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April 16, 2009

California Energy Commission
Docket Unit
1516 Ninth Street
Sacramento, CA 95814-5512

Subject:

CANYON POWER PLANT SIMPLE CYCLE PLANT JUSTIFICATION
DOCKET NO. 07-AFC-09

Enclosed for filing with the California Energy Commission is the original of the **CANYON POWER PLANT SIMPLE CYCLE PLANT JUSTIFICATION**, for the Canyon Power Plant Docket No.07-AFC-09:

Sincerely,

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Canyon Power Plant
Simple Cycle Plant Justification

Prepared by: City of Anaheim and PB Power

Date: April 16, 2009

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1. Executive Summary

The proposed Canyon Power Plant (Project) is a nominal 200 megawatt (MW) peaking power plant facility for the City of Anaheim (COA) that consists of four GE LM6000PC Sprint combustion turbine generators (CTG) operating in simple cycle. The primary purpose for the Project is to allow the COA to be able to meet reliability requirements as well as to provide capacity for future customer load growth and to provide energy during Anaheim's highest peak electrical demand. It has been suggested by intervening parties to the project permitting application process that the COA should have considered utilizing a combined cycle generating resource in lieu of the proposed simple cycle plant.

The purpose of this white paper can be summed up as follows:

- Describe in detail the COA's need for peaking capacity
- Why the choice for simple cycle aero derivative combustion turbine (GE - LM6000) was chosen as the ideal fit for the COA's overall resource portfolio
- That a simple cycle plant is the optimum (least cost) alternative
- Outline why combined cycle is impractical as well as a sub-optimal choice for the COA's electric resource needs.

The COA must be conscious of meeting all federal, state and local licensing and permitting requirements, but at the same time, ensuring that it acts in a prudent and cost-effective manner in order to minimize impacts to its ratepayers based upon its long-term decision process. It is both impractical and an unnecessary cost imposition as well as a disservice to Anaheim's ratepayers to select combined cycle technology based on efficiency for the relatively few annual hours of operations the plant is actually needed to operate. The CPP will be needed for operation typically only when the demand for electricity is high typically during the summer months. The CPP will sit idle the vast majority of the year serving as a back-up reserve plant for electric system reliability purposes.

The COA's current resource portfolio of 500 MW is more than adequate to meet daily loads during most of the year. In fact, 80% of the COA's resources are base-load or must take sources of power. During summer months, however, the COA relies on market purchases of 50 -75 MW in order to meet peak demand that can be as high as 590 MW, depending upon weather conditions. In addition, the COA must provide 15% above peaking needs for reliability purposes, resulting in capacity purchases for an additional 75 MW. Therefore, the COA's most immediate need is for an additional 150 MW of peaking resources.

Customer retail loads above 500 MW do not occur frequently, in fact only average approximately 50 hours per year (less that 1% of the time). The utilization of the peaking resources, therefore, is limited to a small number of annual hours of operations. As a

result, the COA's real need is for peaking capacity and not so much for the energy the facility produces. That is in large part, the rationale for choosing a simple cycle technology such as the LM6000 combustion turbine presented in the COA's application.

The combined cycle plant configuration adds a large degree of power plant system complexity and interdependence between the operating combustion turbine power islands that is not a part of a simple cycle configuration. By its very nature, the independence of each power island in the simple cycle configuration simplifies dispatch ability, operation, and maintenance, as well as providing a higher degree of flexibility. Although the use of a once through steam generator (OTSG) is the most accommodating boiler design for rapid combustion turbine starts, the addition of a steam collection and transport system, steam turbine-generator (STG), steam condensing system, boiler feedwater system, boiler chemical treatment systems, and cooling tower with its circulating water system (or possible air-cooled condenser (ACC)) adds an additional dimension of complexity to a facility that would otherwise require minimal operating staff and maintenance. It is the intention that a simple cycle plant could also be safely and effectively started and operated remotely. This would not be considered as an option for a combined cycle configuration.

While a combined cycle configuration is more energy efficient when compared to simple cycle, the maximum efficiency benefit only occurs when the STG has reached its full operating load (typically a few hours after initial combustion turbine startup). The CPP would be unable to benefit from this efficiency gain since the expected normal daily dispatch duration of the plant will only be 2 to 3 hours. Additionally, since the STG cannot reach any output level in the first 10 minutes (or first hour) its output would not be applicable to satisfying the COA's reserve capacity requirements required by the California Independent System Operator (CAISO).

Even though a combined cycle configuration would probably only utilize 3 combustion turbines (rather than 4 for the simple cycle configuration in order to maintain the nominal 200 MW size plant) the addition of the OTSG, STG, steam condenser, and cooling tower (or ACC) would increase the plant capital cost significantly. The plant capital cost would increase on the order of $70 million dollars (30% increase) whether a wet cooling tower or dry air-cooled steam condenser were used. When finance costs are included, the total increases to $80 million. Represented in cost per kW of capacity, the increased cost would be 38% for a wet cooling tower system and 40% for the ACC system. This would not be consistent with the normal utility practice of minimizing capital cost for an asset whose primary function is to provide reserve capacity.

Merchant "peaking" plants, like those cited by Yorba Linda as examples of combined cycle applications for peaking duty, would have a very different financial paradigm since the expectation would be a daily dispatching of several hours where the cost of energy supplied is a significant consideration in the plant's financial viability. Having a limited number of hours during the summer peak season the COA's generation additions would be operating, and given the limited number of hours in a day (typically 2 to 4 hours per day), it only makes sense that a simple cycle resource be installed. A simple cycle

resource with low capacity cost and high variable cost is the practical technology to utilize in this application. In any optimal generating planning modeling, generation equipment primarily used as reserve with limited annual operating hours, the most optimal solution is to acquire generation resources with low capital investment costs while sacrificing higher operations costs.

2. Introduction

Project Overview

The Canyon Power Plant (CPP) is a proposed simple-cycle power generation project that consists of a nominal 200 MW plant, using four natural gas-fired General Electric LM 6000PC Sprint combustion turbine generators. This particular combustion turbine model has one of the highest fuel efficiency ratings in the market place today. These combustion turbines will have inlet air chilling using chilled water supplied by mechanical chillers that will significantly increase the combustion turbine performance during hot summer days. The Southern California Public Power Authority (SCPPA) will own the proposed plant, and the COA will be the project manager and plant operator once the plant is built.

The CPP will be located on a 10 acre brown field site located at 3071 East Miraloma Avenue within an existing industrial area of Anaheim. Main access to the CPP site will be at the southeast corner of the project site from East Miraloma Avenue. A second gated entrance will be accessible via East Miraloma Avenue with a third gate off the alley to the east of the site.

The CPP is strictly dedicated to providing reserve capacity and for generating power to serve Anaheim's retail customers. Current load/resource balances for Anaheim show a potential power capacity shortage during the peak summer period. As a result the output of the plant will be utilized to meet resource adequacy requirements and to serve native load within Anaheim.

The Southern California Gas Company (SCGC) will supply natural gas fuel for the plant, and water used for process needs will be supplied from the Orange County ground water replenishment system (reclaimed waste water). The electrical transmission of the power produced by CPP will be through the City of Anaheim electrical distribution system that will be upgraded to accommodate the power output of the CPP.

Status of Project

The CPP Project is in the final stages of the California Energy Commission's Application For Certification (AFC) permitting process with the Preliminary Staff Assessment (PSA) due to be issued within the next month. The South Coast Air Quality Management District (SCAQMD) issued the Preliminary Determination of Compliance in February of this year, and SCPPA has obtained all of the required emission reduction credit offsets required to operate the facility on a limited basis. Due to the current market demand for combustion turbines resulting in long equipment delivery times (on the order of 18 months), SCPPA has already ordered the combustion turbines, SCR/CO exhaust systems, and continuous emission monitoring systems. Due to equally long delivery times, the gas insulated switchgear (GIS) equipment has also been ordered. The commitment to purchase the long delivery time equipment was necessary in order to begin the construction process once all of the required permits have been issued and financing

bonds are in place. The contract for the engineering and construction of the CPP was let out to bid and SCPPA is currently in the bid review process. All of this effort is directed to having the CPP operational for summer use to meet the CAISO mandated capacity margin requirements. For every year delay that Anaheim is not able to have the CPP operational, it will continue to be forced to buy power on the open market in order to meet customer requirements as well as comply with the required reserve margins described further in this document. Given the potential volatility and uncertainty in market prices, it would not be prudent utility practice to expose Anaheim's ratepayers to such a economic and financial exposure for continued delay in construction of the project.

Yorba Linda Request to the SCAQMD

On March 11, 2009, as an intervener, the City of Yorba Linda submitted a request to the SCAQMD for a public hearing to present its objection to the CPP project. This White Paper was developed in response to that request to clarify the City of Anaheim's basis for the development of a simple cycle peaking plant configured with simple cycle units as currently being permitted. There were three (3) items that the City of Yorba Linda felt needed to be addressed in the hearing.

First, Yorba Linda indicated that the selection of a combustion turbine in simple cycle configuration was inappropriate and that the configuration should have been a combined cycle. In it's request letter to the SCAQMD the City of Yorba Linda referenced three particular projects that incorporate the same combustion turbines as the one proposed for the CPP and operate in a combined cycle configuration through the utilization of a once through steam generator (OTSG) type boiler design. This unique type of steam boiler does have the capability to produce steam in a relatively short period of time. After the steam turbine is properly heated up and is operating at full load, the overall plant efficiency is better than that for a simple cycle facility. The referenced facilities' use of the OTSG for combined cycle application underscores the appropriate technology match for use in combined cycle for a merchant type power plant where the cost of energy production is key to providing the economic viability of the project.

Merchant type power plants typically only operate when economically profitable to do so due to the price they are paid for the electricity. For the CPP peaking plant, the basis for the plant is not the economic viability of energy production (as in the referenced merchant plants) but rather the economic development of plant capacity to fulfill margin and reserve requirements as discussed more fully in other sections of this paper. The primary difference has to do with the amount of time the units would be operating when dispatched and the dispatch frequency. With regard to the statements concerning the CPP air emissions, the CPP complies with all of the strict emission requirements mandated by the SCAQMD. This is specifically addressed in more detail in another section of this paper.

Secondly, Yorba Linda indicated that the number of operating hours has varied during the permitting process and that the documentation of the changes may not have been clearly

presented. The number of operating hours proposed has changed during the permitting process to address changes in emission requirements (e.g. Rule 1309.1) as well as a better definition of the COA's long-term needs. It should be noted that the COA has two objectives in stating its proposed operating hours: first, the COA needs to establish the best estimate of the expected CPP annual operating hours and dispatching frequency (this would serve to form the basis for design optimization of the plant); and secondly, what capacity the CPP will be capable of producing under the worst case scenario for peak power demand. Based on these, the CPP needs to be permitted for allowable annual emissions sufficient to ensure that the CPP will not be emission quantity limited if the facility needs to be dispatched during a worst-case scenario.

Thirdly, Yorba Linda pointed out that the number of permitted annual starts increased over the permitting period. As stated previously, the emissions permit did change during the project development. The specific number of allowable annual start-stop cycles has to be selected by the COA to cover the worst-case scenario for starts and the increase in permitted allowable starts reflects the COA's expectation that the CPP may be dispatched numerous times for short durations. To fulfill the stated objective of the CPP, which is to provide margin reserves and peaking capacity, the plant must be permitted for an adequate number of starts so that it will be available when needed and not be restrained by exceeding the allowable number of annual starts. The air emissions emitted during startup are somewhat greater than emissions during normal operation, but all emissions, whether during startup or normal operation, are part of the total annual emission limits for the facility.

3. Anaheim's Need for Peaking Capacity

Resource Mix

The primary purpose for the CPP is to meet the COA's retail customer load during peak periods (energy as well as capacity), typically during summer weekdays during the hottest part of the day where air conditioning requirements from customers is its highest. Given that a majority of the COA's daily energy requirements are met through a combination of coal resources and combined cycle natural gas generation, the COA's basic need is to pursue peaking resources that require few operating hours as well as to provide stand-by capacity requirements mandated for local and state-wide reliability objectives.

Current resources owned or under long-term contract for the COA include 236 MW from Intermountain Power Project (IPP) and 50 MW from San Juan unit 4. Both facilities are low cost coal facilities which run on a 24 hourly basis and are base load resources. The COA also has contracts for approximately 40 MW in renewable resources, which primarily are must-take or base load resources. In addition, the COA has an ownership share of the Magnolia Power Project, a combined cycle natural gas fired unit located in Burbank, CA, of which the COA's ownership share is 118 MW. While the unit has some flexibility, it must operate a minimum of 70 MW (the COA's share). The COA also has a 46 MW peaking facility within the City, a 40 MW storage hydro entitlement from the

Hoover Project which is a limited energy resource, and 25 MW of as available wind and hydro renewable energy resources.

It is apparent from this description that a majority of the COA's resources operate around the clock on a daily basis. In fact, of the total generating resource of 500 MW, almost 400 MW or 80% of its resources must be taken on a 24 hour basis. During the non-summer months, the single highest demand from the COA's retail customers range from 360 MW – 420 MW, so in comparison to the base-load resources described above, there a few occasions during the October through June timeframe where the remainder of the COA's resources are not utilized, let alone addition capacity not yet developed. Therefore, the COA has no need for additional production from resources that require a large number of operating hours such as combined cycle facilities. There is no room in Anaheim's existing generation portfolio to economically accommodate an additional combined cycle facility.

Retail Peak Load Requirements

The COA is considered to be a summer peaking utility, meaning that customer demand for electricity is highest during the summer months primarily due to air conditioning load. In absolute numbers, of the 115,000 electric meters, 94,000 of those are residential customers whose typical peak consumption is driven by air conditioning requirements. This particular customer mix results in large swings in daily peak demand that is heavily dependent upon hot weather conditions and time of day. For example, typical daily peaks during the non-summer months, particularly from November through April are in the 360 MW – 400 MW range. That is, the highest consumption for any given hour in the day reaches up to the range; the remainder of the 23 hours in the day are lower. During the summer months, typical daily maximum consumption ranges from 480 MW – 530 MW. Under unusually hot weather, maximum consumption for the peak can range from 540 MW to the all-time peak of 593 MW.

Currently, the COA anticipates its peak demand for summer to be 550 MW. While the current economic climate indicates no additional load growth in the 2008 – 2009 timeframe, in the long term, load growth will cause peak demand to increase to 600 MW by the year 2020. Part of the rationale of adding 200 MW of peaking capability with the CPP is to make one investment that will meet projected peak demand for several years into the future accommodating load growth without having to add more generation in the near future.

Given that the COA's existing resource portfolio is 500 MW, in the short-run the COA has to purchase 50 – 75 MW for the entire summer from third parties in the open market in order to meet its anticipated system peak requirements. Looking long-range, reliance on market power purchases would increase to 125 MW, almost 20% of the COA's capacity needs. These transactions must be made well in advance of the summer season in order to comply with the CAISO tariff. In addition, prices for power for the summer period are the highest during the year and subject to volatility. In fact, this energy could

cost the COA as much as $10 million per year to acquire under current conditions and is forecasted to be in the range of $15 – $20 million per year in next several years.

One of the obvious reasons for adding the CPP is to protect the COA ratepayers from heavy reliance on open power market conditions given the potential cost of power and possible price volatility by having a fixed resource such as the CPP. One only needs to recall the huge volatility and high market prices that occurred during the Energy Crisis in 2000-2001 to understand the financial dangers of being dependant on the open power market for power when the COA needs power the most.

In addition to cost savings by not relying on market power for summer needs, there are changes being undertaken in the CAISO grid that will limit Anaheim's ability to rely on the market to provide power. Under new procedures being developed, CAISO will require a direct linkage to the source of power providing the energy in the open market, rather than a generic source at the trading hub that has been allowed in the past. With particular emphasis on reliability requirements, there will be fewer opportunities to acquire power for the entire summer to dedicate for peak capacity. Given the COA's obligation to provide power for its retail customers as well as meet reliability standards required by the CAISO, having power provided by a physical facility such as the CPP will be absolutely necessary for the COA to meet its obligations.

Utilization of Peaking Resources

During a typical summer the number of times where load exceeds 500 MW is within a range of 5 – 15 days during the entire summer. During those days the peak load typically last between 2 – 5 hours, depending on the weather. The 500 MW level represents the amount of existing capacity in Anaheim's portfolio (while wind is rated at 30 MW, during summer months, the amount of wind available during peak periods typically drops to 0 -10 MW and cannot be reliably counted upon to meet customer load during these periods). Therefore, additional capacity would be needed on a limited basis. Therefore, the COA needs a minimum of 50 MW for meeting the highest summer loads under normal weather conditions and up to 100 MW to meet a peak requirement of 590 MW. For the first 50 MW of capacity, the resource can be utilized 2 to 5 hours a day for 5 to 15 days during the year. It should be noted that the 5 – 15 hot days might not be contiguous. Additional generation beyond this amount would be utilized even less.

This duty cycle of limited number of hours and days in operation during a season and with only 2 to 5 hours in operation during a dispatched day strongly suggests that simple cycle technology is best suited. By design, combined cycle units have better efficiencies during full load operation, which from a dispatch basis, implies the facility should be run more daily hours and more frequent dispatching to take full advantage of its lower cost of operation. However, as demonstrated above, the benefits of such efficiencies are not necessary for the COA's load profile.

In point of fact, Tables 1A through 1C identify how many hours during a typical summer the CPP will be operating, based on normal conditions. The weeks identified in the chart

indicate the highest retail loads the COA encounters during the year to demonstrate the CPP's highest utilization. Note that out of the selected 20 weekdays, there are only 3 days in which unit 1 runs 10 hours; the remaining units show operations of only running 2-4 hours. Of the other 17 days, all units are running substantially fewer hours.

Table 2 identifies the projected number of hours each unit operates for the entire year through 2027. Note that the total number of operating hours for the entire facility is 2,000 hours, with any one unit operating less than 1,000 hours for the entire year. The utilization or capacity factor for each facility is 10% or less on an annual basis.

Both tables reinforce earlier discussions that the purpose of the CPP is for capacity purposes and not for energy production. Such low utilization factors lead to the conclusion that simple cycle technology is perfectly suited for this duty cycle and the most optimal technology choice to meet the COA's current and future power needs. As will be discussed, the primary benefit of combine cycle technology is the efficiency advantage over simple cycle, but that efficiency requires higher capital investment. With better efficiencies, combined cycle operating hours would need to be higher in order for those efficiencies be realized in order to offset the increase in capital investment. As clearly indicated in the tables, the COA's use for peaking facilities is fairly limited on an energy basis. This utilization clearly indicates that combined cycle technology does not fit with the COA's peaking needs.

Reliability Mandates

While utilization for peak operations are limited, the need for a 200 MW peaking facility goes beyond the COA's current and projected customer demand. Given the COA's resource portfolio, there are several reasons for having capacity available without the immediate need to generate power. First, there are reliability standards that require that the COA have additional power generation capacity as a back-up or as standby reserves. While the COA has 500 MW of existing capacity, there are no guarantees that the entire capacity is available when needed. Like any mechanical device, generating resources are subject to mechanical failures that can occur on a random basis, referred to as forced outages. Given that some of the COA's largest facilities are as much as 118 MW, failure of any one of those facilities would require 100 MW in back-up reserves to replace the lost capacity, particularly during peak periods. While the combined probability that those large facilities fail during peak periods are limited, there is a severe economic cost of relying on the energy market to cover the loss of that facility. Typically during the peak periods, market power is priced very high and can be very volatile in nature, depending upon weather conditions. Losing a major resource during that time period and relying on market power for replacement power has cost the COA as much as $350/MWh on a limited basis. Having a 200 MW peaking facility would mitigate that economic exposure and benefit the COA's ratepayers by minimizing the cost of replacement power due to forced outages.

The COA is also required to carry additional capacity as standby reserves. As mandated by AB 380 (Nunez 2005), the COA is required as a load serving entity, to meet minimum

Western Electric Coordinating Council (WECC) planning reserve and reliability requirements. In addition to legal requirements, as a load serving entity within the CAISO, the COA is required by tariff to maintain a minimum of a 15% planning reserve margin. The planning reserve margin is that amount of reserve power generation that is required beyond the COA satisfying projected retail requirements.

For example, if the COA's peak demand is 600 MW, it is required to have enough generating capability to meet the demand plus have an additional 90 MW (15% of 600 MW) capacity as standby reserves. In total, the COA is required to have a minimum of 690 MW in order to meet both its retail customer requirements plus reliability mandates. Based on this determination and given the COA's existing resource mix is only 500 MW, the capacity that the CPP provides will be fully devoted to meeting this requirement. Therefore, much of the capacity from this project would be dedicated as standby capacity and not utilized often for energy purposes.

Market Redesign and Technical Update (MRTU)

The CAISO is undergoing a substantial change in its operating and scheduling procedures under MRTU that will begin April 1, 2009. Under this new process, load serving entities will be required, in addition to having a15% planning reserve margin, to bid those resources into the CAISO's markets. Section 40.4 of the tariff identifies the requirements of bidding in reserve units, so in addition to dedicating the COA's resources to meet retail customer load, the COA expects that a portion of the new turbines will be bid into the CAISO's market; the remainder will be idle capacity.

Under the MRTU environment, CAISO may call upon those reserves for any frequency and for any duration. The CAISO may call upon those resources to provide power for as little as one hour and may require the facility to provide energy within a 10 – minute notice. The COA cannot determine a priori how often the CAISO may call upon those reserves, how much power is required and for what duration. Given the short notice and the fact that the amount of energy required may only be needed for a few hours, Anaheim needs a resource that has short start-up times, ability to shut down quickly when no longer required and the ability to operate at part load as low as 50%. Additionally, there are economic penalties associated with the inability to provide this capacity or to meet performance when the resources are called upon by the CAISO. Anaheim believes that the LM6000 simple cycle technology has the operational flexibility to meet these necessary requirements.

Renewable Energy Considerations

As initiated by passage of SB 1078 (Sher 2002) and adopted by City Council, the Renewable Energy Portfolio (RPS) policy requires that the COA meet 20% of its retail energy requirements with renewable energy resources by 2015. There is also pending legislation and the California Air Resource Board's Scoping Plan to meet AB 32 objectives to require a statewide objective of an RPS goal of 33% by 2020. Note that this goal is based on energy rather requiring 33% of a utility capacity portfolio. This

objective requires the COA to pursue renewable energy resources that are energy intensive, such as geothermal or landfill gas projects that provide power on a 24 hour basis, rather than resources such as wind or solar. This means the COA's future capacity needs will be must-take or base load resources in order to meet those targets in a cost-effective manner. To require combined cycle technology, as Yorba Linda suggests, which are only cost-effective when efficiencies are taken advantage by operating more hours than simple cycle, the COA will be in a difficult and more expensive position to meet its RPS objectives. It has already been discussed that the COA's current resource portfolio consists in a majority of base-load resources. In order to meet its RPS target, the COA will need an additional 70 MW of renewable energy as base load capacity to meet its objective; there's no means of accommodating this level of capacity additions and attempt to receive the efficiencies of a combined cycle "peaking" facility.

In addition to this dilemma, the COA has long-term power contracts for renewable energy sources based on wind and hydro to produce energy that is received on an intermittent or as available basis. From an operational standpoint, these resources require capacity of the kind that serves as back-up in the event the renewable energy is no longer producing. For instance, the COA under the CAISO's MRTU protocols described earlier, must schedule its energy in advance, including its wind and hydro contracts. During the hours when that energy must be delivered to the CAISO, if a renewable resource suddenly ceases production (example: the wind dies down on an operating wind turbine project), the COA must have a resource in standby mode to provide replacement energy. That requires a resource with fast start-up time with short notices and the ability to provide part load power, depending upon the amount of renewable energy needing to be replaced. Again, simple cycle technology is best suited for its ability to start up quickly and to operate for short periods of time.

4. Combined Cycle versus Simple Cycle Configuration

Simple Cycle Independent Units

The current configuration of 4 simple cycle units consists of 4 power islands where the operation of each power island is independent of the status of the other power islands. Simple cycle derives its name from being the simplest arrangement of a combustion turbine directly driving an electrical generator to produce power with air emission controls on the turbine exhaust. This arrangement allows for rapid unit start-up in response to hourly or shorter dispatch notices with a high degree of plant dispatch reliability due to simplicity and independence. Where the number of annual dispatch hours is on an as-needed basis for peaking duty, this arrangement is often employed due to independence of the unit and its low capital cost where the facility's main functional requirement is to provide peaking capacity.

Combined Cycle Interdependence

The combined cycle configuration adds heat recovery steam generators (HRSG) to each combustion turbine power train, collects steam produced by the HRSG's in a steam and

condensate collection system, supplies the steam to a steam turbine generator (STG) system, condenses the STG exhaust steam, and returns the condensate to the HRSG's via a boiler feedwater system. For this application, 3 LM6000 CTGs and 1 STG would be utilized to fulfill the nominal 200 MW plant output needed by the COA. In order to satisfy the rapid start-requirements for the CPP the type of HRSG used would have to be an OTSG design that can allow the CTG to rapidly start up. Without the use of an OTSG type of HRSG, the CTGs could not meet a rapid 10-minute to full load dispatch requirement.

Since an OTSG is capable of being exposed to the hot turbine exhaust gases without water inside the boiler, the exhaust emission control SCR catalyst would be required to be designed to withstand the hot turbine exhaust gas temperatures (over 900°F). This would require a more expensive type of SCR catalyst than is typically used for simple cycle SCR systems. The simple cycle units utilize SCR catalyst inlet tempering air fans to lower the SCR catalyst inlet gas temperature so that the less expensive SCR catalyst can be used.

Once the CTGs have started and the stack temperature has reached 300 deg F, demineralized water can to be introduced into the OTSG to begin the generation of steam that will be delivered to the STG. The rate at which steam is delivered to a cold steam turbine is severely limited to at a rate that allows for gradual and controlled warm-up of the STG. Heating up an STG too quickly can severely damage the STG components due to unequal thermal expansion. This slow heat-up process from a cold standby condition can typically take 1.5 to 2 hours for a STG in the 40 MW size range. The addition of an OTSG to the CTG exhaust system increases the CTG backpressure and results in a slightly lower power output over the CTG operating range independent of the OTSG operational state. This power loss is on the order 200 kW per CTG. After the energy of the high pressure steam has been converted to electrical energy in the STG, the low pressure steam exits the STG and must be condensed before being deaerated and pumped back into the OSTG.

Requirement for STG Exhaust Steam Condensing

The STG exhausts steam after it has extracted the usable steam energy used for power generation. This exhaust steam is condensed in a large heat exchanger that condenses the steam and collects the condensate for return to the boilers. The lower the STG exhaust pressure (cooler, lower pressure condenser) that can be achieved, the more efficiently the STG will operate. Two different approaches were considered for steam condenser systems to perform this condensing and collection function. The first uses a wet mechanical draft type cooling tower configuration; and the second uses a direct air cooled condenser configuration. These configurations are discussed below.

Wet Cooling Tower

This system incorporates a water-cooled steam condenser, cooling water circulation system, and a wet mechanical draft cooling tower. The condenser incorporates a shell and

tube heat exchanger at the STG exhaust that flows cool water inside tubes collecting heat from the steam and consequently condenses the steam on outside of the tubes. The condensed steam is collected and deaerated then pumped back into the boiler. The cooling water inside the tubes that has picked up heat that needs to be dissipated. This cooling water is circulated to a wet cooling tower. The heat loss in the water is achieved by exposing the heated water to ambient air in a cooling tower where a portion of the water is evaporated thus cooling the water. The cooled water is then pumped back to the condenser for condensing steam. In this process water is continuously evaporated in the cooling tower and must be replenished. Additionally, since water is being evaporated, the mineral content in the remaining water in the cooling tower will be increased.

To maintain an acceptable level of mineral content in the water, some water must be drained off (referred to as blowdown). Make up water is added to the cooling tower to replace water lost to evaporation and blowdown. Chemicals are added to the water to prevent scaling and biological fouling. Proper water chemistry can be difficult to control for cooling towers that are used intermittently. It is not known whether this approach would be acceptable to the California Energy Commission (CEC) since the use of water for cooling STG condensers in power plant is not considered to be consistent with California's management of water resources. The CPP water usage with the wet cooling tower system would increase 150% over the simple cycle water usage.

Air Cooled Steam Condenser

Another approach to condensing the STG exhaust steam is to utilize a condensing system known as an air cooled condenser (ACC) which is a direct air to steam heat exchanger. In this system ambient air is utilized to condense the steam from the STG exhaust. A large duct is connected to the turbine exhaust collecting the steam with a series of smaller ducts distributing the steam to large arrays of heat exchanger tubes. Ambient air is then drawn over the tubes removing heat to condense the steam. Large quantities of air need to be drawn over the tubes in order to remove all of the heat released in the steam condensation process. The result is very large array of heat exchanger tube sections with numerous large fans to move the air. This entire system needs to be elevated up high in the air in order to allow air to be drawn over the tubes. A series of condensate drain pipes collect the condensate for pumping back into the boiler. During the startup phase a vacuum needs to be developed within the ACC (inside the tubes) removing all of the air and/or water vapor. As with the wet cooling tower system, the lower the pressure inside the condenser, the more efficient the STG will operate. Vacuum pumps would be used to develop this vacuum that might take several hours to develop sufficiently low vacuum for operation depending upon site particulars.

Since ambient air dry bulb temperature is warmer than the corresponding cooling tower wet bulb temperature, the design vacuum level of the steam condenser will be higher for an ACC as opposed to a wet cooling tower. Therefore, the use of an ACC will lower overall plant thermal efficiency. Due to the large size and number of fans in the ACC system the STG system parasitic electric losses will be somewhat higher that with the wet

cooling tower system. Water usage for the STG with ACC would be lower (3 CTGs vs. 4 CTGs) and would be approximately 75% of the water used in the simple cycle plant.

Air Quality Comparison

As discussed above, the current project configuration consists of 4 simple cycle units capable of a simultaneous startup of all for units with all units achieving full load within 10 minutes and providing up to 200 MW for peaking purposes. Under the Preliminary Determination of Compliance (PDOC) recently issued by the South Coast Air Quality Management District (SCAQMD) for the project, once the units are operating normally following a startup the units must meet NOx and CO levels of 2.5 ppmvc[1] and 4 ppmvc, respectively. These emission levels are achieved with the installation of Selective Catalytic Reduction (SCR) and oxidation catalyst systems which the SCAQMD has determined to be Best Available Control Technology (BACT).

In the City of Yorba Linda's March 11, 2009 letter to the City of Anaheim, the City of Yorba Linda discusses the NOx emission benefits associated with the following three rapid startup combined cycle units:

- Pinelawn Power
- Bethpage 3
- Big Hanaford peaking turbine

Based on a review of the existing Title V permits for each of the above power plants[2], the allowable NOx emission levels for these three units are 2.5 ppmvc with NOx emissions controlled by SCR systems. Since the above three power plants are equipped with the same size gas turbines as those proposed for the proposed project and the allowable NOx emissions levels for these plants are the same as for the proposed project, there is no NOx emissions benefit on a per unit basis associated with these three power plants when compared to the proposed project.

The only possible air quality benefit associated with these types of rapid startup combined cycle units would be if there were improvements in efficiency with the use these combined cycle units. With improved efficiency there would be reduced fuel use on a per MW basis which in turn would result in lower emissions for criteria pollutants (NOx, CO, VOC, PM, SOx), toxic air pollutants, and greenhouse gas emissions on a per MW basis. However, as discussed above, due to the limited number of actual operating hours expected on a daily and annual basis for the proposed project, there would be little actual efficiency gain associated with the use of combined cycle units. Therefore, there would also be little to no actual air quality benefit associated with the use of combined cycle units for the proposed project.

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[1] ppmvc = ppmv @ 15% O2.
[2] New York State Department of Environmental Conservation Permit Numbers 1-2824-00947/00004 and 1-4720-03061/00005, and Southwest Clean Air Agency Permit Number SW98-8-R2-B.

Impacted Construction Schedule

Longer Duration
Due to the added systems to support the OTSG and STG systems, the construction plant schedule would be lengthened by several months resulting in a construction duration extension of approximately 25%. There would also be a substantial increase in the number of construction workers involved with the project with the corresponding increase in traffic as well as other neighborhood disbenefits. If ACC is the system utilized for STG exhaust condensation, then the construction duration of the ACC may be the critical path for the plant construction duration.

STG Delivery Time Impact
STG's are custom designed machinery and there is currently a high demand for steam turbines in the power generation market around the world. The delivery time from order for steam turbine in the 50MW size range is on the order of 18 months or more. This would not include the time to prepare the STG specifications and procure the STG through a competitive bid process that would add another 4 – 6 months to the delivery time for the STG. Therefore the start of on-site construction of the STG could be delayed up to 24 months solely due to the procurement of the STG.

5. Dispatch Requirements

The fundamentals for utility operations are based on economic dispatch; that is, customer load is met hourly with the lowest variable cost generation in the utility's portfolio. Standard utility practice is to stack available generating resources in order of increasing incremental cost of operation, from lowest to highest costs. As load increases during the day, units are dispatched to meet that load on the basis of their respective incremental cost of operation. This cost comprises of the cost of fuel (in $/MMBtu) and efficiency (measured in MMBtu/MWh) plus any variable operating and maintenance costs. Since combined cycle (as suggested by Yorba Linda) and simple cycle technologies both use natural gas for fuel in Southern California, the difference in dispatch order would be the difference in efficiencies.

Economic dispatch requires combined cycles units to operate lower in the dispatch order and hence, would operate more hours during the day than simple cycle units. It is impractical and imprudent to dispatch any other way. As an example, combined cycle units have operating characteristics that prevent them from operating in certain regions of their minimum and maximum operating levels in effect making them non-dispatchable for purposes of reliability. Given the low utilization of power required on the COA's system, the advantages provided by efficiency gains from combined cycle units are lost due to the fact that, as Yorba Linda suggests, these units would be treated as "peaking" facilities.

In its request for hearing, "The City of Yorba Linda has information that suggests at least 130 OTSG combine cycle gas turbine power plants worldwide are capable of operating as peaker plants. Three of these, two in New York State (Pinelawn Power and Bethpage 3) and one in Washington state (Big Hanaford peaking turbine) are comparable in size and scope to the CPP and in fact operate normally as peakers with start-up times the same as proposed for the CPP."

Upon investigation of those facilities, it was learned that the plants suggested by Yorba Linda are "merchant plants", rather than facilities owned and operated by the local utility. As merchant facilities, the ownership by a third party would require the facility to recoup both its operating costs as well as capital investment and still make a profit for its investment, otherwise, independent power producers have no incentive to build merchant plants. In order to capture costs and still make a profit, a merchant plant operating as a combined cycle facility would have to maximize the number of hours it would operate in order to be profitable. Therefore, it's no surprise that these units operate 12-16 hours daily as "peaking" facilities.

The recommendation that the COA should have considered a combined cycle unit on the simple basis that other utilities have done so completely ignores the fact that circumstances driving one utility's decision making process can be totally different than those confronting the COA need for peaking power. What is ignored by Yorba Linda's statement is whether any of these facilities match the exact needs of the COA with respect to (1) existing resource portfolio, (2) low daily and annual utilization factors for the peaking use by the COA, (3) mandates for reliability (having capacity remain idle as standby reserves), and (4) being a summer peaking utility with similar load profiles. No two utilities are exactly alike; what applications work for some utilities or for merchant plants may not make sense for other utilities. Resource mix and unit dispatch criteria can be totally different for the plants identified in Yorba Linda's example and therefore the need for that technology may be for reasons totally different than for how the COA needs to use the CPP facility.

Finally, given the COA's configuration of resources, having better efficiencies from combined cycle options will not improve the potential to operate more hours that takes advantage of those efficiencies. As mentioned, a majority of the COA's resources are coal-fired which is considerably less expensive to operate than gas-fired technologies. In addition, there is energy from several renewable energy contracts which must be taken every hour. Following the operating costs of these resources, the COA has a large combined cycle facility that has a better efficiency than the combined cycle options mentioned by Yorba Linda, so this facility would be utilized fully before dispatching any peaking facility. At that point, there are few hours to dispatch for load purposes, regardless of whether a combined cycle option was in place; there are no other resources that would be displaced due to the efficiency of the combined cycle, so there are no opportunities to be dispatched more hours to meet load requirements in order to take advantage of the efficiencies from the combined cycle units options

6. Efficiency

Simple Cycle Efficiency

The simple cycle system for the 4 CTGs is expected to have a net plant efficiency of 34.4% based on higher heating value (HHV). This number accounts for the individual CTG units' inefficiencies (35.9%) as well as the plant parasitic loads for the auxiliary loads.

Combined Cycle Efficiency

CTG Efficiency loss due to higher backpressure

Due to the addition of an OTSG (boiler) in the CTG exhaust path there will be an increase in the CTG back pressure and a resulting decrease in the kW produced by the CTG. The amount kW loss is approximately 200 kW per CTG for a plant loss of 627 kW. CTG efficiency is reduced to 35.8%.

Efficiency with STG

Plant efficiency with the all turbines operating at full load and the STG at full operating steam flow will be 43.6% based on HHV and a wet cooling tower system. For an ACC system the plant efficiency drops to 42.8 % based on HHV. The lower efficiency is due to the ACC higher parasitic electrical loads and the inability of the ACC to achieve as low a STG backpressure as the wet cooling tower. (The cooling water temperature is lower than the ambient air temperature and therefore the STG exhaust condensing temperature is lower resulting in lower STG electrical output for the same steam flow.)

Plant Efficiency Prior to Full STG Loading

After the CTG begins operating there is a time delay for steam to be produced while the OTSG heats up. After the OTSG has reached a minimum operating temperature, then steam production can commence. Initially, the quantity of steam produced will be small since the STG must be slowly heated up. When the STG has achieved the minimum operating temperature, additional steam can be provided to the STG so that power production can commence. During this time, a vacuum will have to be developed in the condenser (both wet cooling tower and ACC configurations). It is expected that it may be 2 to 3 hours after CTG startup for the STG to realize its full output power capability. Up until this time, the net plant efficiency will be lower (35.8% vs. 35.9 %) based on CTG performance but will incur additional parasitic losses due to the STG auxiliary systems beginning operation prior to the STG producing its design power output. If the CPP is typically dispatched for less than 3 hours as is anticipated, there is little if any economic benefit for the CPP to operate in combined cycle.

STG Efficiency for Various CTG Operating Scenarios

When less than all three CTGs are operating, the STG will be operating at reduced load resulting in reduced plant efficiency. For the ACC cooling system and only one CTG operating the plant efficiency will be approximately 41.4% HHV after the STG has reached fill operating conditions. With two CTGs operating with the ACC system the plant efficiency will be approximately 42.5% HHV after STG reaches fill operating conditions.

7. Capital and Operating Costs

Increased Cost for Combined Cycle

The addition of the OTSG, STG, steam condenser and plant auxiliary systems results in a significant increase in the CPP capital costs. For the basic 4 LM6000 CTG power islands and auxiliaries in simple cycle, the CPP capital cost is estimated to be $195 million dollars. Using the same cost estimating assumptions, the cost of a CPP plant for 3 LM6000 CTGs, 1 STG, and a wet cooling tower system is estimated to be $265 million. The cost of a CPP plant using an ACC in lieu of the wet cooling is estimated to be $264 million. The comparison of costs, efficiencies and effective capacities (accounting for parasitic load) for the three choices is provided in Table 3.

The cost shown in Table 3 represent "overnight" costs to build each option; that is, strictly the cost of labor, material and equipment. It is clear that the combined cycle options are $70 million higher than the LM6000 configuration. To finance the project, there will be addition costs associated with fees and expenses for bond funding, which is typically 15% of the "overnight" costs. In the case of the combined cycle option, these expenses add an additional $10 million above what the simple cycle costs are, making the total capital investment for the combined cycle options over $80 million higher than the simple cycle plan. Assuming a 30-year bond with a 5% interest rate, the capital cost of the combined cycle facilities would cost the COA over $5 million per year more than the simple cycle, or $150 million more over the economic life of the facility.

It is recognized that the benefit of the combined cycle is its efficiency over simple cycle. However, given the current cost of fuel, the combined cycle options would have to operate a minimum of 700 hours more per year at full load than the simple cycle in order to offset the increase in capacity costs. As previously discussed, the COA has limited operating hours needed from the facility. It is not feasible to operate the facility the number of hours to support the increase in capital investment required to install combined cycle options.

On a percentage basis there would be approximately a 31% increase for the wet cooling tower option and a 30% cost increase for the ACC option. These capital costs are essentially equal due to the added cost of a wet cooling tower equipped with a plume abatement system. It is expected that this would be required due to visual considerations of a large plume from a wet cooling tower. When considered on a cost per installed

kWnet (net plant output at maximum rating) basis the cost increases would be a 38% increase for the wet cooling tower option and 40% cost increase for the ACC option. The difference in cost reference reflects the lower plant MWnet for the STG options. The 4 simple cycle CTGs has a net MW output of 195 MW while the 3 CTG and 1 STG options have 185 MW and 182 MW outputs for the wet cooling tower option and ACC option respectively. The COA cannot economically justify the increase in costs for the combine cycle options given the limited number of hours needed from the peaking facility.

Additional Water Treatment Costs

Due to the reduction in CTG units from 4 units in the simple cycle configuration to 3 units in the combined cycle configuration the need for turbine injection of demineralized (DI) water will decrease by 25%. It is expected that the capacity to generate DI water will be essentially unchanged due to the need for the production of DI water associated with the operation of the OTSG.

If the wet cooling tower system is incorporated, then additional storage tank capacity would be required to maintain the onsite reserve of process water. Additionally, there will be increased chemical costs since the cooling tower supporting the STG condenser will be much larger than the small cooling tower for the inlet air chillers.

If the ACC cooling option were to be incorporated there would be minimal impact on the plant process water system and tankage.

Additional Personnel

The basic simple cycle configuration was to be staffed by the addition of one to two operators that would also be working at the existing COA Kraemer peaking power plant. This would be possible due to the highly automated nature of the simple cycle CTG units and the associated auxiliary systems. With the addition of OTSG units, boiler feedwater system, cooling tower or ACC, steam distribution system, associated additional control systems, and additional electrical systems it is expected that the number of personnel to be added to the existing staff would probably double to 4 or more additional personnel beyond the current staff. Since there may long periods, several weeks to months, of time when the STG / OTSG system is not utilized due to non dispatch of the units or only one unit being dispatched for less than 3 hours, additional maintenance will need to be exerted to maintain the idle STG and steam system in a ready mode.

8. Summary and Conclusions

The COA developed a long range planning program to meet the short and long term capacity requirements. The COA's load profile, current and projected, established the need for approximately 200 MW of reserve capacity. In order to fulfill all of the regulatory and reliability requirements this reserve capacity needs to be dispatchable on very short notice (approximately 10 minutes), but will normally remain idle in order to be available for dispatch if needed. These two elements are needed to satisfy the CASIO

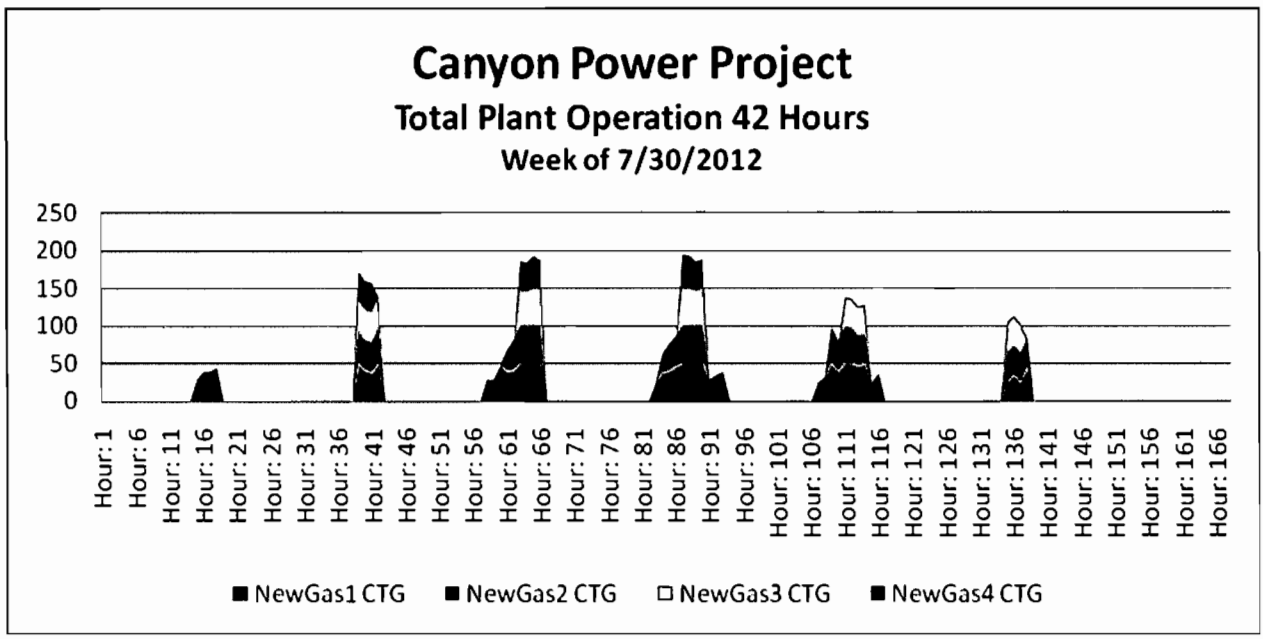
requirement for 15% reserve capacity (idle, not part of the daily base load portfolio), the reliability criteria as required by the Western Energy Coordinating Council (WECC) and for short term dispatchable capability necessary under MRTU.

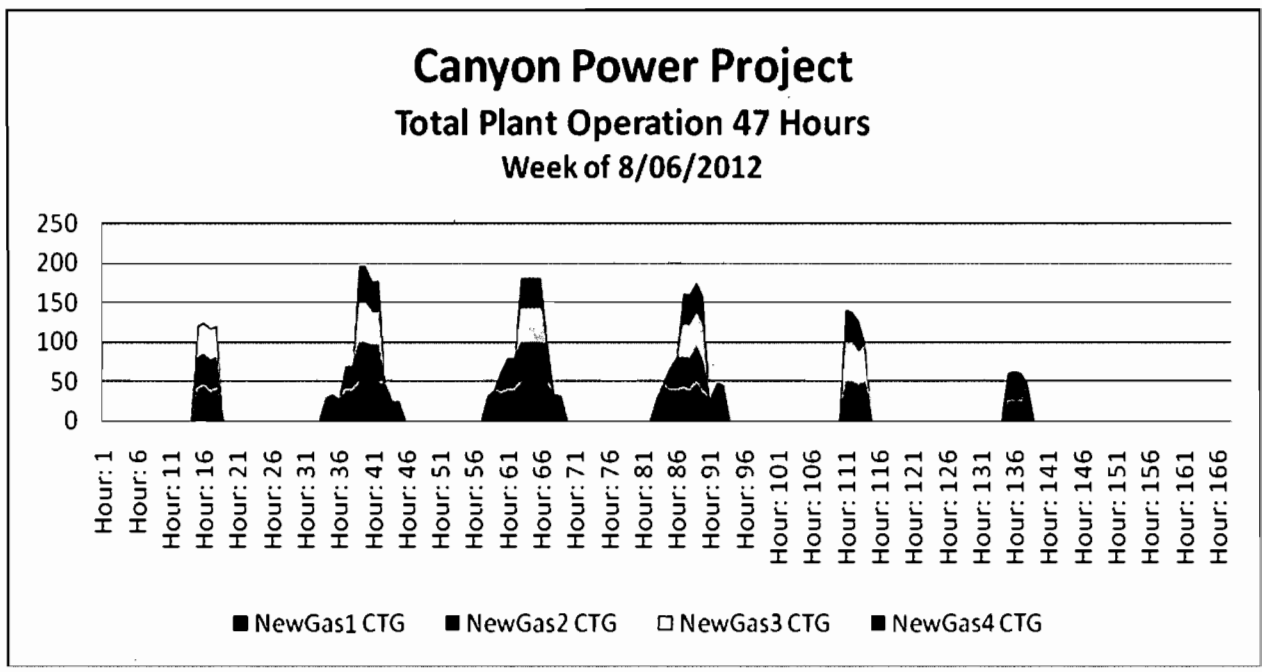
Given these two base premises for the selection of the appropriate technology and SCAQMD's BACT and LAER emission requirements, the technology would need to be natural gas fueled. The combustion turbine satisfies the emission and quick start requirements. This is a well proven and established technology fulfilling the need for a facility with a proven track record of high reliability. As discussed previously, due to the limited number of actual operating hours expected on a daily and annual basis for the proposed project, there would be little or no actual efficiency gain associated with the use of combined cycle units. Therefore, there would also be little to no actual air quality benefits associated with the use of combined cycle units for the proposed project. The simple cycle configuration best fills the requirements for low operating cost, independence of the 4 turbine units, low capital cost, and, most importantly, satisfies the COA's short term and long term generation portfolio requirements.

The COA has a fiduciary responsibility to its ratepayers to provide energy and capacity in the most economical manner. The expected operating profile for the CPP based on the COA's long term planning and regulatory requirements simply do not support the added expenses and complexity associated with substituting a combined cycle plant for the proposed simple cycle facility.

TABLES

TABLE 1A


Canyon Power Project
Total Plant Operation 42 Hours
Week of 7/30/2012
250
200
150
100
50
0
Hour: 1
Hour: 6
Hour: 11
Hour: 16
Hour: 21
Hour: 26
Hour: 31
Hour: 36
Hour: 41
Hour: 46
Hour: 51
Hour: 56
Hour: 61
Hour: 66
Hour: 71
Hour: 76
Hour: 81
Hour: 86
Hour: 91
Hour: 96
Hour: 101
Hour: 106
Hour: 111
Hour: 116
Hour: 121
Hour: 126
Hour: 131
Hour: 136
Hour: 141
Hour: 146
Hour: 151
Hour: 156
Hour: 161
Hour: 166
NewGas1 CTG
NewGas2 CTG
NewGas3 CTG
NewGas4 CTG


Canyon Power Project
Total Plant Operation 47 Hours
Week of 8/06/2012
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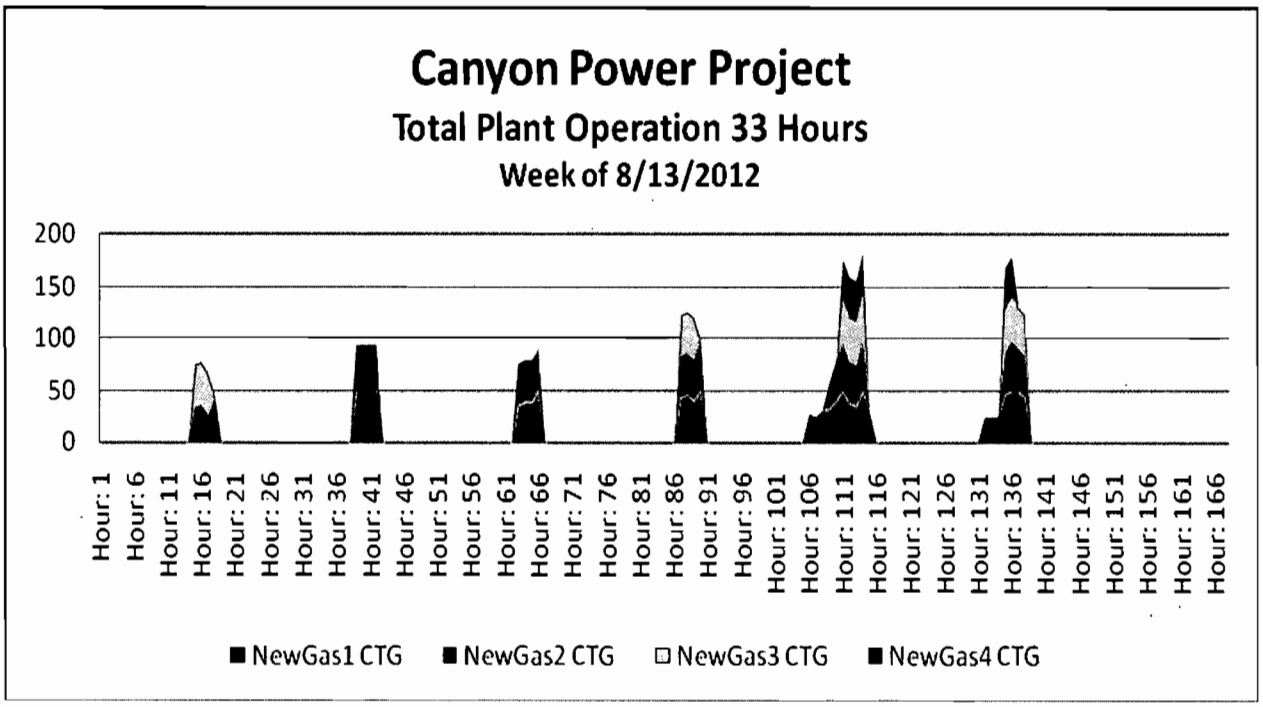
200
150
100
50
0
Hour: 1
Hour: 6
Hour: 11
Hour: 16
Hour: 21
Hour: 26
Hour: 31
Hour: 36
Hour: 41
Hour: 46
Hour: 51
Hour: 56
Hour: 61
Hour: 66
Hour: 71
Hour: 76
Hour: 81
Hour: 86
Hour: 91
Hour: 96
Hour: 101
Hour: 106
Hour: 111
Hour: 116
Hour: 121
Hour: 126
Hour: 131
Hour: 136
Hour: 141
Hour: 146
Hour: 151
Hour: 156
Hour: 161
Hour: 166
NewGas1 CTG
NewGas2 CTG
NewGas3 CTG
NewGas4 CTG

TABLE 1B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Total Plant Operation 33 Hours
Week of 8/13/2012
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150
100
50
0
Hour: 1
Hour: 6
Hour: 11
Hour: 16
Hour: 21
Hour: 26
Hour: 31
Hour: 36
Hour: 41
Hour: 46
Hour: 51
Hour: 56
Hour: 61
Hour: 66
Hour: 71
Hour: 76
Hour: 81
Hour: 86
Hour: 91
Hour: 96
Hour: 101
Hour: 106
Hour: 111
Hour: 116
Hour: 121
Hour: 126
Hour: 131
Hour: 136
Hour: 141
Hour: 146
Hour: 151
Hour: 156
Hour: 161
Hour: 166
NewGas1 CTG
NewGas2 CTG
NewGas3 CTG
NewGas4 CTG

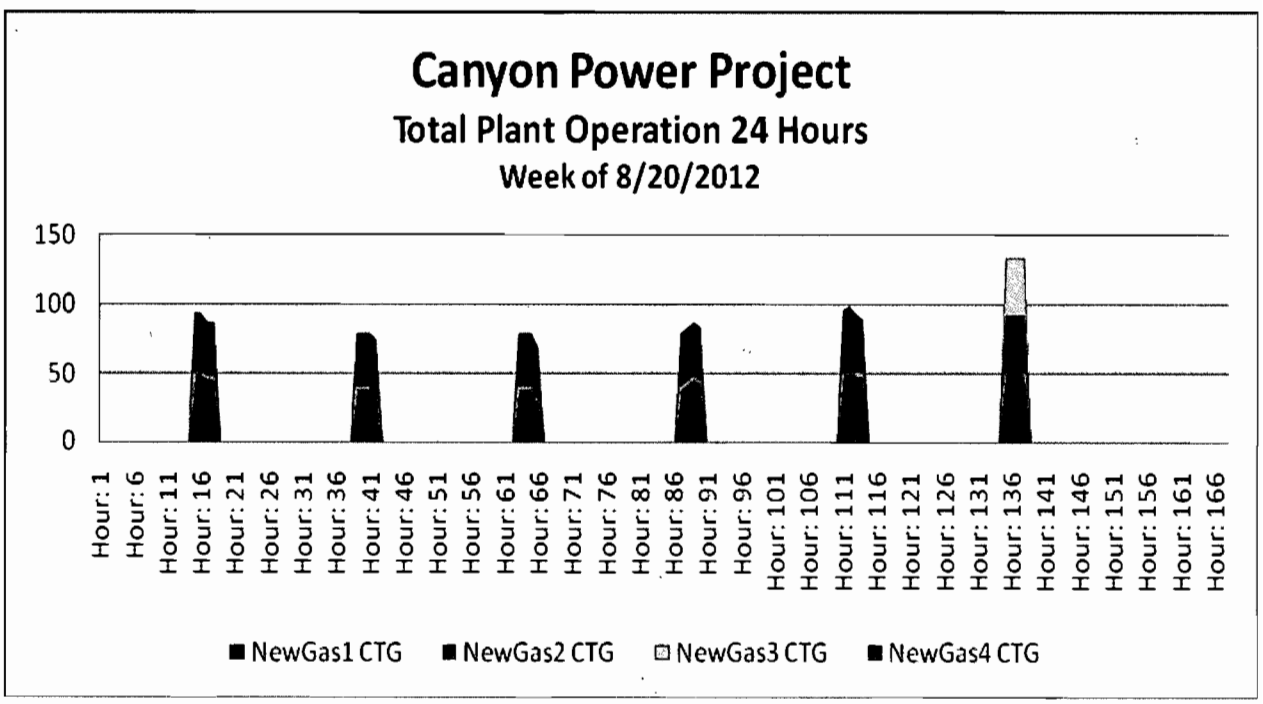
Canyon Power Project
Total Plant Operation 24 Hours
Week of 8/20/2012
150
100
50
0
Hour: 1
Hour: 6
Hour: 11
Hour: 16
Hour: 21
Hour: 26
Hour: 31
Hour: 36
Hour: 41
Hour: 46
Hour: 51
Hour: 56
Hour: 61
Hour: 66
Hour: 71
Hour: 76
Hour: 81
Hour: 86
Hour: 91
Hour: 96
Hour: 101
Hour: 106
Hour: 111
Hour: 116
Hour: 121
Hour: 126
Hour: 131
Hour: 136
Hour: 141
Hour: 146
Hour: 151
Hour: 156
Hour: 161
Hour: 166
NewGas1 CTG
NewGas2 CTG
NewGas3 CTG
NewGas4 CTG

TABLE 1C

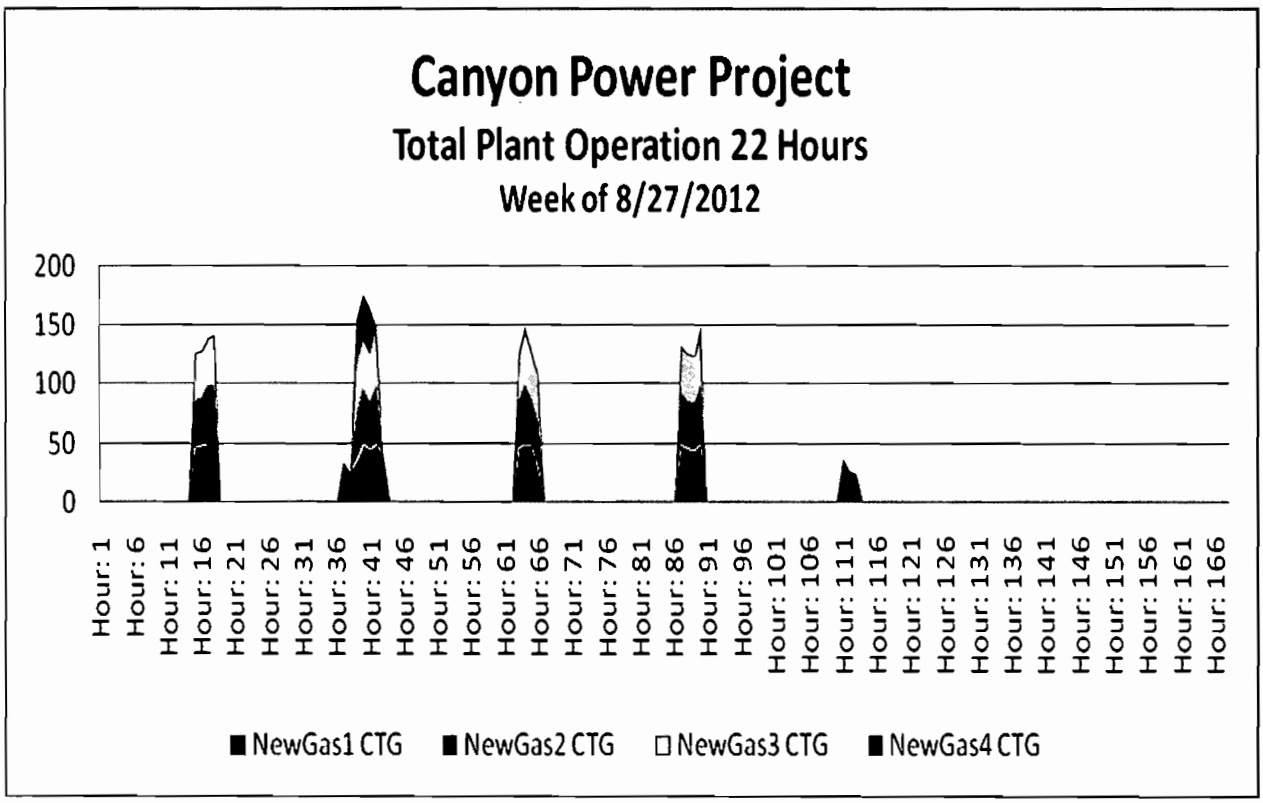
Canyon Power Project
Total Plant Operation 22 Hours
Week of 8/27/2012
200
150
100
50
0
Hour: 1
Hour: 6
Hour: 11
Hour: 16
Hour: 21
Hour: 26
Hour: 31
Hour: 36
Hour: 41
Hour: 46
Hour: 51
Hour: 56
Hour: 61
Hour: 66
Hour: 71
Hour: 76
Hour: 81
Hour: 86
Hour: 91
Hour: 96
Hour: 101
Hour: 106
Hour: 111
Hour: 116
Hour: 121
Hour: 126
Hour: 131
Hour: 136
Hour: 141
Hour: 146
Hour: 151
Hour: 156
Hour: 161
Hour: 166
NewGas1 CTG
NewGas2 CTG
NewGas3 CTG
NewGas4 CTG

TABLE 2

Hours of Operation For Canyon Power Project

Year:	Unit 1	Unit 2	Unit 3	Unit 4	Facility Total
2010	0	0	0	0	
2011	43	0	0	0	43
2012	280	162	61	4	507
2013	326	249	125	47	747
2014	299	212	96	25	632
2015	350	234	100	41	725
2016	364	235	96	37	732
2017	367	225	110	56	758
2018	393	275	138	59	865
2019	589	375	154	76	1194
2020	652	423	214	106	1395
2021	812	639	362	150	1963
2022	934	733	305	129	2101
2023	894	695	333	156	2078
2024	677	479	257	139	1552
2025	715	493	257	131	1596
2026	803	554	308	144	1809
2027	742	472	289	118	1621

TABLE 3

CPP Plant Performance and Cost Summary

	Simple Cycle	**Combined Cycle w/ Wet-Dry Cooling Tower**	**Combined Cycle w/ Air Cooled Condenser**
No of Generators	4 – Combustion Turbines	3 - Combustion Turbines, 1- Steam Turbine	3 - Combustion Turbines, 1- Steam Turbine
Plant Full load Net Output MW	195	185	182
Plant Full Load Net Heat Rate Btu/KWhr (HHV)	9,912	7,823	7,972
Plant Full Load Net Electric Efficiency % (HHV)	34.4	43.6	42.8
Plant Full Load Water Use gpm	422	1,022	314
Plant Direct Construction Cost	$ 195,000,000	$265,000,000	$264,000,000

Notes:

1. Performance based on summer operation, ambient dry bulb temp 89 deg F, 36% RH

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE *CANYON POWER PLANT PROJECT*

Docket No. 07-AFC-9

PROOF OF SERVICE
(Revised 2/25/2009)

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DECLARATION OF SERVICE

I, Ashley Y Garner, declare that on April 16, 2009, I served and filed copies of the attached **CANYON POWER PLANT SIMPLE CYCLE PLANT JUSTIFICATION** dated **April 16, 2009**. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/lodi]**. The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(***Check all that Apply***)

FOR SERVICE TO ALL OTHER PARTIES:

__X__ sent electronically to all email addresses on the Proof of Service list;

__X__ by personal delivery or by depositing in the United States mail at with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

__X__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

OR

____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. **08-AFC-10**
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

Ashley Y Garner

Ashley Y. Garner