL OFFSET PRICE FROM NET INCREASE EMISSIONS ON THE REMAINING CAPACITY OF CCCT 2						
	$6,005,715	$0	$79,024	$2,707,316	$367,468	
TOTAL OFFSET PRICE FROM NET INCREASE EMISSIONS ON SCCT 2						
	$7,401,460	$0	$50,538	$1,593,020	$215,160	
TOTAL PRICE	$17,658,247	$0	$129,562	$4,300,336	$582,628	**$22,670,773**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment
3) LM6000PG SCCT1 is eligible for functionally identical equipment with Gas turbine 8ABC based on the potential to emit reflects the District engineering evaluation on prior permit application A/N 344955.
4) The required fees to use the Rule 1304(a)(2) offset exemption are based on a single payment offset fee rate option.

APPENDIX E - EMISSION OFFSET COSTS
RULE 1304.1 - ELECTRICAL GENERATING FACILITY FEES FOR USE RULE 1304(A)(2) OFFSET EXEMPTION
GRAYSON POWER PLANT

$$Single\ Payment\ Offset\ Fee\ (Fi) = \left(\left[L_{iA1} \times \frac{100}{MW}\right] + \left[L_{iA2} \times \frac{MW - 100}{MW}\right]\right) \times OFi \times PTErepi \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

POLLUTANT	$L_{iA1,}$ SINGLE OFFSET FEE RATE FOR REPOWERING 100 MW OR LESS ($ LB/DAY)	$L_{iA2,}$ SINGLE OFFSET FEE RATE FOR REPOWERING MORE THAN 100 MW ($ LB/DAY)	OF_i, OFFSET FACTOR
NOX	$16,643	$66,571	1.2
VOC	$1,159	$4,635	1.2
PM10	$24,911	$99,643	1.0
SOX	$19,816	$79,262	1.0

MW = Power rating in megawatts (MW) of new replacement unit(s)

PTE_{rep1} = Permitted potential to emit of new replacment unit(s) (lbs/day)

C_{rep} = Maximum permitted annual megawatt hour (MWh) of the new replacement unit(s)
(Maximum rated capacity in megawatts multiply by max. operating annual hours)

$C_{2YRAvgExisting}$ = The average of MWh of the replaced units for the last 24 months prior to issuance of the permit to construct

$C_{2YRAvgExisting}$ for Boiler 3,4,5 for 2012 and 2013

	Power Production (MWh)	
Unit	2012	2013
Boiler 3	9,764	9,397
Boiler 4	81,329	63,957
Boiler 5	56,886	71,061
Total	147,979	144,415

$C_{2YRAvgExisting}$	**146,197**

APPENDIX E - EMISSION OFFSET COSTS
RULE 1304(a)(1) - MODELING AND OFFSET EXEMPTIONS ON REPLACEMENTS
GRAYSON POWER PLANT

Modeling and Offset Exemptions on Replacements:
- The source is replacing a functionally identical source or is a functionally identical modification to a source and there is no increase in maximum rating, and the potential to emit of any air contaminant will not be greater from the new source than from the replaced source, when the replaced source was operated at the same conditions and as if current BACT were applied.

Potential to Emit by definition:
The amount of pollutants calculated using a calendar monthly average and on a pound-per-day basis from permit conditions which directly limit the emissions, or, when no such conditions are imposed from the max rated capacity, max daily hours, and physical characteristics of the materials processed.

Replacement pursuant to 1304(a)(1) can only be applied to a functionally identical source (i.e. boiler for boiler, ICE for ICE, and turbine for turbine) - confirmed by John Yee, SCAQMD engineer, via e-mail dated 11/7/2014.

GAS TURBINE 8ABC POTENTIAL TO EMIT (PTE) EMISSIONS

Pollutant	Daily Emissions[1] (lbs/day)	BACT Daily Emissions[2] (lbs/day)
NOx	871	194
CO	1,475	118
VOC	1,002	66
PM10/2.5	15	122
SOx	15	15

NOTES:
[1]Daily emissions based on SCAQMD District Engineering Evaluation for prior permit application A/N 344955.
The following parameters in the A/N 344955 are used in estimating the daily emissions of Gas Turbine 8ABC with current BACT applied:
- The fuel rate per gas turbine is 0.333 mmscf/hr.
- The flue gas flow for Gas Turbine 8ABC is 680000 cf/min @ 16% O2 dry.

[2]With the adjusment to current BACT, PM emission factor is adjusted using 5.10 lbs/mmscf instead of using 0.6 lbs/mmscf on the eng. evalution on the prior permit

RULE 1304(A)(1) - REPLACEMENTS ELIGIBILITY BASED ON THE POTENTIAL TO EMIT FOR EACH SCENARIO

Pollutant	Gas Turbine 8ABC (lbs/day)	LM6000 SCCT - Scenario 150B (lbs/day)	LM6000 SCCT - Scenario 200B (lbs/day)	LM6000 SCCT - Scenario 200C (lbs/day)	LM6000 CCCT - Scenario 200C (lbs/day)	LM6000 SCCT - Scenario 250D (lbs/day)	LM6000 CCCT - Scenario 250D (lbs/day)
NOx	194	86	84	73	99	56	101
CO	118	78	76	65	57	49	59
VOC	66	17	16	13	27	8	28
PM10/2.5	122	20	19	15	34	9	35
SOx	15	3	3	3	6	2	6

NOTES:
1) Based on the potential to emit emission, gas turbine 8A, 8B, and 8C can be replaced by one gas turbine in simple or combined cycle for all scenarios, except scenario 250D.
2) Based on the potential to emit emissions, 2 LM6000(R) SPRINT simple cycle turbines in scenario 250D are eligible to be functionally identical equipment replacement with gas turbine 8A, 8B, and 8C; however, the maximum rating of these two new gas turbines will exceed the maximum rating of the replaced turbines. As a result, only one gas turbine is eligible for this offset exemption.

APPENDIX F

LANDFILL GAS FACILITY

SOLAR MERCURY™ 50 SPECIFICATIONS

CAT CG260-16 SPECIFICATIONS

EMISSION PROFILES AND OFFSET COSTS

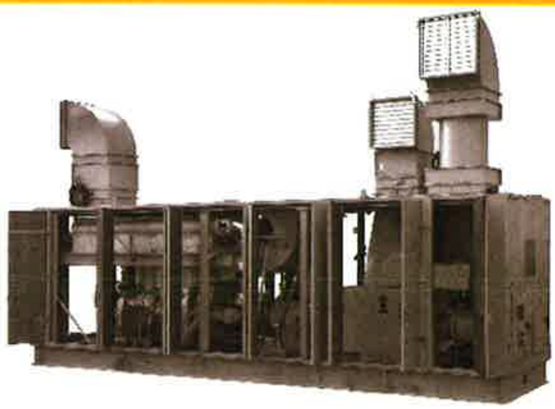
Solar Turbines

A Caterpillar Company

MERCURY 50

Recuperated Gas Turbine Generator Set

Power Generation



General Specifications

Gas Turbine

- *Mercury*™ 50 Recuperated Gas Turbine
- Industrial, Single-Shaft
- 10-Stage Axial Compressor
  - Variable Inlet Guide Vanes and Stators
  - Compression Ratio: 9.9:1
  - Inlet Airflow: 39.2 lb/sec (17.9 kg/sec)
  - Vertically Split Case
- Combustion Chamber, Annular Type
  - Ultra-Lean-Premix Combustion System
  - 8 Fuel Injectors
  - Single Torch Ignitor System
- Proximity Probe Vibration Transducers
- Turbine
  - 2-Stage, Reaction
  - Clockwise Rotation
- Bearings
  - 2 Radial: Viscous Damped Roller Bearings
  - 1 Thrust/Radial: Viscous Damped Split Inner Race Ball Bearing

Recuperator

- Primary Surface Type

Main Reduction Drive

- Epicyclic
  - 1500 or 1800 rpm (50 or 60 Hz)
  - Vibration Monitoring: Acceleration Transducer

Generator

- 4 Pole, 3 Phase, 6 Wire, Wye Connected, Synchronous with Permanent Magnet Exciter
- Available Construction Type:
  - Open Drip-Proof
- Sleeve Bearings
- Vibration Monitoring: Velocity Transducers
- Class F Temperature Rise
- Class B Temperature Rise*
- NEMA Class F Insulation with F Rise
- Continuous Duty Rating Voltages:
  - 3300, 6600, 11,000 (50Hz)
  - 4160, 6900, 12,470, 13,800V(60 Hz)

Package

- Mechanical Construction
  - Steel Base Frame with Drip Pans and Generator Alignment
  - 316L Stainless Steel Piping
- Start System
  - Direct Drive AC Motor with VFD Control
- Package Electrical Certification
  - NEC, CSA Class 1, Group D, Div 2
- Fuel System
  - Natural Gas
  - Landfill Gas*
  - Digester Gas*
- Integrated Lube Oil System
  - Main/Pre/Post Lube PumpBackupLube Pump
  - Air and Oil Cooler
  - Water/Oil Lube Oil Cooler*
  - Integral Lube Oil Tank
  - Lube Oil Tank Heater
  - Simplex Lube Oil Filter
  - Duplex Lube Oil Filters*
  - Oil Mist Eliminator
  - Vent Flame Trap
- Air Inlet and Exhaust Systems
  - Carbon Steel
  - Stainless Steel*
  - Barrier Type Filters
  - Self-Cleaning Filters
  - Inlet and Exhaust Silencers
  - Inlet Evaporative Cooler*
  - Inlet Chiller Coils*
- Enclosure
  - Complete Package
  - Fire Detection and CO2 Suppresion System
- Turbine Compressor Cleaning Systems
  - On-Crank
  - Portable Cleaning Tank*
- Package Power
  - 120VDC Battery/Charger System*
- *Turbotronic*® 4 On-skid Gas Turbine Control System
  - Combination Gas Turbine and Control System
  - Standard Display with Discrete Event Log, Strip Chart, Historical Trend, Mainteneace Screen
  - Vibration and Temperature Monitoring
  - English Display Text and Labels
  - Spanish, Portuguese, German, French or Simplified Chinese Display Text and Labels*
  - Auxiliary and Remote Display/ Control Terminals*
  - Auto Synchronizing
  - KW Import Control
  - KVAR/Power Factor Control*
  - ControlNet Redundant Media, Ethernet, Data Highway Plus or Modbus RS232C/422/485 Supervisory Interface*
  - Heat Recovery Application Interface*
  - Multi-Unit Applications: Load Shed Control, Import/Export or kW/KVAR Control Panels*
  - *InSight System*™ Equipment Health Management
  - Printer/Logger
- Documentation
  - Drawings
  - Quality Control Data Book
  - Test Reports
  - Operation and Maintenance Manuals
- Factory Testing of Turbine and Package
  - Non-Dynamic
  - Dynamic

* Option

Solar Turbines

A Caterpillar Company

MERCURY 50

Recuperated Gas Turbine Generator Set

Power Generation

Nominal Performance*

Output Power	4600 kWe
Heat Rate	9350 kJ/kWe-hr (8865 Btu/kWe-hr)
Exhaust Flow	63 700 kg/hr (140,400 lb/hr)
Exhaust Temperature	365°C (690°F)

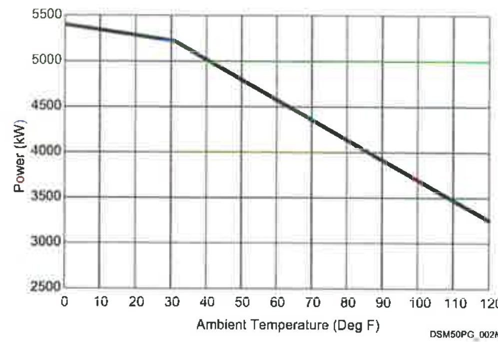
ASSUMPTIONS

Nominal rating – per ISO
At 15°C (59°F), sea level
No inlet/exhaust losses
Relative humidity 60%
Natural gas fuel with
LHV = 35 MJ/Nm³ (940 Btu/scf)
No accessory losses
Engine efficiency: 38.5%
(measured at generator terminals)

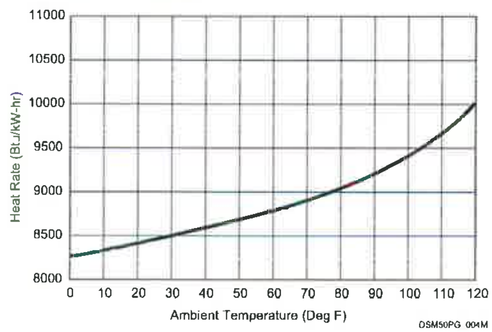
Application Performance

Steam (Unfired)	6.0 tonnes/hr (13,125 lb/hr)
Steam (Fired) 1536 °C (2800°F)	47.1 tonnes/hr (103,865 lb/hr)
Chilling (Absorp.)	5140 kW (1460 refrigeration tons)

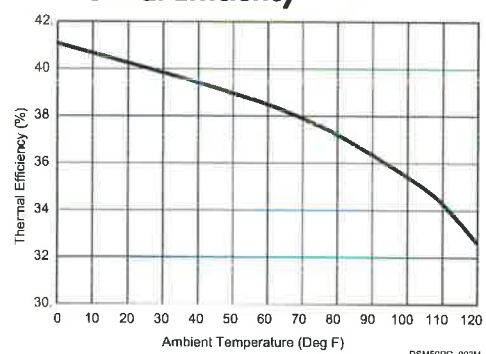
Available Power



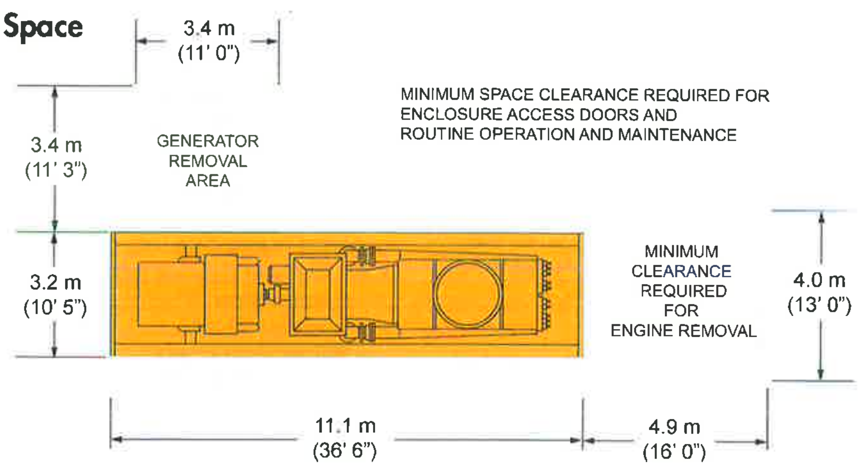
Heat Rate



Thermal Efficiency



Enclosure Access and Maintenance Space



Package Height: 3.7m (12' 3")

Package Weight: 45 700 kg (100,700 lb)

DSM50PG-003C

Solar Turbines Incorporated
P.O. Box 85376
San Diego, CA 92186-5376 U.S.A.

DSM50PG/0113/EO

FOR MORE INFORMATION

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email:powergen@solarturbines.com
Internet: www.solarturbines.com

ISO 9001
DNV
CERTIFICATED FIRM

Mercury 50 Gas Turbine Emissions Signature

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

This Product Information Letter (PIL) presents the warrantable and expected emissions of the *Mercury*™ 50 gas turbine for several regulated pollutants and addresses other frequently requested air permitting related data.

INTRODUCTION

The Advanced Turbine Systems (ATS) Program was initiated by the U.S. Department of Energy (DOE) in 1992 to produce 21st century gas turbines – systems that would be more efficient, cleaner and less expensive to operate than previously available equipment. As part of the ATS program, Solar Turbines designed the *Mercury* 50 gas turbine. The *Mercury* 50 incorporates many state-of-the-art combustion and materials technologies, resulting in an offering at 4600 kW, 8863 Btu/kW-hr, and 38.5% efficiency (ISO conditions).

The *Mercury* 50 is a "recuperated gas turbine" and is available in a gas-only configuration. It incorporates an "Ultra-Lean Premix" (ULP) combustion system, which produces a very favorable emissions signature. The *Mercury* 50 is primarily utilized in industrial power generation and distributed generation market segments where thermal efficiency, first cost and life-cycle costs are key requirements.

Technologies incorporated into the ULP system that impact the emissions signature include ULP injectors, augmented backside cooling (ABC) with a thermal barrier coating (TBC) on the combustion liner, an air diverter valve (ADV) placed upstream of the combustor to vary flow distribution within the combustion system, and the recuperator, which increases the combustion inlet air temperature. All of the technologies contribute to the low emissions signature capability over a wide range of ambient temperatures and loads, without sacrificing thermal efficiency and emissions.

EMISSIONS WARRANTIES FOR NATURAL GAS APPLICATIONS

Emission warranties are available for nitrogen oxide (NOx), carbon monoxide (CO), and unburned hydrocarbons (UHC). Emission warranties are offered subject to express terms and conditions. Table 1 summarizes the lowest allowable emissions warranty for natural gas in ppmv (typical U.S. and Canadian units) and mg/nm^3 (typical European unit). Emission warranties are only offered for steady-state conditions, at ambient temperatures between 0°F and 120°F, and are limited to 50-to-100% load on natural gas fuel. An expanded load range may be available on a case-by-case basis.

Table 1. Mercury 50 Warranty Levels

Pollutant	ppm	~mg/nm^3
NOx	5	11
CO	10	13
UHC	10	8

Air, fuel and water per ES 9-98
ppmv at 15% O_2, dry basis, steady-state operation

Table 2 converts the warranty levels shown in Table 1 into frequently used emission units.

Table 2. Mercury 50 Emissions in Alternate Emissions Units

Emissions	NOx	CO	UHC
ppm	5	10	10
lb/hr	0.81	0.99	0.57
tpy	3.6	4.3	2.5
lb/MMBtu	0.020	0.024	0.014
lb/MW-hr (at generator terminals)	0.17	0.21	0.12
g/bhp-hr (turbine shaft power)	0.06	0.07	0.04

Emission estimates at 59°F, 60% RH, sea level, no losses, full load, LHV

OTHER POLLUTANT EMISSIONS ESTIMATES – NATURAL GAS

Estimates of non-warranted pollutant emissions including particulate matter (PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC) are shown in Table 3.

Table 3. PM10, SO2, and VOC Emission Factors

Pollutant	Emission Factor, lb/MMBtu (HHV)
PM_{10}	0.021
SO_2	0.0034* or mass balance
VOC	Use 10-20% of UHC

*4/00 AP-42, Table 3.1-2a

Formaldehyde

An emissions warranty is not available for formaldehyde. In order to estimate tons per year emissions of formaldehyde for Maximum Achievable Control Technology (MACT) major source determination calculations, any appropriate emission factor can be used. Due to the limited availability of formaldehyde test data from combustion turbines and the difficulty in obtaining good data, published emission factors often vary by orders of magnitude. An example emission factor is 0.00288 lb/MMBtu (HHV) (Source: Revised HAP Emission Factors for Stationary Combustion Turbines, OAR-2002-0060, IV-B-09, 8/22/03, Table 16).

EMISSIONS WARRANTIES FOR LANDFILL AND DIGESTER GAS APPLICATIONS

The *Mercury 50* has been modified to burn landfill gas, digester gas, and other renewable fuels. Emissions capabilities will be assessed on a project-by-project basis based on fuel composition. Siloxane removal is recommended for landfill gas applications (PIL 176). Table 4 summarizes the typical emissions levels for landfill gas (300 to 460 Btu/scf LHV) and digester gas (560 to 665 Btu/scf LHV). Any emissions warranty would only be offered for steady-state conditions, at ambient temperatures between 0°F and 120°F, and limited to 50-to-100% load.

Table 4. Typical Mercury 50 Emission Warranty Levels – Landfill/Digester Gas

	Landfill Gas		Digester Gas	
Pollutant	**ppm**	**~mg/nm^3**	**ppm**	**~mg/nm^3**
NOx	15	30	25	50
CO	25	32	50	64
UHC	25	18	25	18

Air, fuel and water per ES 9-98
ppmv at 15% O_2, dry basis, steady-state operation

Volatile Organic Compounds can be estimated as 20% of UHC emissions. Particulate matter emissions can be estimated using 0.03 lb/MMBtu (HHV). SO_2 emissions can be estimated using a mass balance or other customer preferred emission factor.

COLD AMBIENT EMISSIONS ESTIMATES – NATURAL GAS

Solar's standard temperature range warranty for the *Mercury* 50 is between 0°F and 120°F (-18°C and 49°C). To estimate actual emissions for when the turbine is not operating within the warrantable temperature range, the following expected emission rates were extrapolated from San Diego factory tests. Levels may vary at extreme temperatures and as a result of variations in other parameters such as fuel composition and fuel quality. Table 5 gives expected emissions (ppm corrected to 15% O_2) as a function of ambient temperature.

Table 5. Expected Mercury 50 Emissions Levels below 0°F

Ambient	Engine Load	Fuel	NOx, ppm	CO, ppm	UHC, ppm
0°F to –20°F (-18°C to -29°C)	50 to 100% load	Natural Gas	42	100	50
Below –20°F (-29°C)	50 to 100% load	Natural Gas	120	150	75

EMISSIONS ESTIMATES AT <50% LOAD – NATURAL GAS

The *Mercury* 50 will remain in low emissions mode until the primary zone temperature drops below the design allowable primary zone temperature. Ambient temperature will be a factor.

Table 6 provides estimates of NOx, CO, and UHC emissions when operating below 50% load. No emission guarantee is provided by Solar for <50% load operation.

Table 6. Estimated Non-ULP Mode Emissions

Engine Load	NOx, ppm	CO, ppm	UHC, ppm
Less than 50%	120	50	50
Idle	70	3500	500

START-UP EMISSIONS – NATURAL GAS

The start-up duration is the same for cold, warm, and hot starts. Estimated start-up emissions are summarized in Table 7 in "pounds per start-up and shut-down event". The emission estimates are calculated from empirical exhaust characteristics. Starting up the turbine and getting into the ULP mode takes three steps:

1. Purge-crank
2. Ignition and acceleration to idle
3. Loading / thermal stabilization

During the "purge-crank" step, rotation of the turbine shaft is accomplished with an electric starter motor to remove any residual fuel gas in the engine flow path and exhaust.

During "ignition and acceleration to idle," fuel is introduced into the combustor and ignited in a diffusion flame mode and the engine rotor is accelerated to idle speed. The third step, "Loading thermal stabilization," consists of applying up to 50% load while allowing the combustion flame to transition and stabilize.

Once 50% load is achieved, the turbine transitions to ULP mode and the engine control system begins to hold the combustion primary zone temperature and limit pilot fuel to control the CO and NOx emission levels.

It is important to note that the start-up sequence is a short-term transient condition, with an expected duration of less than 20 minutes.

SHUTDOWN EMISSIONS – NATURAL GAS

Normal, planned cool down shutdown duration for the *Mercury* 50 takes about 9 minutes.

Table 7. Estimated Mercury 50 Emissions per Start-up Sequence and Shutdown Sequence – Natural Gas

	NOx, lb	CO, lb	UHC, lb	CO_2, lb
Total Start-up Emissions	1.4	26.5	2.2	538
Total Shutdown Emissions	0.7	5.1	0.5	579

Assumes ISO conditions: 59°F, 60% RH, sea level, no losses.
Assumes unit is operating at full load prior to shutdown.
Assumes natural gas fuel.

COMMISSIONING EMISSIONS

Commissioning generally takes place over a two-week period. Static testing, where no combustion occurs, usually requires one week and no emissions are expected. Dynamic testing, where combustion will occur, will see the engine start and shut down a number of times during which a variety of loads will be placed on the system. It is impossible to predict how long the turbine will run and in what combustion / emissions mode it will be running during this period. The dynamic testing period is generally followed by one to two days of "tune-up" during which the turbine is running at various loads, most likely within low-emissions mode (warranted emissions range).

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

CAT® CG260

Series Gas Generator Sets

CAT®

CAT® CG260

SMARTER ENERGY SOLUTIONS

COMMERCIAL AND INDUSTRIAL FACILITIES
Facilities such as manufacturing plants, resorts, shopping centers, office or residential buildings, universities, data centers and hospitals reduce operating costs and carbon footprint simultaneously.

ELECTRIC UTILITIES
Caterpillar has led innovation to deliver stationary and containerized gas power plants to electric utilities and district energy facilities around the world for both continuous grid support and peak electricity demand.

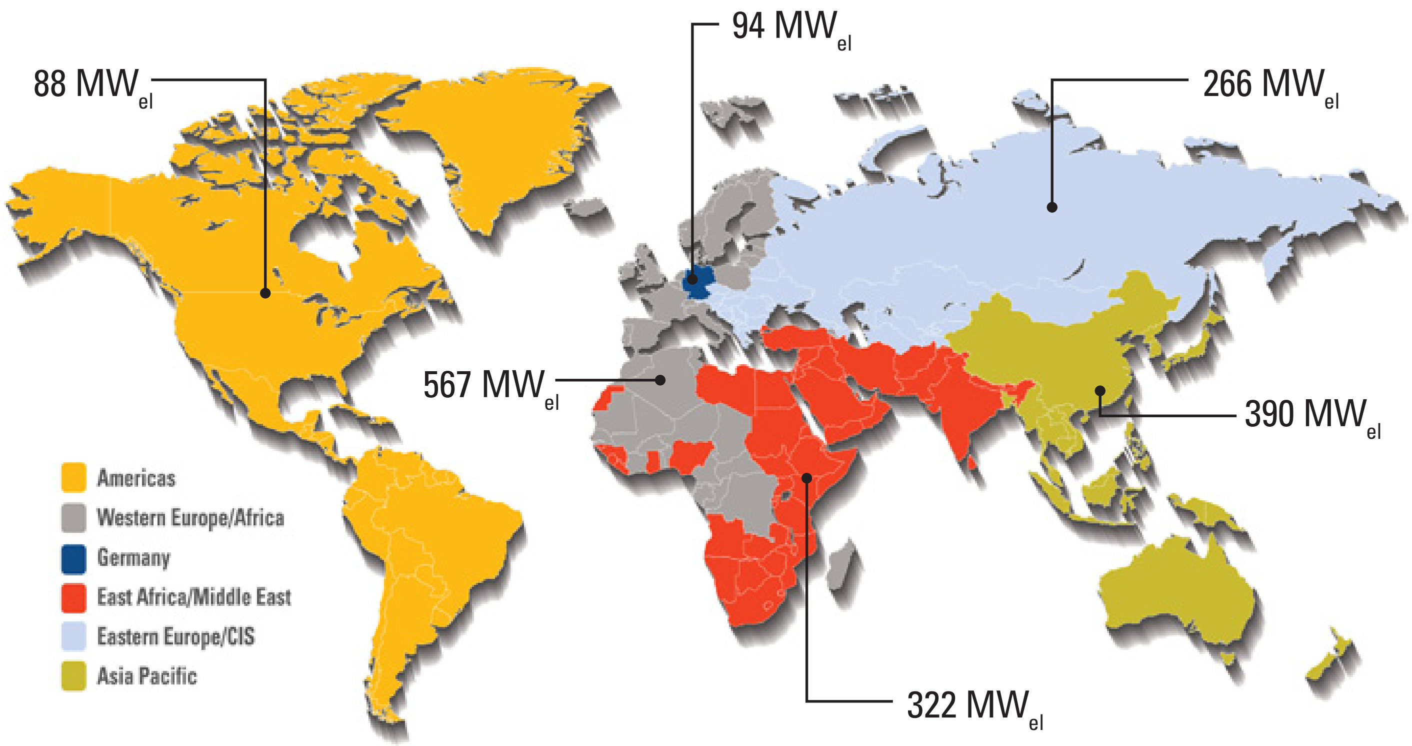
MINES
Mining operators increase mine safety and reduce carbon emissions with coal gas, while many other mining operations are realizing the benefits of onsite gas power generation to support greenfield site development.

AGRICULTURE AND FOOD / BEVERAGE PROCESSING
Biogas, a useful byproduct of the anaerobic digestion of organic waste, is created by food processors, ethanol and biodiesel manufacturers, and farms around the world as a renewable fuel resource for Cat® powered electricity generation.

LANDFILLS AND WASTEWATER TREATMENT PLANTS
Landfill and sewage gases are is generated by communities around the world as part of sanitary process infrastructure. Instead of destroying or flaring the methane gas produced, communities make beneficial use of this fuel as part of a sustainable energy program.

GREENHOUSES
In greenhouses, Cat gas generator sets simultaneously deliver electricity for lighting or sale to the local grid, hot water for facility heating, and carbon dioxide as an organic fertilizer for increased crop production.

Installed capacity of 1,727 MW_{el} with more than 467 generator sets worldwide



MEETING YOUR NEEDS HAS SHAPED OUR HISTORY

At Caterpillar, we understand what it takes to deliver a successful gas power generation system, and it starts with a core machine that is designed for efficiency and reliability. Since the 1920s, Caterpillar has been designing and building engines for power production. Although the technology has changed over the years, the philosophy hasn't: to deliver the most reliable power generation at the lowest possible cost of ownership and operation. Today, Caterpillar not only manufactures power generation equipment, but we also provide customized project financing and trade solutions via Cat Financial and Cat World Trade.

THE COMPLETE SOLUTION

Caterpillar is your complete gas solutions partner. From mechanical systems such as gas fuel train and heat recovery systems, to exhaust aftertreatment that complies with the world's most stringent emission requirements, Cat Gas Solutions engineering works with your local Cat dealer to deliver a complete scope of supply. Caterpillar also provides electrical systems such as master controls and paralleling switchgear, electrical distribution switchgear and uninterruptible power supplies (UPS) that can meet either UL or IEC requirements.

PRODUCT SUPPORT WORLDWIDE

Your gas power system is supported by our factory trained global network of Cat dealers. Therefore, you can rest assured that your equipment will be ordered, delivered, installed and commissioned in consultation with a local expert. You'll also have the confidence that Caterpillar will be there to keep you up and running. Cat dealers have over 1,600 dealer branch stores operating in 200 countries to provide the most extensive post-sales support including oil and fuel monitoring services, preventive maintenance and comprehensive customer support agreements.

LOWER LIFE CYCLE COST

With longer maintenance intervals, higher fuel efficiency and competitive repair options, Caterpillar delivers the lowest total owning and operating costs. When you design your facility within the Cat Application and Installation Guidelines, you can expect generator set availability up to 99 percent of planned operating hours annually. It all adds up to a strong return on your investment, year after year.

CG260: HIGH PERFORMANCE W

HIGHLY EFFICIENT

With recent improvements in turbocharging, system control, and optimized pre-chamber spark plugs, the CG260 gas generator now delivers electrical efficiencies up to 44.1 percent.

LOWER OPERATING COSTS

Optimized engine components mean the CG260 consumes up to 30 percent less lubricating oil than competing gas generators, which means more money stays in your company's pockets.

GREATER AVAILABILITY

The CG260 utilizes particle free combustion with chamber plugs for extended maintenance intervals and improved heat utilization. The CG260 can run on average 200 hours per year longer than competitive systems.

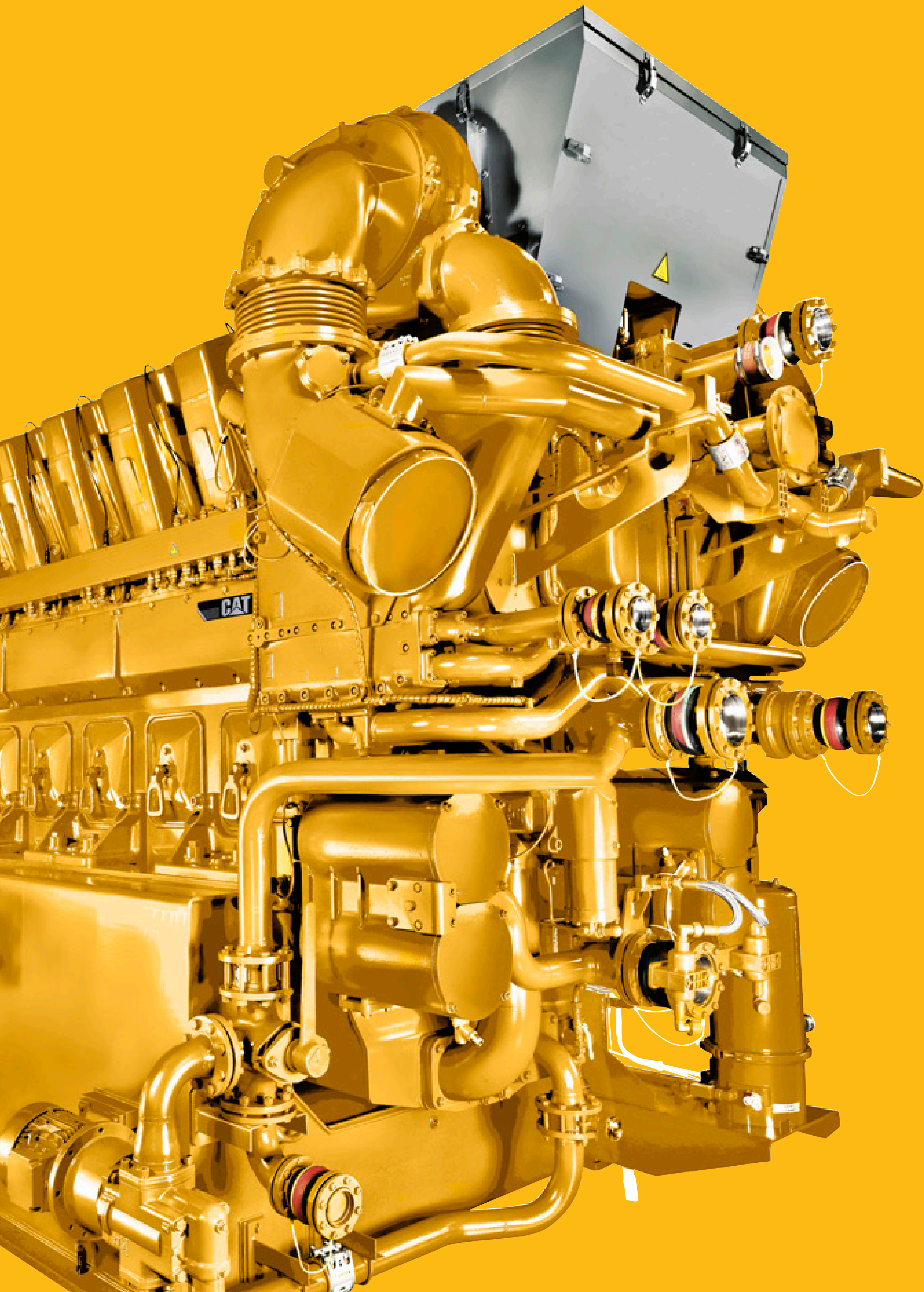
SYSTEM CONTROL

Control the entire system, not just the engine, with the Cat Total Electronic Management System. Control or monitoring of ancillary equipment such as heat recovery modules, exhaust aftertreatment and fuel treatment systems becomes seamless. Features like temperature monitoring for each cylinder and anti-knock control allow for maximum power output and the best possible fuel utilization, even with fluctuating gas composition.

HIGH ALTITUDE AND AMBIENT PERFORMANCE

The new high-boost, waste-gated A140 turbo allows the CG260 to operate at full power up to 45^0 C intake air, and supply stable transient load response at higher altitudes.

VITH LOW OPERATING COSTS



50 Hz PRODUCT PERFORMANCE

ENGINE TYPE	UNITS	CG260-12		CG260-16	
Bore/stroke	mm in	260/320	10.2/12.6	260/320	10.2/12.6
Displacement	l in^3	203.9	12,443	271.8	16,586
Speed	rpm	1,000		1,000	
Mean piston speed	m/s ft/s	10.7	35	10.7	35
Length 1)	mm in	7,860	309	9,200	362
Width 1)	mm in	2,660	105	2,690	106
Height 1)	mm in	3,390	133	3,390	133
Dry weight genset	kg lb	43,100	95,036	51,400	113,337

NATURAL GAS

ENGINE TYPE	UNITS	CG260-12		CG260-16	
Electrical power 2)	kW_e	3,333		4,300	
Mean effective pressure	bar psi	20.0	290	19.4	281
Thermal output (+/-8 %) 3)	kW Btu/m	3,206	182,484	4,164	237,013
Electrical efficiency 2)	%	44.1		44.1	
Thermal efficiency 3)	%	42.4		42.7	
Total efficiency	%	86.5		86.8	

$NO_x \leq$ 500 mg/Nm^3, 1 g/bhp-h

BIOGAS

ENGINE TYPE	UNITS	CG260-12		CG260-16	
Electrical power 2)	kW_e	2,830		3,770	
Mean effective pressure	bar psi	17.0	247	17.0	247
Thermal output (+/-8%) 3)	kW Btu/m	2,734	155,618	3,460	196,942
Electrical efficiency 2)	%	42.3		42.9	
Thermal efficiency 3)	%	40.8		39.4	
Total efficiency	%	83.1		82.3	

$NO_x \leq$ 500 mg/Nm^3, 1 g/bhp-h

1) Transport dimensions of genset; components set up separately must be taken into consideration.
2) According to ISO 3046/1 at voltage = 11 kV, PF = 1.0 for 50 Hz, and a minimum methane number of MN 70 for natural gas, MN 130 for biogas.
3) Cooling of the exhaust gases to 120° C (248° F) for natural gas and 150° C (302° F) for biogas, plus engine jacket water heat.

NO_x emissions: Measured as NO_2 dry exhaust gas @ 5% O_2
Biogas fuels assumed to meet published engine-in contaminant limits with compositions:
Sewage gas (65 % CH_4 / 35 % CO_2)
Biogas (60 % CH_4 / 32 % CO_2 / 8% N_2)
Landfill gas (50 % CH_4 / 27 % CO_2 / 23% N_2)
Minimum heating value (LHV) = 18.0 MJ/Nm^3 or 457 Btu/scf.
Specifications for special gases available.

Engine configuration with dry exhaust manifolds.
Data is representative and non-binding. Contact your Cat dealer for site and fuel specific performance.

60 Hz PRODUCT PERFORMANCE

ENGINE TYPE	UNITS	CG260-12		CG260-16	
Bore/stroke	mm in	260/320	10.2/12.6	260/320	10.2/12.6
Displacement	l in³	203.9	12,443	271.8	16,586
Speed	rpm	900		900	
Mean piston speed	m/s ft/s	9.6	31	9.6	31
Length [1]	mm in	8,000	315	9,420	371
Width [1]	mm in	2,660	105	2,690	106
Height [1]	mm in	3,390	133	3,390	133
Dry weight genset	kg lb	42,500	93,713	51,450	113,447

NATURAL GAS

ENGINE TYPE	UNITS	CG260-12		CG260-16	
Electrical power [2]	kW_e	3,000		4,000	
Mean effective pressure	bar psi	18.1	263	18.1	263
Thermal output (+/-8 %) [3]	kW Btu/m	2,893	164,669	3,884	221,076
Electrical efficiency [2]	%	43.7		43.7	
Thermal efficiency [3]	%	42.1		42.4	
Total efficiency	%	85.8		86.1	

NO_x ≤ 500 mg/Nm³, 1 g/bhp-h

BIOGAS

ENGINE TYPE	UNITS	CG260-12		CG260-16	
Electrical power [2]	kW_e	2,530		3,370	
Mean effective pressure	bar psi	17.0	247	17.0	247
Thermal output (+/-8%) [3]	kW Btu/m	2,416	137,518	3,018	171,784
Electrical efficiency [2]	%	42.2		43.1	
Thermal efficiency [3]	%	40.3		38.6	
Total efficiency	%	82.5		81.7	

NO_x ≤ 500 mg/Nm³, 1 g/bhp-h

1) Transport dimensions of genset; components set up separately must be taken into consideration.
2) According to ISO 3046/1 at voltage = 4.16 kV, PF = 1.0 for 60 Hz, and a minimum methane number of MN 80 for natural gas, MN 130 for biogas.
3) Cooling of the exhaust gases to 120° C (248° F) for natural gas and 150° C (302° F) for biogas, plus engine jacket water heat.

NO_x emissions: Measured as NO_2 dry exhaust gas @ 5% O_2
Biogas fuels assumed to meet published engine-in contaminant limits with compositions:
Sewage gas (65 % CH_4 / 35 % CO_2)
Biogas (60 % CH_4 / 32 % CO_2, rest N_2)
Landfill gas (50 % CH_4 / 27 % CO_2, rest N_2)
Minimum heating value (LHV) = 18.0 MJ/Nm³ or 457 Btu/scf.
Specifications for special gases available.

Engine configuration with dry exhaust manifolds.
Data is representative and non-binding. Contact your Cat dealer for site and fuel specific performance.

For more information and to contact your local Cat dealer, visit www.catelectricpowerinfo.com/gas

LEBE0018-01 June 2012

Customer: Venture - Scholl Canyon Landfill
Attention:
Job Ref:

Engine Mfg: Caterpillar | **Model No:** CG260-16
BHP (KW): 3370 EKW | **Cycle:** 4 | **RPM:** 900
Fuel Type : Clean Landfill Gas | **Load:** 100% | **Hours/Year:** 8,300

SCR Model | **Nbr Units:** 1 | **SCR Controls:** Closed Loop

Item Description	English	Units		
Engine Output	4,643	BHP		
Exhaust Gas Mass Flow	39,659	Lbs/Hour		
Exhaust Gas Temperature	847.4	°F		
Exhaust Flow - Standard Units	514,608	SCFH		
Pre-Catalyst NOx Emissions	1.15	G/BHP-Hr		
Pre-Catalyst NOx Emissions	11.77	Lbs/Hr/Eng		
Pre-Catalyst NOx Emissions	86	PPMV@15% O2		
Post-Catalyst NOx Emissions	0.200	G/BHP-Hr		
Post-Catalyst NOx Emissions	2.047	Lbs/Hr/Eng		
Post-Catalyst NOx Emissions	15	PPMV@15% O2		
Percentage NOx Reduction	82.6	%		
Pre-Catalyst CO Emissions	2.50	G/BHP-Hr		
Pre-Catalyst CO Emissions	25.59	Lbs/Hr/Eng		
Pre-Catalyst CO Emissions	300	PPMV@15% O2		
Post-Catalyst CO Emissions	1.070	G/BHP-Hr		
Post-Catalyst CO Emissions	10.952	Lbs/Hr/Eng		
Post-Catalyst CO Emissions	128	PPMV@15% O2		
Percentage CO Reduction	57.2	%		
Pre-Catalyst NMEHC Emissions	0.45	G/BHP-Hr		
Pre-Catalyst NMEHC Emissions	4.61	Lbs/Hr/Eng		
Pre-Catalyst NMEHC Emissions	97	PPMV@15% O2		
Post-Catalyst NMEHC Emissions	0.095	G/BHP-Hr		
Post-Catalyst NMEHC Emissions	0.972	Lbs/Hr/Eng		
Post-Catalyst NMEHC Emissions	20	PPMV@15% O2		
Percentage NMEHC Reduction	78.9	%		
Pre-Catalyst HCHO Emissions	0.45	G/BHP-Hr		
Pre-Catalyst HCHO Emissions	4.61	Lbs/Hr/Eng		
Pre-Catalyst HCHO Emissions	68	PPMV@15% O2		
Post-Catalyst HCHO Emissions	0.1300	G/BHP-Hr		
Post-Catalyst HCHO Emissions	1.3307	Lbs/Hr/Eng		
Post-Catalyst HCHO Emissions	20	PPMV@15% O2		
Percentage HCHO Reduction	71.1	%		
Pressure Drop Across Catalyst/Mixer	6.0	In. WC		
40% Urea / 60% H2O Consumption Rate	2.3	Gallons/Hour		
SCR Catalyst Volume	70.00	Cu.Ft		
SCR Catalyst Configuration	10x10x3x12			
SCR Catalyst Space Velocity	7,352	SCFH/FT^3		
Oxidation Catalyst Volume	8.00	Cu.Ft		
Oxidation Catalyst Configuration	10x10x1x4			
Oxidation Catalyst Space Velocity	64,326	SCFH/FT^3		

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines[b]		Digester Gas-Fired Turbines[d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[e]	Emission Factor Rating
CO_2[f]	50	D	27	C
Lead	ND	NA	< 3.4 E-06[g]	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO_2	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.
[b] SCC for landfill gas-fired turbines is 2-03-008-01.
[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.
[d] SCC for digester gas-fired turbine include 2-03-007-01.
[e] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.
[f] For landfill gas and digester gas, CO_2 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).
[g] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[h] Based on adding the formaldehyde emissions to the NMHC.

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)
(Amended June 3, 2005)(Amended February 1, 2008)(Amended July 9, 2010)
(Amended September 7, 2012)

RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops or the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

(3) CERTIFIED SPARK-IGNITION ENGINES mean engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(4) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.

90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response plan, because of either high influent flows caused by precipitation or a disaster.

TABLE III-A
CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000

TABLE III-B
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2016

NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

[3] ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

APPENDIX F - LANDFILL GAS FACILITY
EMISSION FACTORS FOR THE PROPOSED EQUIPMENT
SCHOLL CANYON LANDFILL GAS FACILITY

Equipment Type	NO_X		CO		VOC		PM10/2.5		SO_X		NO_X, LBS/HR	CO, LBS/HR	VOC, LBS/HR	PM10/2.5, LBS/HR	SO_X, LBS/HR
Solar Mercury™ 50 Gas Turbine (Simple Cycle)[1]	15	PPMV	25	PPMV	5	PPMV	9.2	LBS/MMCF	1.45	LBS/MMCF	3	3.05	0.35	1.14	0.18
Caterpillar CG260-16 IC Engine[2]	11	PPMV	250	PPMV	30	PPMV	9.2	LBS/MMCF	1.45	LBS/MMCF	1.44	19.89	1.36	0.75	0.12

Equipment Type	Electric Output, $KW_{(NET)}$	Heat Rate (LHV), Btu/kWh	Heat Rate (HHV), Btu/kWh	Fuel Type	Fuel LHV, Btu/SCF	Fuel HHV, Btu/SCF	Dry Fuel Factor (Fd), dscf/mmbtu	Fuel Flow MMBtu/hr	Fuel Flow MMCF/hr	Fuel Flow SCFM
Solar Mercury™ 50 Gas Turbine (Simple Cycle)[1]	4,853	8,951	9,926	Landfill Gas	348	387	9713	48	0.124	2067
Caterpillar CG260-16 IC Engine[2]	3,370	8,378	9290	Landfill Gas	348	387	9713	31	0.081	1350

NOTES:

[1]Solar Mercury™ 50 Gas Turbines (Simple Cycle):
- NO_X, CO, and VOC emission concentration based on the manufacturer warranty levels for landfill gas combustion
- PM10 emission factor based on AP-42, Table 3.1-2b - Landfill Gas Fired Turbines
- SO_X emission factor based on 2009 through 2013 SCAQMD AER

[2]Caterpillar CG260-16IC Engine:
- NO_X, CO, and VOC emission concentration based on Rule 1110.2 Emission Limits
- PM10 emission factor based on AP-42, Table 3.1-2b - Landfill Gas Fired Turbines
- SO_X emission factor based on 2009 through 2013 SCAQMD AER

-Higher heating value is calculated based on the landfill gas composition as reported in the Venture Engineering & Construction Report dated March 20,2015.

APPENDIX F - LANDFILL GAS FACILITY
DAILY, MONTHLY, ANNUAL POTENTIAL EMISSIONS
SCHOLL CANYON LANDFILL GAS FACILITY

SOLAR MERCURY **SIMPLE CYCLE**

Pollutant	No. of Normal Operating Hours per Day	Normal Operating Hour Emission Rate	Number of Normal Operating Hours Per Month	Number of Normal Operating Hours Per Year
NO_X	24.00	3.00	720	7862
CO	24.00	3.05	720	7862
VOC	24.00	0.35	720	7862
PM10	24.00	1.14	720	7862
SO_X	24.00	0.18	720	7862

NOTES:
1) Air pollutants emisison rates during startup, shutdown, and maintenance are assumed to be equal as the emissions during the normal operation.
2) Based on the LFG availability, the annual operating hours per turbine is adjusted by 91%.

CAT CG260-16 **IC ENGINE - 30 MINUTES STARTUP**

Pollutant	No. of Normal Operating Hours per Day	Normal Operating Hour Emission Rate	No. of Startups Per Day	Uncontrolled Emission lb / Startup	No. of Maintenance Operating Hours per Day	Maintenance Operating Hour Emission Rate	Number of Startups/ Shutdowns per Month	Number of Normal Operating Hours Per Month	Number of Startups/ Shutdowns per Year	Number of Normal Operating Hours Per Year
NO_X	13.00	1.44	2	14.40	10	14.40	10	705	120	7965
CO	13.00	19.89	2	132.60	10	132.6	10	705	120	7965
VOC	13.00	1.36	2	2.72	10	2.72	10	705	120	7965
PM10	13.00	0.75	2	0.75	10	0.75	10	705	120	7965
SO_X	13.00	0.12	2	0.12	10	0.12	10	705	120	7965
	Starts/stops =	1.00	hours/day per turbine		5.00	60.00	Hours / year per turbine			
	Maintenance =	10	hours/day per turbine		10	10	Hours / year per turbine			
	Daily = 24 hours with 2 startS		Monthly = 720 hours with 10 starts							

NOTES:
1) The engine is assumed to have a fast start to 100% load. Emissions during shutdown is assumed to be same as controlled emission factors.
2) The engine is assumed to be equipped with emission control technology with 90% NO_X, 85% CO, and 50% VOC control efficiency.
3) Based on the LFG availability, the annual operating hours per engine is adjusted by 93%.

SOLAR MERCURY	EMISSIONS OF 1 TURBINE					EMISSIONS OF 4 TURBINES				
Pollutant	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Annual PTE (tons)	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Annual PTE (tons)
NO_X	72.00	2,160	72	23,587	11.79	288.00	8,640	288	94,349	47.17
CO	73.20	2,196	73	23,980	11.99	292.80	8,784	293	95,921	47.96
VOC	8.40	252	8	2,752	1.38	33.60	1,008	34	11,007	5.50
PM10	27.36	821	27	8,963	4.48	109.44	3,283	109	35,853	17.93
SO_X	4.32	130	4	1,415	0.71	17.28	518	17	5,661	2.83

CAT CG260-16	EMISSIONS OF 1 ENGINE					EMISSIONS OF 6 ENGINES				
Pollutant	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Annual PTE (Tons)	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Annual PTE (Tons)
NO_X	191.52	1,303	43	13,342	6.67	1149.12	7,819	261	80,051	40.03
CO	1849.77	16,674	556	175,666	87.83	11098.62	100,047	3335	1,053,995	527.00
VOC	50.32	1,013	34	11,186	5.59	301.92	6,079	203	67,118	33.56
PM10	18.75	544	18	6,071	3.04	112.50	3,263	109	36,428	18.21
SO_X	3.00	87	3	971	0.49	18.00	522	17	5,829	2.91

APPENDIX F - LANDFILL GAS FACILITY
EMISSION OFFSET COSTS
SCHOLL CANYON LANDFILL GAS FACILITY

SOLAR MERCURY™ 50 GAS TURBINE (SIMPLE CYCLE)

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SO_X 30 day Average, lbs/day	
SOLAR MERCURY™ 50 SCCT1	PTE	72	73	8	27	4	
SOLAR MERCURY™ 50 SCCT2	PTE	72	73	8	27	4	
SOLAR MERCURY™ 50 SCCT3	PTE	72	73	8	27	4	
SOLAR MERCURY™ 50 SCCT4	PTE	72	73	8	27	4	
NET INCREASE EMISSIONS TO OFFSET		288	293	34	109	17	
OFFSET RATIO APPLIED		346	351	40	131	21	
ERC PRICE, $/(LBS/DAY)		$110,000	$0	$5,170	$143,000	$110,000	
TOTAL PRICE		$38,016,000	$0	$208,454	$18,779,904	$2,280,960	**$59,285,318**

CATERPILLAR CG260-16 IC ENGINE

Equipment	Emissions Calculated Based On	NO_X 30 day Average, lbs/day	CO 30 day Average, lbs/day	VOC 30 day Average, lbs/day	PM 30 day Average, lbs/day	SO_X 30 day Average, lbs/day	
CATERPILLAR CG260-16 ICE1	PTE	43	556	34	18	3	
CATERPILLAR CG260-16 ICE2	PTE	43	556	34	18	3	
CATERPILLAR CG260-16 ICE3	PTE	43	556	34	18	3	
CATERPILLAR CG260-16 ICE4	PTE	43	556	34	18	3	
CATERPILLAR CG260-16 ICE5	PTE	43	556	34	18	3	
CATERPILLAR CG260-16 ICE6	PTE	43	556	34	18	3	
NET INCREASE EMISSIONS TO OFFSET		261	3,335	203	109	17	
OFFSET RATIO APPLIED		313	4,002	243	131	21	
ERC PRICE, $/(LBS/DAY)		$110,000	$0	$5,170	$143,000	$110,000	
TOTAL PRICE		$34,404,480	$0	$1,257,179	$18,661,500	$2,296,800	**$56,619,959**

NOTE:
1) ERC price is based on the highest ask South Coast Market Pricing for Coastal Zone plus 10%
2) There is no offset price on CO since it's in attainment

SCPPA/GWP
Glendale, CA

Landfill Gas Processing

Phase 1 – Task # 5
Mercury 50 Turbine, Taurus 60 Turbine & Caterpillar CG260-16 IC Engine Operating on LFG Only at The Scholl Canyon Landfill

Project No. C14-1106-00

Client Representative:
Lon Peters

Venture Project Manager:
Kevin S. O'Connor

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VENTURE™
Engineering & Construction

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1 PROJECT OBJECTIVES

As part of a larger repowering project at the Grayson Power Plant, Glendale Water & Power (GWP) wishes to consume the existing 7,500 SCFM of landfill gas (LFG) at the Scholl Canyon Landfill as supplemental fuel in a prime mover for the purpose of generating electricity. The objective is to utilize the entire volume of the existing LFG (38.3% methane) as fuel in the prime movers selected for this study. Blending the LFG with another source of fuel to increase the heating value has been excluded for the purposes of this study.

The prime movers evaluated during Task #5 project are:

- Mercury 50 Solar Turbine
- Taurus 60 Solar Turbine.
- The CG260-16 Caterpillar Engine

This report provides a summary of the work, including recommendations of equipment, possible plant configurations, supplemental fuel requirements, and order of magnitude capital cost estimates for the technology evaluated to meet the Task #5 project goals.

The flow rate and composition of the raw LFG available at the Scholl Canyon facility are presented below in Table 1.

TABLE 1: Raw LFG Compositions

Parameters			Raw Landfill Gas
Flow Rate		**SCFM**	7,500
Deliver Pressure		**Psig**	45
Temperature		**°F**	90
Heating Value		**BTU/ft^3**	348.3
Methane	(MOL %)	**CH_4**	38.3%
Carbon Dioxide	(MOL %)	**CO_2**	32.2%
Nitrogen	(MOL %)	**N_2**	25.2%
Oxygen	(MOL %)	**O_2**	4.3%
Ethane	(MOL %)	**C_2H_6**	0.0%
Propane	(MOL %)	**C_3H_8**	0.0%
IsoButane	(MOL %)	**C_4H_{10}**	0.0%
N-Butane	(MOL %)	**C_4H_{10}**	0.0%
IsoPentane	(MOL %)	**C_5H_{12}**	0.0%
n-Pentane	(MOL %)	**C_5H_{12}**	0.0%
Hexanes	(MOL %)	**C_6H_{14}**	0.0%

2 SILOXANES

In gas turbines, deposits of silicon dioxide form in the hottest areas, mainly on the first few rows of nozzles and blades. Silicon dioxide is generated from oxidation of siloxane compounds during combustion of biogas in the gas turbine. Prolonged operation of gas turbines where siloxanes are present in the biogas can lead to severe erosion of the turbine blades and a significant drop in operating efficiency.

Venture has reviewed the gas analysis report performed by Gas Technology Institute that was conducted at the Scholl Canyon facility on April 12, 2010, in which they analyzed the raw LFG. A copy of the report is located in Appendix A.

The concentration of siloxanes in the raw LFG sample that was analyzed in 2010 was found to be 7.0 mg Si/Nm3 of LFG.

The manufacturer's specification for siloxane limits in the feed fuel to the IC engine and the gas turbines used in this study are presented in Table 2 and are located in Appendix B.

TABLE 2: Siloxane Limits

Manufacturer Siloxane Limits mg Si/Nm3 of LFG	
Solar – Mercury	1.9
Solar – Taurus 60	3.8
Caterpillar Engine – CG260-16	0.5

The level of siloxanes present in the landfill gas exceed these manufacture limits, and their significant effects on the power generation equipment will occur, as a result, the landfill gas from Scholl Canyon must be pretreated for the removal of siloxanes.

The gas cleaning technology for the removal of siloxanes will involve both a regenerable adsorption system using a multi-layered bed of physical adsorbent media, followed by a non regenerable activated carbon polishing skid. The regenerable gas cleaning system would be regenerated using ambient air heated to 425-455 °F by the use of an electric heater and a centrifugal blower.

3 PRIME MOVERS EVALUATION

Venture has assumed that the plant would be built to handle the consumption of the entire 7,500 SCFM of the LFG available at the Scholl Canyon Facility. The prime mover that is being evaluated in this study includes the Mercury 50 Solar Turbine, Taurus 60 Solar Turbine and the CG260-16 Caterpillar Engine.

3.1 GAS TURBINES

3.1.1 Solar Turbines

Solar Turbines Incorporated is a subsidiary of Caterpillar Inc., and one of the world's leading manufacturers of industrial gas turbines. Solar provides new low-emission industrial gas turbines that can operate on a variety of gaseous fuels.

3.1.2 Mercury 50 and Taurus 60 Gas Turbines

As a power source for landfill gas-to-energy facility, Solar turbines can operate on fuels containing a wide range of heating values, as long as the minimum acceptable heating value and the volumetric flow rate requirements are maintained.

The existing LFG has a heat content of approximately 348 BTU/ft^3. This heating value satisfies the minimum heating value of 300 BTU/ft^3 required by the Mercury 50 turbine and the Taurus 60 Turbine. Therefore, the LFG contains enough energy (heating value) as a stand-alone fuel to generate electricity when burned in a Mercury 50 or a Taurus 60 Turbine. The calculated heating value for the LFG is located in Appendix A.

The Mercury 50 turbine has a volumetric flow rate requirement of ~ 2,080 SCFM when operating at full load. The Taurus 60 turbine has a volumetric flow rate requirement of ~ 3,050 SCFM when operating at full load.

The turbine manufacturer (Solar Turbines) guarantees the exhaust concentrations of the pollutants when the Taurus turbine is operating on loads ranging from 80% to 100%, regardless of the fuel. Therefore, the Taurus 60 turbine must be operated at a minimum load of 80%.
The Mercury 50 turbine can operate on loads ranging from 50% to 100% regardless of the fuel.

The primary project objective states the utilization of the entire volumetric flow rate (7,500 SCFM) of the LFG as a fuel source for the prime movers selected in this study. In order to achieve this primary goal, four (4) Mercury 50 turbines or three (3) Taurus 60 Turbines are needed.

The fuel heat content, volumetric flow rate requirements as well as the power generation data for each the Solar turbines are listed in Table 3. The operating specification sheets of each Turbine are located in Appendix C.

TABLE 3: Fuel Rates and Volumetric Flow Requirements for each Solar Turbine

Solar Turbine	Fuel Heat Content	Load	Minimum Load	Heat Rate per Turbine	Fuel Consumption of One	Flow Requirement of One	Turbines Needed	Power Output from One Turbine	Net Power Output of All Turbines	Gross Power Output of All Turbines
Model	**(BTU/ft^3)**	**(%)**	**(%)**	**(BTU/kWh)**	**(MMBTU/hr)**	**(SCFM)**	**(#)**	**(kWh)**	**(MWh)**	**(MWh)**
MERCURY 50	348.3	100%	50%	8,951	43.4	2,076	3.6	4,853	17.5	19.4
TAURUS 60	348.3	100%	80%	10,624	63.8	3,053	2.5	6,001	15.0	24.0

As indicated in Table 3, a Mercury 50 turbine requires ~ 2,080 SCFM of LFG to operate one turbine at full load. The LFG fuel would provide the necessary fuel consumption of ~ 43 MMBTU/hr. The net power output from consuming all the LFG at full load is ~18 MW.

In addition, a Taurus 60 turbine requires ~3,050 SCFM of LFG to operate one turbine at full load. The LFG fuel would provide the necessary fuel consumption of ~64 MMBTU/hr. The net power from consuming all the LFG at full load is ~15 MW.

3.2 IC ENGINE

3.2.1 Caterpillar Engines

Caterpillar IC engines are designed to operate with flexible fuel options on various gas sources. The engines are designed for high efficiency, and for meeting most global emissions specifications. Their products range from 60 kW to 9.7 MW with customizable options to provide for any power needs.

3.2.2 Caterpillar Engine Model CG260-16

As a power source for landfill gas-to-energy facility, Caterpillar engines can operate on a wide range of heating value fuels; as long as the minimum acceptable heating value and the volumetric flow rate requirements are maintained.

The existing LFG has a heat content of approximately 348 BTU/ft^3. This heating value satisfies the minimum heating value of 350 BTU/ft^3 required by the Caterpillar engine; therefore, the LFG contains enough energy (heating value) to produce electricity using the Caterpillar CG260-16 engine. The calculated heating value for the LFG is located in Appendix A.

The Caterpillar CG260-16 has a volumetric flow rate requirement of ~ 1,350 SCFM when operating at full load.

The engine manufacturer (Caterpillar) guarantees the exhaust concentrations of the pollutants when the engine is operating on loads ranging from 50% to 100%, regardless of the fuel. Therefore, the Caterpillar CG260-16 engine can be operated at a minimum of 50% load.

The primary project objective states the utilization of the entire volumetric flow rate (7,500 SCFM) of the LFG as a fuel source for the prime movers selected in this study. In order to achieve this primary goal, six (6) Caterpillar CG260-16 engines are needed.

The fuel heat content and the volumetric flow rate requirement for the Caterpillar CG260-16 engine operating on LFG as well as its electrical power generation are listed in Table 4. The operating specification sheet of the Caterpillar CG260-16 engine operating on LFG fuel is located in Appendix C.

TABLE 4: Fuel Rates and Volumetric Flow Requirements for Caterpillar Engine

Caterpillar Engine	Fuel Heat Content	Load	Minimum Load	Heat Rate per Engine	Fuel Consumption of One Engine	Flow Requirement of One Engine	Engines Needed	Power Output from One Engine	Net Power Output of All Engines	Gross Power Output of All Engines
Model	(BTU/ft^3)	(%)	(%)	(BTU/kWh)	(MMBTU/hr)	(SCFM)	(#)	(kWh)	(MWh)	(MWh)
CAT- CG260-16	348.3	100%	50%	8,368	28.2	1,349	5.6	3,370	18.9	20.2

As indicated in Table 4, a Caterpillar CG260-16 engine requires ~1,350 SCFM of LFG to operate one engine at full load. The fuel (LFG only) would provide the necessary fuel consumption of ~28 MMBTU/hr. The net power from consuming all the LFG at full load is ~19 MW.

4 TEMPERATURE AND PRESSURE REQUIREMENTS

4.1 GAS TURBINES

The available pressure downstream of the existing dehydration system is assumed to be ~75 psig. The required pressure of the LFG fuel at the turbines is ~ 240 psig for the Mercury 50 turbine and 265 psig for the Taurus 60 turbine assuming an inlet air temperature of 30 °F.

The required gas fuel pressure decreases as the engines inlet air temperature increases. The pressures of 240 psig and 270 psig were selected as conservative pressures (based on 30 °F as the coldest temperature in California) for the purpose of sizing the compressors.

Venture solicited budgetary proposals from Vilter for the compression application associated with burning LFG in either of the selected Solar turbines. The cost presented herein is based on Vilter Model VSG-1851 Single Screw Gas Compressor for LFG stream.

The discharge pressure of the compressor is ~270 psig. For the purpose of this study the Vilter Model VSG-1851 Single Screw Gas Compressor is utilized for compressing the LFG the Mercury 50 turbine or the Taurus 60 Turbine.

Vilter screw compressor performance sheet is listed in Appendix D.

Vilter Gas Compressor Package includes:

- One (1) landfill gas screw compressors, capable of operating at ~9,000 scfm inlet. The compressor would be operated at ~83 % load. Exit temperature is ~ 225 °F
- One (1) air cooled aftercooler.
- One (1) landfill gas discharge coalescer.

The maximum fuel temperature limit for standard applications on the Solar turbines is 200 °F. The specifications listing the temperature and pressure requirements for the Solar Turbines are located in Appendix E.

An aftercooler to remove the heat of compression for the LFG stream is needed to cool the gas stream from ~225 °F compressor discharge temperature to a temperature below the maximum turbine fuel feed requirement of ~200 °F. An aftercooler exit temperature of 120 °F was selected as a conservative temperature for the purpose of sizing the aftercooler.

A discharge coalescer will be installed downstream of the LFG compressor in order to collect entrained oil droplets in the gas streams prior to entering the turbines.

4.2 IC ENGINE

The required pressure of the LFG fuel at the engine is 2.5 psig; therefore a compressor is not needed when LFG is utilized as fuel in the Caterpillar CG260-16 engine.

The maximum fuel temperature limit for standard applications on the Caterpillar CG260-16 engine is 122 °F. The specifications listing the temperature and pressure requirements for the Caterpillar CG260-16 engine is located in Appendix F.

The temperature of the LFG exiting the siloxane skid located upstream of the engines is ~100 °F. Therefore, fuel temperature is not an issue for the Caterpillar CG260-16 engine.

5 AIR PERMIT

Emissions from gas turbines will vary by product, installation elevation, ambient temperature, type of fuel burned, and fuel to air ratio. Any new emissions sources installed at the Scholl Canyon Landfill (gas turbines or IC engines) are required to control the discharge of air pollutants, consistent with the best available technology. The best available technology is defined as equipment, devices, methods or techniques as determined by the South Coast Air Quality Management District (SCAQMD), which will prevent, reduce or control emissions of air contaminants to the maximum degree possible.

The primary pollutants of interest are: nitrogen oxides (NOx), carbon monoxide (CO), unburned hydrocarbons (UHC), and occasionally formaldehyde (HCHO). The concentration of these pollutants is mostly dependent on the fuel used. NOx production is heavily influenced by combustion temperature which, in turn, is affected by the amount of excess air present during combustion. CO is the result of incomplete combustion of carbon and oxygen, when poor mixing interferes with the mechanism to produce CO_2. UHC emissions also result from incomplete combustion of hydrocarbon fuels, and vary according to incoming fuel composition. The final hazardous air pollutant, formaldehyde, can be created by partially burned methane in the combustor.

5.1 GAS TURBINE EMISSION LIMITS

Table 5 lists the proposed emission limits that are expected to be in effect in the future under the SCAQMD regulation for an installed simple cycle gas turbine. The emission standards for a new electrical generation engines operating on LFG are also listed in Table 5.

All gas turbine and engine emission restrictions are at 15% oxygen. The limits listed in Table 5 are used as the basis of design for evaluating the exhaust emission equipment during this study. The documentation listing the limits shown in Table 5 is located in Appendix G.

TABLE 5: SCAQMD Air Emission Limits

Pollutant	SCAQMD Proposed Emission Limits for Digester/Landfill Gas Fired Turbine (ppm, 15 % O2, dry)	Emission Limits for Digester/Landfill Gas Fired Engines - Valid until January 1, 2016 (ppm, 15 % O2, dry)
NOX	15 ppm	36 ppm
CO	130 ppm	2,000 ppm
VOC	20 ppm	40 ppm

The predicted uncontrolled stack emissions for the prime movers evaluated in this study are listed in Table 6. These emissions are provided by Solar and Caterpillar and are listed in Appendix H.

TABLE 6: Uncontrolled Emissions

Pollutant	Uncontrolled Emissions for Mercury 50 Turbine (ppm, 15 % O2)	Uncontrolled Emissions for Taurus 60 Turbine (ppm, 15 % O2)	Uncontrolled Emissions for Caterpillar CG260-16 (ppm, 15 % O2)
NOx	15	42	86
CO	25	150	300
VOC	5	15	13.6

Comparing the uncontrolled emission values against the proposed SCAQMD limits listed in Table 5, it can be determined that the Taurus 60 turbine and the Caterpillar CG260-16 engine operation will require emission reduction technology in order to comply with the proposed SCAQMD standards.

The uncontrolled emissions for Mercury 50 turbine comply with the proposed SCAQMD limits therefore; Mercury 50 turbine will not require emission control equipment.

Among the many systems available, Venture recommends an oxidation catalyst and a selective catalytic reduction (SCR) for either prime mover.

The SCR converts nitrogen oxides with the aid of a catalyst into nitrogen and water. A reducing agent, typically anhydrous ammonia, aqueous ammonia or urea, is added to the exhaust gas and is adsorbed onto a catalyst.

The oxidation catalyst converts both the carbon monoxide (CO) and hydrocarbons (HC) into carbon dioxide and water vapor which are non-toxic gases. The conversion of CO and HC in the catalyst requires oxygen. If there is not enough oxygen in the exhaust gases to burn all the pollutants, then addition oxygen can be introduced into the exhaust system in front of the catalyst.

Venture solicited budgetary proposals from the equipment vendors for this application. The Solar turbine vendor representative and the Caterpillar engine vendor representative each provided budgetary quotes for their emission control equipment. The proposed emissions listed in table 5 are anticipated to be met after utilizing the addition of the pollutant control equipment.

The emission control equipment costs presented herein is based on Solar and Caterpillar quotes.
Taurus 60 Turbines Emission Control Equipment:

- Three (3) Selective catalytic reduction (SCR) Units
- Three (3) Oxidation Catalyst Units

Caterpillar Engines Emission Control Equipment:

- Six (6) Selective catalytic reduction (SCR) Units
- Six (6) Oxidation Catalysts Units

Emission control equipment budgetary quotes can be found in Appendix I.

6 PROJECT COST ESTIMATE

6.1 BASIS OF ESTIMATE

This section summarizes the design basis and assumptions used in developing the cost estimate included in this study.

The process design basis assumed a volumetric flow rate of 7,500 SCFM landfill gas with a composition of 38.3% Methane, 32.2% Carbon Dioxide, 25.2% Nitrogen, and 4.3 % Oxygen. Venture has developed this preliminary basis for design, in order to meet the project objective as discussed in Section 1. All costs are factored from previous projects or vendor provided costs.

6.1.1 Mercury 50 Turbine

The scope of the project includes the use of the existing LFG gathering, dewatering, desulfurization, first stage compression, and pipeline to transmit the LFG to the turbines. The scope of the project includes cleanup to remove NMOC's, siloxanes, new landfill gas compression package and power generation equipment. More specifically, the project scope includes the following unit operations:

A. One (1) Siloxane and NMOC Removal System
B. One (1) LFG Feed Compressor
C. One (1) LFG Feed Compressor After Cooler
D. One (1) LFG Feed Compressor Separator
E. Four (4) Mercury 50 Solar Turbines

The Budgetary equipment quotes pertaining to the Mercury 50 turbine are located in Appendix J.

6.1.2 Taurus 60 Turbine

The scope of the project includes the use of the existing LFG gathering, dewatering, desulfurization, first stage compression, and pipeline to transmit the LFG to the turbines. The scope of the project includes cleanup to remove NMOC's, siloxanes, new landfill gas compression package, emission control equipment and power generation equipment. More specifically, the project scope includes the following unit operations:

A. One (1) Siloxane and NMOC Removal System
B. One (1) LFG Feed Compressor
C. One (1) LFG Feed Compressor After Cooler
D. One (1) LFG Feed Compressor Separator
E. Three (3) Taurus 60 Solar Turbines
F. Three (3) emission control equipment packages

The Budgetary equipment quotes pertaining to the Taurus 60 turbine are located in Appendix J.

6.1.3 Caterpillar CG260-16 Engine

The scope of the project includes the use of the existing LFG gathering, dewatering, desulfurization, first stage compression, and pipeline to transmit the LFG to the engines. The scope of the project includes cleanup to remove NMOC's, siloxanes, emission control equipment and power generation equipment. More specifically, the project scope includes the following unit operations:

A. One (1) Siloxane and NMOC Removal System
B. Six (6) CG260-16 Caterpillar Engines
C. Six (6) Emission Control Equipment packages

The Budgetary equipment quotes pertaining to the Caterpillar CG260-16 Engine are located in Appendix J.

For each prime mover evaluated in Task #5, a conceptual equipment cost estimate representing the total equipment cost (pretreatment equipment and the prime mover costs) has been prepared by Venture. In addition, per client request a conceptual equipment cost estimate representing the gas pretreatment equipment costs excluding the prime mover cost has also been prepared by Venture.

Mercury 50 turbines: The documents providing details on equipment costs are located in Appendix K.

Taurus 60 turbines: The documents providing details on equipment costs are located in Appendix L.

Caterpillar CG260-16 engines: The documents providing details on equipment costs are located in Appendix M.

Venture has developed a preliminary block flow diagram illustrating the conceptual design for consuming the landfill gas for each prime mover evaluated in this study. The block flow diagrams and are located in Appendix N. Venture has also developed a conceptual General Arrangement (GA) and equipment layout for each prime mover evaluated in this study. The GA drawings are located in Appendix O.

Note: Costs for the electrical switch yard or electrical utility interface equipment were not included in this study phase.

7 OPERATING & MAINTENANCE COST

Table 7 lists the Operating and Maintenance (O&M) Costs for the equipment needed to pretreat and deliver the LFG as fuel to each prime mover evaluated in this study.

TABLE 7: Annual Operating and Maintenance Costs

Prime Mover	Quantity	Assumed Hours of Operation	Annual Maintenance and Consumables Gas Conditioning and Compression	Annual Maintenance and Consumable Power Generation	Annual Maintenance and Consumable Power Generation
Model	**#**	**(hrs/yr)**	**($)**	**$/kW-hr**	**($)**
Mercury 50	4	8,000	~167,000	0.0200	~ 2,965,000
Taurus 60	3	8,000	~167,000	0.0130	~ 1,745,000
Caterpillar CG260-16	6	8,000	~154,000	0.0130	~2,100,000

Mercury 50 turbines: The documents providing details on specific vendor O&M costs are located in Appendix K.

Taurus 60 turbines: The documents providing details on specific vendor O&M costs are located in Appendix L.

Caterpillar CG260-16 engines: The documents providing details on specific vendor O&M costs are located in Appendix M.

APPENDIX A

Landfill Gas Fuel Analysis

LFG Heating Value Calcualtions

LHV					
Volumetric Flow Rate	SCFM		7500	0	7500
	Heating Value	**Molecular Formula**	100	0	100
Methane	909	**CH_4**	0.383	0.920	0.383
Carbon Dioxide	0	**CO_2**	0.322	0.008	0.322
Nitrogen	0	**N_2**	0.252	0.016	0.252
Oxygen	0	**O_2**	0.043	0.003	0.043
Ethane	1619	**C_2H_6**	0.000	0.04566	0.000
Propane	2315	**C_3H_8**	0.000	0.00524	0.00000000
IsoButane	3000	**C_4H_{10}**	0.000	0.00067	0.00000000
N-Butane	3011	**C_4H_{10}**	0.000	0.00053	0.00000000
IsoPentane	3699	**C_5H_{12}**	0.000	0.00012	0.00000000
n-Pentane	3704	**C_5H_{12}**	0.000	0.00008	0.00000000
Hexanes	4404	**C_6H_{14}**	0.000	0.00006	0.00000000

Comp. CFM	**LFG**	**Natural Gas**	**Blended Fuel**
CH_4	2873	0	2873
CO_2	2415	0	2415
N_2	1890	0.0	1890
O_2	323	0.0	323
C_2H_6	0	0.0	0
C_3H_8	0	0.0	0.00
C_4H_{10}	0	0.0	0.00
C_4H_{10}	0	0.0	0.00
C_5H_{12}	0	0.0	0.00
C_5H_{12}	0	0.0	0.00
C_6H_{14}	0	0.0	0.00

Total Btu/scf
348.1

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Major Component Analysis by ASTM D1945 / D1946

Component	Detection Limit	101258-001 Raw Gas 01 4/12/10 1000 Scholl Canyon Landfill Mol %	101258-002 Raw Gas 02 4/12/10 1003 Scholl Canyon Landfill Mol %	101258-003 Raw Gas 03 4/12/10 1007 Scholl Canyon Landfill Mol %	101258-004 Processed Gas 01 4/12/10 1022 Scholl Canyon Landfill Mol %
Helium	0.1%	BDL	BDL	BDL	BDL
Hydrogen	0.1%	0.1%	0.1%	0.1%	0.1%
Carbon Dioxide	0.03%	32.0%	32.1%	32.1%	31.2%
Oxygen/Argon	0.03%	4.34%	4.28%	4.30%	4.31%
Nitrogen	0.03%	25.3%	25.1%	25.2%	25.5%
Carbon Monoxide	0.03%	BDL	BDL	BDL	BDL
Methane	0.002%	38.3%	38.4%	38.3%	38.9%
Ethane	0.002%	BDL	BDL	BDL	BDL
Ethene	0.002%	BDL	BDL	BDL	BDL
Ethyne	0.002%	BDL	BDL	BDL	BDL
Propane	0.002%	0.002%	BDL	0.002%	0.002%
Propene	0.002%	BDL	BDL	BDL	BDL
Propadiene	0.002%	BDL	BDL	BDL	BDL
Propyne	0.002%	BDL	BDL	BDL	BDL
i-Butane	0.002%	BDL	BDL	BDL	BDL
n-Butane	0.002%	BDL	BDL	BDL	BDL
1-Butene	0.002%	BDL	BDL	BDL	BDL
i-Butene	0.002%	BDL	BDL	BDL	BDL
trans-2-Butene	0.002%	BDL	BDL	BDL	BDL
cis-2-Butene	0.002%	BDL	BDL	BDL	BDL
1,3-Butadiene	0.002%	BDL	BDL	BDL	BDL
i-Pentane	0.002%	BDL	BDL	BDL	BDL
n-Pentane	0.002%	BDL	BDL	BDL	BDL
neo-Pentane	0.002%	BDL	BDL	BDL	BDL
Pentenes	0.002%	BDL	BDL	BDL	BDL
Hexane Plus	0.0001%	0.0086%	0.0096%	0.0090%	0.0105%
Ammonia	0.001%	BDL	BDL	BDL	BDL
Total					

Calculated Real Gas Properties	per ASTM D3588-98(03), 60°F, 14.73 psia			
Compressibility Factor [z] (Dry)	0.99781	0.99780	0.99781	0.99784
Compressibility Factor [z] (Sat.)	0.99749	0.99748	0.99748	0.99752
Relative Density (Specific Gravity) (Dry)	0.9934	0.9939	0.9941	0.9871
Gross HV (Dry) (Btu/ft^3)	389.4	390.4	389.7	395.5
Gross HV (Sat.) (Btu/ft^3)	382.8	383.8	383.1	388.7
Wobbe Index	390.7	391.7	390.9	398.0
Net HV (Dry) (Btu/ft^3)	350.6	351.6	350.9	356.1
Net HV (Sat.) (Btu/ft^3)	344.6	345.6	344.9	350.0
Real Gas Density (lbs/ft^3)	0.0760	0.0761	0.0761	0.0755

BDL = Below Detection Limit

The results within this report relate only to the items tested.

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Major Component Analysis by ASTM D1945 / D1946

Component	Detection Limit	101258-005 Processed Gas 02 4/12/10 1024 Scholl Canyon Landfill Mol %	101258-006 Processed Gas 03 4/12/10 1026 Scholl Canyon Landfill Mol %
Helium	0.1%	BDL	BDL
Hydrogen	0.1%	0.1%	0.1%
Carbon Dioxide	0.03%	32.3%	32.0%
Oxygen/Argon	0.03%	4.11%	4.26%
Nitrogen	0.03%	25.0%	25.5%
Carbon Monoxide	0.03%	BDL	BDL
Methane	0.002%	38.5%	38.2%
Ethane	0.002%	BDL	BDL
Ethene	0.002%	BDL	BDL
Ethyne	0.002%	BDL	BDL
Propane	0.002%	0.002%	0.002%
Propene	0.002%	BDL	BDL
Propadiene	0.002%	BDL	BDL
Propyne	0.002%	BDL	BDL
i-Butane	0.002%	BDL	BDL
n-Butane	0.002%	BDL	BDL
1-Butene	0.002%	BDL	BDL
i-Butene	0.002%	BDL	BDL
trans-2-Butene	0.002%	BDL	BDL
cis-2-Butene	0.002%	BDL	BDL
1,3-Butadiene	0.002%	BDL	BDL
i-Pentane	0.002%	BDL	BDL
n-Pentane	0.002%	BDL	BDL
neo-Pentane	0.002%	BDL	BDL
Pentenes	0.002%	BDL	BDL
Hexane Plus	0.0001%	0.0088%	0.0112%
Ammonia	0.001%	BDL	BDL
Total			

Calculated Real Gas Properties	per ASTM D3588-98(03), 60°F, 14.73 psia	
Compressibility Factor [z] (Dry)	0.99779	0.99782
Compressibility Factor [z] (Sat.)	0.99747	0.99749
Relative Density (Specific Gravity) (Dry)	0.9943	0.9938
Gross HV (Dry) (Btu/ft^3)	391.4	388.7
Gross HV (Sat.) (Btu/ft^3)	384.7	382.0
Wobbe Index	392.5	389.9
Net HV (Dry) (Btu/ft^3)	352.4	350.0
Net HV (Sat.) (Btu/ft^3)	346.4	344.0
Real Gas Density (lbs/ft^3)	0.0761	0.0760

BDL = Below Detection Limit

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Extended Hydrocarbon Analysis by GC/FID

Component Name	101258-001 Raw Gas 01 4/12/10 1000 Scholl Canyon Landfill Mol %	101258-002 Raw Gas 02 4/12/10 1003 Scholl Canyon Landfill Mol %	101258-003 Raw Gas 03 4/12/10 1007 Scholl Canyon Landfill Mol %	101258-004 Processed Gas 01 4/12/10 1022 Scholl Canyon Landfill Mol %
Cycloalkanes				
Cyclopentane	0.0001%	0.0001%	0.0001%	0.0001%
Methylcyclopentane	BDL	BDL	BDL	BDL
Cyclohexane	0.0001%	0.0001%	BDL	0.0001%
Methylcyclohexane	0.0001%	0.0001%	0.0001%	0.0001%
Aromatics				
Benzene	0.0001%	0.0001%	0.0001%	0.0001%
Toluene	0.0006%	0.0006%	0.0006%	0.0006%
Ethylbenzene	0.0002%	0.0002%	0.0002%	0.0002%
m,p-Xylene	0.0002%	0.0003%	0.0002%	0.0003%
Styrene	BDL	BDL	BDL	BDL
o-Xylene	0.0001%	0.0001%	0.0001%	0.0001%
C3 Benzenes	0.0003%	0.0003%	0.0003%	0.0004%
Naphthalene	BDL	BDL	BDL	BDL
C1 Naphthalenes	BDL	BDL	BDL	BDL
C2 Naphthalenes	BDL	BDL	BDL	BDL
Paraffins				
Hexanes	0.0015%	0.0016%	0.0015%	0.0013%
Heptanes	0.0009%	0.0009%	0.0010%	0.0009%
2,2,4-Trimethylpentane	BDL	BDL	BDL	BDL
Octanes	0.0007%	0.0007%	0.0008%	0.0008%
Nonanes	0.0007%	0.0008%	0.0007%	0.0009%
Decanes	0.0020%	0.0023%	0.0021%	0.0028%
Undecanes	0.0010%	0.0013%	0.0011%	0.0017%
Dodecanes	BDL	0.0001%	0.0001%	0.0001%
Tridecanes	BDL	BDL	BDL	BDL
Tetradecanes	BDL	BDL	BDL	BDL
Pentadecanes	BDL	BDL	BDL	BDL
Hexadecanes	BDL	BDL	BDL	BDL
Heptadecanes	BDL	BDL	BDL	BDL
Octadecanes	BDL	BDL	BDL	BDL
Nonadecanes	BDL	BDL	BDL	BDL
Eicosanes +	BDL	BDL	BDL	BDL
Total from Cyclopentane to Eicosanes +	0.0086%	0.0096%	0.0090%	0.0105%

Detection Limit = 0.0001 mol% (1 ppmv)
BDL = Below Detection Limit

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Extended Hydrocarbon Analysis by GC/FID

Component Name	101258-005 Processed Gas 02 4/12/10 1024 Scholl Canyon Landfill Mol %	101258-006 Processed Gas 03 4/12/10 1026 Scholl Canyon Landfill Mol %
Cycloalkanes		
Cyclopentane	0.0001%	0.0001%
Methylcyclopentane	BDL	BDL
Cyclohexane	0.0001%	0.0001%
Methylcyclohexane	0.0001%	0.0001%
Aromatics		
Benzene	0.0001%	0.0001%
Toluene	0.0005%	0.0007%
Ethylbenzene	0.0002%	0.0002%
m,p-Xylene	0.0002%	0.0003%
Styrene	BDL	BDL
o-Xylene	0.0001%	0.0001%
C3 Benzenes	0.0003%	0.0004%
Naphthalene	BDL	BDL
C1 Naphthalenes	BDL	BDL
C2 Naphthalenes	BDL	BDL
Paraffins		
Hexanes	0.0013%	0.0015%
Heptanes	0.0009%	0.0010%
2,2,4-Trimethylpentane	BDL	BDL
Octanes	0.0007%	0.0009%
Nonanes	0.0007%	0.0009%
Decanes	0.0021%	0.0030%
Undecanes	0.0013%	0.0017%
Dodecanes	0.0001%	0.0001%
Tridecanes	BDL	BDL
Tetradecanes	BDL	BDL
Pentadecanes	BDL	BDL
Hexadecanes	BDL	BDL
Heptadecanes	BDL	BDL
Octadecanes	BDL	BDL
Nonadecanes	BDL	BDL
Eicosanes +	BDL	BDL
Total from Cyclopentane to Eicosanes +	0.0088%	0.0112%

Detection Limit = 0.0001 mol% (1 ppm
BDL = Below Detection Limit

The results within this report relate only to the items tested.

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Trace Sulfur Analysis by ASTM D6228

Component Name	101258-001 Raw Gas 01 4/12/10 1000 Scholl Canyon Landfill ppmv	101258-002 Raw Gas 02 4/12/10 1003 Scholl Canyon Landfill ppmv	101258-003 Raw Gas 03 4/12/10 1007 Scholl Canyon Landfill ppmv	101258-004 Processed Gas 01 4/12/10 1022 Scholl Canyon Landfill ppmv
Hydrogen Sulfide	28.4	28.6	29.2	11.8
Sulfur Dioxide	BDL	BDL	BDL	BDL
Carbonyl Sulfide	0.17	0.15	0.17	0.15
Carbon Disulfide	BDL	BDL	BDL	0.03
Methyl Mercaptan	0.85	1.02	0.91	0.88
Ethyl Mercaptan	BDL	BDL	BDL	BDL
i-Propyl Mercaptan	BDL	BDL	BDL	BDL
n-Propyl Mercaptan	BDL	BDL	BDL	BDL
t-Butyl Mercaptan	BDL	BDL	BDL	BDL
Dimethyl Sulfide	1.58	1.72	1.49	1.55
Methyl Ethyl Sulfide	BDL	BDL	BDL	BDL
Diethyl Sulfide	BDL	BDL	BDL	BDL
Di-t-Butyl Sulfide	BDL	BDL	BDL	BDL
Dimethyl Disulfide	BDL	BDL	BDL	BDL
Methyl Ethyl Disulfide	BDL	BDL	BDL	BDL
Methyl i-Propyl Disulfide	BDL	BDL	BDL	BDL
Diethyl Disulfide	BDL	BDL	BDL	BDL
Methyl n-Propyl Disulfide	BDL	BDL	BDL	BDL
Methyl t-Butyl Disulfide	BDL	BDL	BDL	BDL
Ethyl i-Propyl Disulfide	BDL	BDL	BDL	BDL
Ethyl n-Propyl Disulfide	BDL	BDL	BDL	BDL
Ethyl t-Butyl Disulfide	BDL	BDL	BDL	BDL
Di-i-Propyl Disulfide	BDL	BDL	BDL	BDL
i-Propyl n-Propyl Disulfide	BDL	BDL	BDL	BDL
Di-n-Propyl Disulfide	BDL	BDL	BDL	BDL
i-Propyl t-Butyl Disulfide	BDL	BDL	BDL	BDL
n-Propyl t-Butyl Disulfide	BDL	BDL	BDL	BDL
Di-t-Butyl Disulfide	BDL	BDL	BDL	BDL
Dimethyl Trisulfide	BDL	BDL	BDL	BDL
Diethyl Trisulfide	BDL	BDL	BDL	BDL
Di-t-Butyl Trisulfide	BDL	BDL	BDL	BDL
Thiophene	BDL	0.05	BDL	BDL
C1-Thiophenes	BDL	BDL	BDL	BDL
C2-Thiophenes	BDL	BDL	BDL	BDL
C3-Thiophenes	BDL	BDL	BDL	BDL
Benzothiophene	BDL	BDL	BDL	BDL
C1-Benzothiophenes	BDL	BDL	BDL	BDL
C2-Benzothiophenes	BDL	BDL	BDL	BDL
Thiophane	BDL	BDL	BDL	BDL
Thiophenol	BDL	BDL	BDL	BDL
Unidentified Sulfur Compound				
Calculated Sulfur Content				
Total Sulfur				
As molar PPM S	31.0	31.5	31.8	14.4
As Grains/100 SCF @ 14.73 psia,	1.84	1.87	1.88	0.86

Detection Limit = 0.05 ppmv S
BDL = Below Detection Limit

The results within this report relate only to the items tested.

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Trace Sulfur Analysis by ASTM D6228

Component Name	101258-005 Processed Gas 02 4/12/10 1024 Scholl Canyon Landfill ppmv	101258-006 Processed Gas 03 4/12/10 1026 Scholl Canyon Landfill ppmv
Hydrogen Sulfide	12.1	11.4
Sulfur Dioxide	BDL	BDL
Carbonyl Sulfide	0.15	0.15
Carbon Disulfide	0.03	0.03
Methyl Mercaptan	0.87	0.87
Ethyl Mercaptan	BDL	BDL
i-Propyl Mercaptan	BDL	BDL
n-Propyl Mercaptan	BDL	BDL
t-Butyl Mercaptan	BDL	BDL
Dimethyl Sulfide	1.58	1.54
Methyl Ethyl Sulfide	BDL	BDL
Diethyl Sulfide	BDL	BDL
Di-t-Butyl Sulfide	BDL	BDL
Dimethyl Disulfide	BDL	BDL
Methyl Ethyl Disulfide	BDL	BDL
Methyl i-Propyl Disulfide	BDL	BDL
Diethyl Disulfide	BDL	BDL
Methyl n-Propyl Disulfide	BDL	BDL
Methyl t-Butyl Disulfide	BDL	BDL
Ethyl i-Propyl Disulfide	BDL	BDL
Ethyl n-Propyl Disulfide	BDL	BDL
Ethyl t-Butyl Disulfide	BDL	BDL
Di-i-Propyl Disulfide	BDL	BDL
i-Propyl n-Propyl Disulfide	BDL	BDL
Di-n-Propyl Disulfide	BDL	BDL
i-Propyl t-Butyl Disulfide	BDL	BDL
n-Propyl t-Butyl Disulfide	BDL	BDL
Di-t-Butyl Disulfide	BDL	BDL
Dimethyl Trisulfide	BDL	BDL
Diethyl Trisulfide	BDL	BDL
Di-t-Butyl Trisulfide	BDL	BDL
Thiophene	BDL	BDL
C1-Thiophenes	BDL	BDL
C2-Thiophenes	BDL	BDL
C3-Thiophenes	BDL	BDL
Benzothiophene	BDL	BDL
C1-Benzothiophenes	BDL	BDL
C2-Benzothiophenes	BDL	BDL
Thiophane	BDL	BDL
Thiophenol	BDL	BDL
Unidentified Sulfur Compound		
Calculated Sulfur Content		
Total Sulfur		
As molar PPM S	14.8	14.0
As Grains/100 SCF @ 14.73 psia,	0.87	0.83

Detection Limit = 0.05 ppmv S
BDL = Below Detection Limit

The results within this report relate only to the items tested.

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TO-14 Halocarbon Analysis

Component Name	Detection Limit	101258-001 Raw Gas 01 4/12/10 1000 Scholl Canyon Landfill ppmv	101258-002 Raw Gas 02 4/12/10 1003 Scholl Canyon Landfill ppmv	101258-003 Raw Gas 03 4/12/10 1007 Scholl Canyon Landfill ppmv	101258-004 Processed Gas 01 4/12/10 1022 Scholl Canyon Landfill ppmv
Dichlorodifluoromethane (CFC-12)	0.10	1.15	1.14	1.18	1.95
1,2-Dichlorotetrafluoroethane (CFC-114)	0.10	BDL	BDL	BDL	BDL
1,1,2-Trichloro-1,2,2-trifluoroethane (CFC-113)	0.10	BDL	BDL	BDL	BDL
Trichlorofluoromethane (CFC-11)	0.10	BDL	BDL	BDL	0.10
Chloromethane	0.10	BDL	BDL	BDL	BDL
Dichloromethane (Methylene Chloride)	0.10	0.14	0.15	0.16	0.16
Chloroform	0.10	BDL	BDL	BDL	BDL
Carbon Tetrachloride	0.10	BDL	BDL	BDL	BDL
Chloroethane	0.10	0.47	0.45	0.47	0.47
1,1-Dichloroethane	0.10	BDL	BDL	BDL	BDL
1,2-Dichloroethane	0.10	BDL	BDL	BDL	BDL
1,1,1-Trichloroethane	0.10	BDL	BDL	BDL	BDL
1,1,2-Trichloroethane	0.10	BDL	BDL	BDL	BDL
1,1,2,2-Tetrachloroethane	0.10	BDL	BDL	BDL	BDL
Chloroethene (Vinyl Chloride)	0.10	0.18	0.17	0.19	0.22
1,1-Dichloroethene	0.10	BDL	BDL	BDL	BDL
cis-1,2-Dichloroethene	0.10	0.38	0.39	0.40	0.40
Trichloroethene	0.10	0.11	0.11	0.12	0.13
Tetrachloroethene	0.10	0.15	0.18	0.16	0.19
1,2-Dichloropropane	0.10	BDL	BDL	BDL	BDL
3-Chloropropene	0.10	BDL	BDL	BDL	BDL
cis-1,3-Dichloropropene	0.10	BDL	BDL	BDL	BDL
trans-1,3-Dichloropropene	0.10	BDL	BDL	BDL	BDL
Bromomethane	0.10	BDL	BDL	BDL	BDL
1,2-Dibromoethane	0.10	BDL	BDL	BDL	BDL
Chlorobenzene	0.10	BDL	BDL	BDL	BDL
1,2-Dichlorobenzene	0.10	BDL	BDL	BDL	BDL
1,3-Dichlorobenzene	0.10	BDL	BDL	BDL	BDL
1,4-Dichlorobenzene	0.10	BDL	BDL	BDL	BDL
1,2,4-Trichlorobenzene	0.10	BDL	BDL	BDL	BDL
Hexachloro-1,3-butadiene	0.10	BDL	BDL	BDL	BDL
Total TO-14 Halocarbon Components:		2.58	2.59	2.68	3.62

BDL = Below Detection Limit

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TO-14 Halocarbon Analysis

Component Name	Detection Limit	101258-005 Processed Gas 02 4/12/10 1024 Scholl Canyon Landfill ppmv	101258-006 Processed Gas 03 4/12/10 1026 Scholl Canyon Landfill ppmv
Dichlorodifluoromethane (CFC-12)	0.10	1.95	1.71
1,2-Dichlorotetrafluoroethane (CFC-114)	0.10	BDL	BDL
1,1,2-Trichloro-1,2,2-trifluoroethane (CFC-113)	0.10	BDL	BDL
Trichlorofluoromethane (CFC-11)	0.10	0.10	0.10
Chloromethane	0.10	BDL	BDL
Dichloromethane (Methylene Chloride)	0.10	0.18	0.20
Chloroform	0.10	BDL	BDL
Carbon Tetrachloride	0.10	BDL	BDL
Chloroethane	0.10	0.49	0.47
1,1-Dichloroethane	0.10	BDL	BDL
1,2-Dichloroethane	0.10	BDL	BDL
1,1,1-Trichloroethane	0.10	BDL	BDL
1,1,2-Trichloroethane	0.10	BDL	BDL
1,1,2,2-Tetrachloroethane	0.10	BDL	BDL
Chloroethene (Vinyl Chloride)	0.10	0.24	0.23
1,1-Dichloroethene	0.10	BDL	BDL
cis-1,2-Dichloroethene	0.10	0.44	0.45
Trichloroethene	0.10	0.13	0.14
Tetrachloroethene	0.10	0.20	0.20
1,2-Dichloropropane	0.10	BDL	BDL
3-Chloropropene	0.10	BDL	BDL
cis-1,3-Dichloropropene	0.10	BDL	BDL
trans-1,3-Dichloropropene	0.10	BDL	BDL
Bromomethane	0.10	BDL	BDL
1,2-Dibromoethane	0.10	BDL	BDL
Chlorobenzene	0.10	BDL	BDL
1,2-Dichlorobenzene	0.10	BDL	BDL
1,3-Dichlorobenzene	0.10	BDL	BDL
1,4-Dichlorobenzene	0.10	BDL	BDL
1,2,4-Trichlorobenzene	0.10	BDL	BDL
Hexachloro-1,3-butadiene	0.10	BDL	BDL
Total TO-14 Halocarbon Components:		3.73	3.50

BDL = Below Detection Limit

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Total Organic Silicon, including Siloxanes

	Detection Limit mg/M³	101258-001 Raw Gas 01 4/12/10 1000 Scholl Canyon Landfill mg/M³	101258-002 Raw Gas 02 4/12/10 1003 Scholl Canyon Landfill mg/M³	101258-003 Raw Gas 03 4/12/10 1007 Scholl Canyon Landfill mg/M³
1,1,3,3-Tetramethyldisiloxane	0.3	1.2	1.5	1.2
Pentamethyldisiloxane	0.3	BDL	BDL	BDL
Hexamethyldisilane	0.3	0.7	0.7	0.7
Hexamethyldisiloxane (L2, MM)	0.4	BDL	BDL	BDL
Octamethyltrisiloxane (L3, MDM)	0.4	0.4	BDL	BDL
Octamethylcyclotetrasiloxane (D4)	0.3	3.3	6.0	5.0
Decamethyltetrasiloxane (L4, MD2M)	0.4	BDL	BDL	BDL
Decamethylcyclopentasiloxane (D5)	0.3	BDL	BDL	BDL
Dodecamethylpentasiloxane (L5, MD3M)	0.3	BDL	BDL	BDL
		5.6		

BDL = Below Detection Limit

	Detection Limit mg/M³	101258-004 Processed Gas 01 4/12/10 1022 Scholl Canyon Landfill mg/M³	101258-005 Processed Gas 02 4/12/10 1024 Scholl Canyon Landfill mg/M³	101258-006 Processed Gas 03 4/12/10 1026 Scholl Canyon Landfill mg/M³
1,1,3,3-Tetramethyldisiloxane	0.3	1.2	1.2	1.2
Pentamethyldisiloxane	0.3	BDL	BDL	BDL
Hexamethyldisilane	0.3	0.7	0.7	0.7
Hexamethyldisiloxane (L2, MM)	0.4	BDL	BDL	BDL
Octamethyltrisiloxane (L3, MDM)	0.4	BDL	BDL	BDL
Octamethylcyclotetrasiloxane (D4)	0.3	3.6	5.6	5.0
Decamethyltetrasiloxane (L4, MD2M)	0.4	BDL	BDL	BDL
Decamethylcyclopentasiloxane (D5)	0.3	BDL	BDL	BDL
Dodecamethylpentasiloxane (L5, MD3M)	0.3	BDL	BDL	BDL

BDL = Below Detection Limit

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Volatile Metals Analysis

Component	Detection Limit, µg/M³	101285-001 Raw Gas 01 04/12/10 1413-1424 Scholl Canyon Landfill µg/M³	101285-002 Raw Gas 02 04/12/10 1425-1439 Scholl Canyon Landfill µg/M³	101285-003 Raw Gas 03 04/12/10 1440-1456 Scholl Canyon Landfill µg/M³	101285-004 Processed Gas 01 04/12/10 1417-1508 Scholl Canyon Landfill µg/M³	101285-005 Processed Gas 02 04/12/10 1510-1555 Scholl Canyon Landfill µg/M³
Mercury	0.02	0.16	0.35	0.08	0.21	0.21

Component	Detection Limit, µg/M³	101258-007 Raw Gas 01 04/12/10 0905-1305 Scholl Canyon Landfill µg/M³	101258-008 Raw Gas 02 04/12/10 1325-1630 Scholl Canyon Landfill µg/M³	101258-012 Raw Gas 03 04/13/10 0826-1134 Scholl Canyon Landfill µg/M³	101258-009 Processed Gas 01 04/12/10 0932-1327 Scholl Canyon Landfill µg/M³	101258-010 Processed Gas 02 04/12/10 1343-1648 Scholl Canyon Landfill µg/M³
Arsenic	30	30	19	14	13	10
Barium	30	BDL	BDL	BDL	BDL	BDL
Beryllium	30	BDL	BDL	BDL	BDL	BDL
Cadmium	30	BDL	BDL	BDL	BDL	BDL
Cobalt	30	BDL	BDL	BDL	BDL	BDL
Chromium	30	BDL	BDL	BDL	BDL	BDL
Copper *	30	378	150	BDL	156	24
Molybdenum	30	BDL	BDL	BDL	BDL	27
Nickel	30	BDL	BDL	BDL	BDL	BDL
Lead	30	BDL	BDL	BDL	BDL	BDL
Antimony	30	38	25	24	25	12
Selenium	30	BDL	BDL	BDL	BDL	BDL
Strontium	30	BDL	BDL	BDL	BDL	BDL
Thallium	30	BDL	BDL	BDL	BDL	BDL
Zinc *	30	231	38	BDL	75	2540
						sample appears contaminated

Zinc and copper found in field blanks.
Some metals data reported at levels below the DL due to larger volumes sampled, or for informational purposes.

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Volatile Metals Analysis

Component	Detection Limit, $\mu g/M^3$	101285-006 Processed Gas 03 04/13/10 0845-0915 Scholl Canyon Landfill $\mu g/M^3$
Mercury	0.02	0.30

Component	Detection Limit, $\mu g/M^3$	101258-013 Processed Gas 03 04/13/10 0836-1156 Scholl Canyon Landfill $\mu g/M^3$
Arsenic	30	11
Barium	30	BDL
Beryllium	30	BDL
Cadmium	30	BDL
Cobalt	30	BDL
Chromium	30	BDL
Copper *	30	BDL
Molybdenum	30	BDL
Nickel	30	BDL
Lead	30	BDL
Antimony	30	24
Selenium	30	BDL
Strontium	30	BDL
Thallium	30	BDL
Zinc *	30	BDL

Zinc and copper found in field blanks.
Some metals data reported at levels below the DL due to larger volumes sampled,

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qPCR Biological Analysis

	101258-015 Raw Gas 01 4/12/10 0915-0946 Scholl Canyon Landfill # per 100 scf	101258-016 Raw Gas 02 4/12/10 1017-1052 Scholl Canyon Landfill # per 100 scf	101258-017 Raw Gas 03 4/12/10 1053-1128 Scholl Canyon Landfill # per 100 scf	101258-018 Processed Gas 01 4/12/10 0925-1001 Scholl Canyon Landfill # per 100 scf	101258-019 Processed Gas 02 4/12/10 1109-1143 Scholl Canyon Landfill # per 100 scf
qPCR Biological Analysis					
Total Bacteria	2.11E+05	ND	1.42E+05	9.83E+04	1.91E+05
Total acid-producing bacteria (APB)	5.52E+04	ND	2.34E+04	ND	6.86E+04
Total iron-oxidizing bacteria (IOB)	1.90E+04	ND	3.02E+04	ND	ND
Total sulfate-reducing bacteria (SRB)	8.07E+03	ND	6.38E+03	ND	6.14E+03
Live Bacteria					
Anaerobic	<163	<156	<163	<153	<116
Aerobic	<163	<156	<163	<153	<116
Total	<326	<312	<326	<306	<232
Spores					
Anaerobic	ND	ND	271	255	ND
Aerobic	ND	260	ND	255	ND
Total	ND	260	271	510	ND

ND=Not Detected

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qPCR Biological Analysis

	101258-020 Processed Gas 03 4/12/10 1153-1219 Scholl Canyon Landfill # per 100 scf
qPCR Biological Analysis	
Total Bacteria	9.84E+04
Total acid-producing bacteria (APB)	ND
Total iron-oxidizing bacteria (IOB)	1.29E+04
Total sulfate-reducing bacteria (SRB)	ND
Live Bacteria	
Anaerobic	<131
Aerobic	<131
Total	<262
Spores	
Anaerobic	ND
Aerobic	ND
Total	ND

ND=Not Detected

The results within this report relate only to the items tested.

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Volatiles and Semi-Volatiles by EPA 3540 (performed by Meta Environmental)

	XA100412-01A/B 04/12/10 0831-1228 Raw Gas 01 Scholl Canyon Landfill		XA100412-02A/B 04/12/10 1244-1615 Raw Gas 02 Scholl Canyon Landfill		XA100413-03A/B 04/13/10 0800-1205 Raw Gas 03 Scholl Canyon Landfill		XA100412-01A/B 04/12/10 0845-1248 Processed Gas 01 Scholl Canyon Landfill	
Analyte	ppbv	EDL	ppbv	EDL	ppbv	EDL	ppbv	EDL
2,2-Dichloropropane	U		U		U		U	
Chloroform	10.77 B		12.59 B		7.11 B		10.10 B	
1,1,1-Trichloroethane	U		U		U		U	
1,2-Dichloroethane	U		U		U		U	
1,1-Dichloropropene	U		U		U		U	
Benzene	U		U		U		0.62 J	
Carbon Tetrachloride	U		U		U		U	
1,2-Dichloropropane	U		U		U		U	
Dibromomethane	U		U		U		U	
Bromodichloromethane	U		U		U		U	
Pyridine	U		U		U		U	
cis-1,3-Dichloropropene	U		U		U		U	
N-nitrosodimethylamine	U		U		U		U	
Toluene	16.29		7.90		20.18		32.09	
trans-1,3-Dichloropropene	U		U		U		U	
1,1,2-Trichloroethane	U		U		U		0.781	
1,3-Dichloropropane	U		U		U		U	
Dibromochloromethane	U		U		U		U	
1,2-Dibromoethane	U		U		U		U	
Tetrachloroethene	0.94		0.49 J		0.99		1.50	
Chlorobenzene	1.75		1.52		1.75		2.59	
1,1,1,2-Tetrachloroethane	U		U		U		U	
Ethylbenzene	37.35		33.97		36.08		50.64	
m/p-Xylenes	45.79		44.31		41.36		56.34	
Bromoform	U		U		U		U	
Styrene	4.30		4.47		3.81		5.16	
o-Xylene	35.03		33.97		31.86		43.25	
1,1,2,2-Tetrachloroethane	U		U		U		U	
1,2,3-Trichloropropane	U		U		U		U	
Isopropylbenzene	10.64		11.83		9.67		13.42	
Bromobenzene	U		U		U		U	
2-Chlorotoluene	3.33		3.73		2.85		3.70	
n-Propylbenzene	12.56		13.49		10.53		14.15	
4-Chlorotoluene	U		U		U		U	
1,3,5-Trimethylbenzene	36.16		38.95		30.38		39.70	
tert-Butylbenzene	14.40		15.99		12.27		15.72	
1,2,4-Trimethylbenzene	105.5		115.0		87.79		114.4	
sec-Butylbenzene	U		U		U		U	
Phenol	U		U		U		U	
bis(2-Chloroethyl)ether	U		U		U		U	
Aniline	U		U		U		U	
2-Chlorophenol	U		U		U		U	
1,3-Dichlorobenzene	U		U		U		U	
1,4-Dichlorobenzene	73.91		76.35		58.98		83.05	
p-Isopropyltoluene	469.0 D		435.6 D		353.8 D		459.0 D	
Benzyl Alcohol	U		U		U		U	
2-Methylphenol (m-cresol)	U		U		U		U	
1,2-Dichlorobenzene	U		U		U		U	
3,4-Methylphenol (o,p-cresol)	U		U		U		U	
bis(2-chloroisopropyl)ether	U		U		U		U	
n-Butylbenzene	10.48		U		8.06		11.37	

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Volatiles and Semi-Volatiles by EPA 3540 (performed by Meta Environmental)

	XA100412-01A/B 04/12/10 0831-1228 Raw Gas 01 Scholl Canyon Landfill		XA100412-02A/B 04/12/10 1244-1615 Raw Gas 02 Scholl Canyon Landfill		XA100413-03A/B 04/13/10 0800-1205 Raw Gas 03 Scholl Canyon Landfill		XA100412-01A/B 04/12/10 0845-1248 Processed Gas 01 Scholl Canyon Landfill	
Analyte	ppbv	EDL	ppbv	EDL	ppbv	EDL	ppbv	EDL
N-nitroso-di-n-propylamine		U		U		U		U
Hexachloroethane		U		U		U		U
1,2-Dibromo-3-Chloropropane		U		U		U		U
Nitrobenzene		U		U		U		U
Isophorone		U		U		U		U
2-Nitrophenol		U		U		U		U
2,4-Dimethylphenol		U		U		U		U
bis(2-Chloroethoxy)methane		U		U		U		U
1,2,4-Trichlorobenzene	1.47		1.46		1.36		1.33	
Naphthalene	86.69		85.64		81.80		94.38	
2,4-Dichlorophenol		U		U		U		U
4-Chloroaniline		U		U		U		U
Hexachlorobutadiene		U		U		U		U
1,2,3-Trichlorobenzene	0.454	J	0.532	J	0.505	J	0.411	J
4-Chloro-3-methylphenol		U		U		U		U
2-Methylnaphthalene	12.49		13.06		12.71		10.81	
1-Methylnaphthalene	7.88		8.29		7.66		5.01	
Hexachlorocyclopentadiene		U		U		U		U
2,4,6-Trichlorophenol		U		U		U		U
2,4,5-Trichlorophenol		U		U		U		U
Diphenylamine		U		U		U		U
Azobenzene		U		U		U		U
2-Chloronaphthalene	0.512	J		U		U		U
2-Nitroaniline		U		U		U		U
1,4-Dinitrobenzene		U		U		U		U
Dimethylphthalate		U		U		U		U
1,3-Dinitrobenzene		U		U		U		U
Acenaphthylene		U		U		U		U
2,6-dinitrotoluene		U		U		U		U
1,2-Dinitrobenzene		U		U		U		U
3-Nitroaniline		U		U		U		U
Acenaphthene	2.41		2.32		2.12		0.56	J
2,4-Dinitrophenol		U		U		U		U
4-Nitrophenol		U		U		U		U
Dibenzofuran	0.90		1.00		0.84			U
2,4-dinitrotoluene		U		U		U		U
2,3,4,6-Tetrachlorophenol		U		U		U		U
2,3,5,6-Tetrachlorophenol		U		U		U		U
Diethylphthalate		U		U		U		U
4-Chlorophenyl-phenylether		U		U		U		U
Fluorene	0.60		0.66		0.54	J		U
4-Nitroaniline		U		U		U		U
4,6-Dinitro-2-methylphenol		U		U		U		U
n-Nitrosodiphenylamine		U		U		U		U
4-Bromophenyl phenyl ether		U		U		U		U
Hexachlorobenzene		U		U		U		U
Pentachlorophenol		U		U		U		U
Phenanthrene		U	0.31	J		U		U
Anthracene		U		U		U		U
Carbazole		U		U		U		U
Di-n-butylphthalate		U		U		U		U

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Volatiles and Semi-Volatiles by EPA 3540 (performed by Meta Environmental)

	XA100412-01A/B 04/12/10 0831-1228 Raw Gas 01 Scholl Canyon Landfill			XA100412-02A/B 04/12/10 1244-1615 Raw Gas 02 Scholl Canyon Landfill			XA100413-03A/B 04/13/10 0800-1205 Raw Gas 03 Scholl Canyon Landfill			XA100412-01A/B 04/12/10 0845-1248 Processed Gas 01 Scholl Canyon Landfill		
Analyte	ppbv		EDL	ppbv		EDL	ppbv		EDL	ppbv		EDL
Bis(2-ethylhexyl) adipate		U			U			U			U	
Fluoranthene		U			U			U			U	
Pyrene		U			U			U			U	
Butylbenzylphthalate		BU			BU			BU			BU	
Benz[a]anthracene		U			U			U			U	
Chrysene		U			U			U			U	
bis(2-Ethylhexyl)phthalate	0.20	JB			BU		0.21	JB		0.20	JB	
Di-n-octylphthalate		U			U			U			U	
Benzo[b]fluoranthene		U			U			U			U	
Benzo[k]fluoranthene		U			U			U			U	
Benzo[a]pyrene		U			U			U			U	
Indeno[1,2,3-cd]pyrene		U			U			U			U	
Dibenz[a,h]anthracene		U			U			U			U	
Benzo[g,h,i]perylene		U			U			U			U	

NA - Not applicable.
B - Analyte detected in the Blank.
J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

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Analyte	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill ppbv		EDL	XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill ppbv		EDL
2,2-Dichloropropane		U			U	
Chloroform	10.98	B		6.79	B	
1,1,1-Trichloroethane		U			U	
1,2-Dichloroethane		U			U	
1,1-Dichloropropene		U			U	
Benzene		U			U	
Carbon Tetrachloride		U			U	
1,2-Dichloropropane		U			U	
Dibromomethane		U			U	
Bromodichloromethane		U			U	
Pyridine		U			U	
cis-1,3-Dichloropropene		U			U	
N-nitrosodimethylamine		U			U	
Toluene	37.44			31.61		
trans-1,3-Dichloropropene		U			U	
1,1,2-Trichloroethane		U			U	
1,3-Dichloropropane		U			U	
Dibromochloromethane		U			U	
1,2-Dibromoethane		U			U	
Tetrachloroethene	1.69			1.30		
Chlorobenzene	3.20			2.29		
1,1,1,2-Tetrachloroethane		U			U	
Ethylbenzene	64.14			47.69		
m/p-Xylenes	72.37			51.69		
Bromoform		U			U	
Styrene	6.75			4.80		
o-Xylene	55.49			39.88		
1,1,2,2-Tetrachloroethane		U		0.314	J	
1,2,3-Trichloropropane		U			U	
Isopropylbenzene	17.48			12.30		
Bromobenzene		U			U	
2-Chlorotoluene	4.69			3.29		
n-Propylbenzene	19.57			12.82		
4-Chlorotoluene		U			U	
1,3,5-Trimethylbenzene	52.19			34.48		
tert-Butylbenzene	20.70			13.69		
1,2,4-Trimethylbenzene	151.9			99.90		
sec-Butylbenzene		U			U	
Phenol		U			U	
bis(2-Chloroethyl)ether		U			U	
Aniline		U			U	
2-Chlorophenol		U			U	
1,3-Dichlorobenzene		U			U	
1,4-Dichlorobenzene	109.6			71.78		
p-Isopropyltoluene	565.8	D		405.6	D	
Benzyl Alcohol		U			U	
2-Methylphenol (m-cresol)		U			U	
1,2-Dichlorobenzene		U			U	
3,4-Methylphenol (o,p-cresol)		U			U	
bis(2-chloroisopropyl)ether		U			U	
n-Butylbenzene	14.09			9.85		

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Analyte	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill ppbv		EDL	XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill ppbv		EDL
N-nitroso-di-n-propylamine		U			U	
Hexachloroethane		U			U	
1,2-Dibromo-3-Chloropropane		U			U	
Nitrobenzene		U			U	
Isophorone	3.01				U	
2-Nitrophenol		U			U	
2,4-Dimethylphenol		U			U	
bis(2-Chloroethoxy)methane		U			U	
1,2,4-Trichlorobenzene	1.59			1.40		
Naphthalene	114.1			95.78		
2,4-Dichlorophenol		U			U	
4-Chloroaniline		U			U	
Hexachlorobutadiene		U			U	
1,2,3-Trichlorobenzene	0.48	J		0.42	J	
4-Chloro-3-methylphenol		U			U	
2-Methylnaphthalene	14.30			10.70		
1-Methylnaphthalene	6.81			5.66		
Hexachlorocyclopentadiene		U			U	
2,4,6-Trichlorophenol		U			U	
2,4,5-Trichlorophenol		U			U	
Diphenylamine		U			U	
Azobenzene		U			U	
2-Chloronaphthalene		U			U	
2-Nitroaniline		U			U	
1,4-Dinitrobenzene		U			U	
Dimethylphthalate		U			U	
1,3-Dinitrobenzene		U			U	
Acenaphthylene		U			U	
2,6-dinitrotoluene		U			U	
1,2-Dinitrobenzene		U			U	
3-Nitroaniline		U			U	
Acenaphthene	0.73	J		0.57	J	
2,4-Dinitrophenol		U			U	
4-Nitrophenol		U			U	
Dibenzofuran		U			U	
2,4-dinitrotoluene		U			U	
2,3,4,6-Tetrachlorophenol		U			U	
2,3,5,6-Tetrachlorophenol		U			U	
Diethylphthalate		U			U	
4-Chlorophenyl-phenylether		U			U	
Fluorene		U			U	
4-Nitroaniline		U			U	
4,6-Dinitro-2-methylphenol		U			U	
n-Nitrosodiphenylamine		U			U	
4-Bromophenyl phenyl ether		U			U	
Hexachlorobenzene		U			U	
Pentachlorophenol		U			U	
Phenanthrene		U			U	
Anthracene		U			U	
Carbazole		U			U	
Di-n-butylphthalate		U			U	

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Volatiles and Semi-Volatiles by EPA 3540 (performed by Meta Environmental)

Analyte	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill ppbv		EDL	XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill ppbv		EDL
Bis(2-ethylhexyl) adipate		U			U	
Fluoranthene		U			U	
Pyrene		U			U	
Butylbenzylphthalate		BU			BU	
Benz[a]anthracene		U			U	
Chrysene		U			U	
bis(2-Ethylhexyl)phthalate	0.24	JB		0.19	JB	
Di-n-octylphthalate		U			U	
Benzo[b]fluoranthene		U			U	
Benzo[k]fluoranthene		U			U	
Benzo[a]pyrene		U			U	
Indeno[1,2,3-cd]pyrene		U			U	
Dibenz[a,h]anthracene		U			U	
Benzo[g,h,i]perylene		U			U	

NA - Not applicable.
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J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

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PCB Cogeners by EPA 3540 (performed by Meta Environmental)

	XA100412-01A/B 04/12/10 0831-1228 Raw Gas 01 Scholl Canyon Landfill		XA100412-02A/B 04/12/10 1244-1615 Raw Gas 02 Scholl Canyon Landfill		XA100413-03A/B 04/13/10 0800-1205 Raw Gas 03 Scholl Canyon Landfill		XA100412-01A/B 04/12/10 0845-1248 Processed Gas 01 Scholl Canyon Landfill	
Analyte	ppbv	EDL	ppbv	EDL	ppbv	EDL	ppbv	EDL
PCB 1	U	0.003	U	0.003	U	0.003	U	0.003
PCB 2	U	0.003	U	0.003	U	0.003	U	0.003
PCB 3	U	0.003	U	0.003	U	0.003	U	0.003
PCB 4/10	U	0.003	U	0.003	U	0.003	U	0.003
PCB 7/9	U	0.003	U	0.003	U	0.003	U	0.003
PCB 6	U	0.003	U	0.003	U	0.003	U	0.003
PCB 8	U	0.003	U	0.003	U	0.003	U	0.003
PCB 5	U	0.003	U	0.003	U	0.003	U	0.003
PCB 19	U	0.003	U	0.003	U	0.003	U	0.003
PCB 12/13	U	0.003	U	0.003	U	0.003	U	0.003
PCB 18	U	0.003	U	0.003	U	0.003	U	0.003
PCB 17	U	0.003	U	0.003	U	0.003	U	0.003
PCB 15	U	0.003	U	0.003	U	0.003	U	0.003
PCB 24/27	U	0.003	U	0.003	U	0.003	U	0.003
PCB 16/32	U	0.003	U	0.003	U	0.003	U	0.003
PCB 34	U	0.003	U	0.003	U	0.003	U	0.003
PCB 29	U	0.003	U	0.003	U	0.003	U	0.003
PCB 54	U	0.003	U	0.003	U	0.003	U	0.003
PCB 26	U	0.003	U	0.003	U	0.003	U	0.003
PCB 25	U	0.003	U	0.003	U	0.003	U	0.003
PCB 31	U	0.003	U	0.003	U	0.003	U	0.003
PCB 50	U	0.003	U	0.003	U	0.003	U	0.003
PCB 28	U	0.003	U	0.003	U	0.003	U	0.003
PCB 20/33	U	0.003	U	0.003	U	0.003	U	0.003
PCB 53	U	0.003	U	0.003	U	0.003	U	0.003
PCB 51	U	0.003	U	0.003	U	0.003	U	0.003
PCB 22	U	0.003	U	0.003	U	0.003	U	0.003
PCB 45	U	0.003	U	0.003	U	0.003	U	0.003
PCB 46	U	0.003	U	0.003	U	0.003	U	0.003
PCB 69	U	0.003	U	0.003	U	0.003	U	0.003
PCB 52/73	U	0.003	U	0.003	U	0.003	U	0.003
PCB 49	U	0.003	U	0.003	U	0.003	U	0.003
PCB 47/48/75	U	0.003	U	0.003	U	0.003	U	0.003
PCB 104	U	0.003	U	0.003	U	0.003	U	0.003
PCB 35	U	0.003	U	0.003	U	0.003	U	0.003
PCB 44	U	0.003	U	0.003	U	0.003	U	0.003
PCB 59	U	0.003	U	0.003	U	0.003	U	0.003
PCB 37	U	0.003	U	0.003	U	0.003	U	0.003
PCB 42	U	0.003	U	0.003	U	0.003	U	0.003
PCB 71	U	0.003	U	0.003	U	0.003	U	0.003
PCB 41/64	U	0.003	U	0.003	U	0.003	U	0.003
PCB 40	U	0.003	U	0.003	U	0.003	U	0.003
PCB 103	U	0.003	U	0.003	U	0.003	U	0.003
PCB 67	U	0.003	U	0.003	U	0.003	U	0.003
PCB 100	U	0.003	U	0.003	U	0.003	U	0.003
PCB 63	U	0.003	U	0.003	U	0.003	U	0.003
PCB 74	U	0.003	U	0.003	U	0.003	U	0.003
PCB 70	U	0.003	U	0.003	U	0.003	U	0.003
PCB 66	U	0.003	U	0.003	U	0.003	U	0.003
PCB 93/95	U	0.003	U	0.003	U	0.003	U	0.003

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PCB Cogeners by EPA 3540 (performed by Meta Environmental)

	XA100412-01A/B		XA100412-02A/B		XA100413-03A/B		XA100412-01A/B	
	04/12/10 0831-1228		04/12/10 1244-1615		04/13/10 0800-1205		04/12/10 0845-1248	
	Raw Gas 01		Raw Gas 02		Raw Gas 03		Processed Gas 01	
	Scholl Canyon Landfill		Scholl Canyon Landfill		Scholl Canyon Landfill		Scholl Canyon Landfill	
Analyte	ppbv	EDL	ppbv	EDL	ppbv	EDL	ppbv	EDL
PCB 91	U	0.003	U	0.003	U	0.003	U	0.003
PCB 56/60	U	0.003	U	0.003	U	0.003	U	0.003
PCB 92	U	0.003	U	0.003	U	0.003	U	0.003
PCB 84	U	0.003	U	0.003	U	0.003	U	0.003
PCB 90/101	U	0.003	U	0.003	U	0.003	U	0.003
PCB 99	U	0.003	U	0.003	U	0.003	U	0.003
PCB 119	U	0.003	U	0.003	U	0.003	U	0.003
PCB 83	U	0.003	U	0.003	U	0.003	U	0.003
PCB 97	U	0.003	U	0.003	U	0.003	U	0.003
PCB 117	U	0.003	U	0.003	U	0.003	U	0.003
PCB 81	U	0.003	U	0.003	U	0.003	U	0.003
PCB 87/115	U	0.003	U	0.003	U	0.003	U	0.003
PCB 85	U	0.003	U	0.003	U	0.003	U	0.003
PCB 136	U	0.003	U	0.003	U	0.003	U	0.003
PCB 77	U	0.003	U	0.003	U	0.003	U	0.003
PCB 110	U	0.003	U	0.003	U	0.003	U	0.003
PCB 154	U	0.003	U	0.003	U	0.003	U	0.003
PCB 82	U	0.003	U	0.003	U	0.003	U	0.003
PCB 151	U	0.003	U	0.003	U	0.003	U	0.003
PCB 135/144	U	0.003	U	0.003	U	0.003	U	0.003
PCB 124	U	0.003	U	0.003	U	0.003	U	0.003
PCB 147	U	0.003	U	0.003	U	0.003	U	0.003
PCB 107	U	0.003	U	0.003	U	0.003	U	0.003
PCB 123	U	0.003	U	0.003	U	0.003	U	0.003
PCB 149	U	0.003	U	0.003	U	0.003	U	0.003
PCB 118	U	0.003	U	0.003	U	0.003	U	0.003
PCB 134	U	0.003	U	0.003	U	0.003	U	0.003
PCB 114	U	0.003	U	0.003	U	0.003	U	0.003
PCB 131	U	0.003	U	0.003	U	0.003	U	0.003
PCB 122	U	0.003	U	0.003	U	0.003	U	0.003
PCB 165	U	0.003	U	0.003	U	0.003	U	0.003
PCB 146	U	0.003	U	0.003	U	0.003	U	0.003
PCB 188	U	0.003	U	0.003	U	0.003	U	0.003
PCB 153	U	0.003	U	0.003	U	0.003	U	0.003
PCB 132	U	0.003	U	0.003	U	0.003	U	0.003
PCB 105	U	0.003	U	0.003	U	0.003	U	0.003
PCB 141	U	0.003	U	0.003	U	0.003	U	0.003
PCB 179	U	0.003	U	0.003	U	0.003	U	0.003
PCB 137	U	0.003	U	0.003	U	0.003	U	0.003
PCB 176	U	0.003	U	0.003	U	0.003	U	0.003
PCB 130	U	0.003	U	0.003	U	0.003	U	0.003
PCB 138/163/164	U	0.003	U	0.003	U	0.003	U	0.003
PCB 158	U	0.003	U	0.003	U	0.003	U	0.003
PCB 129	U	0.003	U	0.003	U	0.003	U	0.003
PCB 178	U	0.003	U	0.003	U	0.003	U	0.003
PCB 175	U	0.003	U	0.003	U	0.003	U	0.003
PCB 187	U	0.003	U	0.003	U	0.003	U	0.003
PCB 183	U	0.003	U	0.003	U	0.003	U	0.003
PCB 128	U	0.003	U	0.003	U	0.003	U	0.003
PCB 167	U	0.003	U	0.003	U	0.003	U	0.003

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Analyte	ppbv	EDL	ppbv	EDL	ppbv	EDL	ppbv	EDL
PCB 185	U	0.003	U	0.003	U	0.003	U	0.003
PCB 174	U	0.003	U	0.003	U	0.003	U	0.003
PCB 177	U	0.003	U	0.003	U	0.003	U	0.003
PCB 202	U	0.003	U	0.003	U	0.003	U	0.003
PCB 171	U	0.003	U	0.003	U	0.003	U	0.003
PCB 156	U	0.003	U	0.003	U	0.003	U	0.003
PCB 173	U	0.003	U	0.003	U	0.003	U	0.003
PCB 157	U	0.003	U	0.003	U	0.003	U	0.003
PCB 201	U	0.003	U	0.003	U	0.003	U	0.003
PCB 172	U	0.003	U	0.003	U	0.003	U	0.003
PCB 197	U	0.003	U	0.003	U	0.003	U	0.003
PCB 180	U	0.003	U	0.003	U	0.003	U	0.003
PCB 193	U	0.003	U	0.003	U	0.003	U	0.003
PCB 191	U	0.003	U	0.003	U	0.003	U	0.003
PCB 200	U	0.003	U	0.003	U	0.003	U	0.003
PCB 170	U	0.003	U	0.003	U	0.003	U	0.003
PCB 190	U	0.003	U	0.003	U	0.003	U	0.003
PCB 199	U	0.003	U	0.003	U	0.003	U	0.003
PCB 196/203	U	0.003	U	0.003	U	0.003	U	0.003
PCB 189	U	0.003	U	0.003	U	0.003	U	0.003
PCB 208	U	0.003	U	0.003	U	0.003	U	0.003
PCB 195	U	0.003	U	0.003	U	0.003	U	0.003
PCB 207	U	0.003	U	0.003	U	0.003	U	0.003
PCB 194	U	0.003	U	0.003	U	0.003	U	0.003
PCB 205	U	0.003	U	0.003	U	0.003	U	0.003
PCB 206	U	0.003	U	0.003	U	0.003	U	0.003
PCB 209	U	0.003	U	0.003	U	0.003	U	0.003

NA - Not applicable.
B - Analyte detected in the Blank.
J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

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PCB Cogeners by EPA 3540 (performed by Meta Environmental)

Analyte	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill ppbv		EDL	XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill ppbv		EDL
PCB 1		U	0.003		U	0.003
PCB 2		U	0.003		U	0.003
PCB 3		U	0.003		U	0.003
PCB 4/10		U	0.003		U	0.003
PCB 7/9		U	0.003		U	0.003
PCB 6		U	0.003		U	0.003
PCB 8		U	0.003		U	0.003
PCB 5		U	0.003		U	0.003
PCB 19		U	0.003		U	0.003
PCB 12/13		U	0.003		U	0.003
PCB 18		U	0.003		U	0.003
PCB 17		U	0.003		U	0.003
PCB 15		U	0.003		U	0.003
PCB 24/27		U	0.003		U	0.003
PCB 16/32		U	0.003		U	0.003
PCB 34		U	0.003		U	0.003
PCB 29		U	0.003		U	0.003
PCB 54		U	0.003		U	0.003
PCB 26		U	0.003		U	0.003
PCB 25		U	0.003		U	0.003
PCB 31		U	0.003		U	0.003
PCB 50		U	0.003		U	0.003
PCB 28		U	0.003		U	0.003
PCB 20/33		U	0.003		U	0.003
PCB 53		U	0.003		U	0.003
PCB 51		U	0.003		U	0.003
PCB 22		U	0.003		U	0.003
PCB 45		U	0.003		U	0.003
PCB 46		U	0.003		U	0.003
PCB 69		U	0.003		U	0.003
PCB 52/73		U	0.003		U	0.003
PCB 49		U	0.003		U	0.003
PCB 47/48/75		U	0.003		U	0.003
PCB 104		U	0.003		U	0.003
PCB 35		U	0.003		U	0.003
PCB 44		U	0.003		U	0.003
PCB 59		U	0.003		U	0.003
PCB 37		U	0.003		U	0.003
PCB 42		U	0.003		U	0.003
PCB 71		U	0.003		U	0.003
PCB 41/64		U	0.003		U	0.003
PCB 40		U	0.003		U	0.003
PCB 103		U	0.003		U	0.003
PCB 67		U	0.003		U	0.003
PCB 100		U	0.003		U	0.003
PCB 63		U	0.003		U	0.003
PCB 74		U	0.003		U	0.003
PCB 70		U	0.003		U	0.003
PCB 66		U	0.003		U	0.003
PCB 93/95		U	0.003		U	0.003

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PCB Cogeners by EPA 3540 (performed by Meta Environmental)

	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill		XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill	
Analyte	ppbv	EDL	ppbv	EDL
PCB 91	U	0.003	U	0.003
PCB 56/60	U	0.003	U	0.003
PCB 92	U	0.003	U	0.003
PCB 84	U	0.003	U	0.003
PCB 90/101	U	0.003	U	0.003
PCB 99	U	0.003	U	0.003
PCB 119	U	0.003	U	0.003
PCB 83	U	0.003	U	0.003
PCB 97	U	0.003	U	0.003
PCB 117	U	0.003	U	0.003
PCB 81	U	0.003	U	0.003
PCB 87/115	U	0.003	U	0.003
PCB 85	U	0.003	U	0.003
PCB 136	U	0.003	U	0.003
PCB 77	U	0.003	U	0.003
PCB 110	U	0.003	U	0.003
PCB 154	U	0.003	U	0.003
PCB 82	U	0.003	U	0.003
PCB 151	U	0.003	U	0.003
PCB 135/144	U	0.003	U	0.003
PCB 124	U	0.003	U	0.003
PCB 147	U	0.003	U	0.003
PCB 107	U	0.003	U	0.003
PCB 123	U	0.003	U	0.003
PCB 149	U	0.003	U	0.003
PCB 118	U	0.003	U	0.003
PCB 134	U	0.003	U	0.003
PCB 114	U	0.003	U	0.003
PCB 131	U	0.003	U	0.003
PCB 122	U	0.003	U	0.003
PCB 165	U	0.003	U	0.003
PCB 146	U	0.003	U	0.003
PCB 188	U	0.003	U	0.003
PCB 153	U	0.003	U	0.003
PCB 132	U	0.003	U	0.003
PCB 105	U	0.003	U	0.003
PCB 141	U	0.003	U	0.003
PCB 179	U	0.003	U	0.003
PCB 137	U	0.003	U	0.003
PCB 176	U	0.003	U	0.003
PCB 130	U	0.003	U	0.003
PCB 138/163/164	U	0.003	U	0.003
PCB 158	U	0.003	U	0.003
PCB 129	U	0.003	U	0.003
PCB 178	U	0.003	U	0.003
PCB 175	U	0.003	U	0.003
PCB 187	U	0.003	U	0.003
PCB 183	U	0.003	U	0.003
PCB 128	U	0.003	U	0.003
PCB 167	U	0.003	U	0.003

The results within this report relate only to the items tested.

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PCB Cogeners by EPA 3540 (performed by Meta Environmental)

Analyte	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill ppbv	EDL	XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill ppbv	EDL
PCB 185	U	0.003	U	0.003
PCB 174	U	0.003	U	0.003
PCB 177	U	0.003	U	0.003
PCB 202	U	0.003	U	0.003
PCB 171	U	0.003	U	0.003
PCB 156	U	0.003	U	0.003
PCB 173	U	0.003	U	0.003
PCB 157	U	0.003	U	0.003
PCB 201	U	0.003	U	0.003
PCB 172	U	0.003	U	0.003
PCB 197	U	0.003	U	0.003
PCB 180	U	0.003	U	0.003
PCB 193	U	0.003	U	0.003
PCB 191	U	0.003	U	0.003
PCB 200	U	0.003	U	0.003
PCB 170	U	0.003	U	0.003
PCB 190	U	0.003	U	0.003
PCB 199	U	0.003	U	0.003
PCB 196/203	U	0.003	U	0.003
PCB 189	U	0.003	U	0.003
PCB 208	U	0.003	U	0.003
PCB 195	U	0.003	U	0.003
PCB 207	U	0.003	U	0.003
PCB 194	U	0.003	U	0.003
PCB 205	U	0.003	U	0.003
PCB 206	U	0.003	U	0.003
PCB 209	U	0.003	U	0.003

NA - Not applicable.
B - Analyte detected in the Blank.
J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

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Organochlorine Pesticides by EPA 3540 (performed by Meta Environmental)

	XA100412-01A/B 04/12/10 0831-1228 Raw Gas 01 Scholl Canyon Landfill			XA100412-02A/B 04/12/10 1244-1615 Raw Gas 02 Scholl Canyon Landfill			XA100413-03A/B 04/13/10 0800-1205 Raw Gas 03 Scholl Canyon Landfill			XA100412-01A/B 04/12/10 0845-1248 Processed Gas 01 Scholl Canyon Landfill		
Analyte	ppbv		EDL	ppbv		EDL	ppbv		EDL	ppbv		EDL
a-BHC		U	0.0003		U	0.0003		U	0.0003		U	0.0003
b-BHC		U	0.0003		U	0.0003		U	0.0003		U	0.0003
g-BHC		U	0.0003		U	0.0003		U	0.0003		U	0.0003
d-BHC		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Heptachlor		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Aldrin		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Heptachlor epoxide		U	0.0003		U	0.0003		U	0.0003		U	0.0003
g-Chlordane		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Endosulfan I		U	0.0003		U	0.0003		U	0.0003		U	0.0003
a-Chlordane		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Dieldrin		U	0.0003		U	0.0003		U	0.0003		U	0.0003
4,4'-DDE		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Endrin		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Endosulfan II		U	0.0003		U	0.0003		U	0.0003		U	0.0003
4,4'-DDD		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Endrin aldehyde		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Endosulfan sulfate		U	0.0003		U	0.0003		U	0.0003		U	0.0003
4,4'-DDT		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Endrin ketone		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Methoxychlor		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Toxaphene		U	0.0003		U	0.0003		U	0.0003		U	0.0003
Technical Chlordane		U	0.0003		U	0.0003		U	0.0003		U	0.0003

NA - Not applicable.
B - Analyte detected in the Blank.
J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

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Organochlorine Pesticides by EPA 3540 (performed by Meta Environmental)

Analyte	XA100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill ppbv	EDL	XA100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill ppbv	EDL
a-BHC	U	0.0003	U	0.0003
b-BHC	U	0.0003	U	0.0003
g-BHC	U	0.0003	U	0.0003
d-BHC	U	0.0003	U	0.0003
Heptachlor	U	0.0003	U	0.0003
Aldrin	U	0.0003	U	0.0003
Heptachlor epoxide	U	0.0003	U	0.0003
g-Chlordane	U	0.0003	U	0.0003
Endosulfan I	U	0.0003	U	0.0003
a-Chlordane	U	0.0003	U	0.0003
Dieldrin	U	0.0003	U	0.0003
4,4'-DDE	U	0.0003	U	0.0003
Endrin	U	0.0003	U	0.0003
Endosulfan II	U	0.0003	U	0.0003
4,4'-DDD	U	0.0003	U	0.0003
Endrin aldehyde	U	0.0003	U	0.0003
Endosulfan sulfate	U	0.0003	U	0.0003
4,4'-DDT	U	0.0003	U	0.0003
Endrin ketone	U	0.0003	U	0.0003
Methoxychlor	U	0.0003	U	0.0003
Toxaphene	U	0.0003	U	0.0003
Technical Chlordane	U	0.0003	U	0.0003

NA - Not applicable.
B - Analyte detected in the Blank.
J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

Aldehyde and Ketone Compounds by EPA 3540 (performed by Meta Environmental)

	DN100412-01A/B 04/12/10 0831-1228 Raw Gas 01 Scholl Canyon Landfill			DN100412-02A/B 04/12/10 1244-1615 Raw Gas 02 Scholl Canyon Landfill			DN100413-03A/B 04/13/10 0800-1205 Raw Gas 03 Scholl Canyon Landfill		
Analyte	ppbv		EDL	ppbv		EDL	ppbv		EDL
Formaldehyde	0.508	B	0.113	0.589	B	0.133	1.28	B	0.110
Acetaldehyde	56.4	DB	0.106	57.9	DB	0.125	62.0	DB	0.103
Acetone	40.9	DB	0.100	52.1	DB	0.118	19.9	B	0.097
Acrolein	30.8		0.101	16.9		0.119	27.9		0.098
Propionaldehyde	6.94		0.100	8.2		0.118	7.9		0.097
Crotonaldehyde		U	0.095		U	0.112		U	0.092
2-Butanone	63.7		0.094	43.5	D	0.111		U	0.091
Methacrolein		U	0.095		U	0.112	21.2		0.092
Butanal	11.5		0.094		U	0.111		U	0.091
Benzaldehyde		U	0.0830		U	0.098		U	0.081
Pentanal		U	0.0892		U	0.105		U	0.087
p-Tolualdehyde	2.54		0.0791	4.06		0.093	3.06		0.0768
Hexanal		U	0.0847		U	0.100		U	0.082

	DN100412-01A/B 04/12/10 0845-1248 Processed Gas 01 Scholl Canyon Landfill			DN100412-02A/B 04/12/10 1300-1625 Processed Gas 02 Scholl Canyon Landfill			DN100413-03A/B 04/13/10 0820-1215 Processed Gas 03 Scholl Canyon Landfill		
Analyte	ppbv		EDL	ppbv		EDL	ppbv		EDL
Formaldehyde	1.13	B	0.111	3.79	B	0.223	1.48	B	0.092
Acetaldehyde	41.7	B	0.104	86.35	DB	0.209	34.7	B	0.086
Acetone	44.7	DB	0.098	110	DB	0.196	52.1	DB	0.081
Acrolein	13.9		0.099	33.53		0.198	14.7		0.082
Propionaldehyde	7.63		0.098	16.4		0.196	7.09		0.081
Crotonaldehyde		U	0.093		U	0.187		U	0.078
2-Butanone		U	0.092		U	0.186		U	0.077
Methacrolein	35.2		0.093	75.7	D	0.187	39.9	D	0.078
Butanal		U	0.092		U	0.186	19.5		0.077
Benzaldehyde		U	0.081		U	0.164		U	0.0678
Pentanal	53.1		0.088		U	0.176		U	0.0729
p-Tolualdehyde	3.06		0.0776	5.26		0.156	3.11		0.0646
Hexanal		U	0.083		U	0.167	5.03		0.0692

NA - Not applicable.
B - Analyte detected in the Blank.
J - Estimated value; detected between the RL and DL.
U - Analyte not detected above DL. Detection limits vary based on gas sample volume.
D - Analyte reported from a diluted extract.
E - Estimate, result detected above calibration range.
I - Concentration/Peak ID uncertain due to potential interference.
EDL - Estimated detection limit is 50% of RL.

APPENDIX B

Siloxane Limits

DiFonso, Andy

Subject: Glendale Power Generation Project- Siloxane Limit

Hello Bernie,

Mercury 50 (quantity 4) and Taurus 60 (quantity 3) turbines were selected for step two of Task 5 study (electric generation using LFG as fuel to be located at the Scholl Landfill, no blending with natural gas).

Please provide the following:

1- Budgetary Cost for each turbine, please ensure that the estimated performance run that will be listed in the budgetary cost is consistent with the performance run you already submitted in the first step of this study.

BUDGET PRICING INCLUDING MAINTENANCE FEE AND ESTIMATE FOR SCR AND CO CAT FOR T60

PERFORMANCE PREVIOUSLY SENT

2- Fixed and variable operating and maintenance cost for each turbine.

INCLUDED IN ESTIMATE ABOVE. WE PROVIDE A FULL SERVICE MAINTENANCE AGREEMENT TO COVER PARTS, LABOR AND FREIGHT AND ENGINE OVERHAULS FOR EACH TURBINE. IT IS A MONTHLY FEE.

3- Controlled and uncontrolled emissions for Taurus 60. I have Solar's Product Information Letter (PIL)#173 listing the expected emissions however, for this part of the study we would need to submit a, "Estimated Power Island Emissions".

4- Budgetary cost estimate for the SCR and CO catalyst that will be needed to control the emissions to the following limits. (15ppm NOx, 20 ppm VOC, 130ppm CO…assuming 15% O2.

SCR and CO Supply price included in estimate above

SEE ATTACHED. Note Solar will guarantee 150 ppm CO based on your gas composition.

5- Ammonia Consumption. See calculation above - you can calculate the amount of ammonia by determining how low you plan or need to lower the Nox.

6- Per Solar's Product Information Letter (PIL)#176, -YES THESE VALUES ARE CORRECT.

- Mercury 50: 5 mg Si/nm3 CH4 maximum, is this equivalent to **1.9 mg Si/nm3 LFG**?
- All other turbines(Taurus 60): 10 mg Si/nm3 CH4, is this equivalent to **3.8 mg Si/nm3 LFG**?

Thank you Bernie, please let me know if you need anything from me to aid you in gathering the requested information above.

Have a great day,

Reem Kayali
Process Engineer
1501 Reedsdale Street, Suite 505
Pittsburgh, PA 15233
Office: (412) 231-5890 x332

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Siloxanes in Fuel Gas

Mark Hughes
Solar Turbines Incorporated

FOREWORD

Stop the average person on the street and ask them what they think about the siloxane problem. Odds are you'll get a confused look and the word siloxane repeated back to you with a rising inflection on the end. On the other hand, ask anyone involved with the burning of either landfill or digester gas and their expression will not be one of confusion—most likely it will be one of the variants by which we indicate pain. For though the introduction of siloxanes has improved our lives in a myriad of subtle ways, they've also made things a good deal more difficult for some of us.

This paper presents the distillation of Solar Turbines' experience to date with siloxanes. Our goal, as always, is to help make our customers successful. To that end we will discuss siloxanes and other silicon-based compounds that increasingly contaminate digester and landfill gas fuels, discuss the effect silicon-based deposits have on the performance and durability of our turbines, and present the application guidelines we have developed in response to the problem. Additional information regarding siloxane detection, measurement and currently available removal technologies is also provided.

EXECUTIVE SUMMARY

Doubtless, siloxanes are here to stay. The question is how to best deal with them. Solar Turbines believes it has amassed more experience burning siloxane-contaminated fuels than any other turbine manufacturer in the world. The good news is that this experience has been overwhelmingly positive: even without siloxane removal, our turbines regularly run reliably on these fuels, turning in a time-between-overhaul that would be expected on natural gas operation as well as sustaining emissions over that lifespan. However, performance over that period, in terms of heat rate and power output, *will* be affected to some degree. Overhaul costs may also increase, as parts that would otherwise be reused may be discarded due to silicon-based contamination.

The degree of siloxane contamination in these fuels is rising as time goes on. What wasn't a problem before may be in the future. With this fact in mind, it is the twin effect of unpredictable performance degradation and potentially higher overhaul costs that drive the guidelines presented here. Adequate siloxane removal will produce not only a predictable turbine life, but also performance and maintenance costs similar to operation on natural gas. In the end, as with anything, it comes down to a cost/benefit/risk analysis. Here, then, are our recommendations:

> *Siloxanes in fuel gas can result in silicon-based deposits within the gas turbine that can cause damage and/or unexpectedly high rates of performance degradation. Thus, the use of a reliable siloxane removal system is strongly recommended. In any event, Solar Turbines does not accept responsibility for any such damage or performance loss traceable to silicon-based deposition. As a guideline, Solar Turbines recommends that the amount of silicon, as measured by the Jet-Care SiTest method, never exceed the following levels:*
>
> | | |
> |---|---|
> | *Mercury*™ 50: | 5 mg Si/nm^3 CH_4 (see paragraph below) |
> | All other *Solar*® turbines: | 10 mg Si/nm^3 CH_4 |
>
> *Note that even at these levels, some silicon-based deposition may occur.*

Mercury 50

Owing to its recuperator, the following additional recommendations apply to the *Mercury* 50:

1. *The siloxane removal system should employ at least two vessels in series such that breakthrough in the upstream vessel, or system, will be captured in the downstream vessel.*
2. *During commissioning, the Mercury 50 should not be started and operated until the siloxane removal system is fully functional and on-line.*
3. *A regular testing program, designed according to good engineering practices, should be implemented to monitor the efficacy of the siloxane removal system.*
4. *If siloxane breakthrough downstream of the final polishing vessel is detected, the Mercury 50 should be shut down and the medium in the polishing vessel replaced.*

Note: 5 mg/Nm^3 CH_4 is currently the lowest commercially available guarantee for siloxane removal. This recommended maximum value is not meant to imply that the *Mercury* 50 can operate continuously at this level. The recommendation represents the maximum slip past an upstream removal system, to be subsequently captured by a downstream polishing vessel. Given the expected SiO_2 formation density, the recuperator can tolerate around 200 pounds of silicon oxide before the degree of fouling will force turbine output reduction due to excessive recuperator backpressure.

INTRODUCTION TO SILOXANES

The generic name siloxane is derived from silicon + oxygen + methane. However, these polymers can contain other organic or hydrocarbon molecules attached to a backbone chain of silicon and oxygen atoms. These compounds are also referred to as polysiloxanes, organosiloxanes, organosilicons, or silicons. They are good elastomers and possess other lubricating, surface and sensory enhancement properties. Siloxanes and their precursors, silanes, are widely employed in applications ranging from automotive to electronics, from food and beverage to textile industries, and are formulated in products such as thermoplastic resin additives, dispersants, water repellents, and cleaners as well as many consumer products such as shampoos, cosmetics and deodorants.

When process wastes or products containing these polymers are disposed in a landfill, decomposition and volatilization of some of the entrained siloxanes will occur, allowing them to become part of the gas composition in several forms and concentrations. In a similar way, some of the siloxanes contained in products discharged into wastewater streams, due to their low solubility in water (hydrophobic nature), will end up in the sludge of treatment and digester plants, ultimately volatilizing into the digester gas. Thermophilic digesters operate at higher temperatures than mesophilic digesters and appear to yield significantly higher concentrations of siloxanes in the effluent gas.

Experience indicates there is as much potential for siloxane-related problems using digester gas as with landfill gas. Therefore, our siloxane guidelines are to be applied to both fuel sources. A study conducted by the Los Angeles County Sanitation Districts Joint Water Pollution Control Plant (JWPCP), collected data from more than 30 different landfill and digester sites and found siloxane concentration in the gases ranging from less than 4 mg/nm^3 to well over 140 mg/nm^3 depending on the site. This same range of siloxane concentration was observed at both landfill and digester sites.

In general, siloxane contamination levels are rising as these chemicals gain wider acceptance in the marketplace. One example is that dry cleaners are beginning to shift to a new chemical that is composed primarily of D5 siloxane. So, what may have been a minor problem in the past will most likely become a larger one in the future, closed landfills excluded, of course.

SILICON & COMBUSTION EQUIPMENT

Siloxanes in the fuel can significantly affect the performance and cost of operation of all manner of internal combustion equipment: reciprocating engines, gas turbines, microturbines, flares, and fuel cells. The high pressures and high temperatures of the combustion process break apart the molecules allowing the methane or hydrocarbons to burn but leaving the silicon and the oxygen molecules in an unstable monatomic state. These molecules can recombine and form silicon dioxide, also known as silica or sand and can also mix with other elements or contaminants in the combustion gases. Depending on the type and the concentration of silicon found in the gas and on the characteristics of the combustion process, the silica residue will be found in different forms.

Reciprocating engines burning these fuels typically experience significantly shortened cylinder head life, valve guttering, detonation, and deterioration of emissions performance. With turbines, power and heat rate are often affected by the formation of the silicon-based deposits on turbine hot section components. Emissions are not affected. The deposits reduce turbine efficiency and potentially could block off cooling exit holes, leading to premature equipment failure. Experience with *Solar* turbines, however, has shown that this rarely happens.

Fouling of equipment installed downstream is also very likely to occur. In selective catalytic reduction (SCR) systems for example, the catalyst will become blinded by silicon deposits and rendered useless. Heat recovery steam generators (HRSGs) will lose heat transfer efficiency as the deposits build up on the heat exchanger tube surfaces. Stacks and ductwork will be coated with a white powder.

Deposits inside the turbine often appear as a powdery substance (Figure 1). However, under certain conditions, they can show up as a hard glaze or ceramic like coating (Figure 2). Additionally, it is hypothesized that contaminants can alter the glass formation curves and affect the characteristics of the deposits, as well as the zones of the turbine where the formation of glass-type substances occurs inside the engine.

Often both types of deposits, a top layer of loose powder and a hard glazed layer adhered to the substrate, will be found inside the turbine.

Typically, these deposits cannot be removed with traditional engine cleaning or washing procedures and therefore require equipment teardown and replacement of affected components. No solvent or chemical method has been found that will effectively remove these coatings without damaging the substrate material. Thus, affected components are not normally reusable.

So while the problems caused by siloxanes are certainly not exclusive to Solar's products, to prevent performance losses, reduced life, and potential damage to the gas turbine, we recommend the use of commercially available systems to remove the siloxanes to levels mentioned in the executive summary.

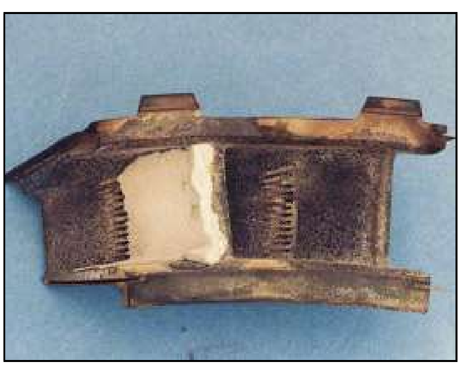


Figure 1. Silicon Deposits on a Turbine Nozzle

Figure 2. Hard Silicon Deposits on a Turbine Nozzle

TESTING FOR SILOXANES

Testing methodologies used to determine the concentration of siloxanes in fuel gases vary widely, and despite the efforts of many, are still not standardized in the industry. While the traditional laboratories typically measure individual siloxane species, other proprietary methods test only for total silicon content. Experience has shown that it's not easy to compare the analyses obtained from the various methods. With this in mind, our focus shifted from an attempt to the correlate results obtained from these various methods to the simpler task of selecting one test method and using it as the standard for our guidelines.

Criteria for selecting the recommended testing method included ease of sample collection, cost of analysis, speed of analysis results, and accuracy. At the end of the investigation, Solar settled on the method developed by Jet-Care International. Their proprietary test is known as the SiTest and provides a result measured in mg/nm^3 CH_4.

Jet-Care International, Inc.

3 Saddle Road
Cedar Knoll, NJ 07927-1902
(201) 292-9597

In Europe, the company operates under the name of Spectro.

Spectro
Palace Gate
Odiham, Hampshire RG29 1NP, UK
+44 (0) 1256 704000

Jet-Care developed a gas sampling kit for siloxane measurements that is automated and passes a predetermined volume of fuel gas through three bottles of mineral oil staged in series. Once the set amount of gas has been run through the bottles (this procedure is controlled automatically by the kit), the bottles are removed from the kit, sealed, and mailed to Jet-Care. Analysis upon receipt is typically 1-2 days.

Figure 3. Jet-Care SiTest Kit in Use.

As previously mentioned, siloxane concentrations in the fuel gas will likely change over time. Therefore, periodic testing of the influent gas to monitor changes in silicon concentration should be included as part of a semi-annual maintenance plan.

SILOXANE REMOVAL

Conventional particulate filtration systems will not remove siloxanes from the fuel gas. Drying the gas will remove some types of siloxanes but is not very effective with the majority of siloxane species. Therefore, other means had to be found to address siloxane removal.

Three different technologies have been used to remove siloxanes from fuel gas:

1. Absorption/scrubbing in a liquid
2. Adsorption into solid media
3. Condensation using refrigeration

Absorption/Scrubbing In Liquid Such As Methanol Or Polypropylene Glycol

This process uses a liquid to absorb/scrub the gas and is based on the coefficient of diffusion, surface area for mass transfer, and concentration gradient between the gas and the liquid phase.

Use of pure methanol in bench scale tests has yielded good results. However, economics, flammability, and toxicity are major concerns. Performance at 50% dilution has proved disappointing and the liquid has not been used in a commercial application.

Glycol solutions have been used on a commercial basis but have proven to be economically prohibitive in most cases. No new commercial liquid-based systems have come into the market in years.

Adsorption Into Solid Media Such As Activated Carbon Or Resins

There are two major divisions in this category—systems that use sacrificial media and those that regenerate their adsorptive media. Though there are many non-regenerative systems installed throughout the world, the trend in recent years has been toward regenerative systems, which require a higher initial capital investment but experience substantially lower O&M costs through the life of the project.

Regardless of whether the system regenerates its media, the adsorption process is the same. The fuel gas is passed through one or more filter vessels that contain a bed of a solid adsorbent material. Media design facilitates diffusion of siloxanes from the gas into the micropores of the solid adsorbent.

When a sacrificial system's capacity has been exhausted the media is disposed of, typically in a landfill. In general, the spent material has been deemed non-hazardous and therefore does not require special handling. With the sacrificial type systems there are typically two to three vessels, which are operated in a lead/lag/standby method. Upon siloxane breakthrough, the lag unit becomes the lead and the standby vessel (when present) becomes the lag while the exhausted unit is replenished. Typical cycles are in the 3-to-10 month range depending upon system design.

Of the regenerative system design, there are again two major types: those that use heated air to regenerate the media, and those that use cleaned product gas (fuel) to regenerate. In both cases the regen gas must be sent to a flare, as VOCs come off with the siloxanes as well as some amount of product gas (initial depressurization of the hot-air regenerated types).

Condensation Using Refrigeration

The siloxanes typically found in landfill and digester fuel gases can be removed through the use of a refrigeration process. Chilling the fuel gas will condense the siloxanes, which must then be reheated and removed.

Chilling the gas to -30°C (-22°F) eliminates virtually 100% of siloxanes present in the gas. The use of a one-micron coalescing filter has proven in bench scale experiments to require a temperature of only -22.8°C (-9°F) to achieve the same siloxane removal effectiveness of nearly 100%.

Experience has shown that this system is more difficult to take from theory to practice than expected. At this point in time, only one manufacturer has had success with their design and then only on a microturbine scale, not with the large gas flows industrial gas turbines require.

Siloxane Removal Summary

The siloxane removal industry has moved in recent years from a small-shop business to one that has attracted the attention of major industry players, companies large enough to stand behind their warranties and therefore provide a higher level of comfort to equipment operators. As more experience is gained, it is expected that the cost of these systems will decrease.

As a final note, recognizing that no siloxane removal method can be 100% effective, that conditions can change, and that fuel gas silicon concentrations lower than the guidelines set forth here may still lead to the formation of deposits, it is recommended that attention be paid during semi-annual borescope examinations to look for evidence of deposition on turbine hot section components.

Additional Mercury 50 Guidelines

Because its recuperator is an efficient collector of any silicon oxides passing through the turbine, it is recommended that regardless of the type of siloxane removal system chosen it include a series arrangement employing a polishing vessel downstream of the main system. Any removal system can develop slip for a variety of reasons and experience has shown that a single line of defense can result in insufficient protection, excessive recuperator fouling, and subsequent turbine output restrictions.

SUMMARY

If not removed, the combustion of the silicon compounds in landfill and digester gases will generate silicon dioxide deposits in the form of a loose powder or a hard glaze coating that is extremely difficult to remove from turbine gas path components, accelerating degradation of performance and potentially adversely affecting the durability of the turbine equipment. Specialized testing is required to detect and measure siloxanes in fuel gases and for this service, Jet-Care's SiTest is recommended.

Though the majority of turbines Solar has shipped into landfill and digester applications over the last three decades operate without siloxane removal, it is a fact that siloxanes create deposits inside turbines that result in unpredictable rates of performance loss and may increase maintenance costs long-term. Insufficient data and multiple variables prevent us from accurately establishing a direct correlation between the amount and type of silicon ingested, severity of deposition incurred, and rate of performance degradation.

The difficulties imposed by siloxanes are not exclusive to gas turbines. Siloxane removal technology has improved dramatically in the last few years and in many cases is now cost-effective. In view of the changing marketplace, Solar has taken steps to mitigate the degradation of performance and life of our turbine equipment through the recommendation of the following guidelines:

> *Siloxanes in fuel gas can result in silicon-based deposits within the gas turbine that can cause damage and/or unexpectedly high rates of performance degradation. Thus, the use of a reliable siloxane removal system is strongly recommended. In any event, Solar Turbines does not accept responsibility for any such damage or performance loss traceable to silicon-based deposition. As a guideline, Solar Turbines recommends that the amount of silicon, as measured by the Jet-Care SiTest method, never exceed the following levels:*

Mercury 50:	*5 mg Si/nm3 CH4 maximum**
All other turbines:	*10 mg Si/nm3 CH4*

Note that even at these levels, some silicon-based deposition may occur.

**Owing to its recuperator, the Mercury 50 needs additional precautions:*

1. The siloxane removal system should employ at least two vessels in series such that breakthrough in the upstream vessel, or system, will be captured in the downstream vessel.
2. During commissioning, the *Mercury* 50 should not be started and operated until the siloxane removal system is fully functional and on-line
3. A regular testing program, designed according to good engineering practices, should be implemented to monitor the efficacy of the siloxane removal system.
4. If siloxane breakthrough downstream of the final polishing vessel is detected, the *Mercury* 50 should be shut down and the medium in the polishing vessel replaced.

Note: 5 mg/Nm^3 CH_4 is currently the lowest commercially available guarantee for siloxane removal. This recommended maximum value is not meant to imply that the *Mercury* 50 can operate continuously at this level. The recommendation represents the maximum slip past an upstream removal system, to be subsequently captured by a downstream polishing vessel. Given the expected SiO_2 formation density, the recuperator can tolerate around 200 pounds of silicon oxide before the degree of fouling will force turbine output reduction due to excessive recuperator backpressure.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

DiFonso, Andy

Subject: FW: Cat Engine Siloxane Limit

From: khertzler@clevelandbrothers.com [mailto:khertzler@clevelandbrothers.com]
Sent: Monday, March 16, 2015 1:51 PM
To: Kayali, Reem
Subject: RE: Cat Engine Siloxane Limit

Reem,

The exhaust after treatment equipment would remain at ~ 0.5 mg/m3.

This is due to the fact that there is air in the landfill gas.
This is the main reason the CH4% is so low. Therefore, less air is required to combust the Glendale LFG. ...so the effect is that the amount of exhaust gas leaving the engine is still at a typical level.

On the other hand the engine maintenance cost may increase somewhat due to the increased mass of SI that will pass through engine when comparing to 0.5 mg/m3 at 50% CH4 vs 0.5 mg/m3 at 38.3% CH4.

I do not have a $ value for you in regard to increased maintenance cost. It seems reasonable that a 5 to 10% increase in maintenance cost might be expected when comparing this engine running on 50% CH4 fuel vs 38.3% CH4 fuel.

Sincerely,

Kurt Hertzler
Cleveland Brothers Equip. Co., Inc.
336 N. Fairville Ave.
Harrisburg PA 17112
Direct Dial: 717-635-7267
E-FAX No: 717-441-3757
Cell Phone: 717-514-7360
Email: khertzler@clevelandbrothers.com

APPENDIX C

Operating Specification Sheets – Prime Movers

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer *Venture Engineering*	Model **MERCURY 50-6400R**
	Package Type **GSC**
Job ID **Scholl Canyon Landfill**	Match **STANDARD**
Run By **Kevin D Jensen** / Date Run **9-Jan-2015**	Fuel System **GAS**
Engine Performance Code **REV 4.54** / Engine Performance Data **REV 1.11**	Fuel Type **CHOICE GAS**

DATA FOR NOMINAL PERFORMANCE

Elevation	feet	600
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	3.0

		1	2
Engine Inlet Temperature	deg F	60.0	60.0
Relative Humidity	%	60.0	60.0
Specified Load*	kW	FULL	90%
Net Output Power*	kW	4853	4382
Fuel Flow	mmBtu/hr	43.44	39.19
Heat Rate*	Btu/kW-hr	8951	8944
Therm Eff*	%	38.120	38.148
Inlet Air Flow	lbm/hr	134296	124438
Engine Exhaust Flow	lbm/hr	143473	132713
PCD	psiG	127.3	116.2
PT Exit Temp. (T7)	deg F	1197	1200
Exhaust Temperature	deg F	728	711

Fuel Gas Composition (Volume Percent)

Methane (CH4)	38.30
Carbon Dioxide (CO2)	32.20
Nitrogen (N2)	25.20
Oxygen (O2)	4.30
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	348.3	Specific Gravity	0.9926	Wobbe Index at 60F	349.6

**Electric power measured at the generator terminals.*

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Notes
Expected Performance - No Emissions Control Equipment

Maximum volumetric flow rate for one Mercury 50:

Solar Turbine:

Mercury 50: $$\left(\frac{43{,}400{,}000\ BTU}{Hour}\right) * \left(\frac{ft^3}{348.3\ BTU}\right) * \left(\frac{1\ Hour}{60\ Minutes}\right) = 2{,}078\ \boldsymbol{SCFM}$$

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer *Venture Engineering*		Model **TAURUS 60-7901**	
		Package Type **GSC**	
Job ID **Scholl Canyon Landfill**		Match **STANDARD**	
Run By **Kevin D Jensen**	Date Run **29-Jan-15**	Fuel System **GAS**	
Engine Performance Code **REV. 4.15.1.17.10**	Engine Performance Data **REV. 2.0**	Fuel Type **CHOICE GAS**	

DATA FOR NOMINAL PERFORMANCE

Elevation	**feet**	**600**	
Inlet Loss	**in H2O**	**4.0**	
Exhaust Loss	**in H2O**	**7.0**	
		1	**2**
Engine Inlet Temperature	**deg F**	**60.0**	**60.0**
Relative Humidity	**%**	**60.0**	**60.0**
Gearbox Efficiency		**0.9800**	**0.9800**
Generator Efficiency		**0.9640**	**0.9640**
Based On 1.0 Power Factor			
Specified Load*	**kW**	**FULL**	**78.6%**
Net Output Power*	**kW**	**6001**	**4717**
Fuel Flow	**mmBtu/hr**	**63.75**	**52.23**
Heat Rate*	**Btu/kW-hr**	**10624**	**11074**
Therm Eff*	**%**	**32.117**	**30.812**
Engine Exhaust Flow	**lbm/hr**	**178001**	**175617**
PT Exit Temperature	**deg F**	**951**	**822**
Exhaust Temperature	**deg F**	**951**	**822**

Fuel Gas Composition (Volume Percent)

Methane (CH4)	**38.30**
Carbon Dioxide (CO2)	**32.20**
Nitrogen (N2)	**25.20**
Oxygen (O2)	**4.30**
Sulfur Dioxide (SO2)	**0.0001**

Fuel Gas Properties

LHV (Btu/Scf)	**348.3**	**Specific Gravity**	**0.9926**	**Wobbe Index at 60F**	**349.6**

**Electric power measured at the generator terminals.*

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Maximum volumetric flow rate for one Taurus 60:

Solar Turbine:

Taurus 60 : $\left(\frac{63{,}800{,}000\ BTU}{Hour}\right) * \left(\frac{ft^3}{348.3\ BTU}\right) * \left(\frac{1\ Hour}{60\ Minutes}\right) = 3{,}053\ \boldsymbol{SCFM}$

DiFonso, Andy

Subject: Performance Specification - LFGTE Plant - The City of Glendale, CA

From: khertzler@clevelandbrothers.com [mailto:khertzler@clevelandbrothers.com]
Sent: Tuesday, March 10, 2015 8:03 AM
To: Kayali, Reem
Cc: Slatosky, Bill; O'Connor, Kevin
Subject: RE: Budget Pricing - LFGTE Plant - The City of Glendale, CA

Kayali,

Perf specs you requested.

Site Conditions Assumed:

110 F Air delivered to the Air Inlet Filters on the Engine.

55% Humidity.

1415 Ft Elevation.

With Landfill gas Composition as follows:

Landfill Gas compositions are:

Components	Molecular Formula	LFG % Mole
Methane	CH_4	0.383
Carbon Dioxide	CO_2	0.322
Nitrogen	N_2	0.252
Oxygen	O_2	0.043

Genset Voltage: 13,800 VAC 3 Phase Wye - 60 HZ

Generator Speed: 900 RPM.

Generator Power Factor Setpoint: 1.0 PF

Genset Electrical Output at Terminals of the Generator end: 3370 kW.

Engine Speed 900 RPM.

Engine Power Output when delivering full Generator output listed above: 3474 bkW - or - 4657 BHP.

Estimated Max Parasitic Power required to operate essential Genset ancillary Equipment: ~

102 kW.
(Note: Assumes genset is in a CBE provided enclosure....includes equipment such as: coolant pumps, radiator fans, ventilation fans, battery chargers, controls, basic lighting).
(Note2: Net Output would therefore be 3268 ekW...Venture must also deduct other site parasitic loads such as gas compression and clean up systems)

Estimated Site Fuel Consumption, LHV: 28,182,060 BTU/Hour.

Estimated Site Fuel Consumption, HHV: 31,306,513 BTU/Hour.

Note3: Emissions will be reduced by the SCR and Oxidation Catalysts (listed in previous emails) to meet Venture's site requirements.

Note4: There is no heat recovery on this project, therefore all excess heat is rejected to the radiators, exhaust stack or air surrounding genset.

Please email or call with any questions or comments.

Sincerely,
Kurt Hertzler
Cleveland Brothers Equip. Co., Inc.
336 N. Fairville Ave.
Harrisburg PA 17112
Direct Dial: 717-635-7267
E-FAX No: 717-441-3757
Cell Phone: 717-514-7360
Email: khertzler@clevelandbrothers.com

Maximum volumetric flow rate for one Caterpillar engine:

Caterpillar Engine:

$\mathrm{CG260-16:}$ $$\left(\frac{28{,}182{,}060\ BTU}{Hour}\right) * \left(\frac{ft^3}{348.3BTU}\right) * \left(\frac{1\ Hour}{60\ Minutes}\right) = 1{,}349\ \boldsymbol{SCFM}$$

APPENDIX D

Vilter Compressor Performance Sheet

Vilter

Vilter GasPro
Process Single Screw Compressor Report

Customer		Date / Time	2/11/2015
Project Name		Registered To	
Program Version	2.1		
Description			

VSG1851 @ 100.0% Capacity - 3550 rpm

System Suction Pressure	88.9psiA	System Discharge Pressure	284.0psiA
Suction Pressure Loss	1psi	Discharge Pressure Loss	8psi
Compressor Suction Pressure	87.9psiA	Compressor Discharge Pressure	292.0psiA
Elevation	1409.0ft	Atmospheric Pressure	13.964psiA

	Temperature	Mass Flow	Volume Flow
Suction	108.0°F	43584.9lbm / hour	1649.2ACFM
Discharge	224.2°F	43584.9lbm / hour	626.9ACFM

Capacity	9113.9 SCFM	Power/Capacity Ratio	0.14BHP / SCFM
Capacity	13.124 MMSCFD	Power/Capacity Ratio	95.08BHP / MMSCFD
Power	1245.5 BHP	Compression Ratio	3.32:1
Torque	1842 ft-lb	Volume Ratio	2.50:1
Speed	3550 rpm	Volumetric Efficiency	89.5%
		Isentropic Efficiency	74.2%

Standard conditions based on 14.7 psia and 60 °F

Gas Mixture Analysis

Average Mole Weight 28.70 Cp/Cv Ratio 1.3076

Gas Name	Mole Percent	Gas Name	Mole Percent
Methane	38.2	Carbon Dioxide	32.1
Nitrogen	25.2	Oxygen	4.3
Water Vapor	0.2		

Vilter Separator Size 48 in with high eff elements

Oil Cooling Data

Oil Name	CP-4601-100		
Oil Cooling Type	External Oil Cooler Required		
Oil Flow Rate	83.4gpm		
Oil Flow Rate	35193.5lbm / hour	Oil Cooling Heat Load	1,756,341.86BTU/H
Oil Injection Temperature	130.0°F	**Lube Pump is OFF**	

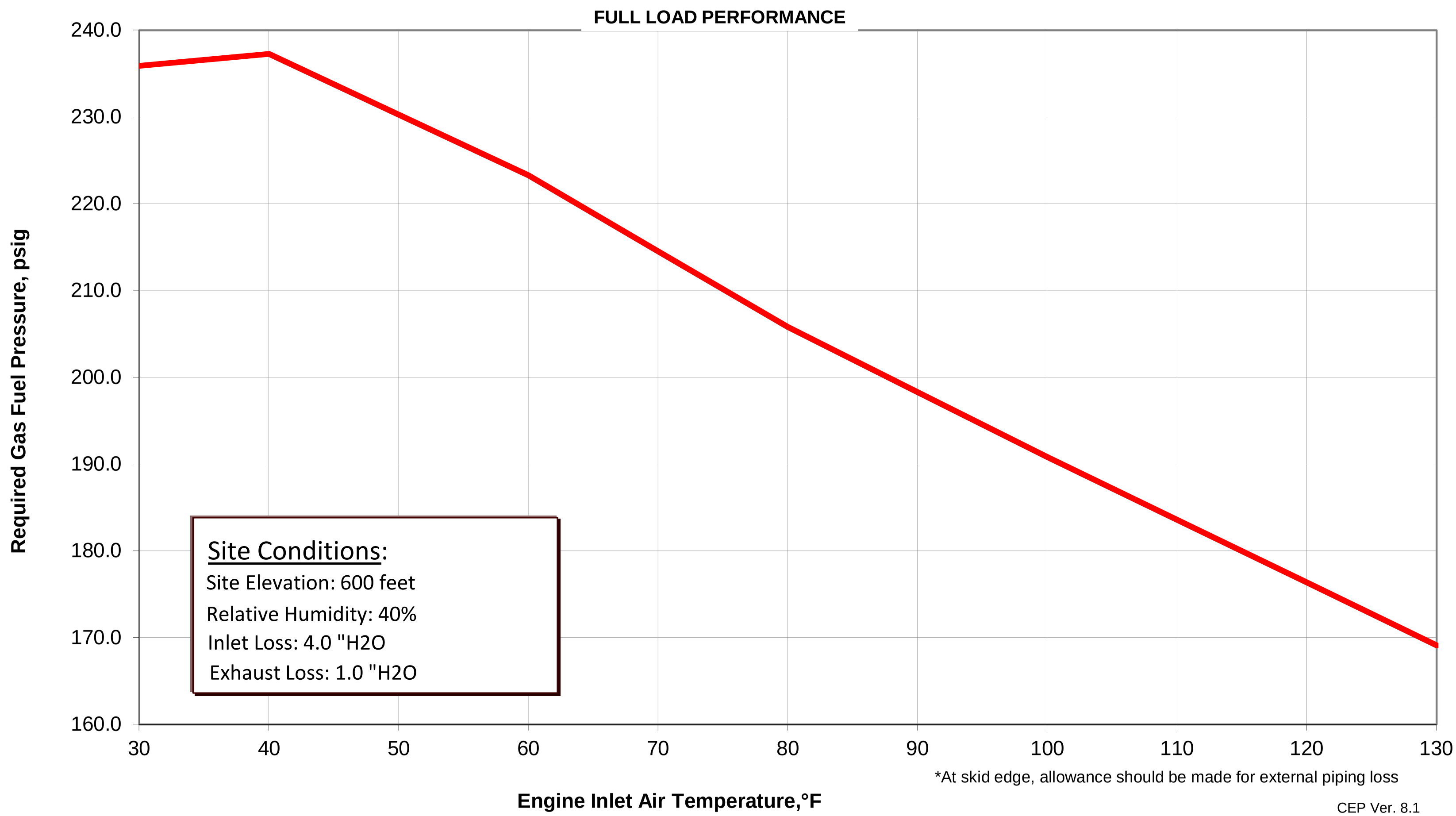
Note: The information contained in this program is subject to change without notice. Vilter reserves the right to final performance verification. The minimum full load driver power should be 110% of the program predicted power.

EMERSON
Climate Technologies

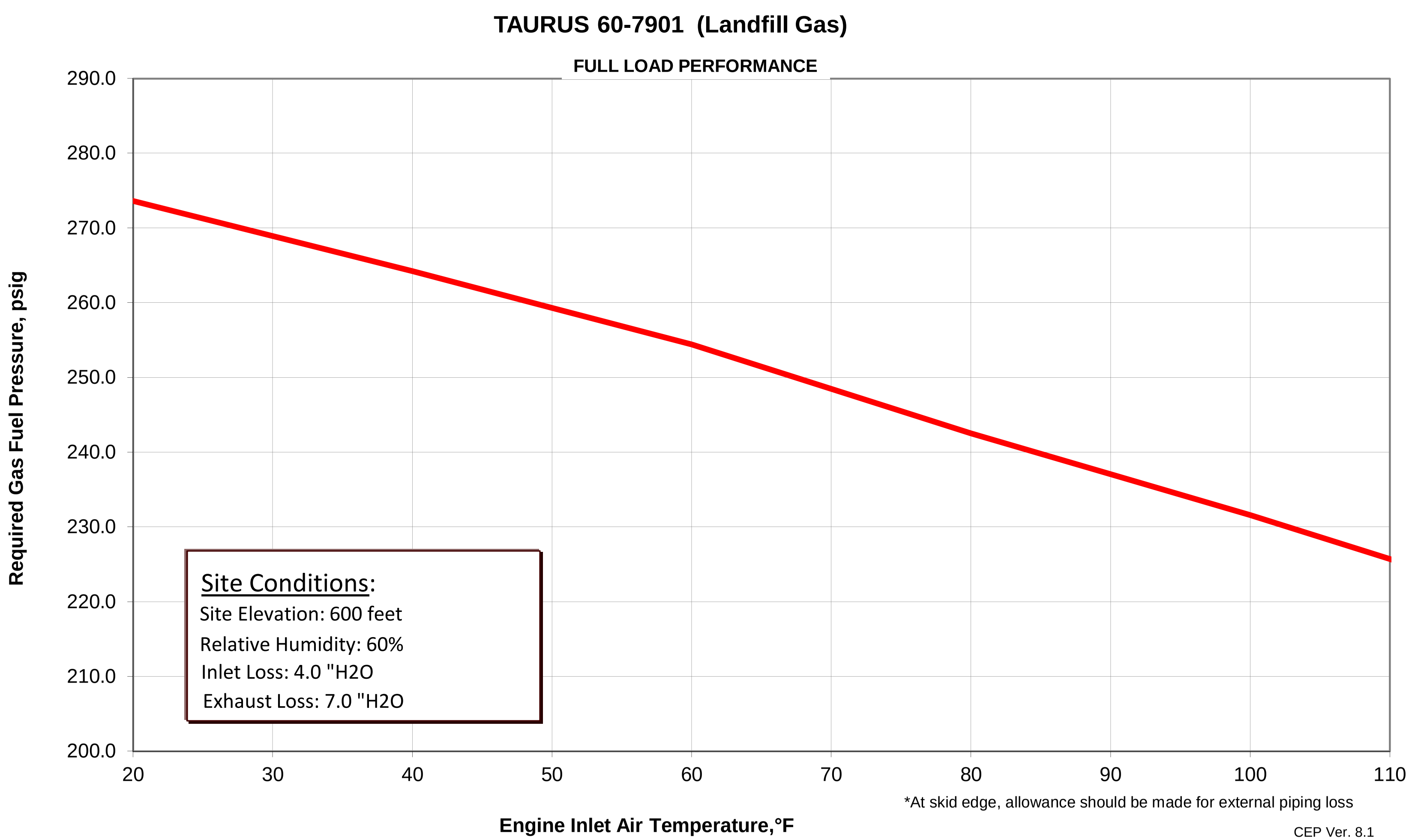
APPENDIX E

Pressure and Temperature Requirements- Solar Turbines

MERCURY 50-6400R (Landfill Gas)



CEP Ver. 8.1



TAURUS 60-7901 (Landfill Gas)
FULL LOAD PERFORMANCE
Required Gas Fuel Pressure, psig
290.0
280.0
270.0
260.0
250.0
240.0
230.0
220.0
210.0
200.0
20
30
40
50
60
70
80
90
100
110
Site Conditions:
Site Elevation: 600 feet
Relative Humidity: 60%
Inlet Loss: 4.0 "H2O
Exhaust Loss: 7.0 "H2O
Engine Inlet Air Temperature,°F
*At skid edge, allowance should be made for external piping loss
CEP Ver. 8.1

Solar Turbines
A Caterpillar Company

SPECIFICATION

FUEL, AIR, WATER (OR STEAM) & COMPRESSOR CLEANING FLUIDS FOR *SOLAR*® GAS TURBINE ENGINES

Data Control Level

1

SPECIFICATION NO. ES 9-98

ISSUED: 10/29/82; ERL5670-1
(Date and PRD No.)

REVISION:
(Letter, Date and PRD/CR No.)

Release Stamp

CDM

A; 03/29/85; ERL8646-1
B; 01/29/87; ERL9338-1
C; 02/20/90; ERL0210-1
D; 05/24/93; ERL10900-1
E; 08/05/93; ERL11071-1
F; 08/10/03; PRD14724-1
G; 03/22/04; CR09269
H; 07/09/04; CR09270
J; 10/14/04; CR10321
K; 01/18/05; CR10788
L; 08/28/06; CR14043
M; 12/12/06, CR15195
N; 01/30/08; CR18878
P; 06/27/08; CR20704
R; 01/06/09; CR22506
T; 02/23/09; CR22863
U; 07/14/09; CR24384
V; 12/16/09; CR24042
W; 02/17/10; CR26201
Y; 05/25/10; CR26924
AA; 03/14/11; CR29413

Rev. Ltr.	CR #	Signature & Title	Date
AB	37814	Prepared By: **Abdul Ahmed** Approved By: **Jose Aurrechoechea**	12-01-11

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

TABLES

FIGURES

1.0 SCOPE - This specification establishes the quality requirements for the fuel, air, water (or steam) and compressor cleaning solutions to be used in *Solar* gas turbine engines.

This specification supersedes all previous Solar fuel, air, or water specifications, including fuel specification ES 1211, ES 9-247, and ES 9-251, for use in *Solar* gas turbine operation.

1.1 RESPONSIBILITY/DEVIATIONS - It is the responsibility of the end user to ensure that where required by this specification, Solar Turbines' approval has been sought for use of the fluids cited. It is also the responsibility of the end user to ensure on a continuing basis that all fluids entering the gas turbines are compliant with this specification. Deviations from the limits and requirements herein shall not be considered without consultation and specific written approval from Solar Engineering. These approvals can be attained through the Special Engine Request Process.

2.0 APPLICABLE DOCUMENTS - The following documents, of issue in effect on the date of this specification, shall be a part of this specification to the extent specified herein.

SPECIFICATIONS

Solar

ES 9-62	Ingestive Cleaning Solar Turbine Engines
ES 2069	Set-up, Installation, and Operating Instructions for Evaporative Coolers
FORM 2594	Liquid Fuel Suitability Inquiry
FORM 2595	Gaseous Fuel Suitability Inquiry
FORM 3091	Total Site Contamination Worksheet

American Society for Testing and Materials

ASTM D86	Method of Test for Distillation of Petroleum Products
ASTM D93	Method of Test for Flash Point by Pensky - Martens Closed Tester
ASTM D97	Method of Test for Pour Points
ASTM D129	Method of Test for Sulfur in Petroleum Products by the Bomb Method
ASTM D130	Method of Test for Copper Corrosion by Petroleum Products, Copper Strip Test
ASTM D240	Method of Test for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter
ASTM D323	Method of Test for Vapor Pressure of Petroleum Products (Reid Method)
ASTM D445	Method of Test for Viscosity of Transparent and Opaque Liquids (Kinematic and Dynamic Viscosities)
ASTM D482	Method of Test for Ash from Petroleum Products
ASTM D511	Tests for Calcium and Magnesium in Water
ASTM D512	Standard Test Method for Chloride Ion in Water
ASTM D524	Method of Test for Ramsbottom Carbon Residue of Petroleum Products
ASTM D808	Tests for Chlorine in New and Used Petroleum Products (Bomb Method)
ASTM D859	Tests for Silica in Water
ASTM D1072	Test for Total Sulfur in Fuel Gases
ASTM D1179	Standard Test Methods for Fluoride Ion in Water
ASTM D1253	Tests for Residual Chlorine in Water
ASTM D1266	Sulfur in Petroleum Products and liquefied Petroleum Gases (Lamp Method)
ASTM D1267	Vapor Pressure of Liquefied Petroleum Gases
ASTM D1293	Tests for pH of Water
ASTM D1298	Density, Specific Gravity or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1319	Method of Test for Hydrocarbon Types in Liquid Petroleum Products by Fluorescent Indicator Absorption

ASTM D1657	Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Thermohydrometer
ASTM D1838	Copper Strip Corrosion by Liquefied Petroleum Gases
ASTM D1945	Standard Test Method for Analysis of Natural Gas By Gas Chromatography
ASTM D2163	Analysis of Liquefied Petroleum Gases by Gas Chromatography
ASTM D2500	Method of Test for Cloud Point
ASTM D2598	Calculation of Physical Characteristics of Liquefied Petroleum Gases From Compositional Analysis
ASTM D3605	Trace Metals in Gas Turbine Fuels by Atomic Absorption and Flame Emission Spectroscopy
ASTM D3373	Tests for Vanadium in Water
ASTM D3559	Tests for Lead in Water
ASTM D3588	Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels
ASTM D3868	Standard Test Methods for Fluoride Ion in Brackish Water, Seawater, and Brines
ASTM D3919	Standard Practice for Measuring Trace Elements in Water By Graphite Furnace Atomic Absorption Spectrophotometry
ASTM D4052	Standard Test Method for Density and Relative Density by Digital Density Meter
ASTM D4192	Standard Test Method for Potassium in Water By Atomic Spectrophotometry
ASTM D4418	Standard Practice for Receipt, Storage, and Handling of Fuels for Gas Turbines
ASTM D4629	Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection
ASTM D5186	Test Method for Determination of Aromatic Content of Diesel Fuels by Supercritical Fluid Chromatography
ASTM D5453	Determination of Total Sulfur in Light Hydrocarbons
ASTM D5673	Standard Test Method for Elements in Water By Inductively Coupled Plasma Spectrometry
ASTM D5762	Standard Test method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence
ASTM D5907	Standard Test Method for Filterable and non-Filterable Matter in Water
ASTM D6079	Evaluating Lubricity of Diesel Fuels by High-Frequency Reciprocating Rig (HFRR)
ASTM D6217	Standard Test Method for Particulate Contamination in Middle Distillate Fuels
ASTM D6304	Standard Test Method for Determination of Water in Petroleum Products
ASTM F25	Standard Test Method for Sizing and Counting Airborne Particulate

Natural Gas Processors Association

NGP 2140-70 Liquefied Petroleum Gas Specifications and Test Methods

Deutches Institute Fur Normung (DIN)

DIN 51850 Gross and Net Calorific Value of Pure Gaseous Fuels

US Bureau of Mines

Bulletin 627 Flammability Characteristics of Combustible Gases and Vapors

3.0 GENERAL REQUIREMENTS - The requirements stated herein govern the quality of air, fuel, and water (steam) entering the engine. Failure to meet the requirements in this specification can result in a negative impact on the performance and life expectations of the engine and package.

3.1 UNDESIRABLE CONTAMINANTS - The contaminants listed here are known to be harmful to engine components and must be controlled to within the maximum allowable limits specified for each contaminant in order to attain maximum engine life. The total quantity of each contaminant ingested by the engine must be limited regardless of whether it enters through the air, fuel, injected water (steam), or as liquid water carryover from evaporative cooling.

The limits for each of the several critical contaminants from all possible sources are provided in Table 1.

Table 1. Maximum Allowable Contaminant Concentrations

Contaminant	Limit(Note 1) in Fuel Equivalent Concentrations	Test Method
Sulfur (see Notes 2, 3, & 4)	**10,000 ppmw FEC (See note 5A & 5B). Additional restrictions apply for *SoLoNOx* liquid operation (See note 6)**	ASTM D129, D1072, D1266 or ASTM D5453
Sodium + Potassium	0.5 ppmw FEC	ASTM D3605 or D1428
Vanadium	0.5 ppmw FEC	ASTM D3605, D3373
Lead	1 ppmw FEC	ASTM D3605, D3559
Calcium + Magnesium	2 ppmw FEC	ASTM D3605, D511
Fluorine	1 ppmw FEC	ASTM D1179, D3868
Chlorine	0.15 weight percent or 1,500 ppmw FEC	ASTM D512, D808, D1253,
Others (See Notes 7 &8)	0.5 ppmw FEC	

Notes:

(1) The limits given are FUEL EQUIVALENT CONCENTRATIONS (FEC), i.e., the maximum allowable concentration of each contaminant as if each contaminant is found solely in a fuel with LHV - 18,380 Btu/lb. (such as diesel #2). Instructions for performing calculations are provided in Appendix A, Form 3091, Total Site Contamination Worksheet.

(2) For installations with exhaust heat recovery equipment, it is important to maintain sulfur levels at below the SO_3 dewpoint. Because conversion from SO_2, to SO_3 in the combustor is a function of several factors that are not readily definable, it is recommended that fuel sulfur is limited to less than 0.5% weight FEC. This value is based on 60:1 air-to-fuel ratio at up to 17% conversion for an acid dewpoint of 240°F.

(3) If sulfur is present in the form of hydrogen sulfide, appropriate precautions must be taken to detect leaks because of the highly toxic nature of this gas even in trace quantities. High sulfur fuels (exceeding limits) may be used with special provisions; however, such fuels must be reviewed and approved in writing by Engineering prior to use.

(4) U.S. Federal and local Air Pollution control districts may require lower limits for sulfur.

(5A) Harsh environment protection hardware and ancillary equipment is required for gas fuel with H_2S concentration greater than 3000 ppmw FEC or liquid fuel with sulfur concentration more than 2000 ppmw FEC..

(5B) Higher sulfur levels (> 10,000 ppmw FEC) can be considered for a specific application and must be approved in writing by engineering.

(6) Liquid fuel sulfur content limits and specific fuel handling and storage requirements are required for *SoLoNOx* liquid fuel operation. See section 8 and appendix C.

(7) The following contaminants are unlikely to be present except in unusual or accidental contamination of air, fuel or water supplies. However, if detected at levels greater than 0.5 ppmw FEC fuel equivalent, special treatment and precautions are required.

Mercury – Cadmium – Bismuth – Arsenic – Indium – Antimony – Phosphorous – Boron - Gallium

(8) Any other trace element with concentrations over 0.5 ppmw FEC fuel equivalent should be discussed with, and reviewed, by Engineering.

3.2 SOURCES OF CONTAMINATION – There are four major potential sources of contamination - air, fuel (gas, liquid, or solid), injected water/steam (for continuous NO_x control) and liquid water carryover from the evaporative cooler (if used). Minor sources of contamination include water for compressor cleaning, water for dual fuel injector purging, and compressor cleaning fluids have also been identified.

In order to effectively control the quality of air, fuel, and water entering the engine as defined in this Specification, Solar's Package Engineering Department shall be consulted in specifying treatment and cleanup systems for the major sources, while the minor sources must meet the quality specified in Tables 3 and 4 of this document.

3.3 DETERMINATION OF TOTAL CONTAMINANTS - The total concentration of each of the major potential sources of contaminants entering the engine can be determined by using the equations provided here.

For direct fired applications:

$$\text{Total Contaminant} = \frac{18{,}380}{LHV} \times [(AFR)A + F + (WFR)W + (CFR)C]$$

For indirect fired applications:

$$\text{Total Contaminant} = 65 \times [A + (WAR)W + (CAR)C]$$

Where:

Total Contaminant	=	total concentration of that particular contaminant, ppmw fuel equivalent (for indirect fired applications, total contaminant is expressed as ppmw air equivalent concentration, normalized to 65 air-to-fuel ratio.
LHV	=	lower heating value of fuel, Btu/lb
AFR*	=	air-to-fuel mass ratio
A	=	concentration of that particular contaminant in air entering the engine, ppmw in air
F	=	concentration of that particular contaminant in fuel, ppmw in fuel
WFR*	=	water-to-fuel mass ratio
W	=	concentration of that particular contaminant in injected water, ppmw in water
CFR*	=	carryover water-to-fuel mass ratio
C	=	concentration of that particular contaminant in evaporative cooler water (or feedwater), ppmw in water
WAR	=	water-to-air mass ratio
CAR	=	carryover water-to-air mass ratio

* Fuel ratios are based on <u>actual</u> fuel rather than combustible fuel

A worksheet (Form 3091) with instructions for performing the above calculation is provided in Appendix A. (Derivation of the above equation for directly fired applications and the functional equation used in Form 3091 are included in Appendix B.)

3.4 ADDITIVES - Chemicals can be added to fuel and water treatment systems for specific purposes, e.g., softening, settling out of particulates, inhibition of organic growths, etc. Caution should be exercised to ascertain that the additives are not comprised of critical elements listed in Table 1 and that the maximum allowable limits specified are complied with.

3.5 CUSTOMER SITE DATA REQUIREMENTS - Information as to the condition and quality of the air, water (including steam), and fuel to be ingested by the engine, and other environmentally influenced conditions such as ambient temperature and humidity ranges is required by Solar to adequately define the necessary combustion system configuration, engine controls, settings, protective coatings, devices and operating procedures.

3.5.1 SAMPLING - Sampling and analyses of air, fuel, and water must be performed by Solar approved laboratories. In certain critical applications, either Solar or the customer may specify a particular facility. Unless specifically instructed otherwise, all sampling should be performed at locations just up stream of the engine.

3.5.2 ADDITIONAL SITE DATA - The following information, if available, is required for all installations:

- Ambient temperature range
- Ambient humidity range
- Altitude
- Type of environment (rural, agricultural, residential, arctic, industrial, offshore, marine, coastal, desert, semi-arid, or tropical)
- Fuel conditions (fuel temperature and pressure ranges)

4.0 AIR

4.1 AIR QUALITY - Air borne constituents such as gases, liquid droplets and solid particles, can contain undesirable contaminants that are considered harmful. Adequate air filtration must be used to remove the bulk of such air borne constituents including water carryover from evaporative cooler applications. The combined concentration of contaminants from air, fuel and water (steam) shall meet the requirements of paragraph 3.1 and the maximum limits specified in Table 1.

4.1.1 ADDITIONAL LIMITS - In addition, quality of air entering the air inlet shall also meet the following requirements.

Maximum particle size	$\leq$10 microns	ASTM F25, ISO 8573
Total particulates	$\leq$500 ppmw	
Total combustibles	$\leq$5 ppmw	ASTM D1945, D3588

4.2 CONCENTRATION OF AIR BORNE CONTAMINANTS - Air borne contaminants constitute only one of several means by which contaminants enter the turbine engine. The minimum air quality allowed depends on the quality of the other fluids, such as injected water, fuel, and water carryover (if applicable). In order to assess the impact of air borne contaminant(s) on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each air borne contaminant can be calculated using the following function.

$$\text{Concentration in air, ppmw FEC} = \text{AFR} \times \frac{18380}{\text{LHV}} \times \text{A}\,(1\text{-N})$$

Where:
- AFR = air-to-fuel ratio
- LHV = lower heating value, Btu/lb.
- A = concentration in ambient air, ppmw
- N = air cleaner efficiency, expressed as value <1.0

4.2.1 CONCENTRATION GUIDELINES FOR AIR BORNE CONTAMINANTS - In general, air borne contaminants are expected to contribute less than 20% of the total concentration allowed except when air and fuel are the two fluids present. Depending on the type of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for air borne contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline.

Table 2. Guidelines for Contaminant Concentrations
(for nominal operating conditions with natural gas fuel)

Available Sources	Air Borne Contaminants (% of Total)	Fuel Borne Contaminants (% of Total)	(Inj.) Water Borne Contaminants (% of Total)	Contaminants From E/C Carryover (% of Total)
Air + Fuel	<70	<10	0	0
Air + Fuel + Inj. Water	<20	<10	<50	0
Air + Fuel + Inj. Water + E/C	<20	<10	<20	<30
Air + Fuel + E/C	<20	<10	0	<50
Note: These values are provided only as guidelines and they are based on experience at Solar. Because of the inexactness of some of the values involved in the calculations, a 20% margin is built in to the numbers provided here.				

4.3 SITE SPECIFIC CONTAMINANTS IN AIR - If ambient air at a particular site is known to be of poor quality, based on prior experience or influence of industries and/or activities in the vicinity, consult with Package Engineering to ascertain compliance with all the requirements of this specification.

5.0 INJECTED WATER (OR STEAM)

5.1 WATER QUALITY FOR WATER INJECTION TO REDUCE NO_x - The quality of water injected into the combustor for NO_x control must meet the general requirements defined in Section 3.1 as well as the specific requirements described here.

	Limit	Test Method
pH	5.5 to 8.5	ASTM D1293
Suspended solids	$\leq$2.6 mg/l	ASTM D5907; ISO 11923
Maximum particle size	10 microns	
90% of particles	$\leq$5 microns	
Dissolved Silica	$\leq$0.1 ppmw SiO_2 ($\leq$0.1 mg/l)	ASTM D859
Electrical Conductivity	5 µS/cm	ASTM D5391

5.2 CONCENTRATION OF (INJECTED) WATER BORNE CONTAMINANTS - Water borne contaminants from injected water/steam constitute only one of several means by which contaminants enter the turbine engine. The minimum water quality allowed depends on the quality of the other fluids, such as air, fuel, and water carryover (if applicable). In order to assess the impact of water borne contaminant(s) from injected water/steam on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each water borne contaminant can be calculated using the following function.

$$\text{Concentration in water, ppmw FEC} = \text{WFR} \times \frac{18380}{\text{LHV}} \times \text{W}$$

Where:
- WFR = water-to-fuel ratio
- LHV = lower heating value, Btu/lb
- W = concentration of contaminant in injected water, ppmw

5.2.1 CONCENTRATION GUIDELINES FOR (INJECTED) WATER BORNE CONTAMINANTS - In general, water borne contaminants from injected water are expected to contribute less than 50% of the total concentration allowed. Depending on the type of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for injected water (steam) borne contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline.

5.3 BOILER FEEDWATER - In general, boiler feedwater is not suitable for use in water injection; additional treatment to remove dissolved and suspended contaminants is usually required to satisfy all the requirements of this specification.

5.4 OPERATION - It is recommended that Package Engineering is consulted in selecting appropriate equipment for treatment water. Continuous monitoring of water quality is strongly recommended with an alarm or automatic shut down device installed between the final stage of treatment and the fuel injector manifold. The trip point shall be set to ensure that water entering the combustor is within the allowable limits of this specification.

5.5 WATER FOR INJECTOR PURGE AND COMPRESSOR CLEANING – Water is used in small quantities from time to time (not continuous operation), to either aid cleaning the compressor or to purge liquid fuel passages in dual fuel injectors during fuel transfers and liquid fuel shutdown. It has been determined that the contaminant limits for the water can be higher for these duties because the consumption is small and Table 3 shows the limits for the particular application.

6.0 EVAPORATIVE COOLER WATER

6.1 GENERAL - For operation in hot and dry environments, evaporative cooling is commonly employed for power augmentation. The design/selection, installation and maintenance of evaporative cooler equipment is critical to engine operation and longevity and also effects the extent of water carryover into the airstream. Appropriate treatment of feedwater must be specified in order to comply with the total requirements of this specification.

6.1.1 EVAPORATIVE COOLER EQUIPMENT - Instructions for set-up, installation and operation of evaporative coolers are provided in Engineering specification ES 2069.

Table 3. Contaminant Limits For Short Duration Water Ingestion Duties

	Test Method	Max. Limits for On-Crank Cleaning	Max. Limits for On-Line Cleaning	Max. Limits for Dual Fuel Injector Water Purge
Sodium + Potassium	ASTM D1428	105 ppmw	1.9 ppmw	1.9 ppmw
Fluorine	ASTM; D1179	100 ppmw	1.9 ppmw	1.9 ppmw
Chlorine	ASTM D512	100 ppmw	40 ppmw	40 ppmw
Lead	ASTM D3559	2 ppmw	0.70 ppmw	0.70 ppmw
Vanadium	ASTM D3373	2 ppmw	0.35 ppmw	0.35 ppmw
Iron, Tin, Silicon, Aluminum, Copper, Manganese, Phosphorus	ASTM D857, D858, D1068, D1688	10 ppmw	3.8 ppmw	3.8 ppmw
Calcium + Magnesium	ASTM D3605, D511	100 ppmw	3.8 ppmw	3.8 ppmw
Total Dissolved Solids	ASTM D1888	350 ppmw	5 ppmw	30 ppmw
Suspended solids	ASTM D5907	2.6 mg/l	2.6 mg/l	2.6 mg/l
Maximum particle size		10 microns	10 microns	10 microns
90% of particles		5 microns	5 microns	5 microns
Dissolved Silica		0.1 mg/l SiO_2	0.1 mg/l SiO_2	0.1 mg/l SiO_2
PH	ASTM D1293	6 - 9	6 - 9	6 - 9
Electrical Conductivity		540 µS/cm	8 µS/cm	50 µS/cm

6.1.2 DEIONIZED WATER - Do not use deionized water unless the evaporative cooler has been specially designed for it. The use of deionized water will require the use of stainless steel construction and binder reinforced media.

6.1.3 SOFT WATER - Soft water is usually high in sodium salts and low in calcium and magnesium salts. Therefore, soft water <u>cannot</u> be used for evaporative cooling unless it can be proven that sodium + potassium (and any other dissolved salts present) are in compliance with the requirements of Section 3.1.

6.2 CONCENTRATION OF CONTAMINANTS IN WATER CARRYOVER - Contaminants from evaporative cooler water carryover constitute only one of several means by which contaminants enter the turbine engine. The minimum evaporative cooler water quality allowed depends on the quality of the other fluids, such as air, fuel, and injected water. In order to assess the impact of contaminant(s) from evaporative cooler water carryover on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each contaminant can be calculated using the following function.

$$\text{Concentration in water carryover, ppmw FEC} = C \times R \times \frac{(1 - E)}{f} \times 9.2$$

Where:

C	=	concentration in water delivered to header of evaporative cooler, ppmw (for recirculating system, C = concentration in reservoir; for non-recirculating system, C = concentration of feedwater)
R	=	carryover rate, gallons per minute (see Section 6.2.2)
E	=	mist eliminator efficiency, expressed as <1.0
f	=	fuel flow rate, MBtu/hour (10^6 Btu/hour)

6.2.1 CONCENTRATION GUIDELINES FOR CONTAMINATION IN EVAPORATIVE COOLER WATER - In general, contaminants from evaporative cooler carryover are expected to contribute less than 50% of the total concentration allowed. Depending on the type of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for water carryover contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline. (Refer to ES 2069 for details on evaporative cooler installation and operation.)

6.2.2 CARRYOVER RATE - In the absence of actual measurements, the following estimated carryover rates could be used.

2.8 GPM for *Titan* 130
1.7 GPM for *Mars*
1.5 GPM for *Taurus* 70
1.3 GPM for *Taurus* 60
0.9 GPM for *Centaur* 40 and 50, *Mercury* 50
0.5 GPM for *Saturn*

6.3 WATER CARRYOVER - While water carryover can be effectively reduced or eliminated with correct equipment specification and installation/operation, it is also recognized that system upsets can be expected to occur during the life cycle of the engine when water from the evaporative cooler can accidentally enter the compressor as liquid water droplets of varying size. Vane type mist eliminators are required for evaporative cooler applications as a means of further reducing or eliminating water carryover. Nevertheless, the general requirements in paragraph 3.1 include evaporative cooler water carryover as a potential source of contamination.

6.4 ADDITIONAL LIMITS FOR EVAPORATIVE COOLER WATER

	Limits
pH	6-9
Turbidity	$\leq$5,000 turbidity units (also know as Jackson units)
Hardness	160 ppmw $CaCO_3$

6.5 OTHER CONTAMINANTS - Algae, aromatic hydrocarbons, oils, grease and wetting/ dispersing agents such as phosphates can be harmful to the evaporative cooler media pad. Precautions must be exercised to prevent the formation or introduction of these contaminants into the feedwater.

7.0 COMPRESSOR CLEANING FLUIDS

7.1 COMPRESSOR CLEANING PRODUCT QUALITY – Composition and physical properties of cleaning products must comply with the limits defined in Table 4. Failure to comply with these limits can cause corrosive attack and/or other harmful effects resulting in rapid engine deterioration. When the cleaning product consists of a mixture of cleaning solution concentrate and water, the limits in Table 4 apply to the resulting cleaning product.

Table 4. Requirements for Cleaning Product Used in Ingestive Cleaning of *Solar* Engines

	Test Method	Max. Limits for On-Crank Solutions	Max. Limits for On-Line Solutions
Sodium + Potassium	ASTM D1428	105 ppmw	1.9 ppmw
Fluorine	ASTM D1179	100 ppmw	1.9 ppmw
Chlorine	ASTM D512	100 ppmw	40 ppmw
Lead	ASTM D3559	2 ppmw	0.70 ppmw
Vanadium	ASTM D3373	2 ppmw	0.35 ppmw
Iron, Tin, Silicon, Aluminum, Copper, Manganese, Phosphorus	ASTM D857, D858, D1068, D1688	10 ppmw	3.8 ppmw
Calcium + Magnesium	ASTM D3605 ASTM D511	100 ppmw	3.8 ppmw
Ash	ASTM D482	0.25 wt. %	0.01 wt. %
Flash Point	ASTM D93	>140^{o}F	>140^{o}F
PH	ASTM D 1293	6 - 9	6 - 9

8.0 FUEL

8.1 GASEOUS FUELS - Gaseous fuels, which meet the limits in Table 5, can be used in the standard fuel systems. The fuels must be free from condensed hydrocarbons, oils or water. Fuels, which do not meet these limits, must be reviewed by Solar. If judged suitable for use, control and/or combustor modifications will generally be required.

8.1.1 GASEOUS FUEL SUITABILITY - The Solar Gaseous Fuel Suitability Inquiry Form 2595 must be completed. In addition, any entrained solid contaminants should be identified, along with their concentrations and size. For gaseous fuels, if water is known to be present, even in minute quantities, the concentration of salts dissolved in this water must be included when calculating the amount of contaminants contributed by the water portion of this fuel to the total system. It is also required that a gas analysis including all heavy hydrocarbons beyond C_6 be provided during the proposal stage of the project.

8.1.2 COKE OVEN GAS – Coke Oven Gas (COG) is the gas released in the process that converts coal into coke. COG is a medium heating value fuel containing mainly hydrogen, methane, water, oxygen, carbon monoxide, nitrogen and carbon dioxide. However, COG also has extreme levels of harmful contaminants including:

- Tar
- Light oil vapors (aromatics), mainly Benzene, Toluene and Xylene (BTX)
- Naphthalene vapor
- Ammonia gas
- Hydrogen sulfide gas
- Hydrogen cyanide gas
- Calcium carbonate from direct water cooling of COG
- Trace metals

The contaminants found in COG must be controlled to levels listed in Tables 1 and 5. Contact Solar for recommendations on Balance of Plant equipment to remove or reduce the contaminants to levels acceptable for gas turbine operation.

The superheat level specified in Table 5 is also required for COG to ensure remaining naphthalene and heavy hydrocarbons do not precipitate out in the fuel system.

Table 5. Requirements for Gaseous Fuels

Fuel Volume Ratio (1220/WOBBE Index*)	0.9 to 1.1
Fuel Mass ratio (21550/LHV Btu/lb)	<5
Hydrogen Content	<4% by volume
Carbon Monoxide Content**	<12.5% by volume
Hydrogen Sulfide**	10,000 ppmw Max. (See Table 1)
Ratio of Flammability Limits Upper flammability limit *** / Lower flammability limit	 >2.2 for Saturn >2.8 for Centaur and Mars
Stoichiometric Flame Temperature with Air Temperature Equal to Compressor Discharge Temperature at Design Point	>3600°F (1980°C)
Total Particulates	<30 ppmw x (LHV/21500)
Maximum Particle Size	10 micron
Gas Supply Temperature (at inlet flange of package) to ensure no liquid condensation:	The higher of dew point temp + 50°F for natural gas liquids and dew point temp + 20 °F for water up to a limit of 200°F at the fuel skid edge supply pressure. and no lower than -40°F.

*WOBBE Index = Lower Heat Value (use ASTM 3588 or DIN 51850 for individual component heating values) in Btu/Scf divided by the square root of the relative density (specific gravity).

**If carbon monoxide or hydrogen sulfide are present in the fuel gas, precautions must be taken to detect leaks.

***Flammability limits at 1 atm and 25°C as defined by M.G. Zabetakis, US Bureau of Mines Bulletin 627.

Note:

If the required fuel temperature is above ambient air temperature, adequate thermal insulation and heat tracing of fuel lines and fuel control system is required to avoid condensation. If condensates form during shutdown or are otherwise introduced, provisions should be made to drain fuel lines just before start up to ensure that gas fuel condensation is completely eliminated.

8.1.3 GASEOUS FUEL SUPPLY PRESSURE - Fuel supply pressure should be maintained at constant level to minimize wear damage to the fuel control system caused by fluctuating and unstable fuel pressures.

8.2 DISTILLATE FUELS - Distillate fuel shall be a homogeneous mixture of hydrocarbon compounds. The fuel, when received, shall be clear, bright, and free of any haze, as viewed in ordinary light through a clear vessel. Technical requirements shall be as specified in Tables 6 and 7.

8.2.1 DISTILLATE FUEL SUPPLY TEMPERATURE - Distillate fuel supply temperature at turbine package fuel inlet shall be no lower than the temperature at which the viscosity is 12 centistokes or cloud point temperature plus 10°F, whichever is higher. The fuel supply temperature shall not be lower than -65°F, nor higher than +140°F.

8.2.2 DISTILLATE FUELS – The Solar Fuel Suitability Inquiry Form in Appendix D must be completed.

Table 6. Distillate Fuels - Physical Requirements

	Test Method
a. Contaminants <u>Solid</u> - The fuel shall contain less than 2.6 mg per liter of sediment, solid or hard contaminants, 90% of the 2.6 mg shall be less than 5 microns in size. Maximum allowable particle size shall be 10 microns. <u>Liquid</u> - The fuel shall contain less than 0.25 cc free water per liter (0.025 % by volume) at an ambient temperature of 80°F.	 ASTM D6217 or by use of Millipore microscan contamination detector ASTM D6304
b. Kinematic Viscosity* The kinematic viscosity of the fuel shall be within the following limits: Maximum: 12 centistokes Minimum: 1 centistoke, at 100°F	 ASTM D445 ASTM D445
c. Relative Density (Specific Gravity) Relative Density shall be between 0.775 and 0.875.	 ASTM D1298 or ASTM D4052
d. Reid Vapor Pressure* The vapor pressure of the fuel shall be less than 3 psia.	 ASTM D323
e. Cloud Point The cloud point shall be at least 10°F below the expected minimum ambient temperature.	 ASTM D2500
f. Pour Point Pour point shall be at least 10°F below the cloud point Temperature	 ASTM D97
g. Lubricity The lubricity of the liquid fuel shall meet an HFRR at 60°C 520 micron maximum.	 ASTM D6079
*EXCEPTIONS: Naphtha fuels, which have a viscosity of 0.5 to 1.0 centistokes, relative density below 0.775, and vapor pressure above 3 psia will be considered. Use of these fuels will require modification to the standard fuel system.	

Table 7. Distillate Fuels - Chemical Requirements

		Test Method
a.	Flash Point	
	100°F minimum or legal limit	ASTM D93
b.	Distillation	
	90% evaporated 640°F maximum. End point 690°F maximum	ASTM D86
c.	Aromatics	
	35% by volume maximum	ASTM D1319*
d.	Olefins and Diolefins	
	5% by volume maximum	ASTM D1319
e.	Lower Heating Value	
	18,000 Btu/lb. minimum	ASTM D240
f.	Carbon Residue on 10% Distillation Residue	
	0.35% maximum	ASTM D524
g.	Ash	
	0.005% by weight maximum	ASTM D482
h.	Copper Strip Corrosion	
	No. 3 (3 hr at 122°F)	ASTM D130
i.	Fuel Bound Nitrogen	ASTM D4629 or ASTM D5762
Measurement required for liquid emissions guarantees		
*Use ASTM D5186 for fuels having final boiling points over 600°F.		

8.3 NATURAL GAS LIQUID FUELS - Natural gas liquid fuels shall consist primarily of saturated paraffinic hydrocarbons such as ethane, propane, butane, pentane, hexane and heptane either individually or mixtures of some or all of the above. Technical requirements shall be as specified in Table 8.

8.3.1 NATURAL GAS LIQUID SUPPLY TEMPERATURE - Liquid gas supply temperature at the fuel inlet to the package shall be between -65°F and +90°F and shall be in a liquid phase only.

8.3.2 NATURAL GAS LIQUID FUELS - The following information is required to determine the suitability of natural gas liquids:

- Composition on volumetric gases
- Relative density at 60°F
- Vapor pressure at 100°F
- Viscosity at 100°F

8.4 MULTIPLE FUEL SOURCES - If more than 1 fuel source is available, individual fuel analyses of all fuel sources must be submitted to review to ensure proper fuel handling.

8.5 CONCENTRATION OF FUEL BORNE CONTAMINANTS - Fuel borne contaminants constitute only one of several means by which contaminants enter the turbine engine. The minimum fuel quality allowed depends on the quality of the other fluids, such as air, injected water and water carryover (if applicable). In order to assess the impact of fuel borne contaminants on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each fuel borne contaminant can be calculated using the following function.

$$\text{Concentration in fuel, ppmw FEC} = \frac{18380}{LHV} \times (1-K) \times F$$

Where: LHV = lower heating value, Btu/lb

K = fuel cleanup (if applicable), expressed as value <1.0
F = concentration in fuel entering combustor, ppmw

8.4.1 CONCENTRATION GUIDELINES FOR FUEL BORNE CONTAMINANTS - In general, contaminants from fuel are expected to contribute less than 10% of the total concentration allowed. Depending on the fuel of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for fuel borne contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline.

9.0 HANDLING AND STORAGE OF DISTILLATE FUELS

9.1 FUEL TEMPERATURE - Fuel should not be stored permanently at ambient temperature above 100°F.

9.2 MAINTENANCE - Fuel should be changed completely or refiltered at least once a year or more frequently, depending on ambient temperatures and contamination experience. Fuel under continuous storage should be cleaned periodically to maintain the contaminant levels below that specified in Table 6a.

9.3 CLEANING - Fuel tanks should be drained, cleaned, flushed, and scoured whenever necessary to control contamination problems.

9.4 STORAGE AND HANDLING EQUIPMENT – The selection of equipment for storage and handling is a crucial part of ensuring that fuel generally conforms to ES 9-98 when it reaches the engine. Cleanup devices will always be required because contamination frequently occurs during transportation. Solar has identified the types of equipment that are required to ensure that liquid fuel being supplied to an engine will be cleaned up to specification. Appendix C lays out the requirements for various liquid fuel applications.

9.5 ADDITIONAL INFORMATION - Refer to ASTM D4418 for more information on handling and storage of fuels.

10.0 NOTES

10.1 SIGNIFICANCE OF LIMITS - Total contaminants should comply with Table 1. The following subparagraphs explain the significance of limits in the specification.

Table 8. Natural Gas Liquid Fuels - Physical and Chemical Requirements

Property	Allowable Limits	Test Method
Composition percent by volume	Report	ASTM D2163
Vapor pressure at 100°F (38°C)	780 psia maximum	ASTM D1267 or ASTM D2598
Relative density at 60°F/60°F (15°C/15°C)	0.37 to 0.68	ASTM D1657 or ASTM D1298
Copper strip	No. 1 maximum	ASTM D1838
Moisture content for fuels with relative density 0.37 to 0.51	Pass	Use one of the methods for moisture content as described in the Commercial Propane Dryness Test, Cobalt Bromide Method or Dew Point Method of the Natural Gas Processors Association Publication 2140
Free water content for fuels with relative density of 0.51 to 0.68	None	ASTM D1657 - The presence or absence of water shall be determined by inspection of the sample on which the relative density is determined
Solid contaminants	Less than 2.6 mg of sediment per liter of fuel 90% of sediment shall be less than 5 microns in size Maximum size of any solid sediment particle shall be less than 10 microns	ASTM D6217
Lower Heating Value	18,000 Btu/lb. Minimum	ASTM D240

10.1.1 SULFUR – Sulfur and sulfur compounds can have an impact on the fuel system life and maintenance, turbine hot section life, exhaust system life and a pollutant emissions signature. The presence of sulfur in the combustor will burn or oxidize to form sulfur dioxide. In the presence of even minute quantities of sodium and potassium in the combustor environment (excess oxygen and high thermal load), sodium and potassium sulfates are readily formed. These salts if condensed onto turbine airfoil surfaces will react with the base metal, resulting in hot corrosion degradation. Gas turbines with waste heat recovery equipment must operate above the sulfuric acid dewpoint, which may require additional sulfur control to prevent cold end corrosion. Additionally, US Federal and certain local air pollution regulations require more restrictive limits on sulfur. Fuel bound sulfur in liquid fuel has been found to promote carbon deposition on hot surfaces of lean premix *SoLoNOx®* injectors leading to the blockage of liquid fuel passages over time. As a result the sulfur content is being limited for *SoLoNOx* liquid fuel operation and is a function of the frequency and duration of liquid operation. See Appendix C for details.

10.1.1.1 HYDROGEN SULFIDE - Hydrogen sulfide can occur both in natural gas, process and manufactured gases. It is corrosive to some materials such as bronze and brass used in fuel gas systems, the corrosiveness being more severe in the presence of water and at high pressure. If the sulfur exceeds the limit then the fuel system materials must be upgraded. Hydrogen sulfide burns to sulfur dioxide and sulfur trioxide, which results in the corrosion described above. Some manufactured gases also contain organic sulfur compounds, which are corrosive to some control system materials. Since hydrogen sulfide is toxic, if it is present in the gas, precautions must be taken to detect leaks.

10.1.1.2 ELEMENTAL SULFUR DEPOSITION - Aside from H2S, natural gas may contain other sulfur compounds or sulfur vapor that even in very low concentrations (ppbw) can form solid elemental sulfur. In sufficient quantities elemental sulfur can impede operation of fuel valves and gas flow measurement devices on the gas turbine package. However, there are no reliable and practical methods for knowing how much elemental sulfur is contained in a gas, and if and where elemental sulfur deposition will occur. If deposition takes place, the solution is to heat the gas fuel prior to the skid edge. The temperature that the gas must be heated to will depend on the concentration of the sulfur in the gas supply. For standard pipeline gas with low concentrations of total sulfur, fuel heating in the range of 120 to 160°F (50 to 70°C) has proven effective at preventing sulfur deposition.

10.1.2 SODIUM AND POTASSIUM - Sodium and potassium can combine with vanadium to form eutectic, which melts at temperatures as low as 1050°F (566°C) and can combine with sulfur in the fuel to yield sulfates with melting points in the operating range of the gas turbine. These compounds produce severe corrosion in the turbine hot section. Accordingly, the sodium plus potassium level must be limited, but each element must be measured separately. These elements can be removed by water washing and subsequent removal with a centrifuge or electrostatic precipitator.

10.1.3 VANADIUM - Vanadium can form low melting compounds such as vanadium pentoxide which melts at 1275°F (691°C), and alkali metal vanadates which melt as low as 1050°F (566°C) which can cause severe corrosive attack on all of the high temperature alloys in the gas turbine hot section.

10.1.4 MERCURY - Mercury compounds are corrosive to aluminum, copper, lead, and silver; therefore, these materials are to be avoided if mercury is present. Mercury compounds are not known to be corrosive to the hot section of a gas turbine. Mercury in the exhaust of the turbine must be limited to comply with local regulations.

10.1.5 LEAD - Lead can cause corrosion and in addition, it can spoil the beneficial effect of magnesium additives on vanadium corrosion. Since lead is rarely found in significant quantities in crude oils, its appearance in fuel oils is primarily the result of contamination during processing or transportation.

10.1.6 FLUORINE AND CHLORINE - Halides such as fluorine and chlorine as well as alkali/mixed halides and alkali sulfates can attack the protective oxide scale on hot turbine components, thus accelerating the rate of oxidation.

10.1.7 CALCIUM AND MAGNESIUM - Calcium and magnesium are not harmful from a corrosion standpoint; in fact, it serves to inhibit the corrosive action of vanadium. However, calcium can produce hard bonded deposits that are not self-spalling when the gas turbine is shut down. These hard bonded deposits are not readily removed by water washing of the turbine (Ref. ES 9-62). The fuel washing systems used to reduce the sodium and potassium levels will also reduce calcium levels.

10.1.8 SILICON - Siloxanes in fuel gas is known to result in silicon-based deposition in the gas turbine flow path that can cause damage, high rates of performance degradation, and higher overhaul costs. The rate of deposition is a function of the type and quantity of silicon-based material contained in the fuel, and is thus produced from the combustion process. As such damage and performance loss is preventable only by control of siloxane levels in the fuel, such damage is not covered by Solar's warranty. It is, therefore, the customer's responsibility to monitor and minimize as appropriate siloxane content through the use of a reliable siloxane removal system.

Based on engine operating experience to date, Solar considers that limiting the amount of silicon, as measured by the Jet-Care SiTest method, to no more than 5 mg Si/nm^3 CH_4 for the Mercury 50™ and 10 mg Si/nm^3 CH_4 for all other turbines should result in target time between overhaul with normal performance degradation.

Contact Solar Turbines for recommendations on Balance of Plant equipment to remove or reduce the contaminants to tolerable levels for gas turbine operation.

10.1.9 OTHER TRACE METALS - Oxides of other trace metals with or without other impurities can be deposited on blades and vanes forming extremely hard and difficult-to-remove deposits. The presence of these oxides will also increase the rate of oxidation of blade and vane alloys at high temperatures.

10.1.10 PARTICULATES IN AIR - Inert particulates in the turbine inlet air cause erosion and/or fouling of the compressor section. By limiting the size of the particulates, erosion is minimized. Contamination of the compressor blading is caused by smaller particulates. Factors such as humidity, presence of oil or soot and dust particle composition affects the rate of fouling.

10.1.11 SOLIDS IN WATER - Inert solid particles in water can cause wear and plugging of control components and fuel injectors. Malfunctions of the control system and damage to the combustor and turbine section would be the result.

10.1.12 pH OF WATER - The pH of water is limited from slightly acidic to slightly basic. Strong bases or acids would attack various components in the water control and injection system.

10.1.13 FUEL GAS VOLUME RATIO - The fuel gas volume ratio is an indication of the capability of the fuel control to properly schedule the fuel flow. If this ratio is within the specified limits, the standard system without modifications can be used. Ratios with values up to 2 can be handled with minor modifications to the fuel injection system. If the ratio is between 2 and 4, the modifications are substantial and if the ratio is above 4, a redesign of the combustor is required.

10.1.14 FUEL GAS MASS RATIO - The fuel gas mass ratio is an indication of the effects of the fuel mass flow on the performance and matching of the turbine. Ratios up to 5 are acceptable without modification. If the ratio is between 5 and 10 then a fuel meeting the standard requirements must be used for start and acceleration to avoid compressor surge. If the ratio is above 10, extensive turbine redesign is required to accommodate larger turbine mass flow.

10.1.15 HYDROGEN AND CARBON MONOXIDE IN GAS - The presence of hydrogen and/or carbon monoxide in the fuel gas above the specified levels can cause safety and materials problems. If hydrogen level is above 4% by volume, a review of the fuel system materials for hydrogen embrittlement is required. If hydrogen level is between 4 and 9% or carbon monoxide level is between 12.5 and 18%, then a specially sequenced start and purge system must be used. At hydrogen levels above 9% or carbon monoxide level is between 12.5 and 18%, then a specially sequenced start and purge system must be used. At hydrogen levels above 9% or carbon monoxide levels above 18%, starts and accelerations must be made on a standard fuel with transfer to the hydrogen or carbon monoxide bearing fuel at idle or above. If hydrogen level is above 4% or carbon monoxide is above 12.5%, special safety provisions must be taken such as detectors in the package, separation of the engine and generator compartments, and leak-free piping joints. Since carbon monoxide is toxic, if it is present in the fuel gas, precautions must be taken to detect leaks.

10.1.16 FLAMMABILITY - The ratio of the upper-to-lower flammability limits is an indication of whether the gas will allow engine starting and adequate range of operation, in particular on single shaft generator sets.

10.1.17 FLAME TEMPERATURE - The adiabatic flame temperature of gas fuels is used to determine its suitability. If the value is below the limit, major combustion system modifications and/or changes to operating procedures may be required.

10.1.18 PARTICULATES IN GAS - Solid particles in gas can cause wear and plugging of control components and fuel injectors. Malfunctions of the control system and damage to the combustor and turbine section would be the result.

10.1.19 FUEL SUPPLY TEMPERATURE - For gas fuels there are two considerations: one is the dew point. The fuel must be supplied at the inlet flange to the package, 50°F above the dew point to ensure that no liquids can enter the fuel control and injection system. Liquids in a gas system cause malfunction and serious thermal damage to the engine if liquid is injected with the gas into the engine. The other consideration is the thermal capability of the materials in the control system.

For distillate fuels, the temperature must be above the cloud point to prevent plugging of the filters and control components. It must also be above the temperature that corresponds to a viscosity of 12 centistokes to ensure satisfactory atomization required for starting performance. The range of allowable temperatures is determined by the thermal capabilities of the materials in the control system.

For natural gas liquid fuels, the allowable temperature range is determined by the control system materials and the critical point of the lightest fuel. This latter constraint is to limit the vapor pressure on the fuel.

10.1.20 VISCOSITY - Viscosity of a fluid is a measure of its resistance to flow. In distillate fuel it is highly significant since it indicates both the relative ease with which the fuel will flow or may be pumped and a measure of atomization by the fuel injectors. Minimum viscosity is limited because standard fuel pumps will not perform satisfactorily if viscosity reaches too low a value. Maximum viscosity is limited since too high a viscosity can cause excessive pressure losses in the piping system and poor fuel atomization.

10.1.21 RELATIVE DENSITY OF DISTILLATE - Relative density alone is of no significance as an indication of the burning characteristics of fuel oil. However, when used in conjunction with other properties, it is of value in weight-volume relationships and in calculating the heating value of the fuel.

10.1.22 REID VAPOR PRESSURE - The Reid vapor pressure is a criterion of freedom from foaming and fuel slugging due to vaporization of the fuel. Special fuel systems are required if the Reid vapor pressure is above the specified level.

10.1.23 CLOUD AND POUR POINTS - Cloud point is the temperature at which a cloud or haze of wax crystals appears. Operation at temperatures below the cloud point causes plugging of filters. Pour point is an indication of the lowest temperature at which a fuel can be stored and still be capable of flowing under gravitational forces. The cloud and pour points are prescribed in accordance with the conditions of storage and use. Heated tanks and lines may be required where ambient temperature is below the cloud and pour points of the proposed fuels.

10.1.24 FLASH POINT - Flash point is an indication of the maximum temperature at which a fuel can be stored and handled without serious fire hazard. The minimum permissible flash point is usually regulated by Federal, State, or Municipal laws and is based on accepted practices in handling and use.

10.1.25 DISTILLATION - The distillation test indicates the volatility of a fuel and the ease with which it can be vaporized and burned. It also indicates the possibility of carbon deposition and smoke formation.

10.1.26 AROMATICS AND OLEFINS - Combustion of highly aromatic fuels can result in increased smoke. Carbon or soot deposition and increased combustor metal temperature resulting in exhaust particulate emissions, opacity violations, and reduced engine life.

Use of fuels with excessive olefin content can result in decomposition of the fuel, which causes plugging of fuel system components including the fuel injectors.

10.1.27 LOWER HEATING VALUE (LHV) - The lower heating value is used to calculate actual fuel consumption. Also, if the value for distillate fuels is below the limit, it is an indication of a heavy fuel, which may have other properties exceed in the limits.

10.1.28 CARBON RESIDUE - Carbon residue is a measure of the carbonaceous material left in a fuel after all the volatile components are vaporized in the absence of air. It is a rough approximation of the tendency of a fuel to form carbon deposits in the combustion system of the gas turbine.

10.1.29 ASH - Ash is the noncombustible material in a fuel. Ash-forming materials may be present in fuel in two forms: (1) solid inert particles and (2) oil or water-soluble metallic compounds. The solid particles are for the most part the same material that is designated as sediment in the water and sediment test. Depending on their size, these particles contribute to wear in the fuel system and to plugging of fuel filter and fuel injectors. The soluble metallic compounds have little or no effect on wear or plugging, but may contain elements that produce hot section corrosion and deposits as described above.

10.1.30 COPPER STRIP CORROSION - This test provides an indication of possible corrosive attack of non-ferrous metals such as copper, brass, and bronze.

10.1.31 WATER AND SEDIMENT IN DISTILLATES - Appreciable amounts of water and sediment in fuel tend to cause fouling of the fuel-handling facilities and to give trouble in the fuel system of the turbine. An accumulation of sediment in storage tanks and on filter screens may obstruct the flow of fuel from the tank to the package. Water in distillate fuels may cause corrosion of tanks and equipment. Water in the fuel also provides a place for microbiological growths to occur. These growths can plug filters and screens and can promote corrosion of fuel tanks.

10.1.32 COMBUSTIBLES IN AIR - If combustibles are ingested into the engine inlet, the hydrocarbon and carbon monoxide levels in the exhaust will be increased assuming none of the combustibles complete combustion.

10.1.33 FUEL BOUND NITROGEN - Fuel Bound Nitrogen (FBN) found in distillate fuels causes NOx in the exhaust to increase. In order to offer liquid emissions guarantee, FBN must be determined by fuel analysis.

10.1.34 LUBRICITY - Low sulfur diesels tend to have a reduced lubricity and that could affect the life and reliability of the fuel pumps. The processes used to remove the sulfur from fuel also remove the natural occurring lubricity compounds in the fuel. Special fuel pumps are required when fuels do not meet the requirement listed in Table 6.

APPENDIX A

TOTAL SITE CONTAMINATION WORKSHEET
FORM 3091

(Blank form and Sample Calculation)

Solar Turbines
A Caterpillar Company

Specification No. ES 9-98AB

TOTAL SITE CONTAMINATION WORKSHEET		INQUIRY NO.	Q.R. NO./S.O. NO.
CUSTOMER		DATE ISSUED	DATE REQUIRED
ENGINE MODEL	FUEL	FREQUENCY OF STARTS	RUNNING TIME PER START
EQUIPMENT LOCATION	LOAD CONDITIONS ☐HIGH ☐LOW ☐STEADY ☐CYCLIC		
ALTITUDE FEET	AMBIENT TEMPERATURE RANGE °F MAXIMUM; °F MINIMUM		AVERAGE HUMIDITY %

INSTRUCTIONS - Enter best known values. Explanations and helpful information are provided on the reverse side. Perform calculations as indicated to obtain total site contamination for each (or all) species of interest.

EVAPORATIVE COOLER ☐YES ☐NO WATER INJECTION ☐YES ☐NO

		Concentrations, ppmw	Na + K	S	F	V	Pb	Ca + Mg
	1	Ambient Air, ppmw						
	2	Fuel, ppmw						
	3	Injected Water, ppmw						
	4	Evaporative cooling water, ppmw						
	5	LHV, Btu/#						
	6	Compute: 18,380/[5]						
Air	7	Air-to-Fuel Ratio						
	8	1 - N (Correction Factor)						
	9	Compute: [1] x [6] x [7] x [8], ppmw FEC						
Fuel	10	1 - K (Fuel Factor)						
	11	Compute: [2] x [6] x [10], ppmw FEC						
Water	12	Water-to-fuel Ratio						
	13	Compute: [3] x [6] x [12], ppmw FEC						
Evaporative Cooling	14	E.C. Carryover Rate, GPM						
	15	1 - E (Mist eliminator Factor)						
	16	Fuel Flow rate, million Btu/hr						
	17	Compute: $\frac{[4]x[5]x[6]x[14]x[15]x5x10^{-4}}{[16]}$ ppmw FEC						
	18	Total Contaminants, ppmw FEC [9] + [11] + [13] + [17]						
	19	Max. Allowable Limits, ppmw FEC per ES 9-98	0.5	10,000	1	0.5	1	2

COMMENTS:

PREPARED BY: ______________________________________ DATE:_____________

Row #	Term Explanation	Typical Values
1	Concentration of contaminant in ambient air, expressed as ppmw in air	Unless available for site of interest, select most appropriate value for S and Na+K from ranges given below. All other contaminants are assumed to be zero unless specifically known to be present. S(ppmw) / Na+K(ppmw): .0.001 — Moderately clean — >0.001 — Arctic 0.050-0.007 — City — >0.010 — Agricultural/Residential .0.100 — Industrial — 0.003-0.010 — Industrial >0.100 — Processing/Chemical Plant — 0.007-0.260 — Coastal (less than 1 mile) 0.010-0.136 — Desert 0.010-3.600 — Offshore platform
2	Concentration of contaminant in fuel supply expressed as ppmw in fuel	For gas fuels, and residual liquid water from processing can be very high in dissolved salts. If possible, analyses of trace water present in gas fuel is the best method for obtaining reliable data. For liquid fuels, direct measurement for contaminants is recommended. Some APPROXIMATE values for S and Na+K are provided here: S(ppmw) — Na+K(ppmw) 1,000 — .0.1 — pipeline gas >10,000 — >3.0 — process gas >10,000 — >3.0 — biomass gas >10,000 — >1.0 — distillate liquid fuel
3	Concentration of contaminant in injected water, expressed as ppmw in water	Contaminants in treated water at entry into combustor should be known, either based on actual water analyses or equipment specifications (auto shut down limit).
4	Concentration of contaminant in water delivered to header of evaporative cooler, expressed as ppmw	Contaminants in reservoir (for recirculating systems) or feedwater (for non-recirculating systems) should be known, either based on actual water analyses or equipment specifications.
5	Lower heating value, expressed as 10^6 But/hr	Available from fuel analysis report.
6	FUEL LHV ADJUSTMENT FACTOR USING 18,380 BTU/# AS REFERENCE FUEL PER ES 9-98.	
7	Air-to-fuel ratio	Use actual value -generated by FASTE run at site specific conditions with project fuel. Otherwise: — Multiply by $\frac{\text{LHV Btu/pound}}{20{,}000}$ 60.04 for *Mars* 100 60.05 64.08 for *Mars* 90 71.58 for *Centaur* 40 58.07 for *Centaur* 50 62.94 for *Saturn* 20 60.61 for *Mercury* 50 57.21 for *Taurus* 60 57.21 for *Taurus* 70 57.74 for *Titan* 130
8	Correction factor for air cleanup system, N	Use N = 0.99
9	CONTAMINANTS FOUND IN AIR ENTERING ENGINE, [1] x [6] x [7] x [8], PPMW, FUEL EQUIVALENT CONCENTRATION	
10	Fuel factor to account for fuel cleanup system, K	Use K = 0.95 unless instructed otherwise. If no fuel treatment is applicable between supply and engine, use 0 here.
11	CONTAMINANTS FOUND IN FUEL ENTERING ENGINE, [2] x [6] x [10], PPMW, FUEL EQUIVALENT CONCENTRATION	
12	Water-to-fuel ratio	Use actual value. Range is typically from 0.5 to 1.0.
13	CONTAMINANTS FOUND IN INJECTED WATER, [3] X [6] X [12], PPMW, FUEL EQUIVALENT CONCENTRATION	

Row #	Term Explanation	Typical Values
14	Rate of liquid water carried off the evaporation cooler (carryover) into air steam, expressed as gallons per minute	It is expected that during the duty cycle of the engine, liquid water can accidentally enter the air steam. Use the following values unless otherwise instructed by Package Engineering. 2.8 GPM for *Titan*130 1.7 GPM for *Mars* 1.5 GPM for *Taurus* 70 1.3 GPM for *Taurus* 60 0.9 GPM for Centaur 40 and 50, *Mercury* 50 0.5 GPM for *Saturn*
15	Adjustment factor for mist eliminator if applicable, E	Mist eliminators are required for evaporative cooler installations. Use the following values unless otherwise instructed. No mist eliminator E = 0 All non-vane type mist eliminators As indicated by manufacturer of mist eliminator. Vane type mist eliminator E > 0.95
16	Fuel flow rate expressed in million Btu per hour	Conversion from million Btu/hour to pounds per sec of fuel flow is included in the expression in the final expression in [17].

17 CONTAMINANT FOUND IN WATER CARRYOVER FROM EVAPORATIVE COOLER, IF USED

$$\frac{[4] \times [5] \times [6] \times [14] \times [15] \times 5 \times 10^{-4}}{[16]}$$ PPMW, FUEL EQUIVALENT CONCENTRATION.

18 TOTAL CONTAMINANT FROM ALL SOURCES, [9] + [11] + [13] + [17], PPMW, FUEL EQUIVALENT CONCENTRATION.

19 MAXIMUM ALLOWABLE LIMITS FOR EACH CONTAMINANT PER ES 9-98, PPMW, FUEL EQUIVALENT CONCENTRATION

Solar Turbines
A Caterpillar Company

Specification No. ES 9-98AB

TOTAL SITE CONTAMINATION WORKSHEET		INQUIRY NO.	Q.R. NO./S.O. NO.
CUSTOMER EXAMPLE		DATE ISSUED	DATE REQUIRED
ENGINE MODEL CENTAUR T4000	FUEL Diesel	FREQUENCY OF STARTS Monthly	RUNNING TIME PER START 500 hours
EQUIPMENT LOCATION San Diego, California	LOAD CONDITIONS ☐HIGH ☐LOW ☐STEADY ☐CYCLIC		
ALTITUDE 100 FEET	AMBIENT TEMPERATURE RANGE 90°F MAXIMUM; 40°F MINIMUM		AVERAGE HUMIDITY 50% RH

INSTRUCTIONS - Enter best known values. Explanations and helpful information are provided on the reverse side. Perform calculations as indicated to obtain total site contamination for each (or all) species of interest.

EVAPORATIVE COOLER ☐NO WATER INJECTION ☐YES ☐NO

		Concentrations, ppmw	Na + K	S	V	Pb	F	Ca + Mg
	1	Ambient Air, ppmw	0.03	20	0	0	0	0
	2	Fuel, ppmw	0.1	500	0.05	0	0	0
	3	Injected Water, ppmw	0.2	0.1	0	0	0	0
	4	Evaporative cooling water, ppmw	10	100	0	0	0	0
	5	LHV, Btu/#	20,100					
	6	Compute: 18,380/[5]	0.914					
Air	7	Air-to-Fuel Ratio	68					
Air	8	1 - N (Correction Factor)	0.01					
Air	9	Compute: [1] x [6] x [7] x [8], ppmw FEC	0.019	12.4	0	0	0	0
Fuel	10	1 - K (Fuel Factor)	1.0	1.0	1.0	1.0	1.0	1.0
Fuel	11	Compute: [2] x [6] x [10], ppmw FEC	0.09	457	0.04	0	0	0
Water	12	Water-to-fuel Ratio	0.8					
Water	13	Compute: [3] x [6] x [12], ppmw FEC	0.15	0.08	0	0	0	0
Evaporative Cooling	14	E.C. Carryover Rate, GPM	0.9					
Evaporative Cooling	15	1 - E (Mist eliminator Factor)	0.05					
Evaporative Cooling	16	Fuel Flow rate, million Btu/hr	40					
Evaporative Cooling	17	Compute: $\frac{[4]x[5]x[6]x[14]x[15]x5x10^{-4}}{[16]}$ ppmw FEC	0.10	1.4	0	0	0	0
	18	Total Contaminants, ppmw FEC [9] + [11] + [13] + [17]	0.36	471	0.04	0	0	0
	19	Max. Allowable Limits, ppmw FEC, per ES 9-98	0.5	10,000	0.5	1	1	2

COMMENTS

PREPARED BY: ______________________________________ DATE:_____________

APPENDIX B

DERIVATION OF TOTAL FUEL EQUIVALENT CONCENTRATION EQUATION FOR UNDESIRABLE CONTAMINANTS

The expression given in paragraph 3.1.3 for directly fired applications is derived from first principles in section 1. Section 2 explains the incorporation of system efficiencies into this fundamental expression and its use in the Total Site Contamination Worksheet, Form, 3091, with the appropriate unit conversions.

B1.0 Derivation of Fundamental Expression for Total Fuel Equivalent Concentration (For Directly Fired Applications Only)

Solar's air, fuel, and water specification is based on FUEL EQUIVALENT CONCENTRATIONS, i.e., the concentration of a given contaminant as if that given contaminant were present in the fuel alone, with the fuel having a LHV of 18,380 Btu/lb or 10,212 kcal/kg.

Nomenclature used in the derivation is given in Table B-1.

Table B-1. Nomenclature for Fuel Equivalent Derivation

Input Steam to Gas Turbine	Mass Flow Rate	Concentration of i^{th} Contaminant	Mass Flow Ratios of Each Steam or Fuel
Reference Fuel	r	R_i	1
Fuel	f	F_i	1
Air	a	A_i	a/f or (AFR)
Water	w	W_i	w/f or (WFR)
Steam	s	S_i	s/f or (SFR)
Carryover	c	C_i	c/f or (CFR)

(LHV) = lower heating of a given fuel, Btu/lb
i = Na, K, V, Pb, etc.
T_i = Fuel equivalent for the reference fuel which has a lower heating value of 18,380 Btu/lb (10,212 kcal/kg)

The mass flow of the i^{th} contaminant in the combustion products burning the reference fuel is:

$$rR_i + aA_i + wW_i + sS_i + cC_i \tag{1}$$

The total mass flow of the combustion product is:

$$r + a + w + s + c \tag{2}$$

The concentration of the i^{th} contaminant in the combustion products is:

$$\frac{rR_i + aA_i + wW_i + sS_i + cC_i}{r + a + w + s + c} \tag{3}$$

Next suppose that the total mass flow of the i^{th} contaminant in the combustion products came from the reference fuel alone. Let T_i equal the reference fuel equivalent concentration of the i^{th} contaminant. Then, the concentration of the i^{th} contaminant in the combustion products, the environment of the hot section components, would be:

$$\frac{rT_i}{r + a + w + s + c} \tag{4}$$

Equating Eq. (3) with Eq. (4) and dividing through r gives:

$$T_i = R_i + (a/r)\,A_i + (w/r)\,W_i + (s/r)\,S_i + (c/r)\,C_i \tag{5}$$

In order to have an expression that gives the Fuel Equivalent, T_i, for the cases where a fuel, f, of any heating value (LHV) are used, Eq. (5) must be modified. It is required that, regardless of the LHV of either fuel, the flow of each fuel be such that the same thermal input is provided to the engine. Therefore,

$$r\ (18{,}380\ \text{Btu/lb}) = f\ (\text{LHV}) \tag{6}$$

or

$$r = \frac{f\ (\text{LHV})}{18{,}380\ \text{Btu/lb}}$$

In addition, it is required for the same T_i that the contribution of the contaminant to the total from either fuel r of fuel f be the same.

$$rR_i = fF_i \tag{7}$$

Combining Eq. (6) and Eq. (7) gives:

$$R_i = \frac{18{,}380}{(\text{LHV})}\ F_i \tag{8}$$

Substituting Eq. (6) and Eq. (8) into Eq. (5) gives:

$$T_i = \frac{18{,}380}{(\text{LHV})}\ F_i + \frac{a}{f(\text{LHV}/18{,}380)}\ A_i + \frac{w}{f(\text{LHV}/18{,}380)}\ W_i + \frac{s}{f(\text{LHV}/18{,}380)}\ S_i \tag{9}$$

$$+ \frac{c}{f(\text{LHV}/18{,}380)}\ C_i$$

Finally, rearranging and substituting the nomenclature in the fourth column of Table B-1 gives:

$$T_i = \frac{18{,}380}{(\text{LHV})}\ [F_i + (AFR)A_i + (WFR)W_i + (SFR)S_i + (CFR)C_i] \tag{10}$$

B2.0 Derivation of Expression Used in Form 3091

Taking Eq. (10) and assigning units to the variables result in the following definition of terms. (The steam term is dropped from the basic expression because it is currently not applicable to *Solar* engines.)

$$T_i = \frac{18{,}380}{(LHV)} [F_i + (AFR)A_i + (WFR)W_i + (SFR)S_i + (CFR)C_i]$$

where

T_i = fuel equivalent concentration of contaminant i, in ppmw

LHV = lower heating value of fuel, in Btu/lb

F_i = concentration of contaminant i in fuel entering combustor, in ppmw

AFR = air-to-fuel mass ratio

A_i = concentration of contaminant i in air entering compressor, in ppmw

WFR = water-to-fuel mass ratio

W_i = concentration of contaminant i in water injected into combustor, in ppmw

CFR = carryover water-to-fuel mass ratio

C_i = concentration of contaminant i in carryover water (same as evaporation cooler feedwater), in ppmw

Examining each term in greater detail:

Fuel Term: F_i

Let K = overall efficiency rating for fuel cleanup system

Adjusted fuel term = $F_i (1 - K)$ (11)

Air Term: $(AFR)A_i$

A_i is concentration air entering compressor

$$A_i = (1 - N)A_i^{amb}$$

where N = efficiency of air filter

A_i^{amb} = concentration of contaminant i in ambient air, in ppmw

Adjusted air term = $(AFR)(1 - N)A_i^{amb}$ (12)

Water Term: $(WFR)W_i$

W_i is concentration in water injected into combustor, ALSO THE SET POINT FOR AUTOMATIC SHUTDOWN

Carryover Term: $(CFR)C_i$

Let water carryover rate = R gal/min x 8.337 lb/gal

$$= 8.337 \text{ R lb/min}$$

Let fuel flow rate = f MBtu/hr

$$f\,\frac{\text{MBtu}}{\text{hr}} \times \frac{1\text{ hr}}{60\text{ min.}} \times \frac{\text{lb}}{\text{LHV Btu}} \times \frac{10^6\text{ Btu}}{\text{MBtu}} = \frac{16{,}700f\text{ lb/min}}{\text{LHV}}$$

Let E = efficiency of mist eliminator

Carryover rate = (1 - E) (8.337R) lb/min

$$\text{CFR} = \frac{8.337R\,(\text{LHV})\,(1 - E)}{16{,}700f}$$

$$= 4.99 \times 10^4 R\,(\text{LHV})\,(1 - E)/f \qquad (13)$$

Substitute in Equation (10),

$$T_i = \frac{18{,}380}{\text{LHV}}\Big[F_i\,(1 - K) + (\text{AFR})\,(1 - N)A_i^{amb} + (\text{WFR})W_i$$

$$+ \frac{[4.99 \times 10^{-4} R\,(\text{LHV})\,(1 - E)]}{f}\,C_i\Big] \qquad (14)$$

or

$$T_i = \frac{(18{,}380)}{\text{LHV}}(1 - K)F_i + \frac{(18{,}380)}{\text{LHV}}(\text{AFR})\,(1 - N)A_i^{amb}$$

$$+ \frac{(18{,}380)}{\text{LHV}}(\text{WFR})W_i + \frac{(18{,}380)}{\text{LHV}}(5 \times 10^{-4})R\,(\text{LHV})\,(1 - E)\,\frac{C_i}{f} \qquad (15)$$

where $\frac{(18.380)}{\text{LHV}}(1 - K)F_i$ = fuel equivalent concentration of i^{th} contaminant in fuel, ppmw

$\frac{(18{,}380)}{\text{LHV}}(\text{AFR})\,(1 - N)A_i^{amb}$ = fuel equivalent concentration of i^{th} contaminant in air, ppmw

$\frac{(18{,}380)}{\text{LHV}}(\text{WFR})W_i$ = fuel equivalent concentration of i^{th} contaminant in injected water, ppmw

$\frac{(18{,}380)}{\text{LHV}}(5 \times 10^{-4})R\,(\text{LHV})\,(1 - E)\,\frac{C_i}{f}$ = fuel equivalent concentration of i^{th} contaminant in evaporation cooler feedwater, ppmw

T_i = sum of fuel equivalent concentration of i^{th} contaminant from all sources, ppmw

Equation (15) is used in Form 3091.

APPENDIX C

LIQUID FUEL HANDLING AND STORAGE REQUIREMENTS

C.1 LIQUID FUEL STORAGE AND HANDLING SYSTEM SELECTION

The following section details the configuration required for liquid fuel handling and storage systems for Solar gas turbines operating in Dual Fuel or Liquid Fuel only configurations. Refined quality liquid fuel may be contaminated during transportation or storage and it is important to provide auxiliary fuel cleaning systems to maintain or restore fuel quality prior to delivery to the gas turbine package.

A complete fuel composition analysis for the liquid fuel should be submitted at time of equipment quotation so that verification of compliance can be confirmed and requirements or recommendations for package modifications to ensure proper operation and turbine durability. This verification also applies to liquid fuel that is to be used at a preliminary package pre-commissioning phase, typically at a shipyard or fabrication yard. Even temporary operation with non-compliant fuel can be detrimental to the durability of a gas turbine.

The selection of liquid fuel storage, handling and treatment systems is a function of the site location and expected liquid fuel operation per year with site qualification as follows:

Inland	10 miles (16 km) away from an ocean or body of salt water. Fuel supply, transportation and handling systems are generally of high quality.
Coastal	Near shore of body of salt water where salt air is present. Fuel supply is not barged or transported by sea, otherwise treat as Marine.
Marine/ Offshore	Offshore fixed or floating platforms as well as land based installations near a body of salt water. Fuel supply is delivered via sea transport or where fuel quality is a concern.

Table C.1 Liquid Fuel Handling, Storage and Treatment Requirements

Liquid or Dual Fuel - Conventional or SoLoNOx (Hours of Operation on Liquid Fuel)			
Installation	**Inland**	**Coastal**	**Marine / Offshore**
Fuel Storage Tank with Central Sump and Floating Suction **See C.2.1**	Required	Required	Required
Dual in-line Filter/Coalescer System **See C.2.2**	Recommended Operation Up to 1,000 hrs/yr	Required Operation Up to 1,000 hrs/yr	Option Not Available
Buffer Tank and Centrifuge System **See C.2.3**	Required Operation 1,000 – 4,000 hrs/yr	Required Operation 1,000 – 4,000 hrs/yr	Required Operation Up to 1,000 hrs/yr
Buffer Tank and Dual Centrifuge System **See C.2.4**	Required Operation over 4,000 hrs/yr	Required Operation over 4,000 hrs/yr	Required Operation Over 1,000 hrs/yr
Monitoring System Comprised of a Duplex Filter for Detecting Solid Contamination **See C.2.5**	Required (Unless C.2.2 is Selected)	Required (Unless C.2.2 is Selected)	Required
Exceptions to these requirements are subject to review and approval by Solar Turbines engineering departments.			

C.2 FUEL STORAGE AND HANDLING REQUIREMENTS

This section describes the fuel handling and treatment equipment specified in Table C.1, along with critical procedures that need to be followed. Three basic fuel handling and storage systems options with varying levels of complexity to meet the requirements defined in Table C1.

C.2.1 FUEL STORAGE TANK WITH CENTRAL SUMP AND FLOATING SUCTION PIPE

Fuel storage facilities must consist of one or several main storage tanks and/or holding tanks with floating suction pipes, sloping bottoms with a drain at the low point to remove water and sediment, and special inlet distributors, such as a velocity diffuser, to minimize sediment disturbance (Figure C.1). Copper-bearing steel or black iron are acceptable for storage tanks and interconnect pipes. Coatings should be insoluble in and non-reactive with the fuel. Galvanized or cadmium plated fittings or other components must be avoided.

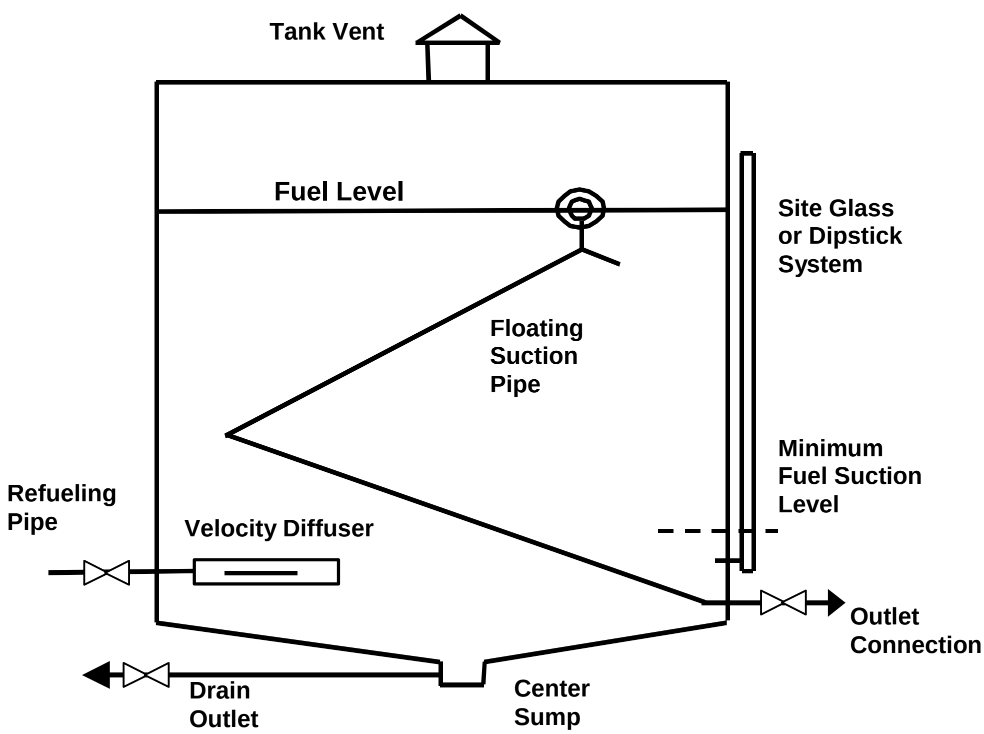


Figure C.1 Schematic of Main Gas Turbine Liquid Fuel Storage Tank

C.2.1.1 FUEL STORAGE TANK HANDLING PROCEDURES

1. Fuel should be clean and conform to Solar's fuel specification, ES 9-98, when the fuel arrives at the site. Gas turbine liquid fuels are often contaminated with leaded gasoline or salty ballast water in the shipping tanks during transportation. Simple tests can be carried out to check for such contamination.
2. Clean truck or barge unloading equipment and hoses from road dust and water before each use. Always keep unloading equipment covered and shipping tanks closed when not in use.
3. Fuel delivery must be monitored by the operator to ensure that contaminants are not introduced in to the tank(s).
4. The fuel cloud point must be suitable for the conditions under which the fuel is to be stored. This may require a heated tank or lines.
5. Frequently drain storage tanks to remove sediment and water.
6. Fuel in the main storage tanks must not be sent directly to the gas turbine package without centrifuging or filtering first.

C.2.2 TWIN FILTER/WATER COALESCER SYSTEM - WHEN CENTRIFUGE IS NOT REQUIRED

Figure C.2 shows a twin filter / water coalescer system. This will typically be specified on such projects where a centrifuge system is not required. The Filter / Coalescer systems are designed to remove water and solids from liquid fuels and positioned in the fuel supply line to the gas turbine package. Water can be automatically drained but solids filters may have to be changed on a regular basis. Two suitably sized units set up in parallel will allow the filters to be changed out without shutting down the engine when the ΔP across the filter becomes too high. Each unit will require a 5-micron filter for solid particles. A ΔP monitor with alarm and shutdown limits should be included to ensure that the filter does not collapse in the event of upstream system failure. A water level gauge will also be required to activate the automatic drain and actuate alarms in the event of drain malfunction.

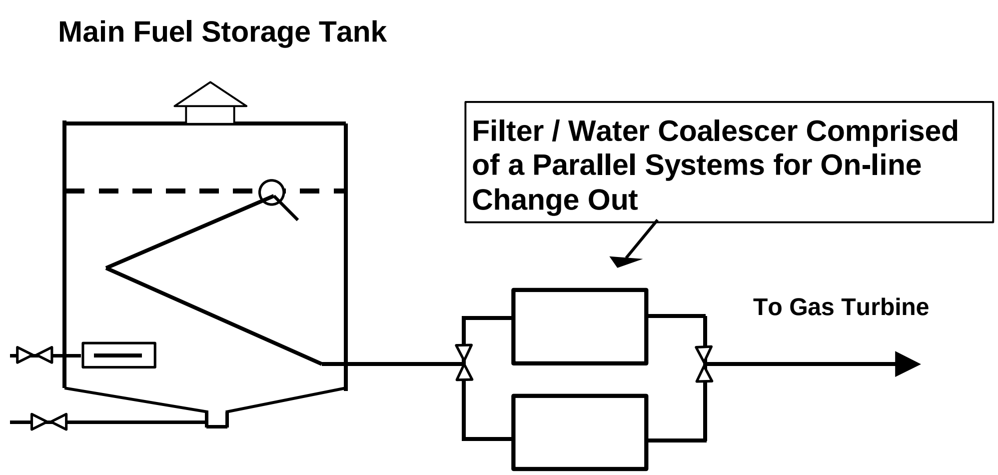


Figure C.2 On line Filter/Coalescer System for Applications not Requiring a Centrifuge Cleaning System

C.2.3 SINGLE CENTRIFUGE AND STORAGE TANK SYSTEM

Figure C.3 shows a single centrifuge and tank storage system for applications where the buffer tank contents are sufficient to cover a complete liquid running period without refilling. The storage tank should be sized to cover the longest single period of liquid operation anticipated. Filling can be from another storage tank, road tanker, or barge.

In this scenario, the centrifuge would be used to clean the fuel after delivery has been made, and then periodically thereafter on a regular basis to remove accumulating moisture and sediment dropping out of the fuel as it sits.

Centrifuges with water scrubbing capability are essential on sites (typically coastal or offshore), where significant contamination is expected.

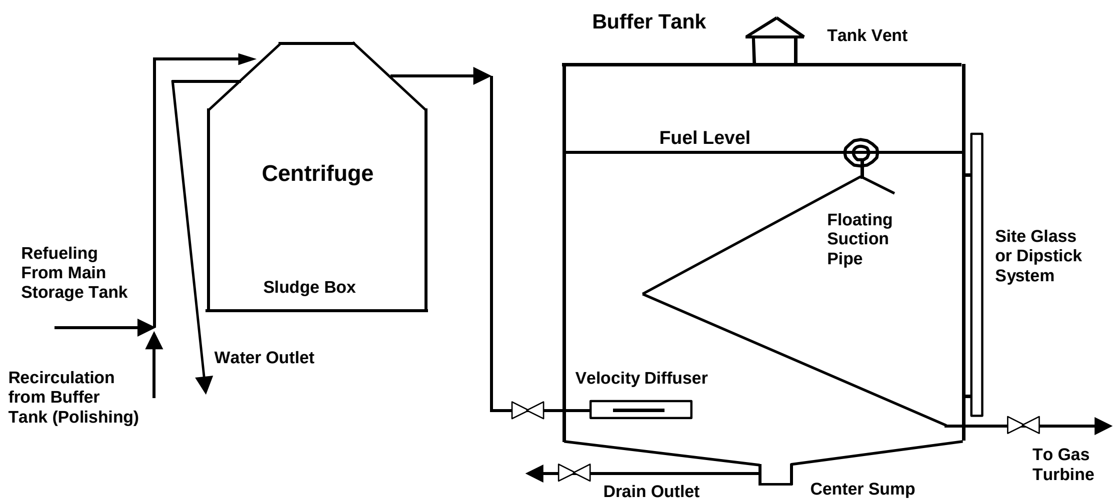


Figure C.3 Single Centrifuge and Storage Tank

C.2.3.1 FUEL BUFFER TANK AND CENTRIFUGE HANDLING PROCEDURES

1. Never “agitate” the fuel. Fuel in a buffer tank should be allowed to settle without being disturbed for at least eight hours before being used as turbine fuel.
2. Tank filling and fuel recirculation through the centrifuge should not be done when the tank is being used to supply a turbine.
3. Periodically remove fuel from the lower end of the holding tank and clean tanks by returning this fuel to the main storage tank(s) via centrifuges. This recirculation minimizes the accumulation of dirt and contaminants in the clean tanks.
4. Centrifuges should be cleaned out per manufacturers recommendations.
5. If sodium and/or potassium are present in the fuel, the centrifuge must also incorporate a water scrubbing system.
6. Frequently drain tanks to remove accumulated sediment and water.

C.2.4 DUAL CENTRIFUGE AND STORAGE SYSTEM

For applications where turbines will be operating continuously on liquid fuel for long periods, there should be at least two fuel conditioning systems feeding into a correctly non-metallic or fully lined buffer tank for final fuel settling and supply.

Figure C.4 shows the most comprehensive system for liquid operation per requirements specified in Table C.1.

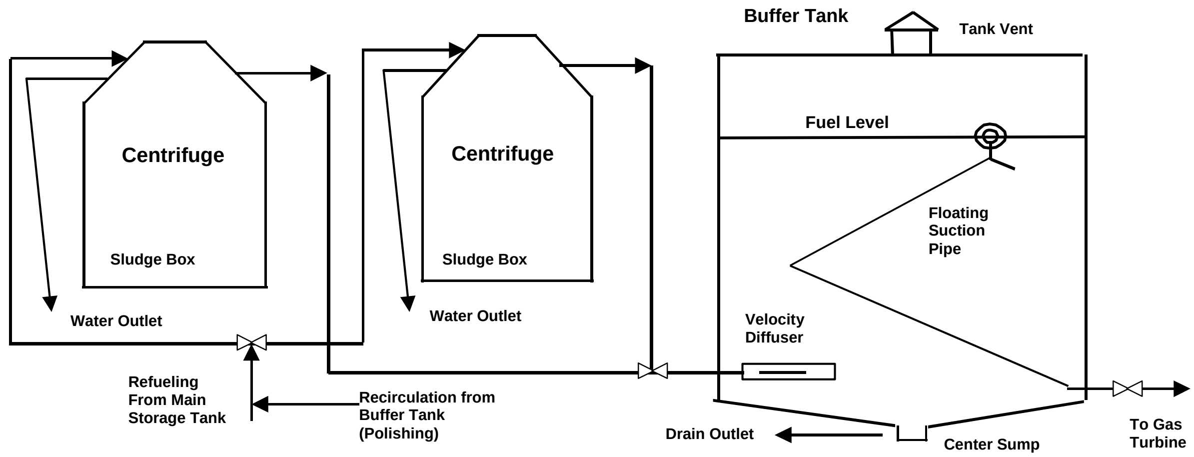


Figure C.4 Dual Centrifuge System

C.2.4.1 FUEL BUFFER TANK AND CENTRIFUGE HANDLING PROCEDURES

1. Never “agitate” the fuel. Fuel in a “buffer tank” should be allowed to settle without being disturbed for at least eight hours before being used as turbine fuel.
2. Tank filling and fuel recirculation through the centrifuge should not be done when the tank is being used to supply a turbine.
3. Periodically remove fuel from the lower end of the holding tank and clean tanks by returning this fuel to the main storage tank(s) via centrifuges. This recirculation minimizes the accumulation of dirt and contaminants in the clean tanks.
4. Centrifuges should be maintained and cleaned per manufacturers recommendations.
5. If sodium and/or potassium are present in the fuel, the centrifuge must also incorporate a water scrubbing system.
6. Frequently drain tanks to remove sediment and water.

C.2.5 Monitoring System – Duplex Filter

The off-skid Filter Monitor System provides monitoring of the fuel quality just prior to delivery to the turbine package. The system detects water or solid contamination and provides an alarm when the delta-p increases above a set point. This system is not a fuel filter system as its primary function is to monitor the liquid fuel in case the primary filtration or centrifuge systems are not able to clean the fuel as required.

C.3 FUEL MONITORING AND MAINTENANCE

C.3.1 FUEL QUALITY MONITORING

A process is required to monitor the quality of the fuel that is being delivered to the engine and to compile a log of physical and chemical properties of the fuel consumed.

Fuel parameters logged must include:

- Water content
- Sediment content
- Sulfur content
- Analysis of metallic elements
- Sodium and potassium content

C.3.1.1 PROCEDURES

Fuel samples must be taken and analyzed on a regular basis while operating on liquid fuel to ensure that the fuel contaminants do not exceed fuel specification. This can be accomplished via an automated system or by taking a sample from the liquid supply line to the engine and sending to a qualified laboratory. The frequency should be sufficient to ensure that every batch of fuel delivered is analyzed at least once. The log should be made available for examination during routine package maintenance and engine inspections.

If specification limits are exceeded the problems must be remedied or prevailing equipment warranties may be affected.

C.3.2 ANNUAL INJECTOR FLOW TESTS AND INSPECTION

An annual inspection measuring the injector flow area is required to determine if the unmonitored main and pilot liquid passages are plugging. Please contact the local Solar District Office for assistance.

Solar's SoLoNOx combustion – liquid fuel systems need additional consideration for successful operation. It has been found that excessive fuel bound sulfur, solids, water, sodium and potassium makes internal passages prone to plugging and operators need to provide the right level of treatment commensurate with the frequency and duration of liquid fuel operation and the quality of fuel being supplied to minimize the effects on the fuel system.

C.3.3 SPARE FUEL INJECTORS

To minimize downtime, spare fuel injectors located near installation are recommended for sites where it has been determined that injectors will require frequent cleaning.

APPENDIX D

LIQUID FUEL SUITABILITY FORM

The table below contains the allowable limits for liquid fuel characteristics and contaminants. Solar's Liquid Fuel System Assessment form should be filled out with the Solar Sales Engineer to specify project information that will identify liquid fuel filtration requirements.

Liquid Fuel Suitability Form

Project			
Characteristics	**ES 9-98**	**Project**	**Comments**
Solids	≤2.6 mg/liter of sediment, solid or hard contaminants, 90% of the 2.6 mg shall be less than 5 micron in size. Max allowable size ≤ 10 micron		
Liquid	≤ 0.25 cc free water per liter at an ambient temp of 80 °F (27 °C)		
Sulfur	**10,000 ppmw. (See Table 1). Additional restrictions apply for *SoLoNOx* liquid operation**		
Fuel Bound Nitrogen	Measurement required for liquid emissions guarantees		
Sodium & Potassium	≤ 0.5ppmw		
Vanadium	≤ 0.5 ppmw		
Lead	≤ 1 ppmw		
Ca & Mg	≤ 2 ppmw		
Fluorine	≤ 1 ppmw		
Chlorine	≤ 0.15 % wt		
Others – Mercury, Cadmium, Bismuth, Arsenic, Antimony, Phosphorous, Boron, Gallium, Indium.	≤ 0.5 ppmw		
Kinematic Viscosity	12 centistokes max 1 centistoke min at 100 °F (38 °C)		
Specific Gravity	0.775 min 0.875 max		
Reid vapor pressure	< 3 psia < 20.6 kPa		
Cloud point	At least 10 °F (6 °C) below expected min ambient temp.		
Pour point	At least 10 °F (6 °C) below cloud point		
Flash point	≥ 100 °F (38 °C) or ≥ legal limit		
Distillation	90% evaporated at 640 °F (338 °C) maximum. End point at 690 °F (366 °C) maximum		
Aromatics	35% by volume maximum		
Olefins and Diolefins	5% by volume maximum		
LHV	>18,000 Btu/lb >41838 kJ/kg		
Carbon residue on 10% distillation residue	≤ 0.35 %		
Ash	≤ 0.005 % max		
Copper strip corrosion	No 3 (3hr at 122 °F (50 °C)) in ASTM D130		
Expected annual liquid operating hours			
Lubricity, HFRR @ 60°C	520 micron maximum. by ASTM D6079 or equivalent.		

Emissions Signatures for Landfill and Digester Gas Fuels

Leslie Witherspoon
Environmental Strategies

PURPOSE

This Product Information Letter summarizes emissions estimates of nitrogen oxides (NO_x), carbon monoxide (CO), and unburned hydrocarbons (UHC) for gas turbines operating on landfill and digester gases. Emissions estimates for other alternative fuels (refinery gas, gasified biomass, coke oven gas, etc.) are outside the scope of this document.

INTRODUCTION

Landfill and digester gases are products of the anerobic decomposition of biodegradable wastes in landfills and wastewater treatment plants. Historically, landfill and digester gases have been vented and/or flared. Over the last 20 years, many landfills and wastewater treatment plants have utilized gas turbines to generate electricity, heat, and/or steam from gas that would otherwise be flared or released to the atmosphere.

The compositions of the landfill and the digester gases are a major factor in determining the emissions signature. The emissions estimates summarized in this document are typical emissions estimates for typical landfill and digester gas compositions. **Site-specific emissions are determined on a case-by-case basis based on fuel composition, site conditions, operating profiles, fuel pre-treatment scenarios, and other factors.**

As a result of the variability of landfill and digester gas compositions from one site to another, it should not be assumed that a published/quoted emissions estimate for one site is representative of another.

FUEL QUALITY AND COMPOSITION

Gaseous fuels are often classified by their Wobbe Index, a parameter that accounts for variation in the fuel gas density and heating value. Wobbe Index is defined as the lower heating value (LHV) of the fuel in Btu/scf divided by the square root of the specific gravity of the fuel with respect to air. The Wobbe Index is an important parameter in designing fuel systems to accommodate fuels with different heating values.

Solar's combustion turbines can burn a wide variety of gaseous (and liquid) fuels. Conventional combustion gas turbines have more fuel flexibility than gas turbines with dry low emissions (DLE) combustion systems. Generally, DLE combustion systems are not compatible with landfill and digester gases, however, the Ultra Lean Premix (ULP) combustion system on the *Mercury* 50 gas turbine has been modified to support landfill and digester gas combustion.

Typical landfill gas contains 35-51% methane (CH_4) with the balance made of up primarily carbon dioxide (CO_2) and nitrogen (N_2). Digester gas contains 60-65% methane with carbon dioxide and nitrogen making up the balance.

EMISSIONS ESTIMATES

The emission estimates, shown in Tables 1 and 2, can be used as preliminary estimates for project planning provided the Wobbe Index of the landfill fuel falls between 300 and 460

Btu/scf LHV, or the digester fuel falls between 560 and 665 Btu/scf LHV, and the balance of the fuel composition is carbon dioxide or nitrogen. The presence of hydrogen (H_2) or hydrocarbons heavier than methane nullifies the applicability of this document.

The emissions estimates reflect typical emissions levels and are valid at steady-state conditions, at ambient temperatures of 0°F (–18°C) and above, and are limited to the load ranges shown in Tables 1 and 2. The estimated emissions levels do not apply during start-up, shut-down, malfunction, or transient events.

Table 1. Landfill Gas Emissions Estimates @ 15% O_2 (Assumes Wobbe Index Range 300 to 460 Btu/scf LHV)

Turbine Model	ISO NO_x*		CO		UHC		Load Range (%)	Ambient Temp °F (°C)
	ppm	mg/Nm³	ppm	mg/Nm³	ppm	mg/Nm³		
Centaur® 40	42	88	250	318	100	72	80-100	>0 (–18)
Centaur 50	42	88	200	254	100	72	80-100	>0 (–18)
Mercury™ 50	15	25	25	30	25	18	50-100	>0 (–18)
Taurus™ 60	42	88	150	191	75	54	80-100	>0 (–18)
Taurus 70	80	166	100	127	50	36	80-100	>0 (–18)
Mars® 100	72	150	100	127	50	36	80-100	>0 (–18)
Titan™ 130	80	166	100	127	50	36	80-100	>0 (–18)

* ISO NOx correction and relative humidity ≥30% applies for all models except the *Mercury* 50.

Table 2. Digester Gas Emissions Estimates @ 15% O_2 (Assumes Wobbe Index Range 550 to 665 Btu/scf LHV)

Turbine Model	ISO NO_x* Uncontrolled (Water Injected)**		CO Uncontrolled (Water Injected)**		UHC Uncontrolled (Water Injected)**		Load Range %	Ambient Temperature °F (°C)
	ppm	mg/Nm³	ppm	mg/Nm³	ppm	mg/Nm³		
Centaur 40	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Centaur 50	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Mercury 50	25	50	50	64	25	18	50-100	>0 (–18)
Taurus 60	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Taurus 70	150 (72)	312 (150)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Mars 100	150 (60)	312 (125)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Titan 130	150 (72)	312 (150)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)

* ISO NOx correction and relative humidity ≥ 30% applies for all models except the *Mercury* 50.

** Water/Fuel ratio is assumed to be 0.8 to 0.85.

Volatile Organic Compound (VOC) emissions can be assumed to be 20% of the UHC values shown in Tables 1 and 2. Note: The 20 ppm VOC (as hexane) @3% O_2 requirement found in 40 CFR 60, Subpart WWW, is approximately equal to 40 ppm VOC (as methane) @15% O_2. Thus, the VOC estimates for *Solar*® turbines comply with the VOC limit in Subpart WWW.

Particulate matter (PM, PM_{10}, $PM_{2.5}$) for landfill and digester gas fuel can be estimated using 0.03 lb/MMBtu (HHV). Reference PIL 171.

Because sulfur content varies site-to-site, Solar recommends that **sulfur dioxide** emissions be estimated using a mass balance approach. Reference PIL 168.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

APPENDIX F

Pressure and Temperature Requirements- Caterpillar Engines

DiFonso, Andy

Subject: LFG consumption in a Cat Engine. - The City of Glendale, CA

From: khertzler@clevelandbrothers.com [mailto:khertzler@clevelandbrothers.com]
Sent: Thursday, January 22, 2015 2:54 AM
To: Kayali, Reem
Cc: Slatosky, Bill
Subject: RE: LFG consumption in a Cat Engine. - The City of Glendale, CA

Kayali,

We will required SCR catalysts with urea injection to meet the Nox requirements......these are very expensive catalysts so you will want to reduce the quantity of engines.

Your gas analysis seems to show that the landfill has excess air in gas. Likely pulling pretty hard on the landfill. Based on this info, the actual landfill gas is not quite as bad as it appears.

I am pretty sure we will be able to use our CG260-16 genset....heat rate will likely be in the ballpark of 8420 BTU/KWH (LHV). It is normally lower but due to your gas being such a low heat value I am adding extra tolerance.
Also, fyi...we only need 2.5 PSIG gas to operate these large engines. You will not need to waste much horsepower compressing the gas.

You will definitely need to clean up the gas. The exhaust treatments systems will not work with out clean landfill gas.

Sincerely,

Kurt Hertzler
Cleveland Brothers Equip. Co., Inc.
336 N. Fairville Ave.
Harrisburg PA 17112
Direct Dial: 717-635-7267
E-FAX No: 717-441-3757
Cell Phone: 717-514-7360
Email: khertzler@clevelandbrothers.com

From: "Kayali, Reem" <RKayali@ventureengr.com>
To: "khertzler@clevelandbrothers.com" <khertzler@clevelandbrothers.com>,
Cc: "Slatosky, Bill" <BSlatosky@ventureengr.com>
Date: 01/16/2015 01:32 PM
Subject: RE: LFG consumption in a Cat Engine. - The City of Glendale, CA

DiFonso, Andy

Subject: Budget Pricing - LFGTE Plant - The City of Glendale, CA

Good morning Kurt,

Quick update: After further discussions with the Venture Team and the Client, it was concluded that the Caterpillar CG260-16 (quantity 6, based engine heat rate of 8420 BTU/kWh and a power generation of 3370 kW) will be selected for the phase 2 of Task #5 study (electric generation using LFG as fuel to be located at the Scholl Landfill in Glendale CA, no blending with natural gas).

1- Predicted performance data. {Working on this}
2- Maximum fuel temperature at the Engine {50 C}
3- Fixed and variable operating and maintenance cost:

- How often does the catalyst need replacement? {With Clean Landfill Gas: SCR to be changed every 24,000 Hours, the oxicat is scheduled for 16,000 hours...we figure maintenance and operation cost to be ~ $0.0031/kWh generated}
- Ammonia consumption? {This system is usually proposed to consume Urea...that breaks down to Ammonia in the presence of the exhaust gas...Urea consumption is expected to be ~ 2.2 GPH of 40% Urea/60% water solution}

As a reminder: the
Volumetric Flow rate = 7,500 SCFM of LFG
Site elevation is 1,415 feet per Topographic Map.
Humidity: min: 10%, expected: 55%, max:100%
Ambient Temperature: Minimum = 35 °F, Expected 90 °F and Maximum = 110 °

Landfill Gas compositions are:

Components	Molecular Formula	LFG % Mole
Methane	CH_4	0.383
Carbon Dioxide	CO_2	0.322
Nitrogen	N_2	0.252
Oxygen	O_2	0.043

Please feel free to call me if you have any questions or need more information.

Regards,

Reem Kayali
Process Engineer
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Pittsburgh, PA 15233
Office: (412) 231-5890 x332

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APPENDIX G

Air Emission Limits

Mihailoff, Amanda

To: Kayali, Reem
Subject: FW: Emission limits for turbines operating at the City of Glendale

From: Edward Krisnadi [mailto:ekrisnadi@montrose-env.com]
Sent: Friday, November 21, 2014 4:37 PM
To: Kayali, Reem
Subject: RE: Emission limits for turbines operating at the City of Glendale

Hi Reem, my contact at the AQMD is on vacation until December 3rd, 2014. However, I saw a permit limit on a source test in 2012 which has a limit of 130 ppm @15% O2 for CO and 20 ppm @15% O2 for VOC.

I let you know if I find something else.

Thanks,

MONTROSE ENVIRONMENTAL

Edward Krisnadi
Project Manager
Regulatory Compliance Services
SCEC
an affiliate of Montrose Environmental Group, Inc.
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T: 714.282.8240 | M: 714.920.5865 | F: 714.282.8247
ekrisnadi@montrose-env.com
www.montrose-env.com

From: Edward Krisnadi [mailto:ekrisnadi@montrose-env.com]
Sent: Friday, November 21, 2014 11:55 AM
To: Kayali, Reem
Cc: Karl Lany
Subject: RE: Emission limits for turbines operating at the City of Glendale

Good morning Reem, I have been working with Karl and responding your e-mail on his behalf.

I had a conversation with the District last month and the Air District has permitted a NOX limit as low as 15 ppmv for landfill gas turbine. There is a good possibility that the limit is going to be even lower in the future. Therefore, the Solar Mars will be required to be equipped with SCR and CO oxidization catalyst due to high concentration of uncontrolled NOX and CO emission rates. Additionally, the vendor also provided me with the following uncontrolled emission concentration on blended landfill gas (60%LFG and 40%NG):

- NOX: 185 ppmvd at 15% O2
- CO: 100 ppmvd at 15% O2
- UHC: 50 ppmvd at 15% O2

I understand that your natural gas composition in the blended landfill gas is pretty low (only 8% - 15%); so, the uncontrolled emission rates based on landfill gas may be valid, but confirmation with the vendor may be necessary.

We also have looked into the Solar Mercury and we found out the vendor provided a warranty for uncontrolled emission rates of 15 ppmv at 15% O2 on NOx, 25 ppmv at 15% O2 on CO, and 25 ppmv at 15% O2 on UHC. This warranty is limited to 50 to 100% load.
I hope this answer your question. Please let me know if you need additional information.

Regards,

MONTROSE ENVIRONMENTAL

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(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)
(Amended June 3, 2005)(Amended February 1, 2008)(Amended July 9, 2010)
(Amended September 7, 2012)

RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops or the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

(3) CERTIFIED SPARK-IGNITION ENGINES mean engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(4) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.

(5) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOCs, but not including engines used for self-propulsion.

(6) EXEMPT COMPOUNDS are defined in District Rule 102 - Definition of Terms.

(7) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the District, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.

(8) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(9) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

(10) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.

(11) NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:

(A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or

(B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or

(C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.

(12) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(13) OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide.

(14) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

(A) the engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or

(B) the engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) the engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

(15) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(16) RICH-BURN ENGINE WITH A THREE-WAY CATALYST means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NOx, CO and VOC.

(17) STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

(18) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.

(19) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may be assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.

(20) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.

(d) Requirements

(1) Stationary Engines:

(A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I ALTERNATIVE TO ELECTRIFICATION CONCENTRATION LIMITS		
NO_x	VOC	CO
(ppmvd)[1]	(ppmvd)[2]	(ppmvd)[1]
11	30	70

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(B) The operator of any stationary engine not covered by (d)(1)(A) and not exempt from this rule shall

(i) Remove such engine permanently from service or replace the engine with an electric motor, or

(ii) Not operate the engine in a manner that exceeds the applicable emission concentration limits listed in either Table II or Table III-A or B.

TABLE II CONCENTRATION LIMITS		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 11 bhp < 500: 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000

CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

The concentration limits effective on and after July 1, 2010 shall not apply to engines that operate less than 500 hours per year or use less than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel.

If the operator of a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing demonstrates that the CO and VOC limits effective on and after July 1, 2010 are not achievable, then the Executive Officer may, with United States Environmental Protection Agency (EPA) approval, establish technologically achievable, case-by-case CO and VOC limits in place of the concentration limits effective on and after July 1, 2010. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO.

If the operator of an engine that uses non-pipeline quality natural gas demonstrates that due to the varying heating value of the gas a longer averaging time is necessary, the Executive Officer may establish for the engine a longer averaging time, not to exceed six hours, for any of the concentration limits of Table II. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility.

(C) The operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III-A, provided that the facility monthly average biogas usage by the biogas engines is

90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response plan, because of either high influent flows caused by precipitation or a disaster.

TABLE III-A
CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000

TABLE III-B
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2016

NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$ECF = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel. ECF shall not be less than 1.0.

The Executive Officer may approve the burning of more than 10% natural gas in a landfill or digester gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10% would be shutting down the engine and flaring more landfill or digester gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.

(D) Notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III.

(E) Biogas engine operators that establish to the satisfaction of the Executive Officer that they have complied with the emissions limits of Table III-B by January 1, 2015 will have their respective engine permit application fees refunded.

(F) Once an engine complies with the concentration limits as specified in Table III-B, there shall be no limit on the percentage of natural gas burned.

(G) The concentration limits effective as specified in Table III-B shall not apply to engines that operate fewer than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value) of fuel.

(H) An operator of a biogas engine may determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth below, provided the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (if CO is elected for averaging), each corrected to 15% O_2, over a 4 month time period. An operator may utilize a monthly fixed interval averaging time for the first 4 months of the retrofitted engine's operation and up to a 24 hour fixed interval averaging time thereafter. For purposes of determining compliance using a longer averaging time:

(i) An operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing zero or calibration checks, cylinder gas audits, or routine maintenance in accordance with the provisions in Rules 218 and 218.1.

(ii) Notwithstanding the requirements of Rules 218 and 218.1, for one-minute time periods where NOx and/or CO CEMS data are greater than 95 percent of the Rule 218.1 Full Scale Range while the underlying equipment is operating, an operator shall use substitute data. A concentration equivalent to 3 times the NOx and/or CO emission limits in Table III-B (each corrected to 15% O2) shall be used as substitute data.

(iii) The intentional shutdown of a CEMS to circumvent the emission limits of Table III-B while the underlying equipment is in operation shall constitute a violation of this rule.

(iv) The averaging provisions of this subparagraph shall not apply to CEMS that are time shared by multiple biogas engines.

(I) The operator of any new engine subject to subparagraph (e)(1)(B) shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a District permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a District permit.

(J) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.

(K) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards:

TABLE IV
EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION ENGINES

Pollutant	**Emission Standard (lbs/MW-hr)**[1]
NOx	0.070
CO	0.20
VOC	0.10[2]

1. The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause.
2. Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

$$\frac{Lbs}{MW\text{-}hr} = \frac{Lbs}{MW_e\text{-}hr} \times \text{Electrical Energy Factor (EEF)}$$

Where:

Lbs/MW-hr = The calculated emissions that shall comply with the emission standards in Table IV

$Lbs/MW_e\text{-}hr$ = The short-term engine emission limit in pounds per MW_e-hr of net electrical energy produced, averaged over 15 minutes. The engine shall comply with this limit at all times.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered. The engine operator shall demonstrate annually that the EEF is less than the value required for compliance.

(iii) For combined heat and power engines, the short-term emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.

(iv) Notwithstanding Rule 2001, the requirements of this subparagraph shall apply to NOx emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).

(v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digester gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(2) Portable Engines:

(A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

(ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

(B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.

(C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

(1) Agricultural Stationary Engines:

(A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3, 2005 shall comply with subparagraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V:

TABLE V COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES		
Action Required	**Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)**	**Other Engines**
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

The notification of applicability shall include the following for each engine:

(i) Name and mailing address of the operator

(ii) Address of the engine location

(iii) Manufacturer, model, serial number, and date of manufacture of the engine

(iv) Application number

(v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)

(vi) Engine fuel type

(vii) Engine use (pump, compressor, generator, or other)

(viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)

(B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(I) immediately upon installation.

(2) Non-Agricultural Stationary Engines:

(A) The operator of any stationary engine not meeting the requirements of subparagraphs (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI:

TABLE VI
COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES

Action Required	Applicable Compliance Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later
Complete initial source testing	60 days after the final compliance date in (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008, and comply with emission limits of the previous version of this rule until February 1, 2009 when the engine shall be in compliance with the emission limits of this rule.

(C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of this rule shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008.

(3) Stationary Engine CEMS

(A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.

(B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES

Action Required	**Applicable Compliance Dates For:**		
	Non-Biogas Engines Rated at 750 bhp or More	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit to the Executive Officer applications for new or modified CEMS	August 1, 2008	August 1, 2009	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES

Action Required	Applicable Compliance Dates For:		
	Non-Biogas Engines Rated at 750 bhp or More	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

(4) Stationary Engine Inspection and Monitoring (I&M) Plans:
The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:

(A) By August 1, 2008, submit an initial I&M plan application to the Executive Officer for approval;

(B) By December 1, 2008, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall:

(C) By February 1, 2009, submit an initial I&M plan application to the Executive Officer for approval;

(D) By June 1, 2009, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

(5) Stationary Engine Air-to-Fuel Ratio Controllers

(A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(J), shall comply with those requirements in accordance with the compliance schedule in Table V, except that the application due date is no later than May 1, 2008 and the initial source testing may be conducted at the time of the testing required by subparagraph (f)(1)(C).

(B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(J), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by April 1, 2008.

(C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to May 1, 2009, to install the equipment on up to 50% of the affected engines.

(6) New Stationary Engines

The operator of any new stationary engine issued a permit to construct after February 1, 2008 shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M plan application is not required.

(7) Biogas Engines

For any biogas engine for which the operator applies to the Executive Officer by April 1, 2008 for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until August 1, 2008, provided the operator continues to comply with all emission limits in effect prior to February 1, 2008.

(8) Compliance Schedule Exception

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.

(9) Exceedance of Usage Limits

(A) If an engine was initially exempt from the new concentration limits in subparagraph (d)(1)(B) or subparagraph (d)(1)(C) that take effect on or after July 1, 2010 because of low engine use but later exceeds the low-use criteria, the operator shall bring the engine into compliance with the rule in accordance with the schedule in

Table VI with the final compliance date in Table VI being twelve months after the conclusion of the first twelve-month period for which the engine exceeds the low-use criteria.

(B) If engines that were initially exempt from new CEMS by the low-use criterion in subclause (f)(1)(A)(ii)(I) later exceed that criterion, the operator shall install CEMS on those engines in accordance with the schedule in Table VII, except that the date for submitting the CEMS application in Table VII shall be six months after the conclusion of the first twelve-month period for which the engines exceed the criterion.

(f) Monitoring, Testing, Recordkeeping and Reporting

(1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

(A) Continuous Emission Monitoring

(i) For engines of 1000 bhp and greater and operating more than two million bhp-hr per calendar year, a NO_x and CO continuous emission monitoring system (CEMS) shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule.

(ii) (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.

(II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that operational needs or space limitations require it.

(III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used); engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014; and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.

(V) Operation of engines by the electric utility in the Big Bear Lake area during the failure of a transmission line to the utility may be excluded from an hours-per-year or fuel usage limit that is elected by the operator pursuant to subclause (f)(1)(A)(ii)(III).

(VI) In lieu of complying with subclause (f)(1)(A)(ii)(I), an operator that is a public agency, or is contracted to operate engines solely for a public agency, may comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), except that the operator shall conduct emission checks at least weekly or every 150 operating hours, whichever occurs later. If any such engine is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or District test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of this subparagraph for such engine in accordance with the compliance schedule of Table VII, except that the operator shall submit a CEMS application to the Executive Officer within six months of the third exceedance.

(iii) All CEMS required by this rule shall:

(I) Comply with the applicable requirements of Rule 218, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;

(II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and

(III) Have data gathering and retrieval capability approved by the Executive Officer

(iv) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to EPA as an amendment to the State Implementation Plan (SIP).

If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.

(v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii) of this subparagraph may:

(I) Store data electronically without a strip chart recorder, but there shall be redundant data storage capability for at least 15 days of data. The operator must demonstrate that both sets of data are equivalent.

(II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.

(vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (ii) of this subparagraph, and that are to be monitored by a timeshared CEMS, may:

(I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.

(II) Record the corrected and uncorrected NOx, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.

(III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.

(IV) Conduct a minimum of five tests for each engine during relative accuracy tests.

(V) Perform a cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.

(VI) Exclude monitoring of nitrogen dioxide (NO_2) for rich-burn engines, unless source testing demonstrates that NO_2 is more than 10 percent of total NOx.

(VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.

(VIII) Stop operating and calibrating the CEMs during any period that the operator has a continuous record that the engine was not in operation.

(vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NOx CEMS by that regulation.

(viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(B) Elapsed Time Meter

Maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(C) Source Testing

(i) Effective August 1, 2008, conduct source testing for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two years, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E will satisfy this requirement for those pollutants monitored by a CEMS. The source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated within three months of the date a source test is required, the source test shall be conducted when the engine resumes operation for a period longer than either seven consecutive days or 15 cumulative days of operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ± 10%. No pre-tests for compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed.

(iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.

(iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a District-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the operator shall be allowed the additional time needed to conduct the test.

(v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.

(vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.

(vii) By February 1, 2009, provide, or cause to be provided, source testing facilities as follows:

(I) Sampling ports adequate for the applicable test methods. This includes constructing the air pollution control system and stack or duct such that pollutant concentrations can be accurately determined by applicable test methods;

(II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;

(III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.

(D) Inspection and Monitoring (I&M) Plan

Submit to the Executive Officer for written approval and implement an I&M plan. One plan application is required for each facility. The I&M plan shall include:

(i) Identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This shall include, but not be limited to:

(I) Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii);

(II) Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by clause (f)(1)(D)(iv);

(III) Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen sensor replacement;

(IV) For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;

(V) For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.

Parameter monitoring is not required for diesel engines without exhaust gas recirculation and catalytic exhaust control devices.

(ii) Procedures for alerting the operator to emission control malfunctions. Engine control systems, such as air-to-fuel ratio controllers, shall have a malfunction indicator light and audible alarm.

(iii) Procedures for at least weekly or every 150 engine operating hours, whichever occurs later, emissions checks by a portable NOx, CO and oxygen analyzer.

(I) If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points, returning to a more frequent emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).

(II) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, a CO emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

(III) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, emission checks are not required.

(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the emission check, unless it is an unscheduled, required repair.

(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.

(iv) Procedures for at least daily monitoring, inspection and recordkeeping of:

(I) engine load or fuel flow rate;

(II) the set points, maximums and acceptable ranges of the parameters identified by clause (f)(1)(D)(i), and the actual values of the same parameters;

(III) the engine elapsed time meter operating hours;

(IV) the operating hours since the last emission check required by clause (f)(1)(D)(iii);

(V) for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);

(VI) engine control system and AFRC system faults or alarms that affect emissions.

The daily monitoring and recordkeeping may be done in person by the operator, or by remote monitoring.

(v) Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range.

(I) For a breakdown resulting in a violation of this rule or a permit condition, or for an emission check that finds emissions in excess of those allowed by this rule or a permit condition, the operator shall correct the problem and demonstrate compliance with another emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonably should have known, whichever is sooner.

(II) For other problems, such as parameters out-of-range, an operator shall correct the problem and demonstrate compliance with another emission check within 48 hours of the operator first knowing of the problem.

(III) An operator shall not be considered in violation of the emission limits of this rule or in permit conditions if the operator complies with this subparagraph and the reporting requirements of subparagraph (f)(1)(H). Any emission check conducted by District staff that finds excess emissions is a violation.

(vi) Procedures and schedules for preventive and corrective maintenance.

(vii) Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H).

(viii) Procedures and format for the recordkeeping of monitoring and other actions required by the plan.

(ix) Procedures for plan revisions. Before any change in I&M plan operations can be implemented, the revised I&M plan shall be submitted to and approved by the Executive Officer. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.

(x) An engine is not subject to this subparagraph if it is required by this rule to have a NOx and CO CEMS, or voluntarily has a NOx and CO CEMS that complies with this rule.

(E) Operating Log

Maintain a monthly engine operating log that includes:

(i) Total hours of operation;

(ii) Type of liquid and/or type of gaseous fuel;

(iii) Fuel consumption (cubic feet of gas and gallons of liquid); and

(iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(K) shall also meet the following requirements.

(i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.

(ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O2, lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NOx shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR 60, Appendix A, Method 19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NOx, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727 x 10^{-7}.

(iii) For NOx and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NOx, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or emission check. Mass emissions of NOx and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415 x 10^{-7}.

(iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.

(v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.

(vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(K)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

(i) The operator shall report to the Executive Officer, by telephone (1-800-CUT-SMOG or 1-800-288-7664) or other District-approved method, any breakdown resulting in emissions in excess of rule or permit emission limits within one hour of such noncompliance or within one hour of the time the operator knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the noncompliance, and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the one-hour limit, the Executive Officer may extend the time for the reporting of required information provided the operator has notified the Executive Officer of the noncompliance within the one-hour limit.

(ii) Within seven calendar days after the reported breakdown has been corrected, but no later than thirty calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, the operator shall submit a written breakdown report to the Executive Officer which includes:

(I) An identification of the equipment involved in causing, or suspected of having caused, or having been affected by the breakdown;

(II) The duration of the breakdown;

(III) The date of correction and information demonstrating that compliance is achieved;

(IV) An identification of the types of excess emissions, if any, resulting from the breakdown;

(V) A quantification of the excess emissions, if any, resulting from the breakdown and the basis used to quantify the emissions;

(VI) Information substantiating whether the breakdown resulted from operator error, neglect or improper operation or maintenance procedures;

(VII) Information substantiating that steps were immediately taken to correct the condition causing the breakdown, and to minimize the emissions, if any, resulting from the breakdown;

(VIII) A description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and

(IX) Pictures of any equipment which failed, if available.

(iii) Within 15 days of the end of each calendar quarter, the operator shall submit to the Executive Officer a report that lists each occurrence of a breakdown, fault, malfunction, alarm, engine or control system operating parameter out of the acceptable range established by an I&M plan or permit condition, or an emission check that finds excess emissions. Such report shall be in a District-approved format, and for each incident shall identify the time of the incident, the time the operator learned of the incident, specific location, equipment involved, responsible party to contact for further information, to the extent known the causes of the event, the time and description of corrective actions, including shutting an engine down, and the results of all portable analyzer NOx and CO emissions checks done before or after the corrective actions. The operator shall also report if no incidents occurred.

(2) Portable engines:

The operator of any portable engine shall maintain a monthly engine operating log that includes:

(i) Total hours of operation; or

(ii) Type of liquid and/or type of gaseous fuel; and

(iii) Fuel consumption (cubic feet of gas and gallons of liquid).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(3) Recordkeeping for All Engines

All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.

(g) Test Methods

Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table VIII, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE VIII

TESTING METHODS

Pollutant	Method
NO_x	District Method 100.1
CO	District Method 100.1

TABLE VIII
TESTING METHODS

Pollutant	Method
VOC	District Method 25.1* or District Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

(h) Alternate Compliance Option

(1) In lieu of complying with the applicable emission limits by the effective date specified in Table III-B, owners or operators of biogas-fired units that operate under long term fixed price power purchase agreements that have been entered into prior to February 1, 2008 and extend beyond January 1, 2016 may elect to defer compliance by up to two years and no later than January 1, 2018, provided the owner or operator:

(A) Submits an alternate compliance plan and pays a Compliance Flexibility Fee, as provided for in paragraph (h)(2), to the Executive Officer at least 150 days prior to the applicable compliance date in Table III-B, and

(B) Maintains on-site a copy of verification of Compliance Flexibility Fee payment and AQMD approval of the alternate compliance plan that shall be made available upon request to AQMD staff.

(2) Plan Submittal

The alternate compliance plan submitted pursuant to paragraph (h)(1) shall include:

(A) A completed AQMD Form 400A with company name, AQMD Facility ID, identification that application is for a compliance plan (Section 7a of form), and identification that request is for Rule 1110.2 Compliance Flexibility Fee option (Section 9 of form);

(B) Attached documentation of unit permit ID, unit rated brake horsepower (bhp), and fee calculation;

(C) Proof that the power purchase agreement was entered into prior to February 1, 2008 and extends beyond January 1, 2016.

(D) Filing Fee payment; and

(E) Compliance Flexibility Fee payment as calculated by the following equation:

$$CFF = bhp \times R \times Y$$

Where,

CFF = Compliance Flexibility Fee, $

bhp = rated brake horsepower of unit

R = Fee Rate = $47 per brake horsepower per year

Y = Number of years (up to 2 years for engines required to comply by January 1, 2016)

(3) Usage of Compliance Flexibility Fee funds

The funds collected from the Compliance Flexibility Fee will be applied to AQMD NOx reduction programs pursuant to protocols approved under District rules.

(i) Exemptions

The provisions of subdivision (d) shall not apply to:

(1) All orchard wind machines powered by an internal combustion engine.

(2) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit operation to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a District permit and operate 200 hours or less per year as determined by an elapsed operating time meter.

(3) Laboratory engines used in research and testing purposes.

(4) Engines operated for purposes of performance verification and testing of engines.

(5) Auxiliary engines used to power other engines or gas turbines during start-ups.

(6) Portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.

(7) Nonroad engines, with the exception that subparagraph (d)(2)(A) shall apply to portable generators.

(8) Engines operating on San Clemente Island; and engines operated by the County of Riverside for the purpose of public safety communication at Santa Rosa Peak in Riverside County, where the site is located at an elevation of higher than 7,400 feet above sea level and is without access to electric power and natural gas.

(9) Agricultural stationary engines provided that:

(A) The operator submits documentation to the Executive Officer by the applicable date in Table V when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and

(B) The operator replaces the engines, in accordance with the compliance schedule of Table IX, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and

(C) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Section 1039.101, Paragraph (e), as determined by the test methods of subdivision (g) of this rule.

TABLE IX
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	**Due Date**
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later

TABLE IX COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES	
Action Required	**Due Date**
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

(10) An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves a longer period not exceeding 2 hours for an engine and makes it a condition of the engine permit.

(11) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head, for a period not to exceed four operating hours.

(12) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.

APPENDIX H

Exhaust Emissions at Stack

Estimated Power Island Emissions

Customer Name

Quoted using data available as of February 20, 2015

(1) Landfill Gas Fuel MERCURY 50-6400R		**Plant Total**
Ambient Temperature	°F	59.0
Gross Power Output	kW	4,807
Fuel Type	Landfill Gas	
Assumed Fuel Sulphur Content	lbm/MMBtu (HHV)	0.045
Gas Turbine Exhaust Flow	lbm/hr	144,700
Stack Exhaust Flow	lbm/hr	144,700
Flue Gas Temperature Leaving Gas Turbine	°F	718.1
Flue Gas Temperature At Stack	°F	718.1
Heat Input to Gas Turbine	MMBtu/hr (LHV)	43.2
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lbm/MMBtu (HHV)	0.03
Turbine Exhaust Gas Analysis		
H_2O	% vol	6.5%
N_2	% vol	73.4%
CO_2	% vol	4.5%
O_2	% vol	14.7%
SO_2	% vol	0.0%
Argon	% vol	0.9%

(1) Landfill Gas Fuel MERCURY 50-6400R		**Plant Total**
Exhaust Emissions At Stack		
NOx	ppm @ 15% O2	15.0
	lbm/MMBtu, HHV	0.0589
	lbm/hr	2.83
	short tons/yr	12.4
CO	ppm @ 15% O2	25.0
	lbm/MMBtu, HHV	0.0598
	lbm/hr	2.87
	short tons/yr	12.6
UHC	ppm @ 15% O2	25.0
	lbm/MMBtu, HHV	0.0342
	lbm/hr	1.64
	short tons/yr	7.18
VOC	ppm @ 15% O2	5.0
	lbm/MMBtu, HHV	0.00683
	lbm/hr	0.328
	short tons/yr	1.44
$PM_{10}/PM_{2.5}$	lbm/hr	1.44
	lbm/MMBtu, HHV	0.03
	short tons/yr	6.31
SO_2	lbm/hr	2.16
	lbm/MMBtu, HHV	0.045
	short tons/yr	9.46
CO_2	lbm/MMBtu (HHV)	207
	lbm/hr	9,930
	short tons/yr	43,500
	metric tonnes/yr	39,500

Emissions Notes:

1. This document is for initial emissions estimates only. For air permit applications, Solar can provide appropriate site-specific turbine emissions documentation.

2. Fuels must comply with Solar specification ES 9-98. Actual emissions may vary due to site fuel characteristics. Zero fuel bound nitrogen is assumed for gaseous fuels, and less than 0.02% for liquid fuels.

3. Turbine "ppm" values are applicable for operation at ambient temperatures greater than 0℉ (-20℃).

4. The table below gives the load ranges to which the turbine ppm emissions listed above apply. Mass based estimates are valid at ambient temperature and operating load noted.

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

5. SO_2 emissions depend upon the fuel's sulfur content. The SO_2 estimate is based upon EPA's AP-42 document (Tables 3.1-2a. and 3.1-2b. April 2000).

6. Annual estimates shown above assume 8760 hours/year operation.

For more information contact: Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

 CEP Ver. 8.0

Estimated Power Island Emissions

City of Glendale, Scholl Canyon Landfill

Estimated using data available as of February 17, 2015

(3) Landfill Gas Fuel TAURUS 60-7901		**Per Unit**	**Plant Total**
Ambient Temperature	°F	60.0	
Gross Power Output (Part Load) Min Load = 80%	kW	4,781	14,343
Fuel Type		Landfill Gas	
Assumed Fuel Sulphur Content	lbm/MMBtu (HHV)	0.045	
Gas Turbine Exhaust Flow	lbm/hr	175,800	527,300
Stack Exhaust Flow	lbm/hr	175,800	527,300
Flue Gas Temperature Leaving Gas Turbine	°F	829	
Flue Gas Temperature At Stack	°F	829	
Heat Input to Gas Turbine	MMBtu/hr (LHV)	52.9	158.8
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lbm/MMBtu (HHV)	0.03	
Turbine Exhaust Gas Analysis			
H2O, assumes 60% relative humidity	% vol	6.6%	
N_2	% vol	73.3%	
CO_2	% vol	4.5%	
O_2	% vol	14.7%	
SO_2	% vol	0.0%	
Argon	% vol	0.9%	
Exhaust Emissions At Stack			
NOx	ppm @ 15% O2	42.0	42.0
	lbm/MMBtu, HHV	0.165	
	lbm/hr	9.68	29.03
	short tons/yr	42.4	127.2
CO	ppm @ 15% O2	150.0	150.0
	lbm/MMBtu, HHV	0.359	
	lbm/hr	21	63.1
	short tons/yr	92.1	276.4
UHC	ppm @ 15% O2	75.0	75.0
	lbm/MMBtu, HHV	0.102	
	lbm/hr	6.01	18.03
	short tons/yr	26.3	79
VOC	ppm @ 15% O2	15.0	15.0
	lbm/MMBtu, HHV	0.0205	
	lbm/hr	1.2	3.61
	short tons/yr	5.27	15.8
$PM_{10}/PM_{2.5}$	lbm/hr	1.76	5.28
	lbm/MMBtu, HHV	0.03	
	short tons/yr	7.71	23.12
SO_2	lbm/hr	2.64	7.92
	lbm/MMBtu, HHV	0.045	
	short tons/yr	11.6	34.7
CO_2	lbm/MMBtu (HHV)	207	
	lbm/hr	12,100	36,400
	short tons/yr	53,100	159,400
	metric tonnes/yr	48,200	144,600

(3) Landfill Gas Fuel TAURUS 60-7901	**Per Unit**	**Plant Total**

Emissions Notes:

1. This document is for initial emissions estimates only. For air permit applications, Solar can provide appropriate site-specific turbine emissions documentation.

2. Fuels must comply with Solar specification ES 9-98. Actual emissions may vary due to site fuel characteristics. Zero fuel bound nitrogen is assumed for gaseous fuels, and less than 0.02% for liquid fuels.

3. Turbine "ppm" values are applicable for operation at ambient temperatures greater than 0°F (-20°C).

4. The table below gives the load ranges to which the turbine ppm emissions listed above apply. Mass based estimates are valid at ambient temperature and operating load noted.

Pollutant	Load Range
NOx	80 to 100%
CO	80 to 100%
UHC	80 to 100%

5. SO_2 emissions depend upon the fuel's sulfur content. The SO_2 estimate is based upon EPA's AP-42 document (Tables 3.1-2a. and 3.1-2b. April 2000).
6. Annual estimates shown above assume 8760 hours/year operation.

For more information contact: Kevin Jensen, +1 619 544 5956, kjensen@solarturbines.com

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SCR ammonia consumption estimation, assuming to control ammonia to 15 ppm NOx.
All calculations are estimates. Contact your SCR manufacturer for actual values.

42 ppm to 15 ppm
= 27 ppm NOx removal
27 ppm NOx equates to 18.7 lbm/hr NOx (by scaling 42 ppm and 29 lbm/hr NOx)

The chemical equation for Ammonia to NOx is 1:1 molecularly.
18.7 lbm/hr * (17 molecular weight of Ammonia / 46 molecular weight of NOx)
= 6.91 lbm/hr of Ammonia

Assume 20% increase in consumption from slip.
= 8.293 lbm/hr of Ammonia
= 36.3 short tons/year

Emissions Signatures for Landfill and Digester Gas Fuels

Leslie Witherspoon
Environmental Strategies

PURPOSE

This Product Information Letter summarizes emissions estimates of nitrogen oxides (NO_x), carbon monoxide (CO), and unburned hydrocarbons (UHC) for gas turbines operating on landfill and digester gases. Emissions estimates for other alternative fuels (refinery gas, gasified biomass, coke oven gas, etc.) are outside the scope of this document.

INTRODUCTION

Landfill and digester gases are products of the anerobic decomposition of biodegradable wastes in landfills and wastewater treatment plants. Historically, landfill and digester gases have been vented and/or flared. Over the last 20 years, many landfills and wastewater treatment plants have utilized gas turbines to generate electricity, heat, and/or steam from gas that would otherwise be flared or released to the atmosphere.

The compositions of the landfill and the digester gases are a major factor in determining the emissions signature. The emissions estimates summarized in this document are typical emissions estimates for typical landfill and digester gas compositions. **Site-specific emissions are determined on a case-by-case basis based on fuel composition, site conditions, operating profiles, fuel pre-treatment scenarios, and other factors.**

As a result of the variability of landfill and digester gas compositions from one site to another, it should not be assumed that a published/quoted emissions estimate for one site is representative of another.

FUEL QUALITY AND COMPOSITION

Gaseous fuels are often classified by their Wobbe Index, a parameter that accounts for variation in the fuel gas density and heating value. Wobbe Index is defined as the lower heating value (LHV) of the fuel in Btu/scf divided by the square root of the specific gravity of the fuel with respect to air. The Wobbe Index is an important parameter in designing fuel systems to accommodate fuels with different heating values.

Solar's combustion turbines can burn a wide variety of gaseous (and liquid) fuels. Conventional combustion gas turbines have more fuel flexibility than gas turbines with dry low emissions (DLE) combustion systems. Generally, DLE combustion systems are not compatible with landfill and digester gases, however, the Ultra Lean Premix (ULP) combustion system on the *Mercury* 50 gas turbine has been modified to support landfill and digester gas combustion.

Typical landfill gas contains 35-51% methane (CH_4) with the balance made of up primarily carbon dioxide (CO_2) and nitrogen (N_2). Digester gas contains 60-65% methane with carbon dioxide and nitrogen making up the balance.

EMISSIONS ESTIMATES

The emission estimates, shown in Tables 1 and 2, can be used as preliminary estimates for project planning provided the Wobbe Index of the landfill fuel falls between 300 and 460

Btu/scf LHV, or the digester fuel falls between 560 and 665 Btu/scf LHV, and the balance of the fuel composition is carbon dioxide or nitrogen. The presence of hydrogen (H_2) or hydrocarbons heavier than methane nullifies the applicability of this document.

The emissions estimates reflect typical emissions levels and are valid at steady-state conditions, at ambient temperatures of 0°F (–18°C) and above, and are limited to the load ranges shown in Tables 1 and 2. The estimated emissions levels do not apply during start-up, shut-down, malfunction, or transient events.

Table 1. Landfill Gas Emissions Estimates @ 15% O_2 (Assumes Wobbe Index Range 300 to 460 Btu/scf LHV)

Turbine Model	ISO NO_x*		CO		UHC		Load Range (%)	Ambient Temp °F (°C)
	ppm	mg/Nm^3	ppm	mg/Nm^3	ppm	mg/Nm^3		
Centaur® 40	42	88	250	318	100	72	80-100	>0 (–18)
Centaur 50	42	88	200	254	100	72	80-100	>0 (–18)
Mercury™ 50	15	25	25	30	25	18	50-100	>0 (–18)
Taurus™ 60	42	88	150	191	75	54	80-100	>0 (–18)
Taurus 70	80	166	100	127	50	36	80-100	>0 (–18)
Mars® 100	72	150	100	127	50	36	80-100	>0 (–18)
Titan™ 130	80	166	100	127	50	36	80-100	>0 (–18)

* ISO NOx correction and relative humidity ≥30% applies for all models except the *Mercury* 50.

Table 2. Digester Gas Emissions Estimates @ 15% O_2 (Assumes Wobbe Index Range 550 to 665 Btu/scf LHV)

Turbine Model	ISO NO_x* Uncontrolled (Water Injected)**		CO Uncontrolled (Water Injected)**		UHC Uncontrolled (Water Injected)**		Load Range %	Ambient Temperature °F (°C)
	ppm	mg/Nm^3	ppm	mg/Nm^3	ppm	mg/Nm^3		
Centaur 40	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Centaur 50	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Mercury 50	25	50	50	64	25	18	50-100	>0 (–18)
Taurus 60	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Taurus 70	150 (72)	312 (150)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Mars 100	150 (60)	312 (125)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Titan 130	150 (72)	312 (150)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)

* ISO NOx correction and relative humidity ≥ 30% applies for all models except the *Mercury* 50.

** Water/Fuel ratio is assumed to be 0.8 to 0.85.

Volatile Organic Compound (VOC) emissions can be assumed to be 20% of the UHC values shown in Tables 1 and 2. Note: The 20 ppm VOC (as hexane) @3% O_2 requirement found in 40 CFR 60, Subpart WWW, is approximately equal to 40 ppm VOC (as methane) @15% O_2. Thus, the VOC estimates for *Solar*® turbines comply with the VOC limit in Subpart WWW.

Particulate matter (PM, PM_{10}, $PM_{2.5}$) for landfill and digester gas fuel can be estimated using 0.03 lb/MMBtu (HHV). Reference PIL 171.

Because sulfur content varies site-to-site, Solar recommends that **sulfur dioxide** emissions be estimated using a mass balance approach. Reference PIL 168.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

[redacted]

Customer: Venture - Scholl Canyon Landfill
Attention:
Job Ref:

Engine Mfg: Caterpillar **Model No:** CG260-16
BHP (KW): 3370 EKW **Cycle:** 4 **RPM:** 900
Fuel Type : Clean Landfill Gas **Load:** 100% **Hours/Year:** 8,300

SCR Model **Nbr Units:** 1 **SCR Controls:** **Closed Loop**

Item Description	English	Units		
Engine Output	4,643	BHP		
Exhaust Gas Mass Flow	39,659	Lbs/Hour		
Exhaust Gas Temperature	847.4	°F		
Exhaust Flow - Standard Units	514,608	SCFH		
Pre-Catalyst NOx Emissions	1.15	G/BHP-Hr		
Pre-Catalyst NOx Emissions	11.77	Lbs/Hr/Eng		
Pre-Catalyst NOx Emissions	86	PPMV@15% O2		
Post-Catalyst NOx Emissions	0.200	G/BHP-Hr		
Post-Catalyst NOx Emissions	2.047	Lbs/Hr/Eng		
Post-Catalyst NOx Emissions	15	PPMV@15% O2		
Percentage NOx Reduction	82.6	%		
Pre-Catalyst CO Emissions	2.50	G/BHP-Hr		
Pre-Catalyst CO Emissions	25.59	Lbs/Hr/Eng		
Pre-Catalyst CO Emissions	300	PPMV@15% O2		
Post-Catalyst CO Emissions	1.070	G/BHP-Hr		
Post-Catalyst CO Emissions	10.952	Lbs/Hr/Eng		
Post-Catalyst CO Emissions	128	PPMV@15% O2		
Percentage CO Reduction	57.2	%		
Pre-Catalyst NMEHC Emissions	0.45	G/BHP-Hr		
Pre-Catalyst NMEHC Emissions	4.61	Lbs/Hr/Eng		
Pre-Catalyst NMEHC Emissions	97	PPMV@15% O2		
Post-Catalyst NMEHC Emissions	0.095	G/BHP-Hr		
Post-Catalyst NMEHC Emissions	0.972	Lbs/Hr/Eng		
Post-Catalyst NMEHC Emissions	20	PPMV@15% O2		
Percentage NMEHC Reduction	78.9	%		
Pre-Catalyst HCHO Emissions	0.45	G/BHP-Hr		
Pre-Catalyst HCHO Emissions	4.61	Lbs/Hr/Eng		
Pre-Catalyst HCHO Emissions	68	PPMV@15% O2		
Post-Catalyst HCHO Emissions	0.1300	G/BHP-Hr		
Post-Catalyst HCHO Emissions	1.3307	Lbs/Hr/Eng		
Post-Catalyst HCHO Emissions	20	PPMV@15% O2		
Percentage HCHO Reduction	71.1	%		
Pressure Drop Across Catalyst/Mixer	6.0	In. WC		
40% Urea / 60% H2O Consumption Rate	2.3	Gallons/Hour		
SCR Catalyst Volume	70.00	Cu.Ft		
SCR Catalyst Configuration	10x10x3x12			
SCR Catalyst Space Velocity	7,352	$SCFH/FT^3$		
Oxidation Catalyst Volume	8.00	Cu.Ft		
Oxidation Catalyst Configuration	10x10x1x4			
Oxidation Catalyst Space Velocity	64,326	$SCFH/FT^3$		

APPENDIX I

Emission Control Equipment Budgetary Quotes

Solar Turbines Incorporated
Budgetary Estimate for Customer Name

Inquiry # TBD prepared on February 20, 2015

For more information contact:
Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

(Prices shown below quoted in US Dollars $, using a conversion of US dollar prices times 1)

Quotation is for information only and does not constitute Solar's agreement to offer a firm proposal in the future.

Gas Turbine Equipment	
(1) Landfill Gas Fuel, TAURUS 60-7901 Turbine Generator Set…………………………	$3,600,000
Commissioning Parts, Startup, and Site Testing……………………………………	$146,000
Electrical Equipment	
No Additional Electrical Equipment Included	
Mechanical Equipment	
Fuel Gas Compressor ………………………………………………………………	By Others
Emissions Control Equipment:(SCR and CO Catalyst)………………………………	$1,148,000
Continuous Emission Monitoring System, indoor installation………………………	$115,000
Miscellaneous	
Construction Estimate………………………………………………………………	by others
Project Management & Engineering (Loose Ship Equipment Only)………………	$88,000
Shipping……………………………………………………………………………	$100,000
0% Balance of Plant Contingency……………………………………………………	$0
Total for BOP Equipment (installation not included)………………………………	$1,451,000
Grand Total for Turbomachinery and Balance of Plant……………………	**$5,197,000**
Estimation of cost per ISO rating kilowatt for selected equipment………………	$849
ESA Cost per Month (Only Turbomachinery Covered)……………………………	$32,920

*Duties and taxes not included in estimate.

Caterpillar Confidential: Green

CEP Ver. 8.0

TAURUS 60-7901 Generator Set Package Features

Engine:
Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor

Basic Options:
Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and axially oriented exhaust outlet
1800 rpm; 60 Hz
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:
Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:
- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:
Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):
Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:
Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous
Short-term preservation for shipment
Four (4) paper copies of Solar's Instruction, Operation and Maintenance manuals
Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system

Cogeneration Plant Estimated Performance Summary

Customer Name
Solar Turbines Incorporated
February 20, 2015
Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	6,120	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	0	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	7.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	64.1	MMBtu/hr
KW Gross Output @ specified site conditions:	5,937	kW
Gas Compressor Power Consumption:	1680	kW
Turbine Auxiliary Power Consumption:	10	kW
Total Auxiliary Power Consumption:	1690	kW
Net Turbine Power Production:	4,247	kW
Black Start kW Requirement (Turbine Generator Set Only)	304	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Electrical Heat Rate:	15,080	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	15,080	Btu/kWHR
Overall Cycle Efficiency (LHV):	22.6	%

Caterpillar Confidential: Green

CEP Ver. 8.0

DiFonso, Andy

Subject: FW: Budget Pricing - LFGTE Plant - The City of Glendale, CA

From: khertzler@clevelandbrothers.com [mailto:khertzler@clevelandbrothers.com]
Sent: Thursday, February 05, 2015 11:31 AM
To: Kayali, Reem
Cc: Slatosky, Bill; O'Connor, Kevin
Subject: Budget Pricing - LFGTE Plant - The City of Glendale, CA

Kayali,

All Pricing Good for 6 months.

Fuel gas must be cleaned to spec required by emissions controls.

Budget Price for One CG260-16 with all Balance of Plant equipment, emissions controls, cooling systems, pumps, controls, and delivery to site, included: $2,320,000.00 each.
Scada system is included. Allows local and remote monitoring, trending and data recording of every parameter available from the control system.
Commissioning is also included.

Budget Price for Special Enclosures: $770,000.00 each
These enclosures are super sound attenuated, weather protected, walk in packaged units.
They have lighting, overhead cranes pre-mounted control panels etc..
These enclosures have multiple sections. There is an air inlet section with inlet fans, filters, acoustical duct etc.. Air outlet sections with fans and acoustical duct etc..
There is the main engine housing that drops over the engine and the Emissions control and super critical exhaust silencers pre-packaged on the roof of the enclosure.
These enclosures as with the exhaust and mechanical silencing equipment included will meet your noise limits required at the property lines of the landfill in Glendale.
Delivery to site and commissioning Included.

Budget Price for 8 unit Switchgear, 15 kV and 480 V plus Generator step up transformers and local station power transformers included. Commissioning and Delivery to site is includes.
GSU Transformers will step the plan generation voltage from 15 kV to 27 kV or 35 kV as required by site. This is all accomplished with metal clad switchgear included in the price.
If if the Utility Voltage is higher than 35 kV then a substation will be required and that could easily add another 300 to 500 K to the price.
Switchgear is provided with a walk-in, air conditioned aisle way/enclosure.
Switchgear housing will also included 480 V gear to distribute power to the gensets, gas compression and clean up systems, as well as offices, flares, site lighting etc..
Transformers are sized to provide all site power needs.
GSU transformers are sized to provide to full output of the generation plant.

Price..........................$2,500,000.00 for an 8 Genset Plant.

<u>Regarding the G3520C gensets:</u>

Budget Price for One G3520C genset with all Balance of Plant equipment, emissions controls, cooling systems, pumps, controls, and delivery to site, included: <u>$1,300,000.00</u> each.
Scada system is included. Allows local and remote monitoring, trending and data recording of every parameter available from the control system.
Commissioning is also included.

Budget Price for Special Enclosures: <u>$550,000.00</u> each
These enclosures are super sound attenuated, weather protected, walk in packaged units. They have lighting, overhead cranes pre-mounted control panels etc..
These enclosures have multiple sections. There is an air inlet section with inlet fans, filters, acoustical duct etc.. Air outlet sections with fans and acoustical duct etc..
There is the main engine housing that drops over the engine and the Emissions control and super critical exhaust silencers pre-packaged on the roof of the enclosure.
These enclosures as with the exhaust and mechanical silencing equipment included will meet your noise limits required at the property lines of the landfill in Glendale.
Delivery to site and commissioning Included.
With this enclosure a base is included. Therefore the genset will be shipped pre-packaged and in the enclosure.

Budget Price for 12 unit Switchgear, 15 kV and 480 V plus Generator step up transformers and local station power transformers included. Commissioning and Delivery to site is includes.
GSU Transformers will step the plan generation voltage from 15 kV to 27 kV or 35 kV as required by site. This is all accomplished with metal clad switchgear included in the price.
If if the Utility Voltage is higher than 35 kV then a substation will be required and that could easily add another 300 to 500 K to the price.
Switchgear is provided with a walk-in, air conditioned aisle way/enclosure.
Switchgear housing will also included 480 V gear to distribute power to the gensets, gas compression and clean up systems, as well as offices, flares, site lighting etc..
Transformers are sized to provide all site power needs.
GSU transformers are sized to provide to full output of the generation plant.

Price..........................<u>$2,800,000.00</u>for a 12 Genset Plant.

Please email or call with any questions or concerns.

Kurt Hertzler
Cleveland Brothers Equip. Co., Inc.
336 N. Fairville Ave.
Harrisburg PA 17112
Direct Dial: 717-635-7267
E-FAX No: 717-441-3757
Cell Phone: 717-514-7360
Email: khertzler@clevelandbrothers.com

Solar Turbines Incorporated

Budgetary Estimate for Customer Name

Inquiry # TBD prepared on February 20, 2015

For more information contact:

Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

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Project Management & Engineering (Loose Ship Equipment Only)………………	$88,000
Shipping………………………………………………………………………………	$100,000
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Total for BOP Equipment (installation not included)………………………………	$1,451,000
Grand Total for Turbomachinery and Balance of Plant…………………….	**$5,197,000**
Estimation of cost per ISO rating kilowatt for selected equipment………………	$849
ESA Cost per Month (Only Turbomachinery Covered)…………………………..…	$32,920

*Duties and taxes not included in estimate.

Caterpillar Confidential: Green

CEP Ver. 8.0

TAURUS 60-7901 Generator Set Package Features

Engine:

Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor

Basic Options:

Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and axially oriented exhaust outlet
1800 rpm; 60 Hz
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:

Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:
- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:

Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):

Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:

Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous

Short-term preservation for shipment
Four (4) paper copies of Solar's Instruction, Operation and Maintenance manuals
Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system

Cogeneration Plant Estimated Performance Summary

Customer Name
Solar Turbines Incorporated
February 20, 2015
Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	6,120	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	0	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	7.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	64.1	MMBtu/hr
KW Gross Output @ specified site conditions:	5,937	kW
Gas Compressor Power Consumption:	1680	kW
Turbine Auxiliary Power Consumption:	10	kW
Total Auxiliary Power Consumption:	1690	kW
Net Turbine Power Production:	4,247	kW
Black Start kW Requirement (Turbine Generator Set Only)	304	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Electrical Heat Rate:	15,080	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	15,080	Btu/kWHR
Overall Cycle Efficiency (LHV):	22.6	%

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APPENDIX J

Equipment-Budgetary Quotes

Solar Turbines Incorporated

Budgetary Estimate for Customer Name

Inquiry # TBD prepared on February 20, 2015

For more information contact:

Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

(Prices shown below quoted in US Dollars $, using a conversion of US dollar prices times 1)

Quotation is for information only and does not constitute Solar's agreement to offer a firm proposal in the future.

Gas Turbine Equipment	
(1) Landfill Gas Fuel, MERCURY 50-6400R Turbine Generator Set…………….…………….	$4,655,000
Commissioning Parts, Startup, and Site Testing……………………………………	$158,000
Electrical Equipment	
No Additional Electrical Equipment Included	
Mechanical Equipment	
Fuel Gas Compressor ………………………………………….………………..	By Others
No Mechanical Equipment Selected	
Miscellaneous	
Construction Estimate…………………………………………………………..….	by others
Project Management & Engineering (Loose Ship Equipment Only)…………….	$0
Shipping……………………………………………………………………………….	$96,000
0% Balance of Plant Contingency…………………………………………………….	$0
Total for BOP Equipment (installation not included)………………………………	$96,000
Grand Total for Turbomachinery and Balance of Plant……………………..	**$4,910,000**
Estimation of cost per ISO rating kilowatt for selected equipment………………	$999
ESA Cost per Month (Only Turbomachinery Covered)…………………………..…	$58,310

*Duties and taxes not included in estimate.

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MERCURY 50-6400R Generator Set Package Features

Engine:

Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor

Basic Options:

Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and upward oriented exhaust outlet
1800 rpm; 60 Hz
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:

Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:
- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:

Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):

Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:

Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous

Short-term preservation for shipment
Four (4) paper copies of Solar's Instruction, Operation and Maintenance manuals
Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system

Cogeneration Plant Estimated Performance Summary

Customer Name
Solar Turbines Incorporated
February 20, 2015
Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	4,910	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	0	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	1.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	43.2	MMBtu/hr
KW Gross Output @ specified site conditions:	4,807	kW
Gas Compressor Power Consumption:	852	kW
Turbine Auxiliary Power Consumption:	40	kW
Total Auxiliary Power Consumption:	892	kW
Net Turbine Power Production:	3,915	kW
Black Start kW Requirement (Turbine Generator Set Only)	206	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Electrical Heat Rate:	11,040	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	11,040	Btu/kWHR
Overall Cycle Efficiency (LHV):	30.9	%

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Estimated Power Island Emissions

Customer Name

Quoted using data available as of February 20, 2015

(1) Landfill Gas Fuel MERCURY 50-6400R		**Plant Total**
Ambient Temperature	°F	59.0
Gross Power Output	kW	4,807
Fuel Type	Landfill Gas	
Assumed Fuel Sulphur Content	lbm/MMBtu (HHV)	0.045
Gas Turbine Exhaust Flow	lbm/hr	144,700
Stack Exhaust Flow	lbm/hr	144,700
Flue Gas Temperature Leaving Gas Turbine	°F	718.1
Flue Gas Temperature At Stack	°F	718.1
Heat Input to Gas Turbine	MMBtu/hr (LHV)	43.2
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lbm/MMBtu (HHV)	0.03
Turbine Exhaust Gas Analysis		
H_2O	% vol	6.5%
N_2	% vol	73.4%
CO_2	% vol	4.5%
O_2	% vol	14.7%
SO_2	% vol	0.0%
Argon	% vol	0.9%

(1) Landfill Gas Fuel MERCURY 50-6400R		**Plant Total**
Exhaust Emissions At Stack		
NOx	ppm @ 15% O2	15.0
	lbm/MMBtu, HHV	0.0589
	lbm/hr	2.83
	short tons/yr	12.4
CO	ppm @ 15% O2	25.0
	lbm/MMBtu, HHV	0.0598
	lbm/hr	2.87
	short tons/yr	12.6
UHC	ppm @ 15% O2	25.0
	lbm/MMBtu, HHV	0.0342
	lbm/hr	1.64
	short tons/yr	7.18
VOC	ppm @ 15% O2	5.0
	lbm/MMBtu, HHV	0.00683
	lbm/hr	0.328
	short tons/yr	1.44
$PM_{10}/PM_{2.5}$	lbm/hr	1.44
	lbm/MMBtu, HHV	0.03
	short tons/yr	6.31
SO_2	lbm/hr	2.16
	lbm/MMBtu, HHV	0.045
	short tons/yr	9.46
CO_2	lbm/MMBtu (HHV)	207
	lbm/hr	9,930
	short tons/yr	43,500
	metric tonnes/yr	39,500

(1) Landfill Gas Fuel MERCURY 50-6400R	**Plant Total**

Emissions Notes:

1. This document is for initial emissions estimates only. For air permit applications, Solar can provide appropriate site-specific turbine emissions documentation.

2. Fuels must comply with Solar specification ES 9-98. Actual emissions may vary due to site fuel characteristics. Zero fuel bound nitrogen is assumed for gaseous fuels, and less than 0.02% for liquid fuels.

3. Turbine "ppm" values are applicable for operation at ambient temperatures greater than 0℉ (-20℃).

4. The table below gives the load ranges to which the turbine ppm emissions listed above apply. Mass based estimates are valid at ambient temperature and operating load noted.

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

5. SO_2 emissions depend upon the fuel's sulfur content. The SO_2 estimate is based upon EPA's AP-42 document (Tables 3.1-2a. and 3.1-2b. April 2000).

6. Annual estimates shown above assume 8760 hours/year operation.

For more information contact: Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

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Solar Turbines Incorporated

Budgetary Estimate for Customer Name

Inquiry # TBD prepared on February 20, 2015

For more information contact:

Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

(Prices shown below quoted in US Dollars $, using a conversion of US dollar prices times 1)

Quotation is for information only and does not constitute Solar's agreement to offer a firm proposal in the future.

Gas Turbine Equipment	
(1) Landfill Gas Fuel, TAURUS 60-7901 Turbine Generator Set...................................	$3,600,000
Commissioning Parts, Startup, and Site Testing..	$146,000
Electrical Equipment	
No Additional Electrical Equipment Included	
Mechanical Equipment	
Fuel Gas Compressor	By Others
Emissions Control Equipment:(SCR and CO Catalyst)..	$1,148,000
Continuous Emission Monitoring System, indoor installation.........................	$115,000
Miscellaneous	
Construction Estimate..	by others
Project Management & Engineering (Loose Ship Equipment Only)................	$88,000
Shipping..	$100,000
0% Balance of Plant Contingency..	$0
Total for BOP Equipment (installation not included)....................................	$1,451,000
Grand Total for Turbomachinery and Balance of Plant........................	**$5,197,000**
Estimation of cost per ISO rating kilowatt for selected equipment..................	$849
ESA Cost per Month (Only Turbomachinery Covered).................................	$32,920

*Duties and taxes not included in estimate. Caterpillar Confidential: Green CEP Ver. 8.0

TAURUS 60-7901 Generator Set Package Features

Engine:
Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor

Basic Options:
Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and axially oriented exhaust outlet
1800 rpm; 60 Hz
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:
Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:
- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:
Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):
Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:
Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous
Short-term preservation for shipment
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Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system

Cogeneration Plant Estimated Performance Summary

Customer Name
Solar Turbines Incorporated
February 20, 2015

Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	6,120	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	0	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	7.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	64.1	MMBtu/hr
KW Gross Output @ specified site conditions:	5,937	kW
Gas Compressor Power Consumption:	1680	kW
Turbine Auxiliary Power Consumption:	10	kW
Total Auxiliary Power Consumption:	1690	kW
Net Turbine Power Production:	4,247	kW
Black Start kW Requirement (Turbine Generator Set Only)	304	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Electrical Heat Rate:	15,080	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	15,080	Btu/kWHR
Overall Cycle Efficiency (LHV):	22.6	%

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DiFonso, Andy

Subject: FW: Budget Pricing - LFGTE Plant - The City of Glendale, CA

From: khertzler@clevelandbrothers.com [mailto:khertzler@clevelandbrothers.com]
Sent: Thursday, February 05, 2015 11:31 AM
To: Kayali, Reem
Cc: Slatosky, Bill; O'Connor, Kevin
Subject: Budget Pricing - LFGTE Plant - The City of Glendale, CA

Kayali,

All Pricing Good for 6 months.

Fuel gas must be cleaned to spec required by emissions controls.

Budget Price for One CG260-16 with all Balance of Plant equipment, emissions controls, cooling systems, pumps, controls, and delivery to site, included: $2,320,000.00 each.
Scada system is included. Allows local and remote monitoring, trending and data recording of every parameter available from the control system.
Commissioning is also included.

Budget Price for Special Enclosures: $770,000.00 each
These enclosures are super sound attenuated, weather protected, walk in packaged units.
They have lighting, overhead cranes pre-mounted control panels etc..
These enclosures have multiple sections. There is an air inlet section with inlet fans, filters, acoustical duct etc.. Air outlet sections with fans and acoustical duct etc..
There is the main engine housing that drops over the engine and the Emissions control and super critical exhaust silencers pre-packaged on the roof of the enclosure.
These enclosures as with the exhaust and mechanical silencing equipment included will meet your noise limits required at the property lines of the landfill in Glendale.
Delivery to site and commissioning Included.

Budget Price for 8 unit Switchgear, 15 kV and 480 V plus Generator step up transformers and local station power transformers included. Commissioning and Delivery to site is includes.
GSU Transformers will step the plan generation voltage from 15 kV to 27 kV or 35 kV as required by site. This is all accomplished with metal clad switchgear included in the price.
If if the Utility Voltage is higher than 35 kV then a substation will be required and that could easily add another 300 to 500 K to the price.
Switchgear is provided with a walk-in, air conditioned aisle way/enclosure.
Switchgear housing will also included 480 V gear to distribute power to the gensets, gas compression and clean up systems, as well as offices, flares, site lighting etc..
Transformers are sized to provide all site power needs.
GSU transformers are sized to provide to full output of the generation plant.

Price..........................$2,500,000.00 for an 8 Genset Plant.

<u>Regarding the G3520C gensets:</u>

Budget Price for One G3520C genset with all Balance of Plant equipment, emissions controls, cooling systems, pumps, controls, and delivery to site, included: <u>$1,300,000.00</u> each.
Scada system is included. Allows local and remote monitoring, trending and data recording of every parameter available from the control system.
Commissioning is also included.

Budget Price for Special Enclosures: <u>$550,000.00</u> each
These enclosures are super sound attenuated, weather protected, walk in packaged units. They have lighting, overhead cranes pre-mounted control panels etc..
These enclosures have multiple sections. There is an air inlet section with inlet fans, filters, acoustical duct etc.. Air outlet sections with fans and acoustical duct etc..
There is the main engine housing that drops over the engine and the Emissions control and super critical exhaust silencers pre-packaged on the roof of the enclosure.
These enclosures as with the exhaust and mechanical silencing equipment included will meet your noise limits required at the property lines of the landfill in Glendale.
Delivery to site and commissioning Included.
With this enclosure a base is included. Therefore the genset will be shipped pre-packaged and in the enclosure.

Budget Price for 12 unit Switchgear, 15 kV and 480 V plus Generator step up transformers and local station power transformers included. Commissioning and Delivery to site is includes.
GSU Transformers will step the plan generation voltage from 15 kV to 27 kV or 35 kV as required by site. This is all accomplished with metal clad switchgear included in the price.
If if the Utility Voltage is higher than 35 kV then a substation will be required and that could easily add another 300 to 500 K to the price.
Switchgear is provided with a walk-in, air conditioned aisle way/enclosure.
Switchgear housing will also included 480 V gear to distribute power to the gensets, gas compression and clean up systems, as well as offices, flares, site lighting etc..
Transformers are sized to provide all site power needs.
GSU transformers are sized to provide to full output of the generation plant.

Price...........................<u>$2,800,000.00</u>for a 12 Genset Plant.

Please email or call with any questions or concerns.

Kurt Hertzler
Cleveland Brothers Equip. Co., Inc.
336 N. Fairville Ave.
Harrisburg PA 17112
Direct Dial: 717-635-7267
E-FAX No: 717-441-3757
Cell Phone: 717-514-7360
Email: khertzler@clevelandbrothers.com

Fast • Convenient • Real-Time Pricing • Pick-Up or Delivery • Order Your Parts Online with Ease at
www.ClevelandBrothers.com/PartStore

Vilter

EMERSON
Climate Technologies

QUOTE

Created by Shawn Goggins
Phone 360-805-0590
Fax
Email shawn.goggins@emerson.com
Cell 414-403-3752

Sales Rep.
5555 S Packard Ave
Cudahy, WI 53110

Quote # SHGGQ2622
Date 03/16/15
Doc Name GC-Glendale Updated Feb 2015

Quote To: Venture Engineering   Reem Kayali

Thank for your request to quote the following detailed Vilter equipment. If you have any questions or concerns, please feel free to contact me at any time.

Qty	Description	Ext. Price
1	Vilter Model VSG-1851-VVR-G-HP-EMD-48H-NEC-REM-AIR - Heavy Shaft Included Single Screw Gas Compressor Unit(s) designed for use with remote oil cooling and pre-piped in accordance with ASME B31.3 piping code with threaded joints minimized per Vilter's latest standards. Standard unit features include: < Single Screw Compressor with Parallex capacity and variable volume slide valves < Unit mounted electric motor driven C-flange design lube oil pump, strainer and isolating valve < Mounted Suction inlet Tee with Strainer and Wafer Check Valve - Carbon Steel Body with SS Internals < Suction Block Valve - Carbon Steel Body with SS Internals (Shipped Loose) < Discharge block and check valve - Carbon Steel Body with SS Internals (Shipped Loose) < Full Flow Discharge Gas Relief Valve - (Shipped Loose) < Multiple stage horizontal ASME Code gas/oil separator - Carbon Steel < Motor Operated 2-way Oil Temperature Control Valve - Class I, Div 1, Group D Rated - Carbon Steel Body with SS Internals < Unit Oil Line Relief Valve - Carbon Steel < Large Capacity ASME Code lube Oil Filter - Carbon Steel. < Transducers for Suction, Discharge, Filter Inlet and Oil Pressure each with block and Bleed Valves (Carbon Steel) < RTD's Mounted in Wells for Suction, Discharge and Oil Temperatures < Unit mounted NEMA 4 steel control enclosure with the following: - Allen Bradley CompactLogix 1769-L33ER with 2 MB Memory - Panel View Plus 1500 HMI/graphic Anti-Glare Display with Sun Shade - ANSI 12.12.01 UL Listed and Labeled for Class I, Div 2, Group C & D - Designed for indoor/outdoor service (30 Deg. F to 130 Deg. F) < Unit wiring run inside 3/4" minimum Rigid Metal Conduit or Approved Cables. < Unit primed and painted per Vilter Standard T00480 indoor/outdoor normal degree of protection against corrosion	
1	High Torque Severe Duty 4340 Material Larger Diameter Straight Shaft Option for Vilter Single Screw Compressor	
1	Thermal Blanket Insulation for Oil separator.	
1	Dual Oil Filters with isolation, vent and drain valves for each filter.	
7	Gas compression PAO oil (55 gal drum) part# 3143B (CP-4601-100)	
1	Seismic Calculations & Certified Documentation	
1	1500 Hp Motor, 3600 Rpm, 4160v/3/60, WPII, Class 1 Div II w/ Heaters - 1.15 SF, 50 C Ambient temp rating, 100 Ohm Bearing and Stator RTD's	
1	Bypass valve (Electric or Pneumatic) - shipped loose	
	SubTotal	$291,162

Qty	Description	Ext. Price
1	@@@@@@ VSG 1851 Reheat Heat Exchanger (Shipped Loose) @@@@@@	
	(1) 24" x 204" Shell & Tube Heat Exchanger - Rated at 350 PSIG on both Shell and Tube Side. 304ss Steel Constuction - Cool 7,500 SCFM from 225 deg to 164 deg on Tube Side and Reheat 7,500 SCFM from 120 deg to 180 deg on Shell Side. Design and construction to ASME Code, TEMA class "C"	
1	Valving - 304SS Internals & RTDS Shell side Vent and drain Tube side Vent and Drain	
	SubTotal	$96,180
1	##### Remote air cooled Oil cooler, with TEFC motor- shipped loose ####### VSG 1851 Oil Cooler - Coded < Unit will include : (Axial Fan Forced Draft w/ (1) 96" Fan) 40 hp VFD Motor - Wiring by others < Unit will be a 1 Circuit Cooler for 1 Compressor based on 98 Deg Ambient at 467 ft Elevation - CS Construction : < A) 84 gpm of Oil entering at 225 and leaving at 130 deg F. Carbon Steel Construction - 16.3 KW Heater Kit, Gravity Dampers & Bug Screen. Heat Tracing & Insulation of Lines to and from the Compressor by others. RTD, Purge and Drain Valves Mounted - 85 dba at 3 feet	
	SubTotal	$112,000
1	##### Common Remote air cooled After cooler, with TEFC motor(s), shipped loose ####### VSG 1851 After Cooler - Coded < Unit will include : (Axial Fan Forced Draft w/ (1) 96" Fan) 40 hp VFD Motor - Wiring by others < Unit will be a 1 Circuit Cooler for 2 Compressors :Unit Coil will be 304 Stainless Steel & CS Box Header < Unit will be a based on 98 Deg Ambient at 467 ft Elevation : < A) 7,500 SCFM of LFG entering at 225 and leaving at 120 deg F. < RTD, Purge and Drain Valves Mounted	
	SubTotal	$92,400
1	@@@@@@ VSG 1851 Discharge Scrubber - shipped loose on skid @@@@@@ Discharge 304 Final Coalescing Separator. 24" dia. x 96" seam to seam lower section vertical Plate-Pak Vane / Flow Distributor: Style: V-V-38, Material: 304SS , Const.: 3 Piece Construction, ASME Code Vessel rated for 350 psig, 250F, flowing 7500 SCFM +15% landfill gas at 120F, 284 psia, .3 gpm oil (1)Technolab coalescing element in upper section on tube sheet, with the velocity would be less than 7 fpm to guarantee .1 ppm oil carryover Seismic calcs 6" inlet and outlet nozzles (5) 2" level switch couplings (4) 1" level gauge connection couplings (2) 2"drain coupling (1) ½" scavenging line coupling	
1	Seismic	
1	Mounted and Wired on a Skid	
1	Double Chamber Coalescing Scrubber accessories to include the following items : >Two (2) level gauge columns each with isolation valves > Four (4) ultrasonic level switches > ASME certified safety relief valve - SS Body & Trim (Shipped Loose) > Service valves for drainers > Two (2) Pressure Transducers for Pressure Drop Measurement	
	SubTotal	$80,916

Qty	Description	Ext. Price
1	@@@@@@ VSG-1851 Polishing Discharge Scrubbers - shipped loose on skid @@@@@@ Discharge 304 Final Coalescing Separator. 24" dia. x 96" seam to seam lower section vertical Plate-Pak Vane / Flow Distributor: Style: V-V-38, Material: 304SS , Const.: 3 Piece Construction, ASME Code Vessel rated for 350 psig, 250F, flowing 7500 SCFM +15% landfill gas at 120F, 415 psia, .3 gpm oil (1)Technolab coalescing element in upper section on tube sheet, with the velocity would be less than 7 fpm to guarantee .01 ppm oil carryover Seismic calcs 6" inlet and outlet nozzles (5) 2" level switch couplings (4) 1" level gauge connection couplings (2) 2"drain coupling (1) ½" scavenging line coupling	
1	Seismic	
1	Mounted and Wired on a Skid	
1	Double Chamber Coalescing Scrubber accessories to include the following items : >Two (2) level gauge columns each with isolation valves > Four (4) ultrasonic level switches > ASME certified safety relief valve - SS Body & Trim > Two (2) Solenoid Operated Liquid Dump valves > Service valves for drainers > Two (2) Pressure Transducers for Pressure Drop Measurement	
	SubTotal	$81,336
1	Adder to Mount, Wire and Pipe Reheat and Scrubbers on Common Skid with Base Plate and Enviromental Lip	$123,845
	@@@@@@@ START UP, TRAINING @@@@@@@	
1	Start up costs provided are for estimation purposes only and at the time start up services are requested the rate sheet and terms and conditions will take precedence over any estimate	$47,500
2	Start-Up - Basic Spare Parts for units with Allen Bradley control panel which includes the following: 55 gal Oil, RTD, 1 low press and 1 hi press transducer, Panel Fuses, Shaft Seal Kit for Compressor & Oil Pump mechanical seal, Actuator Slide Motor, 2 Oil Filters and Oil Sample Kit, spare set of elements and gasket for each coalescer.	$35,736

The above pricing does not include : Freight, Pre-Start-Up Duties, Spare Parts , Applicable Taxes and Duty Fees. - Unless stated above.

Purchase orders over $100,000 are subject to progress payments.

Unless Otherwise Stated, this quotation, due to constant material cost increases, is valid for 30 days from quotation date.

Pre-Start Up Duties Include, but are not limited to : Oil Charging of Equipment, Motor Cold and Hot Alignment, Verification of Power and Control wiring between and to skids, On site Pressure or Vacuum testing. - These can be performed by one of Vilter's GC Centers . Vilter can provide you with one upon request. (Pre-Start Up Check List will be provided upon Submittals)

The above Estimated Start-Up Costs are for Budgetary Purposes Only. Actual charges will be based on Vilter's "Technical Start Up / Service Rate Schedule". Vilter will provide this document upon request.

Payment Terms:
15% down
30% due after drawing submittal
30% after receipt of major purchased components
20% At shipment - Invoiced 2 weeks before Shipment
5% Upon Receipt of Equipment and Inspection for Shipping Damage.
Payments due upon receipt.

The following is not included in the above quote unless othewise stated:

> Seismic Design & Documentation
> Factory Unit Run-In on Air
> Equipment and Valve Tagging
> ISA Documentation
> 3rd Party Inspections for Electrical & Code Verification adherence
> Piping and Electrical will adhere to B31.3, UL - Other codes will have to reviewed - additional costs, if required, will be added to the customer's account.
> On Site Training

The above that is not included can be quoted upon request.

THE ABOVE PRICING IS IN USD, NET EX-WORKS, SUBJECT TO VILTER STANDARD TERMS AND CONDITIONS.

TERMS AND CONDITIONS OF SALE

Introduction. The seller of goods or services is herein referred to as “Seller” and the customer, person or entity purchasing products (collectively “Products”), or services (collectively “Services”), or products and/or services (collectively referred to as “Goods”) from Seller is herein referred to as “Buyer”. Sale of Goods includes Seller granting to Buyer a license to use any software and/or firmware ("Software") which are preloaded, or to be loaded into such Goods. These Terms and Conditions, any price list or schedule, quotation, acknowledgment or invoice from Seller relevant to the sale of the Goods and all documents incorporated by specific reference herein or therein, constitute the complete and exclusive statement of the terms of the agreement governing the sale of Goods by Seller to Buyer. Buyer's acceptance of the Goods will manifest Buyer's assent to these terms and conditions without variation or addition. Any different or additional terms in Buyer's purchase order or other Buyer documents are hereby objected to. Seller reserves the right in its sole discretion to refuse orders.

1. Prices. Prices for Goods, whether specified in Seller’s price list or schedule, acknowledgement or written quotation, are subject to change without notice and the prices invoiced will be those in effect at the time of shipment.

2. Taxes. Any current or future tax or governmental charge (or increase in same) affecting Seller's costs of production, sale, delivery or shipment, or which Seller is otherwise required to pay or collect in connection with the sale, purchase, delivery, storage, processing, use or consumption of Goods, other than taxes based on Seller's net income or profit, shall be for Buyer's account and if paid by or levied or assessed against Seller, shall either be added to the price of the Goods or billed to Buyer separately, at Seller’s election.

3. Terms of Payment. Unless otherwise specified by Seller, terms are net thirty (30) days from the date of Seller's invoice in U.S. currency. Seller shall have the right, among other remedies, either to terminate this agreement or to suspend further performance under this and/or other agreements with the Buyer, which other agreements Buyer and Seller hereby amend accordingly, in the event Buyer fails to make any payment when due. Buyer shall be liable for all expenses, including attorneys’ fees, relating to the collection of past due amounts. If any amount owed to Seller is not paid when due, it shall bear interest at a rate to be determined by Seller, which shall not exceed the maximum rate permitted by law, from the date on which it is due until it is paid. Should Buyer's financial condition become unsatisfactory to Seller, cash payments or security satisfactory to Seller may be required by Seller for future deliveries and for the Goods theretofore delivered. If such cash payment or security is not provided, in addition to Seller's other rights and remedies, Seller may discontinue deliveries. Buyer hereby grants Seller a security interest in all Goods sold to Buyer by Seller, which security interest shall continue until such Goods are fully paid for in cash, and Buyer, upon Seller's demand, will execute and deliver to Seller such instruments as Seller requests to protect and perfect such security interest.

4. Shipment, Delivery & Title. While Seller will use all reasonable commercial efforts to maintain the delivery date(s) acknowledged or quoted by Seller, all shipping dates are approximate and not guaranteed. Seller reserves the right to make partial shipments. Seller, at its option, shall not be bound to tender delivery of any Goods for which Buyer has not provided shipping instructions and other required information. If the shipment of the Goods is postponed or delayed by Buyer for any reason, Seller reserves the right to ship Goods to a storage facility in Seller’s sole discretion and Buyer agrees to pay for any and all storage costs and other additional expenses resulting therefrom. Risk of loss and legal title to the Goods, with a total value of $100,000 or lower, shall transfer to Buyer for sales in which the end destination of the Goods is outside of the United States immediately after the Goods have passed beyond the territorial limits of the United States. For all other shipments, risk of loss for damage and responsibility shall pass from Seller to Buyer upon delivery to and receipt by carrier at Seller’s shipping point. All shipments are made FCA Seller’s plant of origin. Any claims for shortages or damages suffered in transit are the responsibility of Buyer and shall be submitted by Buyer directly to the carrier. Shortages or damages must be identified and signed for at the time of delivery.

5. Limited Warranty. Subject to Sections 6, 7 and 8, Seller warrants to its direct purchasers and to no others that Services provided will be performed by trained personnel using proper equipment and instrumentation for the Service provided. Services and consumables are warranted for a period of ninety (90) days from the date of provision or shipment. Subject to the limitations of Sections 6, 7 and 8, Seller warrants, to its direct purchasers and to no others, that all Products manufactured by Seller will be free from defects in material and workmanship under normal use and regular service and maintenance. This warranty only applies when such defect appears in Seller Products within twelve (12) months from the date such Products are placed in service and which are returned to and received by Seller, within eighteen (18) months from the date of manufacture by Seller. This warranty does not extend to any losses or damages due to misuse, accident, abuse, neglect, normal wear and tear, negligence (other than Seller's), unauthorized modification or alteration, use beyond rated capacity, unsuitable power sources or environmental conditions, improper installation, repair, handling, maintenance or application or any other cause not the fault of Seller. To the extent that Buyer or its agents has supplied specifications, information, representation of operating conditions or other data to Seller in the selection or design of the Goods and the preparation of Seller's quotation, and in the event that actual operating conditions or other conditions differ from those represented by Buyer, any warranties or other provisions contained herein which are affected by such conditions shall be null and void. If within ten (10) days after Buyer's discovery of any warranty defects within the warranty period, Buyer notifies Seller thereof in writing, Seller shall, at its option and as Buyer’s exclusive remedy, repair, correct or replace F.O.B. point of manufacture, or issue credit or refund the purchase price for, that portion of the Goods found by Seller to be defective. Failure by Buyer to give such written notice within the applicable time period shall be deemed an absolute and unconditional waiver of Buyer's claim for such defects. Buyer assumes all other responsibility for any loss, damage, or injury to persons or property arising out of, connected with, or resulting from the use of Goods, either alone or in combination with other products/components. Goods repaired or replaced pursuant to this warranty shall be warranted for the unexpired portion of the warranty applying to the original Goods. Products purchased by Seller from a third party for resale to Buyer shall carry only the warranty extended by the original manufacturer. IF THE GOODS ARE FOR A GAS COMPRESSION APPLICATION, THIS WARRANTY DOES NOT APPLY IF THE GOODS ARE OPERATED IN CONJUNCTION WITH A GAS WITH AN H_2S LEVEL ABOVE 100 PPM. Any description of the Goods, whether in writing or made orally by Seller or Seller’s agents, specifications, samples, models, bulletins, diagrams, engineering sheets or similar materials used in connection with Buyer’s order are for the sole purpose of identifying the Goods and shall not be construed as an express warranty. Any suggestions by Seller or Seller’s agents regarding use, application or suitability of the Goods shall not be construed as an express warranty unless confirmed to be such in writing by Seller.

6. SOLE WARRANTY. THE WARRANTIES IN SECTIONS 5 AND 9 CONSTITUTE SELLER'S SOLE AND EXCLUSIVE WARRANTIES WITH RESPECT TO THE GOODS AND ARE IN LIEU OF AND EXCLUDE ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, ARISING BY OPERATION OF LAW OR OTHERWISE, INCLUDING WITHOUT LIMITATION, MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE WHETHER OR NOT THE PURPOSE OR USE HAS BEEN DISCLOSED TO SELLER IN SPECIFICATIONS, DRAWINGS OR OTHERWISE, AND WHETHER OR NOT SELLER'S GOODS ARE SPECIFICALLY DESIGNED AND/OR MANUFACTURED BY SELLER FOR BUYER'S USE OR PURPOSE.

7. LIMITATION OF REMEDY. THE SOLE AND EXCLUSIVE REMEDY FOR BREACH OF ANY WARRANTY HEREUNDER (OTHER THAN THE WARRANTY PROVIDED UNDER SECTION 9) SHALL BE LIMITED TO REPAIR, REPLACEMENT, CREDIT OR REFUND OF THE PURCHASE PRICE UNDER SECTION 5.

8. LIMITATION OF LIABILITY. SELLER SHALL NOT BE LIABLE FOR DAMAGES CAUSED BY DELAY IN PERFORMANCE AND THE REMEDIES OF BUYER SET FORTH IN THIS AGREEMENT ARE EXCLUSIVE. IN NO EVENT, REGARDLESS OF THE FORM OF THE CLAIM OR CAUSE OF ACTION (WHETHER BASED IN CONTRACT, INFRINGEMENT, NEGLIGENCE, STRICT LIABILITY, OTHER TORT OR OTHERWISE) SHALL SELLER'S LIABILITY TO BUYER AND/OR ITS CUSTOMERS EXCEED THE PRICE PAID BY BUYER FOR THE SPECIFIC GOODS OR PORTION OF THE GOODS PROVIDED BY SELLER GIVING RISE TO THE CLAIM OR CAUSE OF ACTION, AND BUYER SHALL INDEMNIFY AND HOLD HARMLESS SELLER FOR ANY DAMAGES INCURRED BY SELLER IN EXCESS THEREOF. BUYER AGREES THAT IN NO EVENT SHALL SELLER'S LIABILITY TO BUYER AND/OR ITS CUSTOMERS EXTEND TO INCLUDE INCIDENTAL, CONSEQUENTIAL OR PUNITIVE DAMAGES. The term "consequential damages" shall include, but not be limited to, loss of anticipated profits, business interruption, loss of use, revenue, reputation and data, costs incurred, including without limitation, for capital, fuel, power and loss or damage to capital or equipment. Buyer agrees that all instructions and warnings supplied by Seller will be passed on to those persons who use the Goods. Seller's Goods are to be used in their recommended applications and all warning labels adhered to the Goods by Seller are to be left intact. It is expressly understood that any technical advice furnished by Seller before or after delivery in regard to the use or application of the Goods is furnished without charge, and Seller assumes no obligation or liability for the advice given or results obtained, all advice being given and accepted at Buyer’s sole risk.

9. Patents and Copyrights. Subject to the limitations set forth herein and in Sections 7 and 8, Seller warrants that the Goods sold, except those Goods made specifically for Buyer according to Buyer's drawings or specifications or otherwise at Buyer's direction, do not infringe any valid U.S. patent or copyright, as the case may be, in existence as of the date of shipment. This warranty is given upon the condition that Buyer promptly notify Seller of any claim or suit involving Buyer in which such infringement is alleged, and that Buyer cooperate fully with Seller and permit Seller to control completely the defense, settlement or compromise of any such allegation of infringement. Seller's warranty as to use patents only applies to infringements arising solely out of the inherent operation, according to Seller's specifications and instructions, of such Goods. In the event such Goods are held to infringe upon a U.S. patent or copyright in such suit, and the use of such Goods is enjoined, or in the case of a compromise or settlement by Seller, Seller shall have the right, at its option and expense, to procure for Buyer the right to continue using such Goods, or replace them with non-infringing Goods, or modify same to become non-infringing, or grant Buyer a credit for the purchase price less 20% for each year or fraction thereof since it was shipped to Buyer. In the event of the foregoing, Seller may also, at its option, cancel this agreement as to future deliveries of such Goods, without liability. Buyer agrees to indemnify and save Seller harmless from all expenses and damages resulting from any claim, suit or proceeding for alleged infringement of any patent or copyright based in whole or in part upon the manufacture, sale or use of any Goods or any part thereof, in combination or assembly with machinery or apparatus not furnished under this agreement.

10. Excuse of Performance. Seller shall not be liable for any nonperformance or any default or delay in performance if caused, directly or indirectly, by acts of God, acts of Buyer, war, fire, flood, weather, sabotage, riot, civil commotion, strikes, lock-outs, slow downs, picketing or other labor controversies, accidents, delay or default of or failure by carriers, shortages of labor, delay in obtaining or inability to obtain materials, equipment or parts from regular sources, action, request or regulation of or by any government or governmental authority, or any other happening or contingency beyond Seller's reasonable control, or without Seller's fault, whether similar or dissimilar to the foregoing. Deliveries or other performance may be suspended for an appropriate period of time or canceled by Seller upon notice to Buyer in the event of the foregoing, but the balance of this agreement shall otherwise remain unaffected as a result of the foregoing. If Seller determines that its ability to supply the total demand for the Goods, or to obtain material used directly or indirectly in the manufacture of the Goods, is hindered, limited or made impracticable due to causes set forth herein, Seller may allocate its available supply of the Goods or such material (without obligation to acquire other supplies of any such Goods or materials) among itself and its purchasers on such basis as Seller determines to be equitable without liability for any failure of performance which may result therefrom.

11. Cancellation. Buyer may cancel orders only upon reasonable advance written notice and upon payment to Seller of Seller's cancellation charges which include, among other things, all costs and expenses incurred, and to cover commitments made, by Seller and a reasonable profit thereon. Seller's determination of such termination charges shall be conclusive.

12. Changes. Buyer may request changes or additions to the Goods consistent with Seller's specifications and criteria. In the event such changes or additions are accepted by Seller, Seller may revise the price(s) and date(s) of delivery. Seller reserves the right to change designs and specifications for the Goods without prior notice to Buyer, except if otherwise specified herein. Seller shall have no obligation to install or make such change in any Goods manufactured prior to the date of such change.

13. Buyer Responsibilities. Buyer shall provide Seller ready access to the site where Services are to be performed and adequate workspace and facilities to perform same as provided in these terms and conditions. Buyer agrees to allow Seller to stop and start equipment as necessary to fulfill the terms of the engagement. Buyer shall not require Seller or its employees, as a condition to site access or otherwise, to further agree or enter into any agreement which waives, releases, indemnifies or otherwise limits or expands any rights or obligations whatsoever. Any such agreements shall be null and void. Buyer shall inform Seller, in writing, at the time of order placement, of any known hazardous substance or condition at the site, including, but not limited to, the presence of asbestos or asbestos containing materials, and shall provide Seller with any applicable Material Data Safety Sheets regarding same. Any losses, costs, damages, claims and expenses incurred by Seller as a result of Buyer's failure to so advise Seller shall be borne by Buyer. Buyer shall appoint a representative familiar with the site and the nature of the Services to be performed by Seller to be accessible at all times that Seller personnel are at the site. Seller shall not be liable for any expenses incurred by Buyer in removing, replacing or refurbishing any Buyer equipment or any part of Buyer's building structure that restricts Seller's access. Buyer personnel shall cooperate with and provide all necessary assistance to Seller. Seller shall not be liable or responsible for any work performed by Buyer. Seller assumes all equipment which is a subject of the Services is in maintainable condition. Repair or replacement of non-maintainable parts of the system(s) such as, but not limited to, piping, insulating materials, electrical wiring, structural supports and other non-moving parts are not included in the Services.

14. Assignment. Buyer shall not assign its rights or delegate its duties hereunder or any interest herein without the prior written consent of Seller, and any such assignment, without such consent, shall be void.

15. Examination – Claims – Inspection/Testing. Buyer shall inspect Goods delivered to it by Seller immediately upon receipt, and, any course of dealing to the contrary notwithstanding, failure of Buyer to give Seller notice of any claim within 30 days after receipt of such Goods shall be an unqualified acceptance of such Goods. Buyer may not return Goods without first advising Seller of the reasons therefore, obtaining from Seller a material authorization number and observing such instructions as Seller may give in authorizing such return. Buyer, at its option and expense, may inspect and observe the testing by Seller of the Goods for compliance with Seller's standard test procedures prior to shipment, which inspection and testing shall be conducted at Seller's plant at such reasonable time as is specified by Seller. Any alleged rejection of the Goods at Seller's plant must be made promptly by Buyer before shipment. Tests shall be deemed to be satisfactorily completed and the test fully met when the Goods meet Seller's criteria for such procedures.

16. Drawings. Seller's prints and drawings (including without limitation, the underlying technology) furnished by Seller to Buyer in connection with this agreement are the property of Seller and Seller retains all rights, including, without limitation, exclusive rights of use, licensing and sale of same. Possession of such prints or drawings does not convey to Buyer any rights therein or license thereto. Upon termination of this agreement, or at any time upon Seller's request, all such prints and drawings, and any copies or duplications of same (in whatever medium), shall be immediately returned to Seller.

17. Software. Notwithstanding any other provision herein to the contrary, Seller or applicable third party licensor to Seller shall retain all rights of ownership and title in its respective Software, including without limitation all rights of ownership and title in its respective copies of such Software. Except as otherwise provided herein, Buyer is hereby granted a nonexclusive, non-transferable royalty free license to use the Software incorporated into the Goods solely for purposes of Buyer properly utilizing such Goods purchased from Seller. All other Software shall be furnished to, and used by, Buyer only after execution of Seller's (or the licensor's) applicable standard license agreement, the terms of which are incorporated herein by reference.

18. Documentation. Seller shall provide Buyer with that data/documentation which is specifically identified in Seller's quotation. If additional copies of data/documentation are to be provided by Seller, it shall be provided to Buyer at Seller's applicable prices then in effect.

19. Export/Import: Buyer agrees that all applicable import and export control laws, regulations, orders and requirements, including without limitation those of the United States and the European Union, and the jurisdictions in which the Seller and Buyer are established or from which Goods and Services may be supplied, will apply to their receipt and use. In no event shall Buyer use, transfer, release, import or export, Goods in violation of such applicable laws, regulations, orders or requirements.

20. Nuclear/Medical. GOODS AND SERVICES SOLD HEREUNDER ARE NOT FOR USE IN CONNECTION WITH ANY NUCLEAR, MEDICAL, LIFE-SUPPORT AND RELATED APPLICATIONS. Buyer accepts the Goods and services with the foregoing understanding, agrees to communicate the same in writing to any subsequent purchaser or users and to defend, indemnify and hold harmless Seller from any claims, losses, suits, judgments and damages, including incidental and consequential damages, arising from such use, whether the cause of action be based in tort, contract or otherwise, including allegations that Seller's liability is based on negligence or strict liability.

21. General Provisions. These terms and conditions supersede all other communications, negotiations and prior oral or written statements regarding the subject matter of these terms and conditions. No change, modification, rescission, discharge, abandonment, or waiver of these terms and conditions shall be binding upon Seller unless made in writing and signed on its behalf by its duly authorized representative of Seller. No conditions, usage or trade, course of dealing or performance, understanding or agreement purporting to modify, vary, explain, or supplement these terms and conditions shall be binding unless hereafter made in writing and signed by the party to be bound. No modification or additional terms shall be applicable to this agreement by Seller's receipt, acknowledgement or acceptance of Buyer's purchase orders, shipping instruction forms, or other documentation containing terms at variance with or in addition to those set forth herein. Any such modifications or additional terms are specifically rejected and deemed a material alteration hereof. If this document shall be deemed an acceptance of a prior offer by Buyer, such acceptance is expressly conditional upon Buyer's assent to any additional or different terms set forth herein. No waiver by either party with respect to any breach or default or of any right or remedy, and no course of dealing, shall be deemed to constitute a continuing waiver of any other breach or default or of any other right or remedy, unless such waiver be expressed in writing and signed by the party to be bound. All typographical or clerical errors made by Seller in any quotation, acknowledgment or publication are subject to correction. The validity, performance, and all other matters relating to the interpretation and effect of this agreement shall be governed by the laws of the State of Wisconsin, USA without regard to its conflict of law principles. Buyer and Seller agree that the proper venue for all actions arising in connection herewith shall be deemed exclusively proper only in state court in Wisconsin or a federal court located in the state of Wisconsin and the parties agree to submit to such jurisdiction. No action, regardless of form, arising out of transactions relating to this contract may be brought by either party more than two (2) years after the cause of action has accrued. Further, the United Nations Convention on Contracts for the International Sale of Goods shall not apply to this agreement or any transactions relating thereto. The terms of Sections 2, 3, 5, 6, 7, 8, 9, 16, 17, 20 and 21 shall survive termination or expiration of this Agreement.

APPENDIX K

Total Equipment Cost and O&M Cost Estimate – Mercury 50

CLIENT	SCPPA	PREPARED BY: Reem Kayali, Process Engineer	VENTURE™
PLANT:	Scholl/Grayson	CHEDKED BY: K. Zabelsky	
AREA NO:	Glendale, CA	DATE: March 16, 2015	
DESCRIPTION:	7500 scfm Biomethane Plant, Task #5	REV: A	

Equipment, Operational and Maintenance Cost Estimates (Mercury 50 Turbines)

LIST ITEM	EQUIPMENT	QUANTITY	MODEL	UNIT COST	EQUIPMENT COST	ANNUAL OPERATING AND MAINTENANCE COST DESCRIPTION	ANNUAL OPERATING AND MAINTENANCE COST EXCLUDING ELECTRIC COST
1	Gas Conditioning System	1	---	$ 1,800,000	$ 1,940,000	Maintenance: $24,000/year Media: $130,000/year	$154,000
	Regeneration Enclosed Flare	1	---	$ 140,000		---	---
2	LFG Feed Compressor package includes:	1	---	---	$ 576,478	Change Out: 7 Drums per compressor (55 gal/drums), $2500/drum every two years Make Up: 139 oz/week per compressor Coalescers: 2 filters @ $1,250/year 1500 Hp Motor x 1 = 1500 HP Air cooled oil cooler: 16.3 KW heater kit x 1 = 16.3 KW Air cooled oil cooler fan 40 hp each x 1 = 40 hp Remote air cooled after cooler 40 hp motor	$12,567
	Vilter Compressor	1	VSG-1851	$ 291,162			
	Remote Air Cooled Oil Cooler	1	VSG-1851	$ 112,000			
	Remote Air Cooled After Cooler	1	VSG-1851	$ 92,400			
	Discharge Separator	1	VSG-1851	$ 80,916			
3	Mercury 50 Turbine	4	---	$ 4,909,000	$ 19,636,000	Maintenance is $58,310/ month per turbine	$2,798,880
						$/kw-h	0.0200
					Total Equipment Cost		**Total O&M Cost**
					$ 22,152,478		**$ 2,965,447**

CLIENT	SCPPA	PREPARED BY: Reem Kayali, Process Engineer	VENTURE™
PLANT:	Scholl/Grayson	CHEDKED BY: K. Zabelsky	
AREA NO:	Glendale, CA	DATE: March 16, 2015	
DESCRIPTION:	7500 scfm Biomethane Plant, Task #5	REV: A	

Equipment, Operational and Maintenance Cost Estimates (Mercury 50 Turbines)

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1	Gas Conditioning System	1	---	$ 1,800,000	$ 1,940,000	Maintenance: $24,000/year Media: $130,000/year	$154,000
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2	LFG Feed Compressor package includes:	1	---	---	$ 576,478	Change Out: 7 Drums per compressor (55 gal/drums), $2500/drum every two years Make Up: 139 oz/week per compressor Coalescers: 2 filters @ $1,250/year 1500 Hp Motor x 1 = 1500 HP Air cooled oil cooler: 16.3 KW heater kit x 1 = 16.3 KW Air cooled oil cooler fan 40 hp each x 1 = 40 hp Remote air cooled after cooler 40 hp motor	$12,567
	Vilter Compressor	1	VSG-1851	$ 291,162			
	Remote Air Cooled Oil Cooler	1	VSG-1851	$ 112,000			
	Remote Air Cooled After Cooler	1	VSG-1851	$ 92,400			
	Discharge Separator	1	VSG-1851	$ 80,916			
					Total Equipment Cost		**Total O&M Cost**
					$ 2,516,478		**$ 166,567**

Solar Turbines Incorporated

Budgetary Estimate for Customer Name

Inquiry # TBD prepared on February 20, 2015

For more information contact:

Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

(Prices shown below quoted in US Dollars $, using a conversion of US dollar prices times 1)

Quotation is for information only and does not constitute Solar's agreement to offer a firm proposal in the future.

Gas Turbine Equipment	
(1) Landfill Gas Fuel, MERCURY 50-6400R Turbine Generator Set……………..…………	$4,655,000
Commissioning Parts, Startup, and Site Testing……………………………………	$158,000
Electrical Equipment	
No Additional Electrical Equipment Included	
Mechanical Equipment	
Fuel Gas Compressor ………………………………………………….………………..	By Others
No Mechanical Equipment Selected	
Miscellaneous	
Construction Estimate………………………………………………………………..….	by others
Project Management & Engineering (Loose Ship Equipment Only)…………….	$0
Shipping………………………………………………………………………………	$96,000
0% Balance of Plant Contingency……………………………………………………	$0
Total for BOP Equipment (installation not included)………………………………	$96,000
Grand Total for Turbomachinery and Balance of Plant……………………..	**$4,910,000**
Estimation of cost per ISO rating kilowatt for selected equipment………………	$999
ESA Cost per Month (Only Turbomachinery Covered)…………………………..…	$58,310

*Duties and taxes not included in estimate. Caterpillar Confidential: Green CEP Ver. 8.0

MERCURY 50-6400R Generator Set Package Features

Engine:

Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor

Basic Options:

Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and upward oriented exhaust outlet
1800 rpm; 60 Hz
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:

Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:
- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:

Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):

Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:

Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous

Short-term preservation for shipment
Four (4) paper copies of Solar's Instruction, Operation and Maintenance manuals
Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system

Cogeneration Plant Estimated Performance Summary

Customer Name
Solar Turbines Incorporated
February 20, 2015

Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	4,910	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	0	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	1.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	43.2	MMBtu/hr
KW Gross Output @ specified site conditions:	4,807	kW
Gas Compressor Power Consumption:	852	kW
Turbine Auxiliary Power Consumption:	40	kW
Total Auxiliary Power Consumption:	892	kW
Net Turbine Power Production:	3,915	kW
Black Start kW Requirement (Turbine Generator Set Only)	206	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Electrical Heat Rate:	11,040	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	11,040	Btu/kWHR
Overall Cycle Efficiency (LHV):	30.9	%

Caterpillar Confidential: Green

CEP Ver. 8.0

Estimated Power Island Emissions

Customer Name

Quoted using data available as of February 20, 2015

(1) Landfill Gas Fuel MERCURY 50-6400R		**Plant Total**
Ambient Temperature	°F	59.0
Gross Power Output	kW	4,807
Fuel Type	Landfill Gas	
Assumed Fuel Sulphur Content	lbm/MMBtu (HHV)	0.045
Gas Turbine Exhaust Flow	lbm/hr	144,700
Stack Exhaust Flow	lbm/hr	144,700
Flue Gas Temperature Leaving Gas Turbine	°F	718.1
Flue Gas Temperature At Stack	°F	718.1
Heat Input to Gas Turbine	MMBtu/hr (LHV)	43.2
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lbm/MMBtu (HHV)	0.03
Turbine Exhaust Gas Analysis		
H_2O	% vol	6.5%
N_2	% vol	73.4%
CO_2	% vol	4.5%
O_2	% vol	14.7%
SO_2	% vol	0.0%
Argon	% vol	0.9%

(1) Landfill Gas Fuel MERCURY 50-6400R		**Plant Total**
Exhaust Emissions At Stack		
NOx	ppm @ 15% O2	15.0
	lbm/MMBtu, HHV	0.0589
	lbm/hr	2.83
	short tons/yr	12.4
CO	ppm @ 15% O2	25.0
	lbm/MMBtu, HHV	0.0598
	lbm/hr	2.87
	short tons/yr	12.6
UHC	ppm @ 15% O2	25.0
	lbm/MMBtu, HHV	0.0342
	lbm/hr	1.64
	short tons/yr	7.18
VOC	ppm @ 15% O2	5.0
	lbm/MMBtu, HHV	0.00683
	lbm/hr	0.328
	short tons/yr	1.44
$PM_{10}/PM_{2.5}$	lbm/hr	1.44
	lbm/MMBtu, HHV	0.03
	short tons/yr	6.31
SO_2	lbm/hr	2.16
	lbm/MMBtu, HHV	0.045
	short tons/yr	9.46
CO_2	lbm/MMBtu (HHV)	207
	lbm/hr	9,930
	short tons/yr	43,500
	metric tonnes/yr	39,500

(1) Landfill Gas Fuel MERCURY 50-6400R	**Plant Total**

Emissions Notes:

1. This document is for initial emissions estimates only. For air permit applications, Solar can provide appropriate site-specific turbine emissions documentation.

2. Fuels must comply with Solar specification ES 9-98. Actual emissions may vary due to site fuel characteristics. Zero fuel bound nitrogen is assumed for gaseous fuels, and less than 0.02% for liquid fuels.

3. Turbine "ppm" values are applicable for operation at ambient temperatures greater than 0℉ (-20℃).

4. The table below gives the load ranges to which the turbine ppm emissions listed above apply. Mass based estimates are valid at ambient temperature and operating load noted.

Pollutant	Load Range
NOx	50 to 100%
CO	50 to 100%
UHC	50 to 100%

5. SO_2 emissions depend upon the fuel's sulfur content. The SO_2 estimate is based upon EPA's AP-42 document (Tables 3.1-2a. and 3.1-2b. April 2000).

6. Annual estimates shown above assume 8760 hours/year operation.

For more information contact: Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

 CEP Ver. 8.0

EXTENDED SERVICE AGREEMENT

Solar Turbines' Extended Service Agreement (ESA) is an overall machinery management solution designed to maximize the value of your Solar turbomachinery through the provision of comprehensive overhaul coverage, scheduled maintenance, and Solar's InSight Equipment Health Management system in a single monthly fee. The ESA includes:

Comprehensive Overhaul Coverage

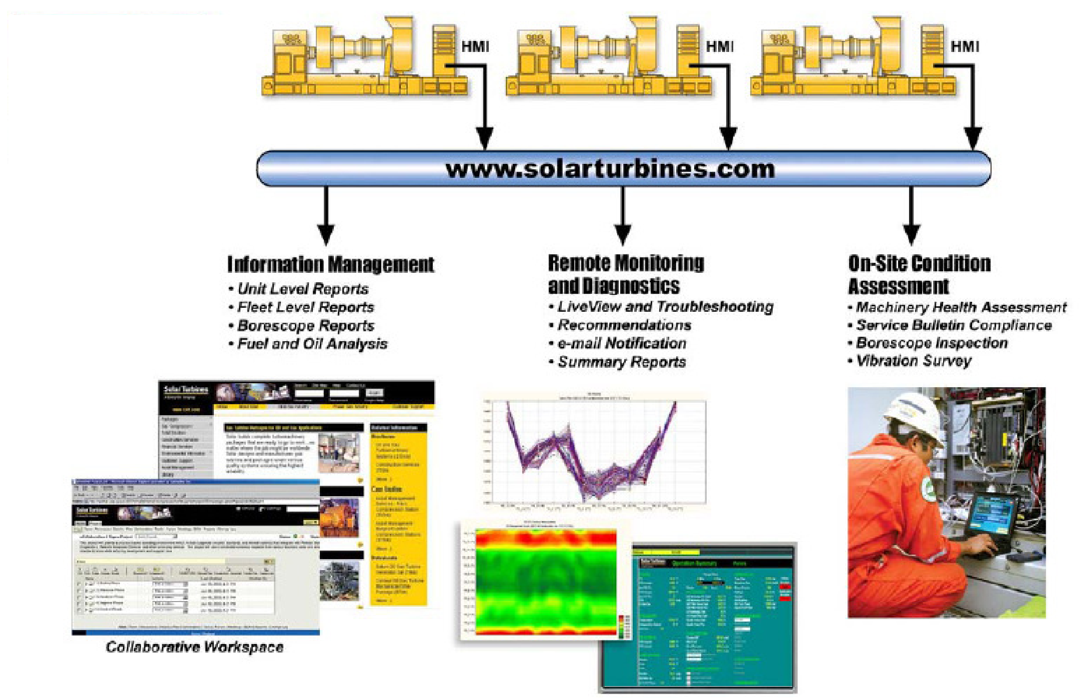
- Repair or Overhaul of the Gas Turbine – For the duration of the contract, all required repair and overhaul of the gas turbine will be provided at Solar's expense.
- Turbine Exchange Program – Should an overhaul be required, Solar can provide an turbine of similar configuration to minimize customer downtime.

Comprehensive Parts and Maintenance Coverage

- Preventive Maintenance – On a quarterly basis, experienced Solar Field Service Representatives (FSR) will provide scheduled maintenance (including parts) of the turbomachinery package.
- Certified OEM Condition Assessment Reports – Every six months a report, used to optimize maintenance planning, is prepared to document specific indicators of equipment health.
- Call Outs for Troubleshooting and Repairs – Solar FSRs will provide all unscheduled inspections to ensure maximum availability (normal travel and subsistence costs included).
- Service Parts – Solar will recommend an appropriate spare parts inventory for the covered equipment, to be purchased by CUSTOMER. Any parts used from this inventory in support of the ESA will be replaced by Solar free of charge for the duration of the contract.

Equipment Health Management (EHM)

- Remote Monitoring and Diagnostics (RM&D) – RM&D continuously monitors equipment health, posting daily package data to a San Diego based Oracle database. Data are analyzed by Solar Engineers to optimize equipment availability and maintenance planning.
- Predictive Maintenance – Through Remote Monitoring and Diagnostics and Condition Assessment Reports, Solar will provide predictive maintenance to ensure the health of the turbomachinery package(s), with annual reporting of the results.



The InSight Enabled Equipment Health Management System

APPENDIX L

Equipment Cost and O&M Cost Estimate – Taurus 60

CLIENT	SCPPA	PREPARED BY: Reem Kayali, Process Engineer	VENTURE
PLANT:	Scholl/Grayson	CHEDKED BY: K. Zabelsky	
AREA NO:	Glendale, CA	DATE: March 16, 2015	
DESCRIPTION:	7500 scfm Biomethane Plant, Task #5	REV: A	

Equipment, Operational and Maintenance Cost Estimates (Taurus 60 Turbines)

LIST ITEM	EQUIPMENT	QUANTITY	MODEL	UNIT COST	EQUIPMENT COST	ANNUAL OPERATING AND MAINTENANCE COST DESCRIPTION	ANNUAL OPERATING AND MAINTENANCE COST EXCLUDING ELECTRIC COST
1	Gas Conditioning System	1	---	$ 1,800,000	$ 1,940,000	Maintenance: $24,000/year Media: $130,000/year	$154,000
	Regeneration Enclosed Flare	1	---	$ 140,000		---	---
2	LFG Feed Compressor package includes:	1	---	---	$ 576,478	Change Out: 7 Drums per compressor (55 gal/drums), $2500/drum every two years Make Up: 139 oz/week per compressor Coalescers: 2 filters @ $1,250/year 1500 Hp Motor x 1 = 1500 HP Air cooled oil cooler: 16.3 KW heater kit x 1 = 16.3 KW Air cooled oil cooler fan 40 hp each x 1 = 40 hp Remote air cooled after cooler 40 hp motor	$12,567
	Vilter Compressor	1	VSG-1851	$ 291,162			
	Remote Air Cooled Oil Cooler	1	VSG-1851	$ 112,000			
	Remote Air Cooled After Cooler	1	VSG-1851	$ 92,400			
	Discharge Separator	1	VSG-1851	$ 80,916			
3	Taurus 60 Turbine	3	---	$ 3,846,000	$ 11,538,000	Maintenance $32,920/ month per turbine	$1,185,120
4	Emission Control Equipment SCR and CO Catalyst	3	---	$ 1,148,000	$ 3,444,000	SCR Catalyst Cost = $350000 SCR replacement every six years CO Catalyst Cost = $350000 SCR replacement every six years Pure Ammonia consumption 36.3 tons/year per turbine Cost of Ammonia = $0.20/lb	$393,560
						$/kw-h	0.0132
					Total Equipment Cost		**Total O&M Cost**
					$ 17,498,478		**$ 1,745,247**

.

CLIENT	SCPPA	PREPARED BY: Reem Kayali, Process Engineer	VENTURE™
PLANT:	Scholl/Grayson	CHEDKED BY: K. Zabelsky	
AREA NO:	Glendale, CA	DATE: March 16, 2015	
DESCRIPTION:	7500 scfm Biomethane Plant, Task #5	REV: A	

Equipment, Operational and Maintenance Cost Estimates (Taurus 60 Turbines)

LIST ITEM	EQUIPMENT	QUANTITY	MODEL	UNIT COST	EQUIPMENT COST	ANNUAL OPERATING AND MAINTENANCE COST DESCRIPTION	ANNUAL OPERATING AND MAINTENANCE COST EXCLUDING ELECTRIC COST
1	Gas Conditioning System	1	---	$ 1,800,000	$ 1,940,000	Maintenance: $24,000/year Media: $130,000/year	$154,000
	Regeneration Enclosed Flare	1	---	$ 140,000		---	---
2	LFG Feed Compressor package includes:	1	---	---	$ 576,478	Change Out: 7 Drums per compressor (55 gal/drums), $2500/drum every two years Make Up: 139 oz/week per compressor Coalescers: 2 filters @ $1,250/year 1500 Hp Motor x 1 = 1500 HP Air cooled oil cooler: 16.3 KW heater kit x 1 = 16.3 KW Air cooled oil cooler fan 40 hp each x 1 = 40 hp Remote air cooled after cooler 40 hp motor	$12,567
	Vilter Compressor	1	VSG-1851	$ 291,162			
	Remote Air Cooled Oil Cooler	1	VSG-1851	$ 112,000			
	Remote Air Cooled After Cooler	1	VSG-1851	$ 92,400			
	Discharge Separator	1	VSG-1851	$ 80,916			
					Total Equipment Cost		**Total O&M Cost**
					$ 2,516,478		**$ 166,567**

.

Solar Turbines Incorporated

Budgetary Estimate for Customer Name

Inquiry # TBD prepared on February 20, 2015

For more information contact:

Bernie Pfeifer, 1-203-644-8264, berniepfeifer@solarturbines.com

(Prices shown below quoted in US Dollars $, using a conversion of US dollar prices times 1)

Quotation is for information only and does not constitute Solar's agreement to offer a firm proposal in the future.

Gas Turbine Equipment	
(1) Landfill Gas Fuel, TAURUS 60-7901 Turbine Generator Set	$3,600,000
Commissioning Parts, Startup, and Site Testing	$146,000
Electrical Equipment	
No Additional Electrical Equipment Included	
Mechanical Equipment	
Fuel Gas Compressor	By Others
Emissions Control Equipment:(SCR and CO Catalyst)	$1,148,000
Continuous Emission Monitoring System, indoor installation	$115,000
Miscellaneous	
Construction Estimate	by others
Project Management & Engineering (Loose Ship Equipment Only)	$88,000
Shipping	$100,000
0% Balance of Plant Contingency	$0
Total for BOP Equipment (installation not included)	$1,451,000
Grand Total for Turbomachinery and Balance of Plant	**$5,197,000**
Estimation of cost per ISO rating kilowatt for selected equipment	$849
ESA Cost per Month (Only Turbomachinery Covered)	$32,920

*Duties and taxes not included in estimate. Caterpillar Confidential: Green CEP Ver. 8.0

TAURUS 60-7901 Generator Set Package Features

Engine:
Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor

Basic Options:
Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and axially oriented exhaust outlet
1800 rpm; 60 Hz
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:
Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:
- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:
Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):
Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:
Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous
Short-term preservation for shipment
Four (4) paper copies of Solar's Instruction, Operation and Maintenance manuals
Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system

Cogeneration Plant Estimated Performance Summary

Customer Name

Solar Turbines Incorporated

February 20, 2015

Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	6,120	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	0	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	7.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	64.1	MMBtu/hr
KW Gross Output @ specified site conditions:	5,937	kW
Gas Compressor Power Consumption:	1680	kW
Turbine Auxiliary Power Consumption:	10	kW
Total Auxiliary Power Consumption:	1690	kW
Net Turbine Power Production:	4,247	kW
Black Start kW Requirement (Turbine Generator Set Only)	304	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Electrical Heat Rate:	15,080	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	15,080	Btu/kWHR
Overall Cycle Efficiency (LHV):	22.6	%

Caterpillar Confidential: Green

CEP Ver. 8.0

EXTENDED SERVICE AGREEMENT

Solar Turbines' Extended Service Agreement (ESA) is an overall machinery management solution designed to maximize the value of your Solar turbomachinery through the provision of comprehensive overhaul coverage, scheduled maintenance, and Solar's InSight Equipment Health Management system in a single monthly fee. The ESA includes:

Comprehensive Overhaul Coverage

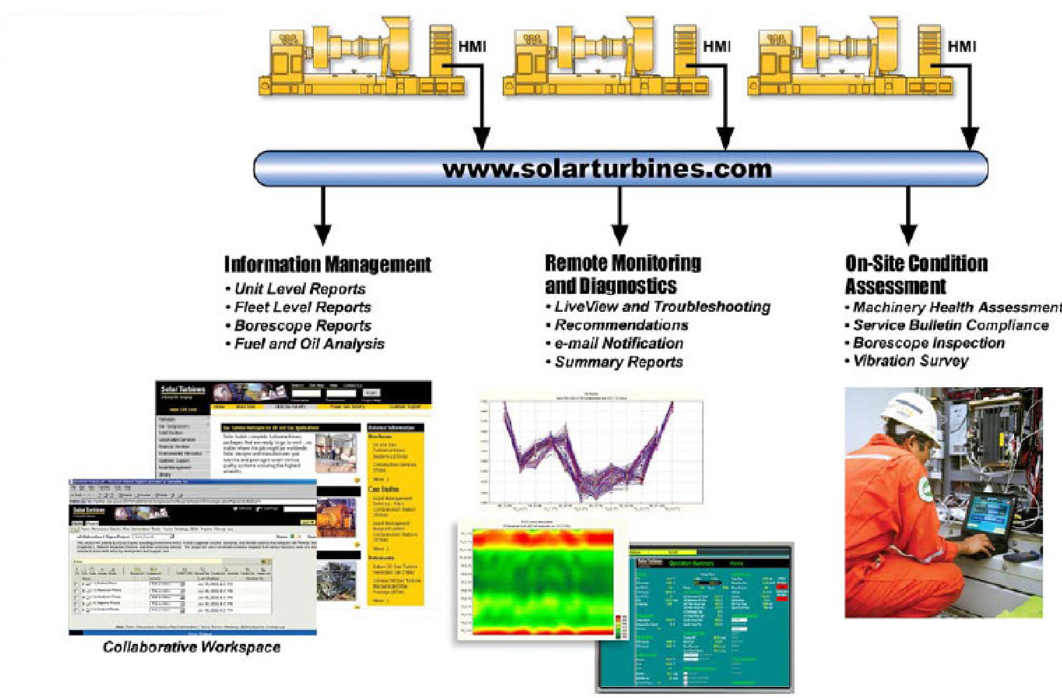
- Repair or Overhaul of the Gas Turbine – For the duration of the contract, all required repair and overhaul of the gas turbine will be provided at Solar's expense.
- Turbine Exchange Program – Should an overhaul be required, Solar can provide an turbine of similar configuration to minimize customer downtime.

Comprehensive Parts and Maintenance Coverage

- Preventive Maintenance – On a quarterly basis, experienced Solar Field Service Representatives (FSR) will provide scheduled maintenance (including parts) of the turbomachinery package.
- Certified OEM Condition Assessment Reports – Every six months a report, used to optimize maintenance planning, is prepared to document specific indicators of equipment health.
- Call Outs for Troubleshooting and Repairs – Solar FSRs will provide all unscheduled inspections to ensure maximum availability (normal travel and subsistence costs included).
- Service Parts – Solar will recommend an appropriate spare parts inventory for the covered equipment, to be purchased by CUSTOMER. Any parts used from this inventory in support of the ESA will be replaced by Solar free of charge for the duration of the contract.

Equipment Health Management (EHM)

- Remote Monitoring and Diagnostics (RM&D) – RM&D continuously monitors equipment health, posting daily package data to a San Diego based Oracle database. Data are analyzed by Solar Engineers to optimize equipment availability and maintenance planning.
- Predictive Maintenance – Through Remote Monitoring and Diagnostics and Condition Assessment Reports, Solar will provide predictive maintenance to ensure the health of the turbomachinery package(s), with annual reporting of the results.



The InSight Enabled Equipment Health Management System

Mihailoff, Amanda

To: Kayali, Reem
Subject: FW: Glendale Project- MARS Turbines

From: Bernie Pfeifer [mailto:Pfeifer_Bernie@solarturbines.com]
Sent: Friday, November 21, 2014 12:23 PM
To: Kayali, Reem
Cc: Kevin D. Jensen
Subject: RE: Glendale Project- MARS Turbines

Hi Reem,

My guesstimate for the CO catalyst cost is as follows (we dont provide CO or SCRs so our numbers our a best estimate at this stage).

Mars CO = $300k-$400k..I dont know the maintenance cost but I would assume these are replaced every 5-8 years depending on condition/usage. Same with SCR catalyst.

SCR - $100/KW to buy and $50/kw to allow for installation. Its a rule of thumb we have used for several years.

Kevin can provide ammonia consumption.

See write up of Turbine maintenance program.

Long-Term Service Agreements - TURBINE ONLY continuous use - 8000/yr plus.

The majority of our Power Generation customers enter into a Long term service (maintenance) agreement (LTSA). These agreements can vary in duration from 5 to 15 years (normally 5 year renewable). These agreements provide considerable value to the customer by assuming the risk of the maintenance by including all parts and labor for the gas turbine package as well as unlimited warranted gas turbine overhauls. Depending on annual hours of operation, maintenance practices and the operating environment, we expect to overhaul the gas turbine every 4 to 5 years. Solar's philosophy is for the engines to have a design life of 30,000 hours before an overhaul. The service agreement is a renewable 5 year agreement where the fee is paid monthly. The fee covers all parts (except air filters) and labor on the generator set package as well as all turbine overhauls. It includes all planned (4 times a year) and unplanned service calls. Day to day operation and maintenance is by the customers personnel. The agreement includes the exchange engine (turbine) program whereby we swap out the existing engine at time of overhaul for a new one minimizing the plant downtime. Exchange engine program is provided as part of the LTSA agreement at no additional charge.

On-line Condition Monitoring and Diagnostic.

Solar's Long-Term Service Agreement program includes continuous RM&D (Remote monitoring and Diagnostics) designed to monitor the equipment health, posting daily package data to a San Diego based Oracle database. Data is analyzed and used to assist in managing the condition of the gas turbine, ensuring high availability and reliability, minimizing downtime and optimize maintenance planning. This also allows Solar the capability to quickly and efficient resolve issues by remote trouble shooting.

Summary of the Service Program

Sincerely,

Bernie Pfeifer
Sales Manager, Northeast US

Solar Turbines - Power Generation
Cell: (203) 644-8264

Estimated Power Island Emissions

City of Glendale, Scholl Canyon Landfill

Estimated using data available as of February 17, 2015

(3) Landfill Gas Fuel TAURUS 60-7901		**Per Unit**	**Plant Total**
Ambient Temperature	°F	60.0	
Gross Power Output (Part Load) Min Load = 80%	kW	4,781	14,343
Fuel Type		Landfill Gas	
Assumed Fuel Sulphur Content	lbm/MMBtu (HHV)	0.045	
Gas Turbine Exhaust Flow	lbm/hr	175,800	527,300
Stack Exhaust Flow	lbm/hr	175,800	527,300
Flue Gas Temperature Leaving Gas Turbine	°F	829	
Flue Gas Temperature At Stack	°F	829	
Heat Input to Gas Turbine	MMBtu/hr (LHV)	52.9	158.8
$PM_{10}/PM_{2.5}$ Particulates from Gas Turbine	lbm/MMBtu (HHV)	0.03	
Turbine Exhaust Gas Analysis			
H2O, assumes 60% relative humidity	% vol	6.6%	
N_2	% vol	73.3%	
CO_2	% vol	4.5%	
O_2	% vol	14.7%	
SO_2	% vol	0.0%	
Argon	% vol	0.9%	
Exhaust Emissions At Stack			
NOx	ppm @ 15% O2	42.0	42.0
	lbm/MMBtu, HHV	0.165	
	lbm/hr	9.68	29.03
	short tons/yr	42.4	127.2
CO	ppm @ 15% O2	150.0	150.0
	lbm/MMBtu, HHV	0.359	
	lbm/hr	21	63.1
	short tons/yr	92.1	276.4
UHC	ppm @ 15% O2	75.0	75.0
	lbm/MMBtu, HHV	0.102	
	lbm/hr	6.01	18.03
	short tons/yr	26.3	79
VOC	ppm @ 15% O2	15.0	15.0
	lbm/MMBtu, HHV	0.0205	
	lbm/hr	1.2	3.61
	short tons/yr	5.27	15.8
$PM_{10}/PM_{2.5}$	lbm/hr	1.76	5.28
	lbm/MMBtu, HHV	0.03	
	short tons/yr	7.71	23.12
SO_2	lbm/hr	2.64	7.92
	lbm/MMBtu, HHV	0.045	
	short tons/yr	11.6	34.7
CO_2	lbm/MMBtu (HHV)	207	
	lbm/hr	12,100	36,400
	short tons/yr	53,100	159,400
	metric tonnes/yr	48,200	144,600

(3) Landfill Gas Fuel TAURUS 60-7901	**Per Unit**	**Plant Total**

Emissions Notes:

1. This document is for initial emissions estimates only. For air permit applications, Solar can provide appropriate site-specific turbine emissions documentation.

2. Fuels must comply with Solar specification ES 9-98. Actual emissions may vary due to site fuel characteristics. Zero fuel bound nitrogen is assumed for gaseous fuels, and less than 0.02% for liquid fuels.

3. Turbine "ppm" values are applicable for operation at ambient temperatures greater than 0°F (-20°C).

4. The table below gives the load ranges to which the turbine ppm emissions listed above apply. Mass based estimates are valid at ambient temperature and operating load noted.

Pollutant	Load Range
NOx	80 to 100%
CO	80 to 100%
UHC	80 to 100%

5. SO_2 emissions depend upon the fuel's sulfur content. The SO_2 estimate is based upon EPA's AP-42 document (Tables 3.1-2a. and 3.1-2b. April 2000).

6. Annual estimates shown above assume 8760 hours/year operation.

For more information contact: Kevin Jensen, +1 619 544 5956, kjensen@solarturbines.com

 CEP Ver. 8.1

SCR ammonia consumption estimation, assuming to control ammonia to 15 ppm NOx.
All calculations are estimates. Contact your SCR manufacturer for actual values.

42 ppm to 15 ppm
= 27 ppm NOx removal
27 ppm NOx equates to 18.7 lbm/hr NOx (by scaling 42 ppm and 29 lbm/hr NOx)

The chemical equation for Ammonia to NOx is 1:1 molecularly.
18.7 lbm/hr * (17 molecular weight of Ammonia / 46 molecular weight of NOx)
= 6.91 lbm/hr of Ammonia

Assume 20% increase in consumption from slip.
= 8.293 lbm/hr of Ammonia
= 36.3 short tons/year

APPENDIX M

Equipment Cost and O&M Cost Estimate – Caterpillar Engine

CLIENT	SCPPA	PREPARED BY: Reem Kayali, Process Engineer	VENTURE
PLANT:	Scholl/Grayson	CHEDKED BY: K. Zabelsky	
AREA NO:	Glendale, CA	DATE: March 16, 2015	
DESCRIPTION:	7500 scfm Biomethane Plant, Task #5	REV: A	

Equipment, Operational and Maintenance Cost Estimates (Caterpillar CG260-16)

LIST ITEM	EQUIPMENT	QUANTITY	MODEL	UNIT COST	EQUIPMENT COST	ANNUAL OPERATING AND MAINTENANCE COST DESCRIPTION	ANNUAL OPERATING AND MAINTENANCE COST EXCLUDING ELECTRIC COST
1	Gas Conditioning System	1	---	$ 1,800,000	$ 1,940,000	Maintenance: $24,000/year Media: $130,000/year	$154,000
	Regeneration Enclosed Flare	1	---	$ 140,000		---	---
3	Caterpillar Engine CG260-16 Emission Control Equipment	6	---	$ 2,320,000	$ 13,920,000	**$0.013/kwh** for emisisoin control equipment and Engine SCR replacement every 24,000 hours Oxicat replacement every 16,000 hours Urea consumption (40% Urea, 60% H2O) = ~ 2.2 GPH per engine	$1,944,800
4	Emission Control Equipment SCR and CO Catalyst	Included in List Item 3	Included in List Item 3	Included in List Item 3	Included in List Item 3		
						$/kw-h	0.0129
					Total Equipment Cost		**Total O&M Cost**
					$ 15,860,000		**$ 2,098,800**

CLIENT	SCPPA	PREPARED BY: Reem Kayali, Process Engineer	VENTURE™
PLANT:	Scholl/Grayson	CHEDKED BY: K. Zabelsky	
AREA NO:	Glendale, CA	DATE: March 16, 2015	
DESCRIPTION:	7500 scfm Biomethane Plant, Task #5	REV: A	

Equipment, Operational and Maintenance Cost Estimates (Caterpillar CG260-16)

LIST ITEM	EQUIPMENT	QUANTITY	MODEL	UNIT COST	EQUIPMENT COST	ANNUAL OPERATING AND MAINTENANCE COST DESCRIPTION	ANNUAL OPERATING AND MAINTENANCE COST EXCLUDING ELECTRIC COST
1	Gas Conditioning System	1	---	$ 1,800,000	$ 1,940,000	Maintenance: $24,000/year Media: $130,000/year	$154,000
	Regeneration Enclosed Flare	1	---	$ 140,000		---	---
					Total Equipment Cost		**Total O&M Cost**
					$ 1,940,000		**$ 154,000**

DiFonso, Andy

Subject: FW: Budget Pricing - LFGTE Plant - The City of Glendale, CA

From: ExportkW [mailto:exportkw@gmail.com]
Sent: Tuesday, March 17, 2015 2:06 PM
To: Kayali, Reem
Cc: khertzler@clevelandbrothers.com; Slatosky, Bill; O'Connor, Kevin
Subject: Re: Budget Pricing - LFGTE Plant - The City of Glendale, CA

Reem,

Figure $0.013/kWh "all in" except fuel.

On Mar 17, 2015, at 1:37 PM, Kayali, Reem <RKayali@ventureengr.com> wrote:

> Kurt,
> What about the operating and maintenance cost associated with the engine. $/kwh?
>
> **Reem Kayali**
> Process Engineer
> 1501 Reedsdale Street, Suite 505
> Pittsburgh, PA 15233
> Office: (412) 231-5890 x332
>
> www.VentureEngr.com | Facebook
>
> *Venture Engineering & Construction*
> *#1 Fastest-Growing Engineering Firm in Pittsburgh (Pittsburgh Business Times, 2010 & 2011)*
> *A Pittsburgh "Best Places to Work" Award Winner (PBT, 2011)*
>
> **From:** khertzler@clevelandbrothers.com [mailto:khertzler@clevelandbrothers.com]
> **Sent:** Tuesday, March 17, 2015 11:27 AM
> **To:** Kayali, Reem
> **Cc:** Slatosky, Bill; O'Connor, Kevin
> **Subject:** RE: Budget Pricing - LFGTE Plant - The City of Glendale, CA
>
> Reem,
> $0.0031/kwh is "all in" for 10 years....including Urea cost plus 3% inflation per year.
>
> Sincerely,
> Kurt Hertzler
> Cleveland Brothers Equip. Co., Inc.
> 336 N. Fairville Ave.
> Harrisburg PA 17112
> Direct Dial: 717-635-7267
> E-FAX No: 717-441-3757
> Cell Phone: 717-514-7360
> Email: khertzler@clevelandbrothers.com

DiFonso, Andy

Subject: Budget Pricing - LFGTE Plant - The City of Glendale, CA

Good morning Kurt,

Quick update: After further discussions with the Venture Team and the Client, it was concluded that the Caterpillar CG260-16 (quantity 6, based engine heat rate of 8420 BTU/kWh and a power generation of 3370 kW) will be selected for the phase 2 of Task #5 study (electric generation using LFG as fuel to be located at the Scholl Landfill in Glendale CA, no blending with natural gas).

1- Predicted performance data. {Working on this}
2- Maximum fuel temperature at the Engine {50 C}
3- Fixed and variable operating and maintenance cost:

- How often does the catalyst need replacement? {With Clean Landfill Gas: SCR to be changed every 24,000 Hours, the oxicat is scheduled for 16,000 hours...we figure maintenance and operation cost to be ~ $0.0031/kWh generated}
- Ammonia consumption? {This system is usually proposed to consume Urea...that breaks down to Ammonia in the presence of the exhaust gas...Urea consumption is expected to be ~ 2.2 GPH of 40% Urea/60% water solution}

As a reminder: the
Volumetric Flow rate = 7,500 SCFM of LFG
Site elevation is 1,415 feet per Topographic Map.
Humidity: min: 10%, expected: 55%, max:100%
Ambient Temperature: Minimum = 35 °F, Expected 90 °F and Maximum = 110 °

Landfill Gas compositions are:

Components	Molecular Formula	LFG % Mole
Methane	CH_4	0.383
Carbon Dioxide	CO_2	0.322
Nitrogen	N_2	0.252
Oxygen	O_2	0.043

Please feel free to call me if you have any questions or need more information.

Regards,
Reem Kayali
Process Engineer
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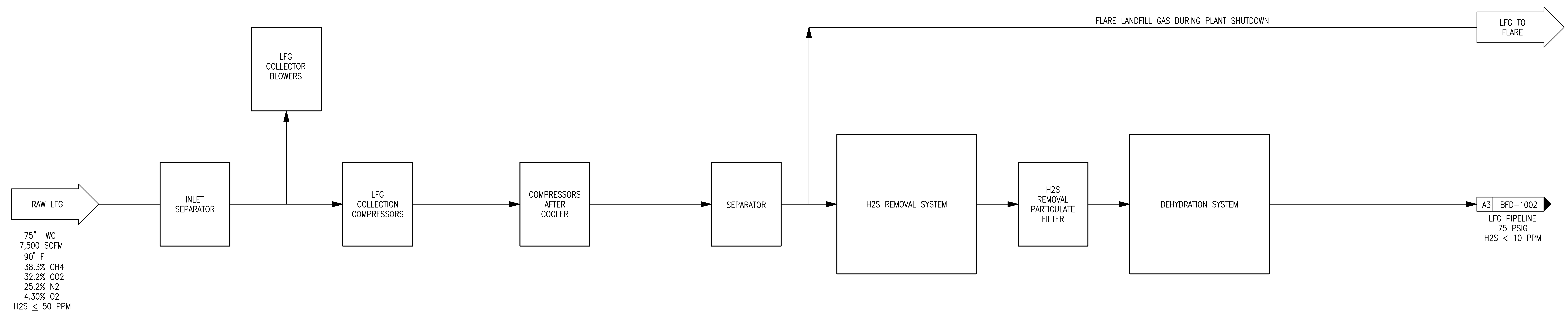
APPENDIX N

Block Flow Diagrams



FOR REFERENCE ONLY

NO.	REVISION	DWN.	CHK.	ENG.	PM.	DATE
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SCALE	NONE		

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SCHOLL CANYON LFG – MERCURY 50 TURBINE STUDY
EXISTING EQUIPMENT
BLOCK FLOW DIAGRAM
FOR DISCUSSION TASK-5

DRAWING NUMBER

REV. A

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SCHOLL CANYON LFG – MERCURY 50 TURBINE STUDY
NEW EQUIPMENT
BLOCK FLOW DIAGRAM
FOR DISCUSSION TASK-5

DRAWING NUMBER: ☐☐☐-☐002 REV. A

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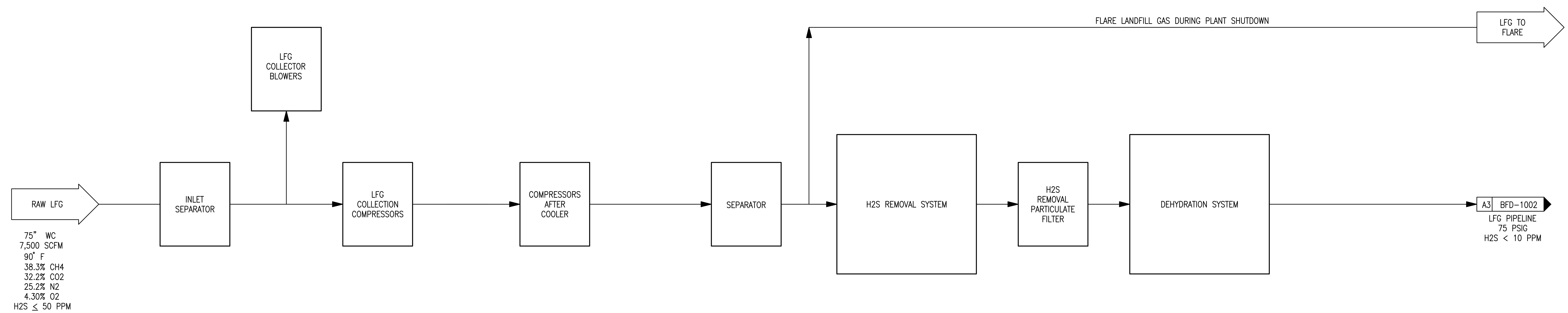

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SCHOLL CANYON LFG – TAURUS 60 TURBINE STUDY
EXISTING EQUIPMENT
BLOCK FLOW DIAGRAM
FOR DISCUSSION TASK-5

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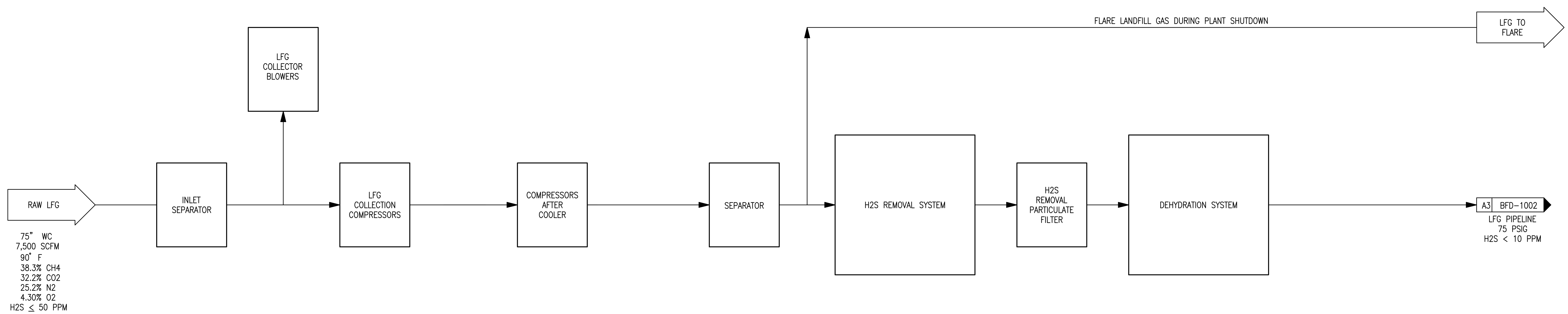

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SCHOLL CANYON LFG – CATERPILLAR IC ENGINE STUDY
EXISTING EQUIPMENT
BLOCK FLOW DIAGRAM
FOR DISCUSSION TASK-5

DRAWING NUMBER

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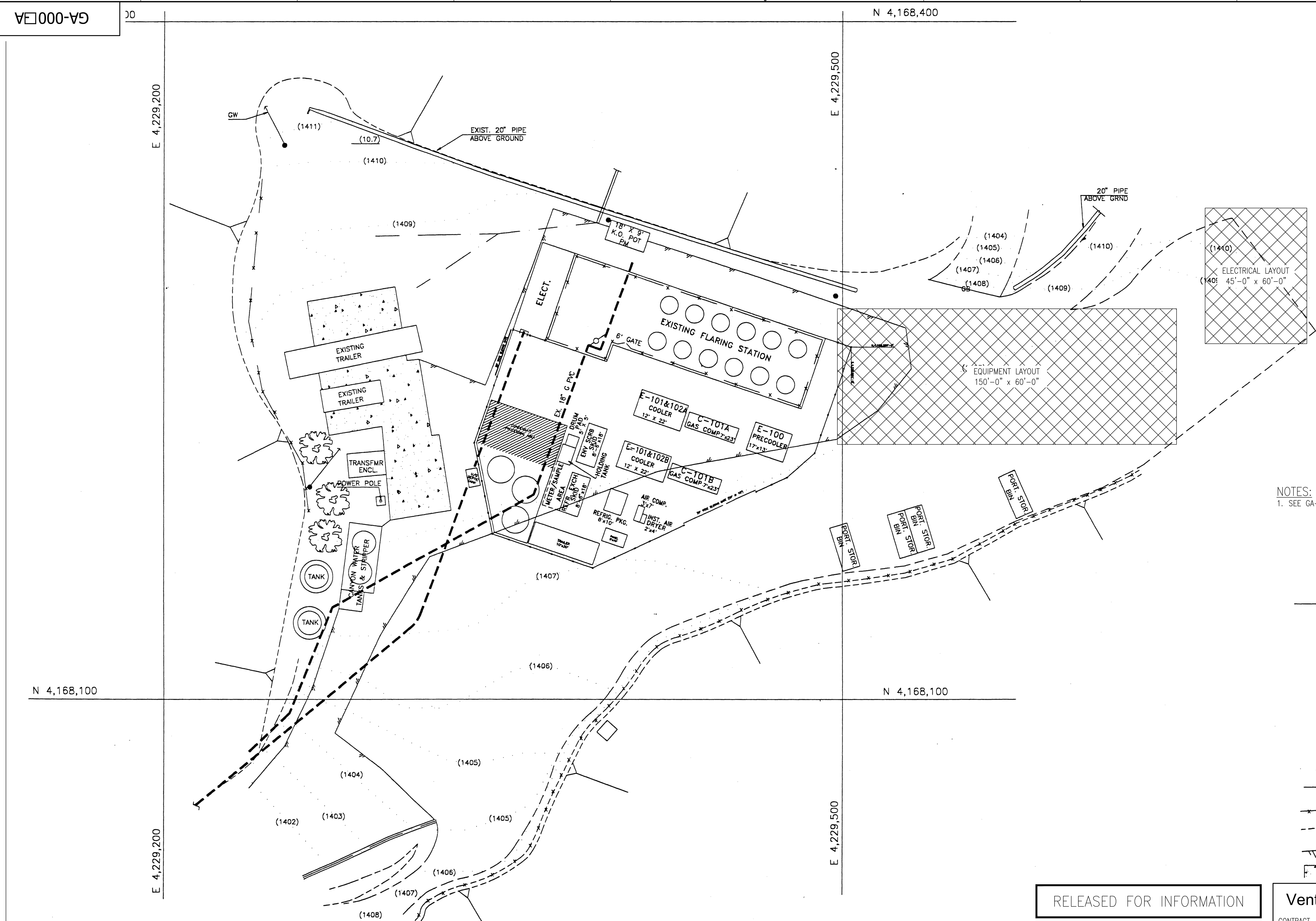
SCHOLL CANYON LFG – CATERPILLAR IC ENGINE
NEW EQUIPMENT
BLOCK FLOW DIAGRAM
FOR DISCUSSION TASK-5

DRAWING NUMBER □□□-□002 REV. A

APPENDIX O

General Arrangement Drawings



NOTES:
1. SEE GA-0002 FOR LAYOUT DETAILS.

LEGEND

AC	ASPHALT CONCRETE
BW	BACK OF WALK
FF	FINISHED FLOOR
FG	FINISHED GRADE
FS	FINISHED SURFACE
FL	FLOW LINE
GB	GRADE BREAK
HP	HIGH POINT
IE	INVERT ELEVATION
PA	PLANTER AREA
PL	PROPERTY LINE
PP	POWER POLE
TC	TOP OF CURB
TG	TOP OF GRATE
TW	TOP OF WALL
EG	EDGE OF GUTTER
TS	TOP OF SLOPE
GW	GUY WIRE
WV	WATER VALVE
(90)	EXISTING CONTOUR
	CHAIN LINK FENCE
	BARRIER FENCE
	TOP OF SLOPE
	EDGE OF ASPHALT PAVEMENT
	CONCRETE PAVEMENT

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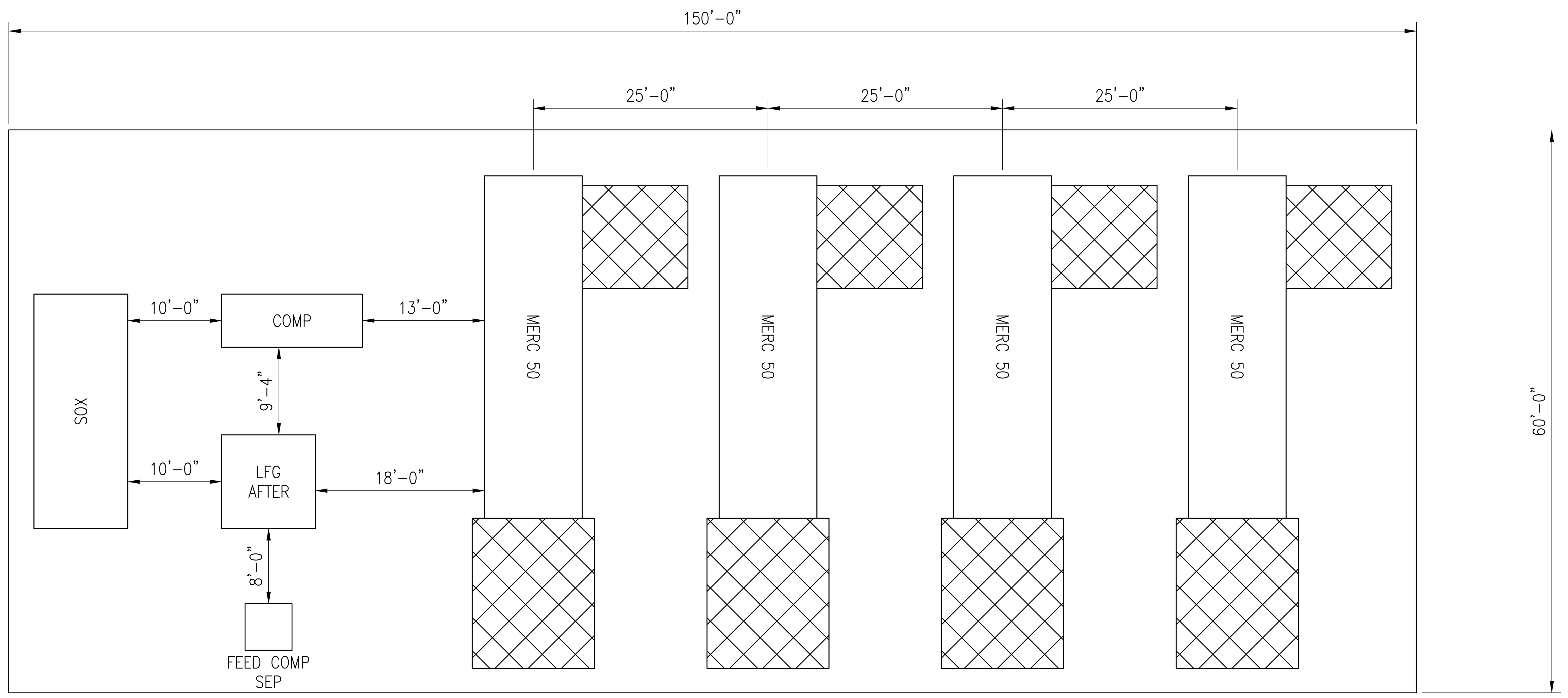
NEW EQUIPMENT
GENERAL ARRANGEMENT
FOR DISCUSSION TASK – 5

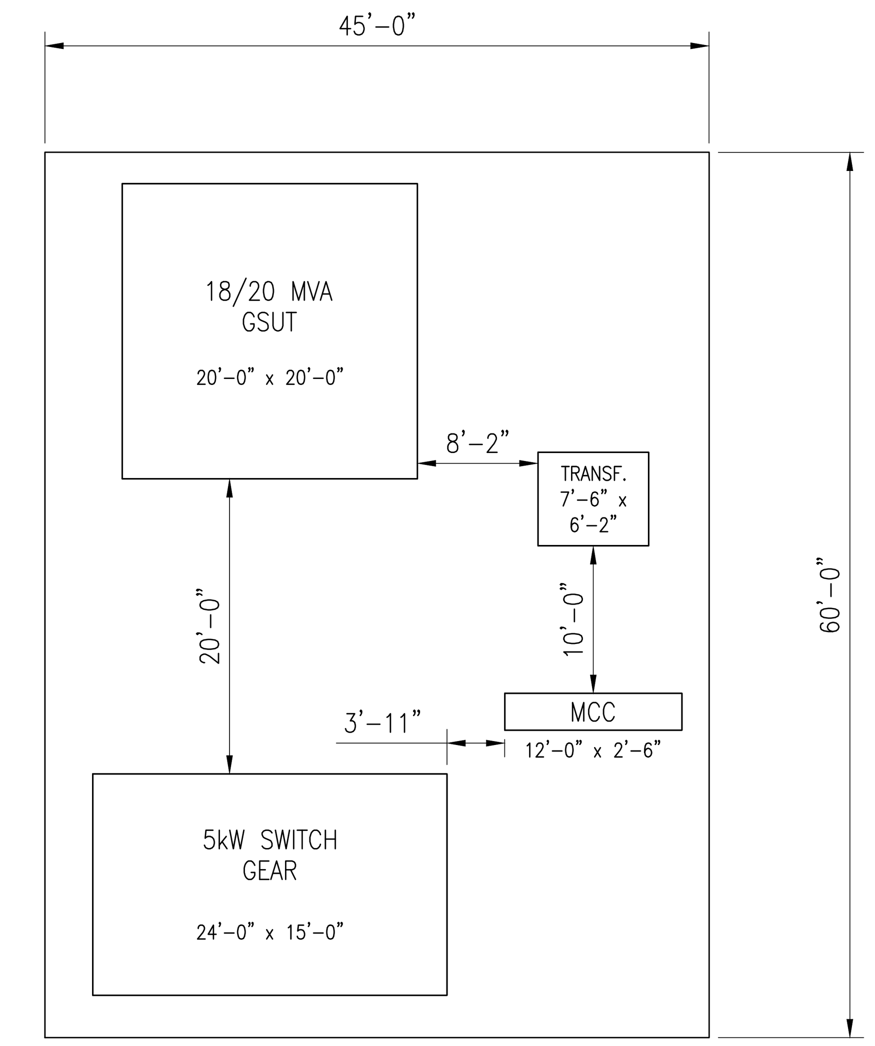
DRAWING NUMBER GA-000□A

REV. A

GA-0002-A



EQUIPMENT LAYOUT
GA-0001



ELECTRICAL LAYOUT
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NEW EQUIPMENT
GENERAL ARRANGEMENT-DETAILS
FOR DISCUSSION TASK – 5

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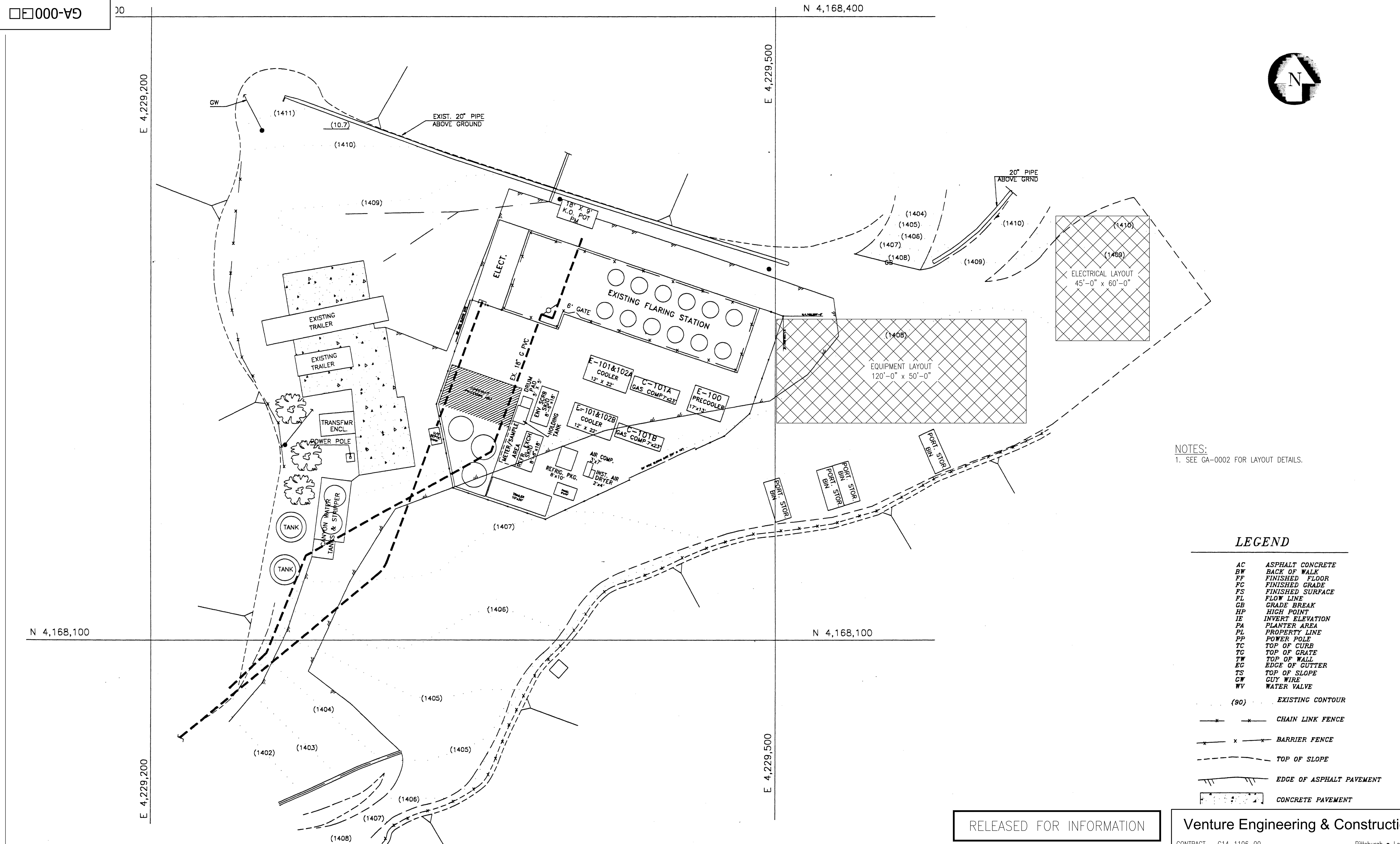

NOTES:
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TG	TOP OF GRATE
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EG	EDGE OF GUTTER
TS	TOP OF SLOPE
GW	GUY WIRE
WV	WATER VALVE
(90)	EXISTING CONTOUR
	CHAIN LINK FENCE
	BARRIER FENCE
	TOP OF SLOPE
	EDGE OF ASPHALT PAVEMENT
	CONCRETE PAVEMENT

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GENERAL ARRANGEMENT
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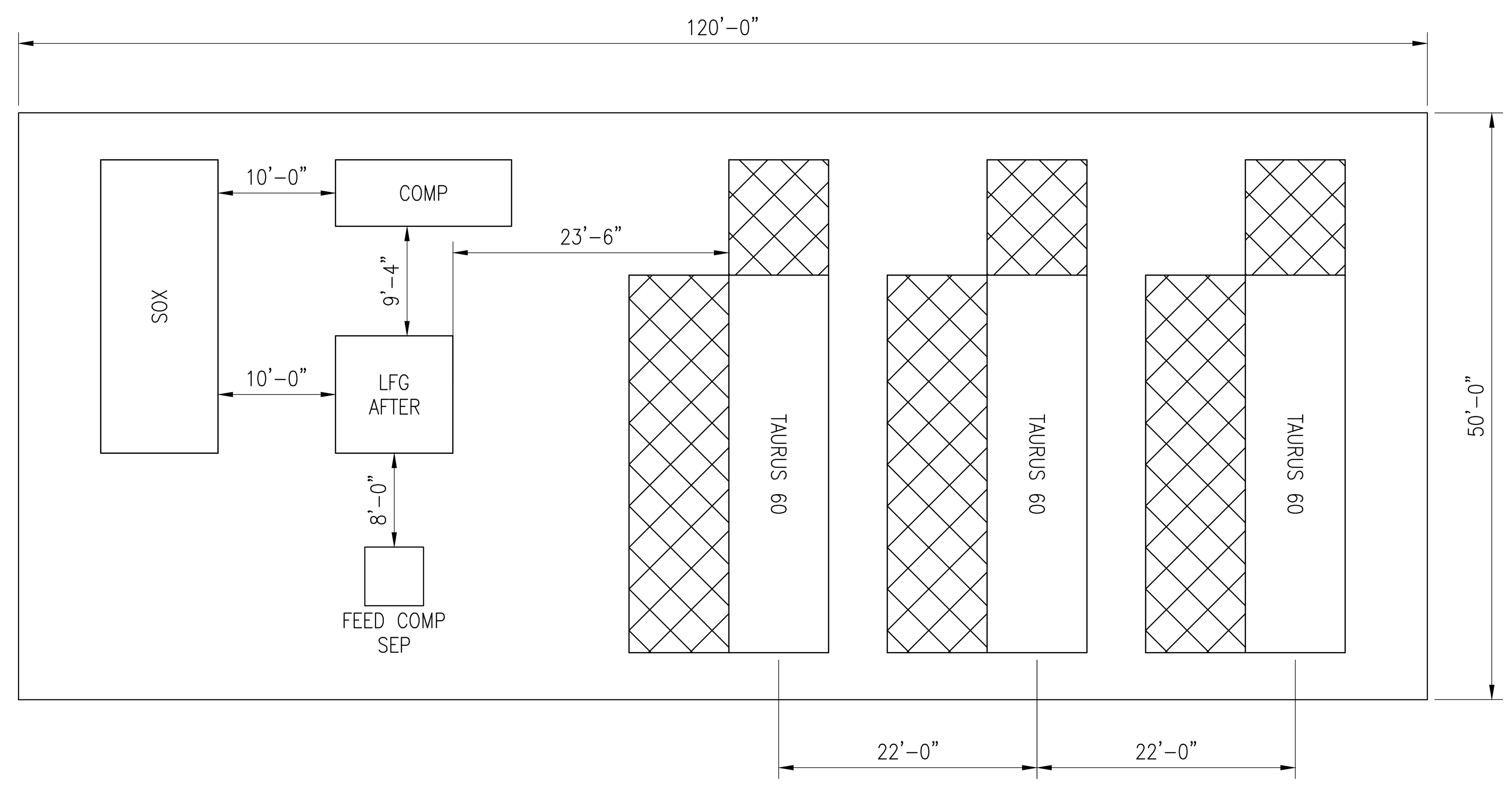

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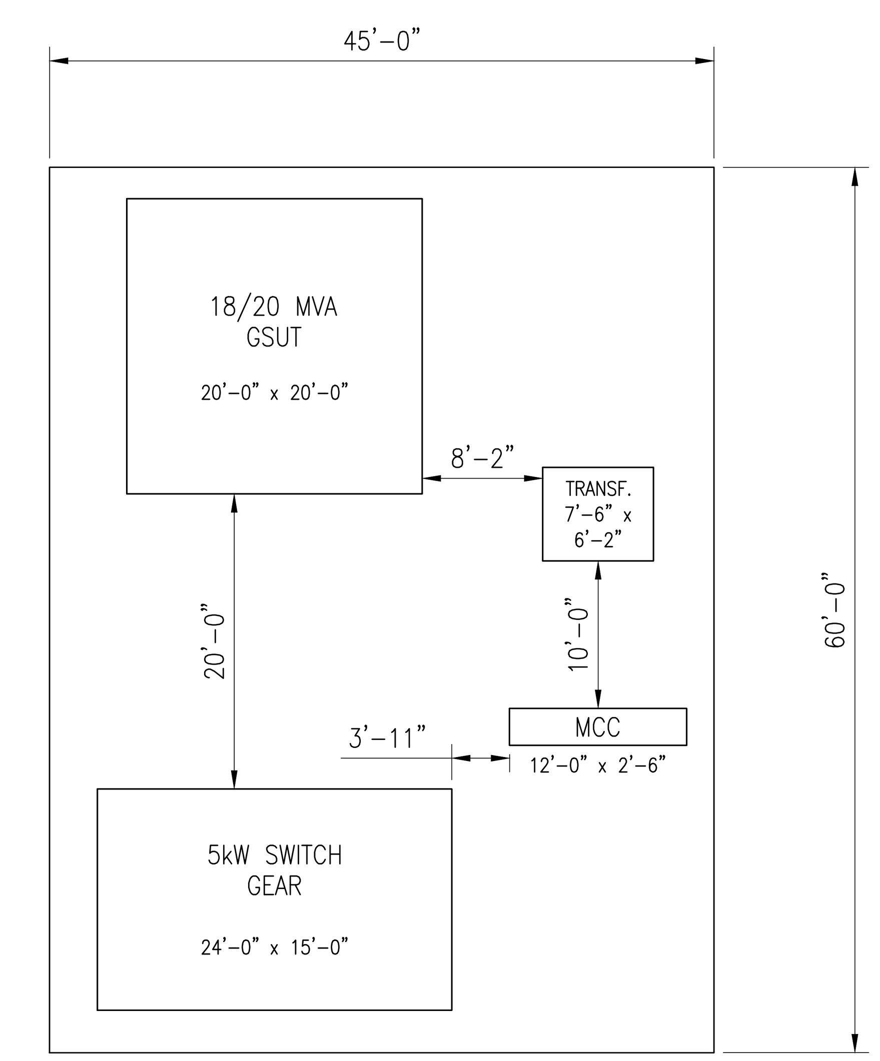
GA-0001



ELECTRICAL LAYOUT
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GA-0002-☐

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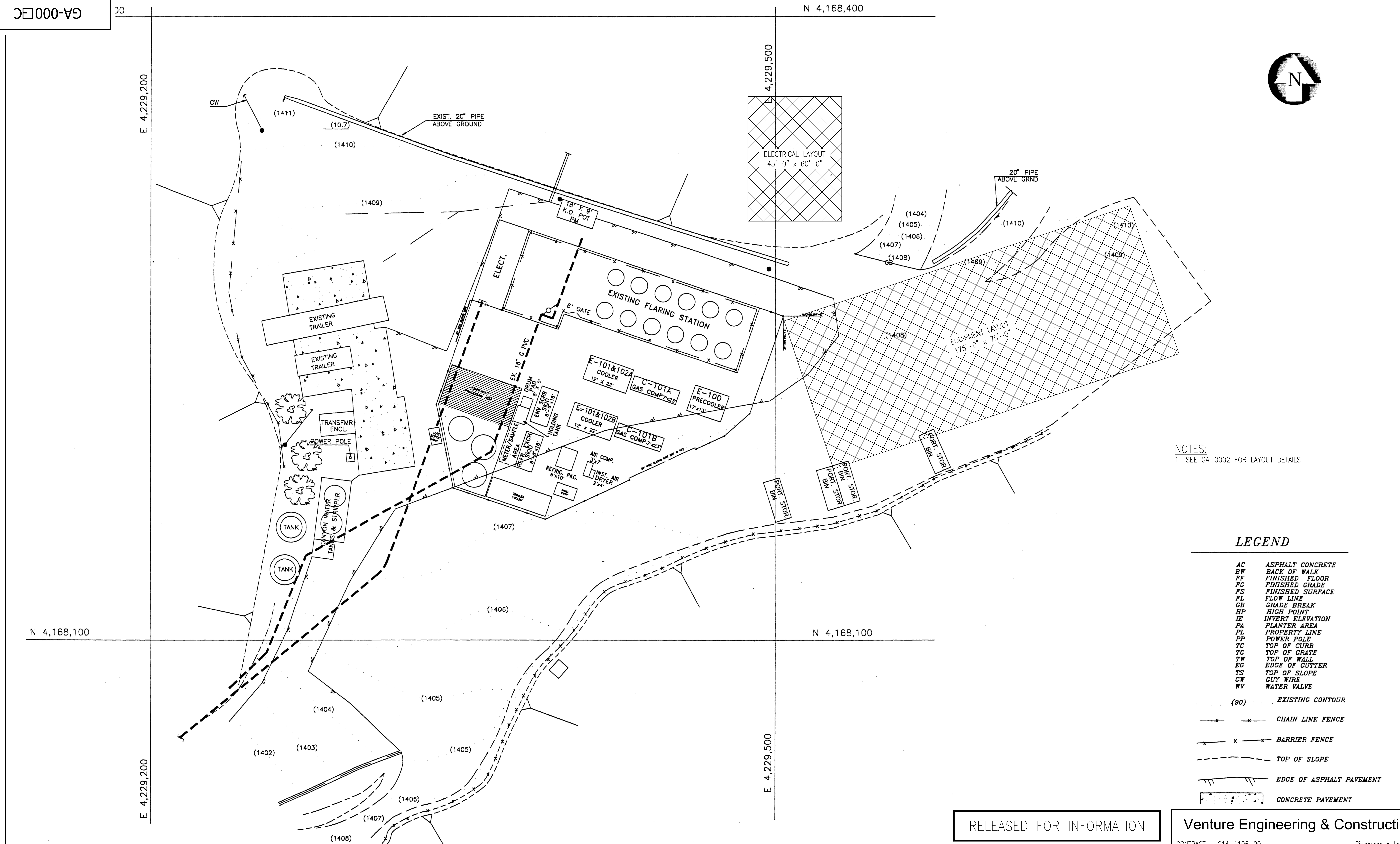

NOTES:
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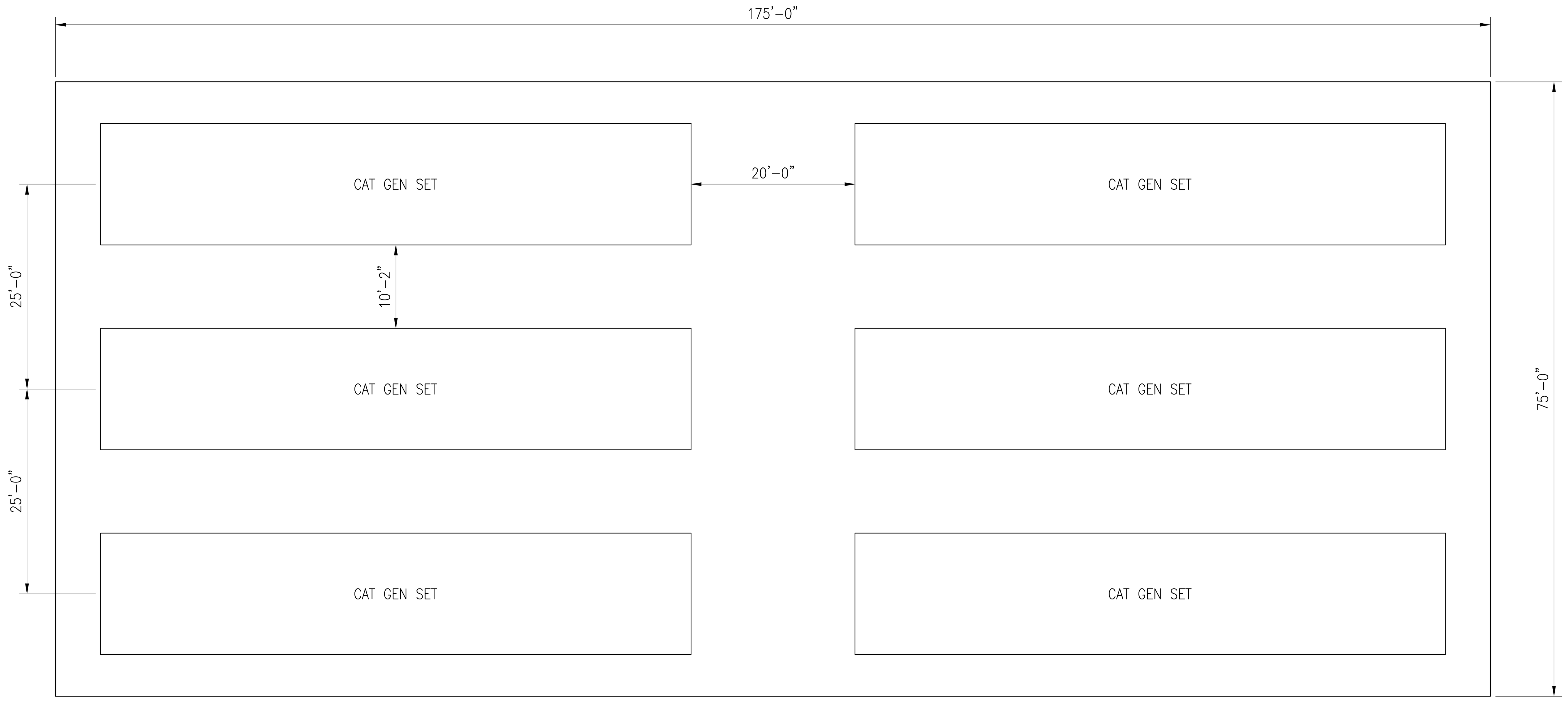
SCHOLL CANYON LFG – CATERPILLAR IC ENGINE
NEW EQUIPMENT
GENERAL ARRANGEMENT
FOR DISCUSSION TASK 5

DRAWING NUMBER GA-000□C

REV. A

GA-000□C

GA-0002-C



EQUIPMENT LAYOUT
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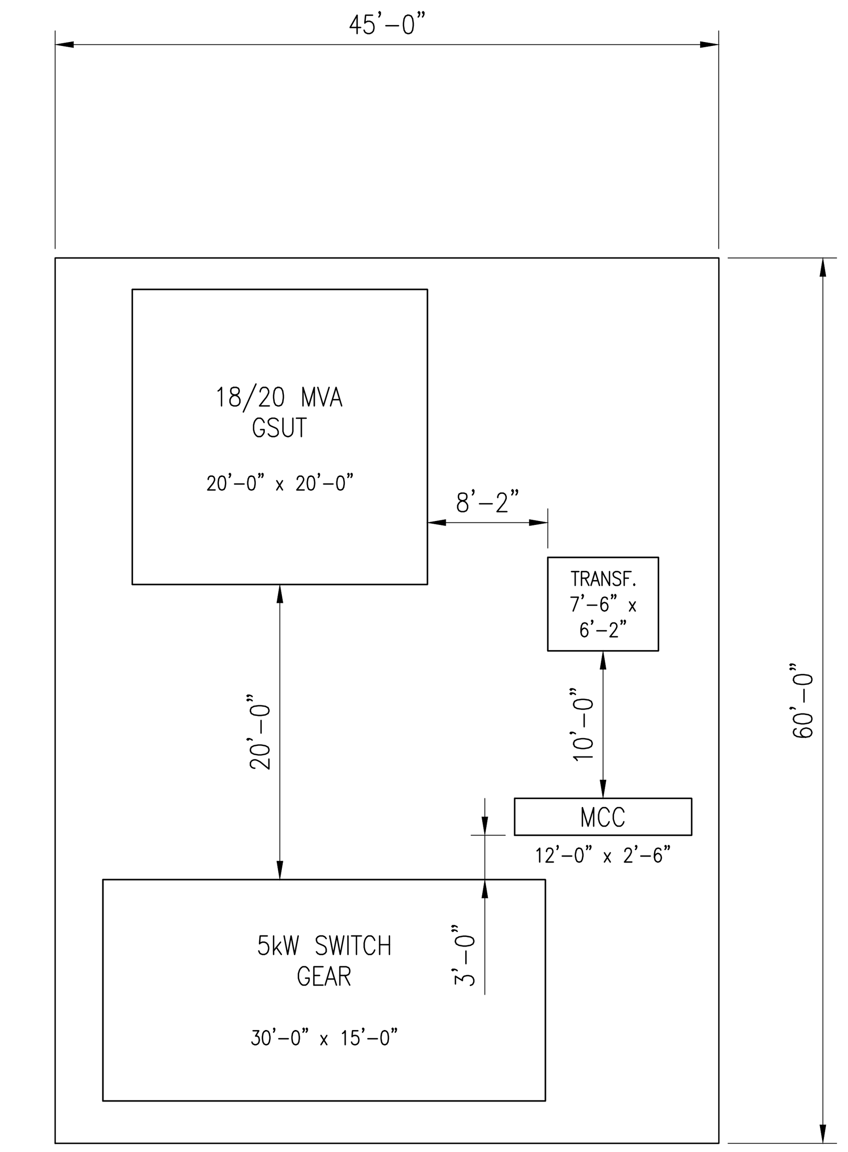

ELECTRICAL LAYOUT
GA-0001

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SCHOLL CANYON LFG – CATERPILLAR IC ENGINE
NEW EQUIPMENT
GENERAL ARRANGEMENT-DETAILS
FOR DISCUSSION TASK 5

DRAWING NUMBER GA-0002-C

REV. A

Emissions Signatures for Landfill and Digester Gas Fuels

Leslie Witherspoon
Environmental Strategies

PURPOSE

This Product Information Letter summarizes emissions estimates of nitrogen oxides (NO_x), carbon monoxide (CO), and unburned hydrocarbons (UHC) for gas turbines operating on landfill and digester gases. Emissions estimates for other alternative fuels (refinery gas, gasified biomass, coke oven gas, etc.) are outside the scope of this document.

INTRODUCTION

Landfill and digester gases are products of the anerobic decomposition of biodegradable wastes in landfills and wastewater treatment plants. Historically, landfill and digester gases have been vented and/or flared. Over the last 20 years, many landfills and wastewater treatment plants have utilized gas turbines to generate electricity, heat, and/or steam from gas that would otherwise be flared or released to the atmosphere.

The compositions of the landfill and the digester gases are a major factor in determining the emissions signature. The emissions estimates summarized in this document are <u>typical</u> emissions estimates for <u>typical</u> landfill and digester gas compositions. **Site-specific emissions are determined on a case-by-case basis based on fuel composition, site conditions, operating profiles, fuel pre-treatment scenarios, and other factors.**

As a result of the variability of landfill and digester gas compositions from one site to another, it should not be assumed that a published/quoted emissions estimate for one site is representative of another.

FUEL QUALITY AND COMPOSITION

Gaseous fuels are often classified by their Wobbe Index, a parameter that accounts for variation in the fuel gas density and heating value. Wobbe Index is defined as the lower heating value (LHV) of the fuel in Btu/scf divided by the square root of the specific gravity of the fuel with respect to air. The Wobbe Index is an important parameter in designing fuel systems to accommodate fuels with different heating values.

Solar's combustion turbines can burn a wide variety of gaseous (and liquid) fuels. Conventional combustion gas turbines have more fuel flexibility than gas turbines with dry low emissions (DLE) combustion systems. Generally, DLE combustion systems are not compatible with landfill and digester gases, however, the Ultra Lean Premix (ULP) combustion system on the *Mercury* 50 gas turbine has been modified to support landfill and digester gas combustion.

Typical landfill gas contains 35-51% methane (CH_4) with the balance made of up primarily carbon dioxide (CO_2) and nitrogen (N_2). Digester gas contains 60-65% methane with carbon dioxide and nitrogen making up the balance.

EMISSIONS ESTIMATES

The emission estimates, shown in Tables 1 and 2, can be used as preliminary estimates for project planning provided the Wobbe Index of the landfill fuel falls between 300 and 460

Btu/scf LHV, or the digester fuel falls between 560 and 665 Btu/scf LHV, and the balance of the fuel composition is carbon dioxide or nitrogen. The presence of hydrogen (H_2) or hydrocarbons heavier than methane nullifies the applicability of this document.

The emissions estimates reflect typical emissions levels and are valid at steady-state conditions, at ambient temperatures of 0°F (–18°C) and above, and are limited to the load ranges shown in Tables 1 and 2. The estimated emissions levels do not apply during start-up, shut-down, malfunction, or transient events.

Table 1. Landfill Gas Emissions Estimates @ 15% O_2
(Assumes Wobbe Index Range 300 to 460 Btu/scf LHV)

Turbine Model	ISO NO_x*		CO		UHC		Load Range (%)	Ambient Temp °F (°C)
	ppm	mg/Nm^3	ppm	mg/Nm^3	ppm	mg/Nm^3		
Centaur® 40	42	88	250	318	100	72	80-100	>0 (–18)
Centaur 50	42	88	200	254	100	72	80-100	>0 (–18)
Mercury™ 50	15	25	25	30	25	18	50-100	>0 (–18)
Taurus™ 60	42	88	150	191	75	54	80-100	>0 (–18)
Taurus 70	80	166	100	127	50	36	80-100	>0 (–18)
Mars® 100	72	150	100	127	50	36	80-100	>0 (–18)
Titan™ 130	80	166	100	127	50	36	80-100	>0 (–18)

* ISO NOx correction and relative humidity ≥30% applies for all models except the *Mercury* 50.

Table 2. Digester Gas Emissions Estimates @ 15% O_2
(Assumes Wobbe Index Range 550 to 665 Btu/scf LHV)

Turbine Model	ISO NO_x* Uncontrolled (Water Injected)**		CO Uncontrolled (Water Injected)**		UHC Uncontrolled (Water Injected)**		Load Range %	Ambient Temperature °F (°C)
	ppm	mg/Nm^3	ppm	mg/Nm^3	ppm	mg/Nm^3		
Centaur 40	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Centaur 50	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Mercury 50	25	50	50	64	25	18	50-100	>0 (–18)
Taurus 60	100 (42)	208 (88)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Taurus 70	150 (72)	312 (150)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Mars 100	150 (60)	312 (125)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)
Titan 130	150 (72)	312 (150)	100 (200)	127 (254)	50 (25)	36 (18)	80-100	>0 (–18)

* ISO NOx correction and relative humidity ≥ 30% applies for all models except the *Mercury* 50.

** Water/Fuel ratio is assumed to be 0.8 to 0.85.

Volatile Organic Compound (VOC) emissions can be assumed to be 20% of the UHC values shown in Tables 1 and 2. Note: The 20 ppm VOC (as hexane) @3% O_2 requirement found in 40 CFR 60, Subpart WWW, is approximately equal to 40 ppm VOC (as methane) @15% O_2. Thus, the VOC estimates for *Solar*® turbines comply with the VOC limit in Subpart WWW.

Particulate matter (PM, PM_{10}, $PM_{2.5}$) for landfill and digester gas fuel can be estimated using 0.03 lb/MMBtu (HHV). Reference PIL 171.

Because sulfur content varies site-to-site, Solar recommends that **sulfur dioxide** emissions be estimated using a mass balance approach. Reference PIL 168.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398