VALUATION OF THE GLENARM GT 2 UNIT

FINAL REPORT

PREPARED FOR

Pasadena Water & Power (PWP)

OCTOBER 13, 2016

BLACK & VEATCH
Building a world of difference.

Assumptions and Limitations Disclaimer

This report was prepared for Pasadena Water & Power ("Pasadena") by Black & Veatch Management Consulting, LLC ("Black &Veatch") and is based on information not within the control of Black & Veatch. Black & Veatch has assumed that the information both verbal and written, provided by others is complete and correct; however, Black & Veatch does not guarantee the accuracy of the information, data, or opinions contained herein.

Any information shared with the Company prior to the release of the report is superseded by the Report.

Black & Veatch owes no duty of care to any third party and none is created by this report. Use of this report, or any information contained therein, by a third party shall be at the risk of such party and constitutes a waiver and release of B&V its directors, officers, partners, employees and agents by such third party from and against all claims and liability, including, but not limited to, claims for breach of contract, breach of warranty, strict liability, negligence, negligent misrepresentation, and/or otherwise, and liability for special, incidental, indirect, or consequential damages, in connection with such use.

Table of Contents

LIST OF FIGURES

LIST OF TABLES

1 Introduction

Pasadena Water & Power ("PWP") has requested the services of Black & Veatch Management Consulting, LLC ("Black & Veatch") to provide an independent third party assessment of the merchant value of the Glenarm GT2 unit which is part of the four unit 179 MW (nameplate) Glenarm power plant. The Glenarm power plant is owned 100% by the City of Pasadena and is located on a 14 acre site in the southwestern portion of the city. The site consists of two groups of generating facilities bisected by the Los Angeles County Metropolitan Transportation Authority (Metro) Gold Line tracks. The Glenarm Plant is located the west of the Gold Line and the Broadway Plant located east of the Gold Line. Glenarm GT2 is composed of a Pratt & Whitney GG4C-1DF gas generator and Curtiss-Wright CT2 power turbine. Units 1 and 2 were built in 1976 and units 3 and 4 were built in 2004. In October of 2012, a fire broke out at Glenarm GT 2, which has caused the plant to be shutdown ever since. PWP has started the process of investigating the cost to repair or rebuild the unit. This report will provide an estimate of the future value of the Glenarm GT2 if PWP were to go ahead and authorize repair of the unit.

1.1.1 Glenarm Repowering Project

PWP has started a major project to replace an aging power generating unit with a more efficient combined cycle unit at the plant called the Glenarm Power Plant Repowering Project.
The Broadway/Glenarm Power Plant allows PWP to generate electricity as needed and provides a dependable, local electricity generating source by lessening PWP's reliance on outside sources for energy. The upcoming, quick-starting and highly-efficient combined cycle unit, Glenarm GT5 will replace the aging conventional boiler/steam turbine-generating unit Broadway 3 (B-3), which has been serving PWP since 1965. The repowering will allow Glenarm GT5 to startup within minutes as opposed to Broadway B3's 72-hour startup time. The repower Glenarm GT5 unit will allow PWP to integrate more renewable resources by providing a quick-start flexible resource.

1.1.2 Local Reliability Needs

The return of Glenarm GT2 is important to PWP primarily due to local reliability reasons. Although PWP is long on capacity, the utility is constrained by local transmission issues. PWP is electrically connected to the CAISO wholesale market by a single 220 kV line at the TM Goodrich substation. The transmission line allows for approximately 245 MW of import capability from generation resources outside of the local PWP area and approximately 100 MW of export capability. The export capability is limited due to cross-town transmission issues. When demand exceeds 245 MW in the PWP service territory, PWP is forced to operate local generation resources at the Broadway and Glenarm power plants to maintain system reliability. The single transmission line to the CAISO poses a system reliability problem for PWP. Should the TM Goodrich line go out for some reason (N-1 contingency[1]) PWP will be electrically isolated from the CAISO and will only be able to use approximately 185 MW in local generation capacity to meet load. Therefore it is important that PWP replace capacity that is located within city limits rather than procure capacity that requires transmission to the CAISO.

1.1.3 Intermountain Power Plant Retirement

PWP owns a 102 MW share of the coal-fired 1,900 MW Intermountain Power Plant (IPP) located in Delta, Utah. IPP is scheduled to be retired in 2025 and replaced with a natural gas unit. PWP will have the option to participate in ownership replacement natural gas unit for IPP. According to the

[1] N-1 contingency represents the loss of the single largest generator or transmission line.

2015 IRP PWP the retirement of IPP will require PWP to procure additional capacity to meet resource adequacy requirements.

1.2 GLENARM GT 2 OPERATING CHARACTERISTICS

The Glenarm power plant has not historically operated at a very high capacity factor in the past because the plant was designed to provide emergency peaking power to help maintain system reliability rather than generating low cost electricity. Table 1-1 below lists the operating costs and characteristics that were used to value the repaired unit.

Table 1-1 Glenarm GT2 Operating Assumptions

CHARACTERISTIC	GLENARM GT 2
Generation Fuel	Natural Gas
Heat Rate at Full Load (HHV, Btu/kWh)	14,131
Max Capacity (MW)	22
Start Costs ($/Start)	$2,015
Max Number of Starts per Day	4
Variable O&M ($/MWh)	$4.80
Min Load Adder ($/MWh)	$30.30
Maintenance Rate %	3%
Forced Outage Rate %	4%
Ramp Rate (MW/minute)	12/min
CO2 Emissions (lbs/MMBtu)	118
SO2 (lbs/MMBtu)	0.0005
NOx (lbs/MMBtu)	0.025

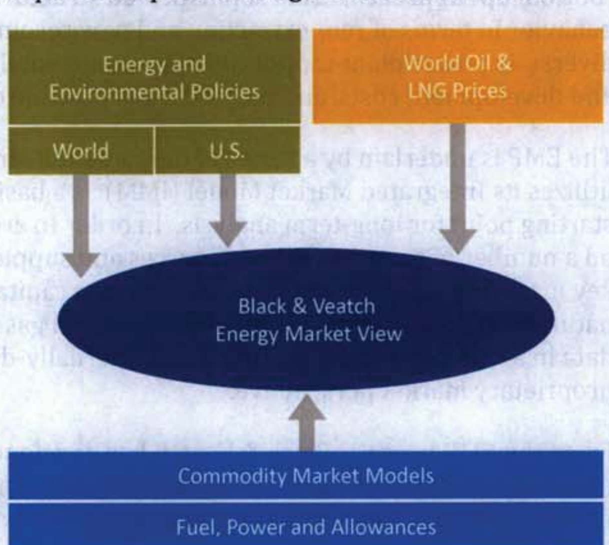
Source: Black & Veatch

The repaired Glenarm GT2 unit if brought back into service would provide similar emergency power as it had in the past.

2 Power Market Assumptions

2.1 ENERGY MARKET PERSPECTIVE

The method typically applied in integrated resource planning incorporates a risk based approach to determining the most optimal resource portfolio. The development and optimization of the resource portfolio starts with evaluation of several potential portfolios against Black & Veatch's Energy Market Perspective ("EMP") - long-term fuel and power price forecast. Under this approach, expected fuel market conditions influence resource options and costs evaluated in developing the IRP, and resulting forecast energy and capacity prices represent benchmark pricing and cost levels for evaluating renewable and traditional supply resources.



The Black & Veatch Energy Market Perspective (EMP) has been designed to respond to the needs of a wide range of energy industry participants: investors, developers, lenders, utilities and energy users. The energy industry has been in a nearly continuous state of rapid evolution for several decades now. Dating back to the first OPEC oil embargo in 1973, consumers, investors and governments have all struggled with making energy decisions in a world of uncertainty. Central to their decision process, all stakeholders need an objective view of the energy industry and markets—an understanding of how the future may unfold, given the lessons of the past and current trends in economics, technology, markets and government regulation. By providing a careful consideration of the multiplicity of factors impacting today's energy markets, the Black & Veatch EMP uses an integrated, iterative analytical process to develop a comprehensive view of the energy industry and how it can evolve in light of multiple dynamic factors, providing a sound framework for decision making.

The vision of the EMP is to provide a world-class energy market benchmark which can be used by clients across a wide range of applications. It is prepared every six months to provide Black & Veatch clients with a contemporary and insightful assessment of the current state of North American energy markets, and long-term base case view of how those markets may function. Critical elements of the EMP include:

- A thoughtful, transparent and internally consistent approach to analyses of the energy markets, industry trends, and the government policies that influence them.
- Incorporation of Black & Veatch's engineering and technical expertise across all key assumptions.
- A view of the markets for generation fuel sources.
- A view of the electric power markets.

The EMP is designed to capture both the broad policy level assumptions and detailed structural market representations to arrive at a consistent market view. From a "top down" perspective, Black

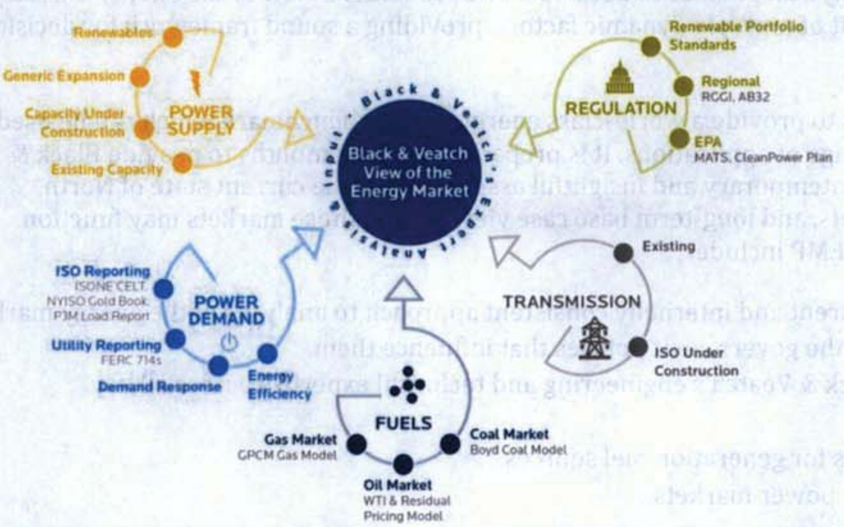
& Veatch assesses the current state of energy and environmental policies at both a US and global level to determine their impact on North American and regional energy markets and prices. Black & Veatch also analyzes likely future conditions in world oil and liquefied natural gas (LNG) markets, as these markets are becoming increasingly linked to U.S. market conditions.

Concurrently, Black & Veatch addresses North American commodity markets with a very detailed "bottom up" approach, using sophisticated structural market models to simulate market participant behavior in terms of rent extraction and new resource development, utilizing model inputs as diverse as power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and projected gas pipeline expansions.

The EMP is underlain by a series of fundamental structural energy market models. Black & Veatch utilizes its Integrated Market Model (IMM) as a basis for the current industry structure as well as a starting point for long-term analysis. In order to arrive at this market view, Black & Veatch draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, natural gas finding and development costs, and gas pipeline expansions. Black & Veatch uses this data in a series of vendor-supplied and internally-developed energy market models to arrive at its proprietary market perspective.

From the EMP process, Black & Veatch has developed independent forecasts of every North American wholesale electricity market. This zonal analysis of the regional markets incorporates the results of Black & Veatch's assessment of market-based capacity additions and retirements, the impact of potential greenhouse gas legislation, and the inter-zonal transmission transfer capabilities implicit in the existing transmission system and the new transmission facilities needed to facilitate renewable resource development.

Figure 2-1 Black & Veatch's Integrated Market Modeling Process



The assumptions used in the valuation of the Glenarm GT2 unit were performed using the assumptions from Black & Veatch's EMP.

2.2 REGULATORY ENVIRONMENT

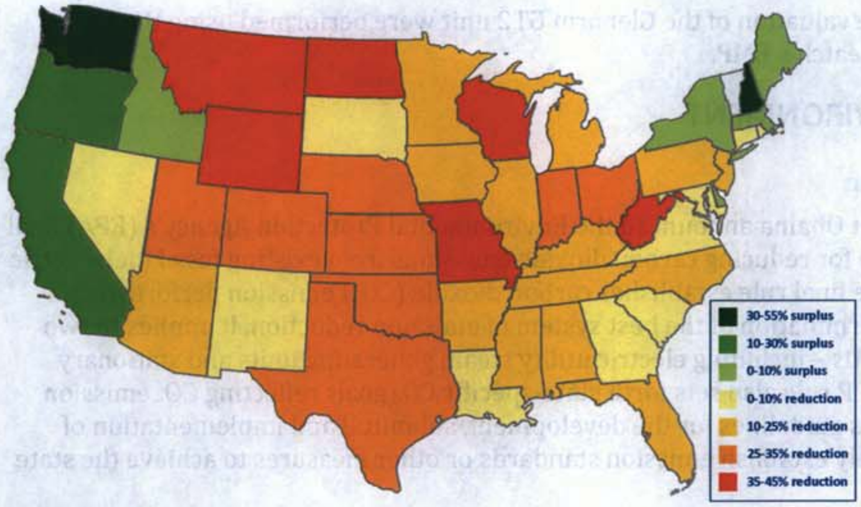
2.2.1 US Clean Power Plan

On August 3, 2015, President Obama announced the Environmental Protection Agency's (EPA) final Clean Power Plan (CPP) rule for reducing carbon dioxide emissions from existing fossil fuel electric generating units (EGUs). The final rule establishes carbon dioxide (CO_2) emission performance rates based upon EPA's determination of the best system of emission reduction. It applies to two subcategories of existing EGUs – including electric utility steam generating units and stationary combustion turbines. The CPP rule also sets forth state-specific CO_2 goals reflecting CO_2 emission performance rates, as well as guidelines for the development, submittal and implementation of state plans that will ultimately establish emission standards or other measures to achieve the state CO_2 reduction goals.

The implementation of the Clean Power Plan will include an individual rate-based (pounds of CO2 per megawatt-hour [lb CO2/MWh]) average for each state[2]. The CO_2 targets are based on performance standards adopted by EPA for steam fossil units and for combustion turbine/combined cycle fossil units, and upon the EPA's application of building blocks to existing generation mix, 2012 emissions, and electricity data. States may also adopt mass-based standards to enable emissions trading. The individual statewide goals are rate-based CO_2 goals (expressed in lbs. CO_2/MWh) that represent the weighted aggregate of these emission performance rates for each state's electric generating units, as well as alternative equivalent mass-based goals (expressed in tons of CO_2). Each state must now decide whether to apply these performance rates to each affected EGU, or to take an alternative approach and meet either an equivalent statewide rate-based goal or statewide mass-based goal.

Based on the current expectations of generation capacity changes and regional plans to reduce emissions, some states are well positioned to meet CPP's 2030 emissions rate goals. States along the West Coast and in the Northeast are expected to have state CO_2 emission rates below what is prescribed in the final CPP rule by 2030. States in red, like Missouri, West Virginia, and Wisconsin, will need to make sizeable reductions or start developing multi-state plans with nearby states that may have a surplus.

[2] Basic formula for the state = pounds of CO_2 from affected sources, divided by state electricity generation (MWh) from affected sources.



Source: EPA, SNL

Figure 2-2 Progress 2020 to 2030 CPP Emissions Rate Based Goal

2.2.1.1 Clean Power Plan (CPP) Ruling Vacated

On February 10, 2016 the Supreme Court of the United States put a temporary halt to the CPP by vacating the CPP while it continues to be litigated through federal appeals court. More than two dozen states, joined by industry groups and some utilities, have sued the EPA arguing the EPA exceeded its authority in implementing the CPP regulation. Black & Veatch interprets the vacating of the CPP regulations as a temporary setback that will impact the timing of the state implementation plan (SIPs) rather than the implementation of the CPP.

2.2.2 State Implementation Plans (SIPs)

States must submit implementation plans by 2022, assuming that the CPP will be implemented after all the legal uncertainties are resolved. The EPA expects that states will begin the formal process of developing their own SIPs. Each state will need to determine whether their plan will result in the achievement of the CO2 emission performance rates, statewide rate-based goals, or statewide mass-based goals by the affected EGUs. A state may choose to establish emission standards for its affected EGUs sufficient to meet the requisite performance rates or statewide goal under what EPA calls the "emission standards approach." In doing so, the state would effectively place all of the requirements directly on its affected existing EGUs. Alternatively, a state can adopt a "state measures approach" which could include a mix of measures such as renewable energy standards and programs to improve residential energy efficiency to assist affected EGUs in meeting the statewide goal. The final rule also gives states the opportunity to design state rate-based or mass-based plans that will make their units "trading ready", allowing individual power plants to use out-of-state reductions (in the form of credits or allowances, depending upon the plan type) to achieve required CO2 reductions, without the need for up-front interstate agreements. States may also opt to participate in the Clean Energy Incentive Program (CEIP) to reward early investments in certain renewable energy and demand-side energy efficiency projects that generate carbon-free energy or reduce end-use energy demand during 2020 and 2021. EPA will provide matching allowances or Emission Rate Credits to states that participate in the CEIP, up to an amount equal to 300 million short tons of equivalent CO2 emissions through the Clean Energy Incentive Program3.

To provide states with assistance in developing their SIPs, EPA has included two model rules that states can adopt or use to build their own plans. These model rules also represent EPA's proposed Federal Implementation Plan (FIP). EPA can impose a FIP on a state if either disapproves the state's SIP, or if the state fails to submit a SIP. Slated to be finalized in August 2016, the model FIPs gives those states that may choose not to submit an SIP understanding of how the EPA will seek to implement the CPP within their jurisdiction. Figure 2-3 below shows the timing on the CPP.

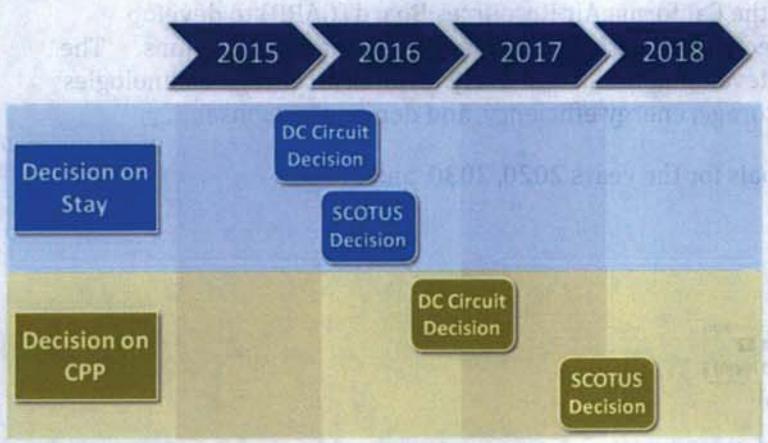


Figure 2-3 Legal Challenges to the Clean Power Plan

California is currently making good progress towards meeting the CPP's rate based goals, mostly in part of the passage of Senate Bill 250, which increases the renewable portfolio standard (RPS) to 50% by 2030.

2.2.3 California Senate Bill 350

In October 2015 Senate Bill 350 (SB 350) was passed into law by California Governor Jerry Brown. SB 350 established California's 2030 greenhouse gas reduction target of 40 percent below 1990 levels. To achieve this goal, SB 350 sets ambitious 2030 targets for energy efficiency and renewable electricity, among other actions aimed at reducing greenhouse gas emissions. SB 350 enhances the state's ability to meet its long-term climate goal of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. SB 350 increases California's renewable electricity procurement goal from 33 percent by 2020 to 50 percent by 2030. This will increase the use of Renewables Portfolio Standard (RPS) eligible resources, including solar, wind, biomass, geothermal, and others. In addition, SB 350 requires the state to double statewide energy efficiency savings in electricity and natural gas end uses by 2030. Much of the incremental requirements to reduce GHG will require electrification of the transportation sector. Regulatory agencies such as the California Energy Commission (CEC), California Air Resources Board (CARB), and the California Public Utilities commissions are working toward setting guidelines and regulations that will help the publically owned utilities (POUs) meet the SB 350 targets.

2.2.4 Assembly Bill 32 (AB32)

AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020, a reduction of approximately 15 percent below emissions expected under a "business as usual" scenario. AB32 also provides the California Air Resource Board (CARB) the authority to develop policies such as the GHG cap & trade program to meet the GHG reduction goal by 2020. Under the current trajectory of GHG emission California is expected to reduce its GHG emissions back to 1990 levels by 2020.

2.2.5 Senate Bill 32 (SB32)

The passage of Senate Bill 32 (SB32) puts into law a goal for California to reduce GHG emissions by 40% below 1990 levels by 2030. SB32 builds off of AB32 and SB350 and extends the GHG reduction goals to 2030. SB32 does not however provide additional clarity on the status of GHG cap & trade after 2020. SB32 empower the California Air Resources Board (CARB) to develop technologically feasible and cost-effective regulations to achieve the targeted reductions. The scoping plan for SB32 is still under development but will likely favor clean energy technologies such as renewable energy, energy storage, energy efficiency, and demand response.

Figure 2-4 below depicts the GHG goals for the years 2020, 2030, and 2050.

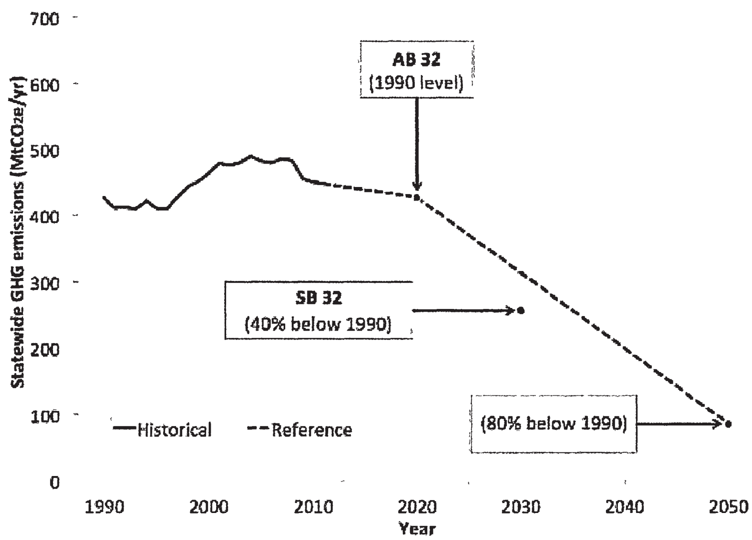


Figure 2-4 California GHG Reduction Goals

Source: California Air Resource Board

SB32 has far wider impacts that go beyond just the electric sector, many of the GHG reduction goals will require electrification of vehicles in the transportation sector and impacts across all industries that emit GHG.

2.2.6 New Source Review (NSR) Permitting

PWP is looking to repair the damaged Glenarm GT rather than build a new plant. This distinction is important given the permitting procedures for the US Environmental Protection Agency (EPA) New Source Review. Since the plant is not considered a new major source the repair of the Glenarm GT2 will not require new permitting based upon the New Source Review. New Source Reviews establishes regulations on emission levels for major new sources that are designed to comply with National Ambient Air Quality Standards. There are three types of New Source Review (NSR) permitting requirements. A source may have to meet one or more of these permitting requirements.

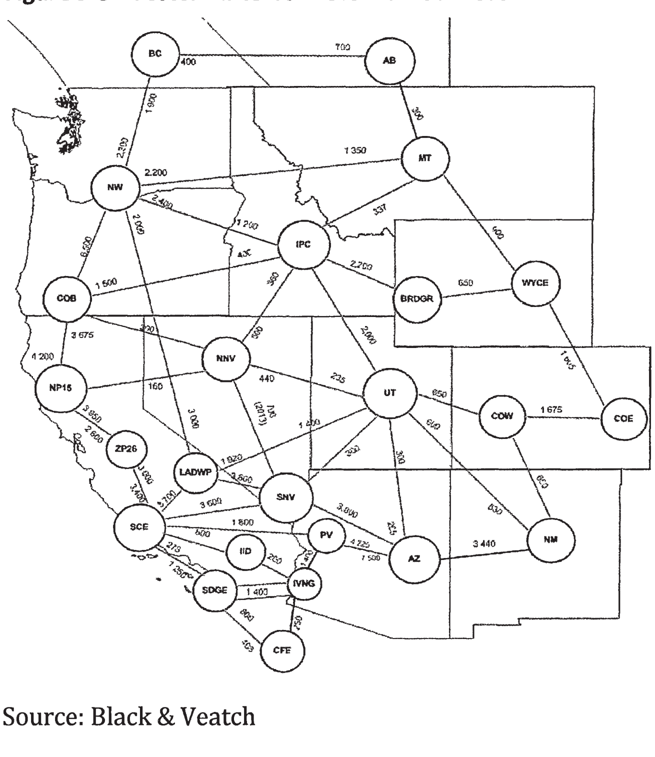
1. Prevention of Significant Deterioration (PSD) permits are required for new major sources or a major source making a major modification in areas that meet the National Ambient Air Quality Standards;
2. Nonattainment NSR permits which are required for new major sources or major sources making a major modification in areas that do not meet one or more of the National Ambient Air Quality Standards; and
3. Minor source permits
4.

NSR permits specify what construction is allowed, emission limits, and often how the source must be operated. Most NSR permits are issued by state or local air pollution control agencies. EPA issues permits in some cases. EPA establishes the basic requirements for an NSR program in its federal regulations. States may develop unique NSR requirements and procedures tailored for their air quality needs as long as the program is at least as stringent as EPA's requirements. EPA must approve these programs in the State Implementation Plan (SIP).

2.3 WESTERN POWER MARKET

The EMP has a modeling representation of the Western Interconnect market. The Western Interconnect which is composed of 23 major market pricing zones reflecting supply, demand, and transmission between those zones. The pricing of the California – Southern California Edison (CSCE) zone is a close proxy to the SP15 market. Hourly prices from 2017-2040 were forecasted for the SP15 zone and used for the energy valuation for the Glenarm GT2 unit.

Figure 2-5 Western Interconnect Market Areas



Source: Black & Veatch

2.4 NATURAL GAS PRICE

Natural gas prices are important in California and in the Western Interconnect because natural gas is the marginal fuel in over 90% of the hours over the course of the year. This means that natural gas prices are highly correlated with electricity prices because the price of electricity is set by natural gas generators in most hours.

2.4.1 Natural Gas Demand

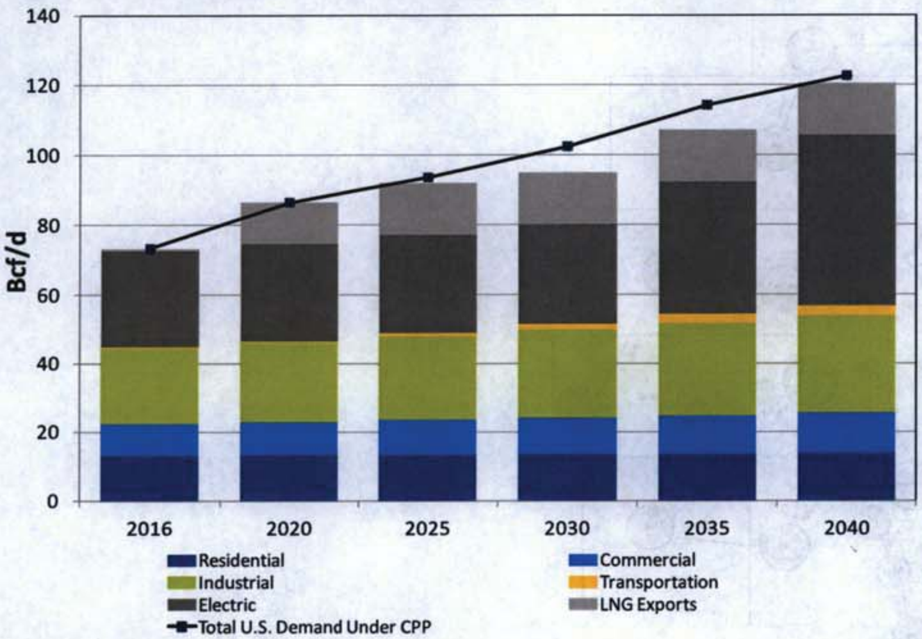
Natural gas demand is projected to rise by more than 45 Bcf per day over the forecast period, from approximately 74 Bcf per day or more in 2016 to approximately 120 Bcf per day in 2040. For the forecast period, Compound Annual Growth Rates (CAGR) for different demand sectors is shown in Table 2-1.

Table 2-1 Natural Gas CAGR for Different Demand Sectors

ELECTRIC	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	TOTAL
2.36%	0.26%	0.93%	1.07%	2.16%

Figure 2-6 shows that the two leading sources of demand increase are LNG exports and electric sector growth, which begin with small initial volumes in late 2016, and rise to 14 Bcf per day (Lower 48 states only) by 2025. Residential, commercial, and industrial domestic sectors are projected to grow slowly because of increased investment in and results from energy efficiency. The impact of the Clean Power Plan can be seen on Figure 2-6, when demand for natural gas for power generation increases after 2022.

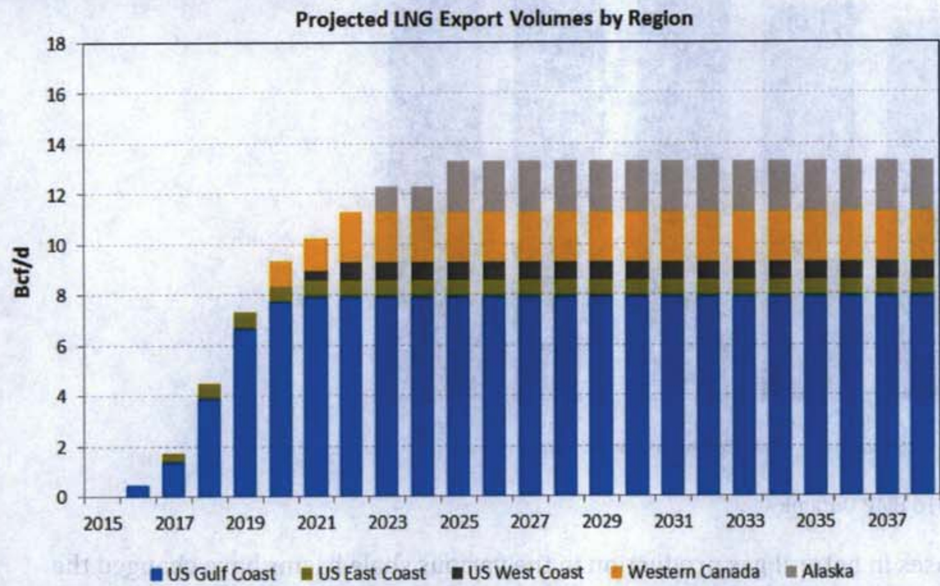
Figure 2-6 U.S. Natural Gas Demand (U.S. lower 48)



Source: Black & Veatch 2016 EMP Outlook

LNG exports remain a strong source of demand despite current depression of global LNG prices, as capacity holders will choose to utilize North American export capacity in order to either phase out oil-indexed volumes or to place price pressure on global spot cargoes. LNG export demand grows to almost 14 BCF/day by 2025 and is assumed to remain flat thereafter.

Figure 2-7 Projected LNG Exports



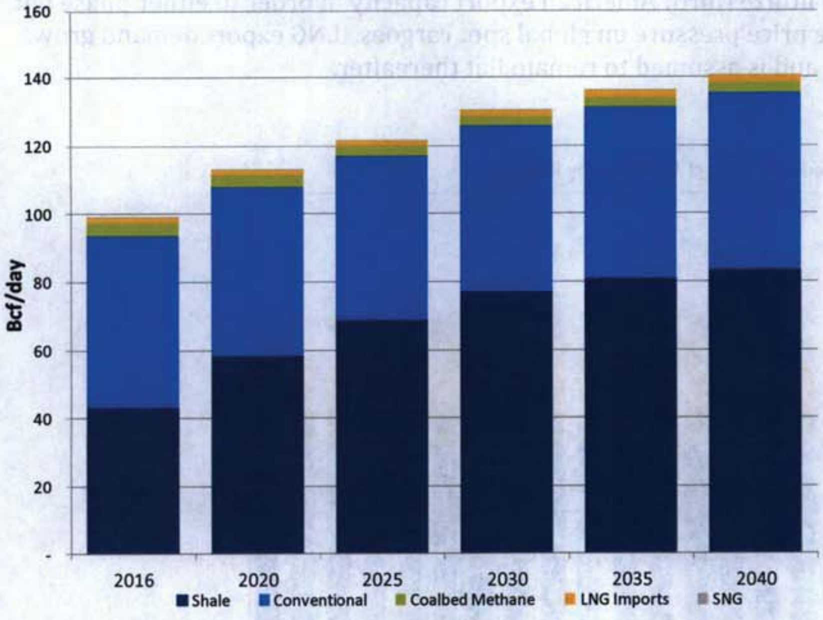
The ramp up in LNG export demand translates to a faster ramp up of corresponding natural gas prices.

2.4.2 Natural Gas Supply

The projected increase in demand for natural gas over the next 25 years is anticipated to provide a steady market incentive for the exploration for and production of natural gas in the U.S. While the share of natural gas in California is expected to decline the exact opposite will occur though out the rest of US as coal generation is replaced by natural gas generation. As oil prices begin to recover from current lows, Black & Veatch expects the producers to start drilling programs to meet the projected growth in gas demand, primarily from the power sector and LNG exports.

Figure 2-8 shows that North American natural gas production will grow by 40 Bcf per day over the next two decades. Production from tight and shale gas resources drives the aggregate production growth but conventional production is also expected to benefit from the new drilling technologies (hydraulic fracturing and horizontal drilling) in tight sands, and will remain relatively constant beyond 2030.

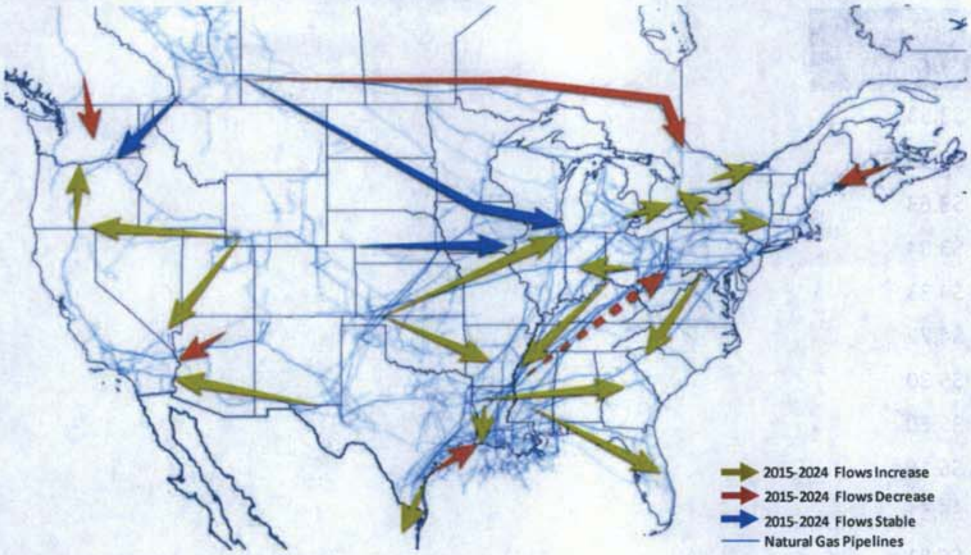
Figure 2-8 Forecast of Natural Gas Supply



Source: Black & Veatch 2016 EMP Outlook

The significant increases in natural gas production in the various shale basins have changed the traditional pipeline flows on the U.S. pipeline system and will continue to do so during the forecast horizon. The dynamics of shale gas production are re-defining the historical price/basis, and transportation capacity values as shown in Figure 2-9.

Figure 2-9 Forecasted Pipeline Flow Changes[3]



Source: Black & Veatch 2016 EMP Outlook

Several trends will impact regional gas supplies and prices:

- In the northeast Canada Atlantic region, the continued declines of SOEP and Deep Panuke production will require new sources of Appalachian supplies to reach New England and the Maritimes.
- Marcellus production growth is expected continue to flow to Midwest, Southeast and reverse flow back to the Gulf Coast. More Gulf Coast production will remain to serve local regional demand instead of flowing to traditional northern markets.
- WCSB, San Juan, Permian and Rockies production will be competing to serve Western US and Canadian market growth.
- Continuing decline in flows on TransCanada Pipeline from western Canada to the large Canadian eastern markets will offer markets for Marcellus production to flow north across the U.S. border as exports to Canada.

Overall, increased pipeline flows from growing shale gas production to emerging market centers will reduce price volatility and price/basis blowouts, which would help moderate and stabilize electric prices. In today's natural gas market the last units of production at Marcellus Shale or from the Gulf Coast set the price of natural gas.

Table 2-2 below is the average annual delivered burner tip forecast for natural gas generators in southern California. The delivered natural gas price includes all costs required to deliver the natural gas source to the burner tip.

[3] Dotted red line denotes new pipelines

Table 2-2 Delivered Burner Tip Natural Gas Forecast

Delivered SoCal Citygate	
Year	**2016 $/mmBtu**
2017	$3.53
2018	$3.49
2019	$3.63
2020	$3 94
2021	$4.33
2022	$4.72
2023	$5.30
2024	$5.80
2025	$6.16
2026	$6.51
2027	$6.81
2028	$7.10
2029	$7.47
2030	$7.76
2031	$8.14
2032	$8.47
2033	$8.90
2034	$9.22
2035	$9.56
2036	$9.99
2037	$10 44
2038	$10.92
2039	$11.37
2040	$11 77

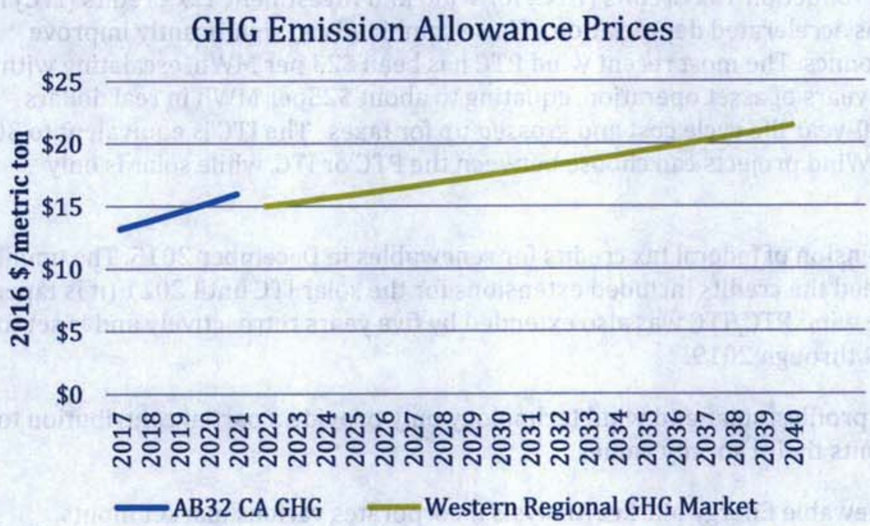
Source: Black & Veatch

2.5 ENVIRONMENTAL ASSUMPTIONS

2.5.1 Carbon Pricing

Black & Veatch's EMP Base Case assumptions anticipate US federal regulatory action to address carbon emissions and Greenhouse Gas (GHG) pollution. That assumption contributes to higher natural gas prices, because it increases projected natural gas demand for electricity generation which will displace coal fired generation. It also contributes to a projected increase in electricity prices in 2022, when GHG rules are projected to first begin to take hold. The assumed GHG regulations would build off of and expand emission limitations compared to the current AB32 regulations in place in California. The GHG forecast assumes that CPP will be implemented in 2022 assuming a regional cap and trading program is implemented in the West. California's existing AB32 and future SB32 policy is assumed to merge with the Western GHG trading market.

Figure 2-10 Base Case Carbon Allowance Prices



Source: Black & Veatch

2.5.2 Renewable Resources

To forecast future renewable energy development across the U.S., Black & Veatch developed an innovative GIS-based analysis of wind and solar resources across the U.S. The analysis captured the variations in resource production (capacity factor), capital costs, operation and maintenance costs and transmission costs based on the location of individual sites. The Net Cost of individual sites was then calculated to develop a supply curve for resources to serve individual state's Renewable Portfolio Standard (RPS) requirements.

Renewable energy costs vary widely depending on these critical assumptions. While costs have declined substantially in the last 20 years, solar and wind technologies are capital cost intensive, making energy production assumptions (expressed as capacity factor) key. Higher capacity factors (CFs) dramatically lower levelized busbar costs. Therefore, it is important to attempt to capture these differences across the country.

Recent technological and manufacturing improvements have dramatically altered the cost of energy from solar and wind. Historical wind projects have capacity factors of roughly 25 to 40 percent. With increases in hub height, blade span, and improvements in capturing lower wind speeds, the capacity factors are expected to improve for the same resource. These technological advancements to improve wind generation mean that the capital cost of wind turbines will likely not decline going forward. If additional wind generation does get built over time in this region, it is unlikely to impact the peak energy prices in the region (which would impact the Castle Gap plant in case it were to be a merchant plant), since wind generation is counter cyclical to demand and solar generation both on a daily basis and on a seasonal basis. On the other hand, solar has experienced dramatic declines in capital costs in the past five years, especially for large utility-scale systems, and Black & Veatch expects additional cost declines are still achievable going forward. Furthermore, the industry has shifted to deploying single-axis tracking systems more economically, which can increase the capacity factor of solar by 10 to 15 percent compared to a fixed-tilt system.

Renewable energy projects historically have been able to take advantage of a number of federal tax incentives, such as the Production Tax Credits (PTC) for wind and Investment Tax Credits (ITC) for wind and solar as well as accelerated depreciation. These combined can significantly improve renewable energy economics. The most recent wind PTC has been $23 per MWh, escalating with the CPI, for the first ten years of asset operation, equating to about $25per MWh in real dollars when levelized over a 20-year life cycle cost and grossed up for taxes. The ITC is equivalent to 30 percent of capital cost. Wind projects can choose between the PTC or ITC, while solar is only eligible for the ITC.

Congress passed an extension of federal tax credits for renewables in December 2015. The omnibus spending bill that included the credits included extensions for the solar ITC until 2021 (it is tapered beginning in 2020). The wind PTC/ITC was also extended by five years retroactively and is set to step down the tax credit through 2019.

Due to their generating profiles, solar and wind technology only provide a partial contribution to peak capacity, which limits their capacity value.

The Black & Veatch Renewable Energy Market Analysis incorporates various market inputs, including:

- Renewables supply curve
- State RPS targets
- Federal policy
- Delivery constraints
- Proprietary energy, capacity and carbon/emissions pricing models

In preparing its Renewable Energy Market Analysis, Black & Veatch made the following market assumptions:

- Solar costs will decline to 70 percent of current levels in real dollars in 2016 and stabilize thereafter.
- Wind costs remain stable in real dollars over the study period.
- Federal Tax Credits: The 2016 EMP Outlook has been updated to reflect the recent actions taken by Congress at the end of 2015, including the extension of tax credits for renewable development.
- Future demand for renewable energy to meet RPS requirements is reduced by existing projects and projects that are under constructions, as well as solar distributed generation carve out programs.
- RPS percentages targets are sustained throughout the duration of the model to the extent ACP caps are not exceeded.
- States with alternative compliance payment (ACP) caps may limit future RPS renewable energy build out if the renewable energy credit (REC) price exceeds the ACP.

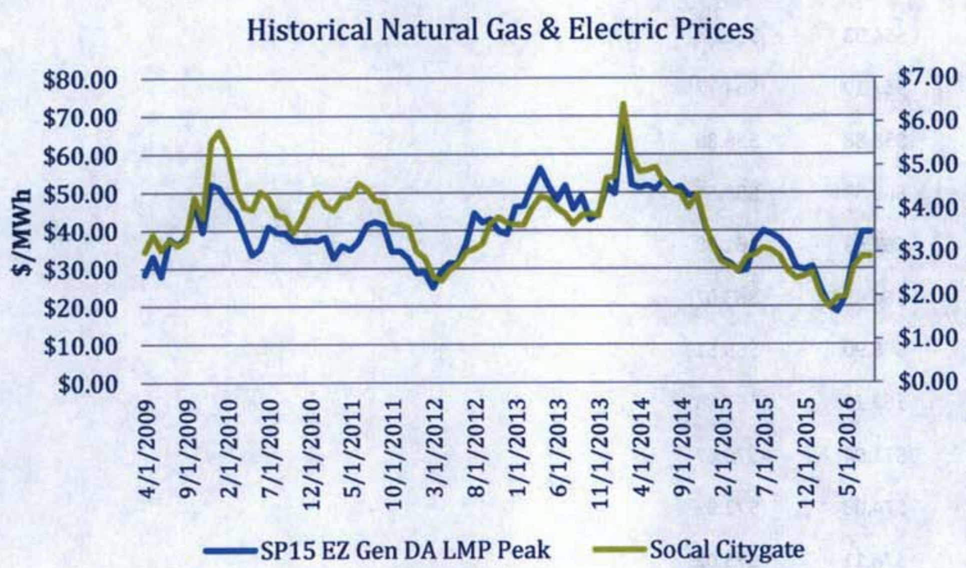
- Both solar and wind, being variable generation, are both assumed to have a capacity contribution of 10 percent of their nameplate capacity.
- Only states with RPS requirements build out renewable energy.

The renewable build in California assumes that all load serving entities will meet the RPS which will be 33% in 2020, 40% by 2024, and 50% by 2030. Higher levels of renewables on the system will increase the emphasis on having flexible capacity and less on baseload natural gas generation sources.

2.6 ELECTRIC POWER PRICE FORECAST

Historically, natural gas prices are highly correlated with electricity prices and that correlation is expected to continue in the future even with increasing levels of renewable resources. Changes in supply and demand conditions (i.e. shale gas revolution) along with recent tax incentives have created an environment in which natural gas and power prices to record lows. Figure 2-11 below shows the historical day ahead on-peak power price and natural gas price from 2009-2016.

Figure 2-11 Historical Natural Gas and Electric Prices



Source: Energy Velocity (Intercontinental Exchange Data)

The relationship between electricity prices and natural gas prices can be measures through the calculation of the market heat rate. The market heat rate is simply the electricity price divided by the natural gas price. Since the start of the CAISO MRTU in 2009 the on peak market heat rate has averaged ~11,000 btu/kWh. The Glenarm GT2 heat rate is ~ 14,000 btu/kWh, which is an indication that on most on peak hours the unit is "out of the money" and is not an economic resources compared to other resources available in the market. Black & Veatch expects long term fundamental market conditions to put upward pressure on electricity prices due to increasing natural gas and carbon prices. The result of increasing natural gas and carbon prices can be been seen in corresponding higher electricity prices.

Table 2-3 Base Case Electricity Price Forecast

SP15 ELECTRICITY PRICE (2016 $/MWH)			
YEAR	ON PEAK	OFF PEAK	AVERAGE
2017	$39.93	$36 67	$33 71
2018	$40 16	$36 81	$33 75
2019	$40 98	$37 61	$34 54
2020	$42.57	$39 23	$36 19
2021	$44 88	$41 72	$38 84
2022	$50 20	$46.85	$43 82
2023	$53 20	$49.92	$46 96
2024	$55 93	$52 87	$50 09
2025	$57 76	$54 93	$52.35
2026	$59 66	$57.10	$54 77
2027	$61 11	$58 88	$56 86
2028	$62 72	$60.59	$58 67
2029	$64 26	$62 59	$61 08
2030	$65 98	$64.45	$63 07
2031	$68 45	$66 90	$65 51
2032	$70 68	$69 20	$67 88
2033	$73 35	$71.94	$70 67
2034	$75 20	$74 03	$72 95
2035	$77.31	$76 11	$75 02
2036	$80 03	$78 81	$77 71
2037	$83 86	$82 36	$81 00
2038	$87 18	$85 61	$84 21
2039	$90 51	$88 83	$87 31
2040	$93 44	$91.70	$90 13

Source: Black & Veatch

3 Glenarm GT2 Valuation

Although PWP currently is long on capacity and does not require the Glenarm GT2 unit to meet system RA requirements, the GT2 has value as it relates to meeting future local and flexible capacity RA requirements. In this section Black & Veatch will provide some indicative ranges for capacity and energy values if the plant were to be repaired and brought back into commercial operation. Black & Veatch valued the energy value of the Glenarm GT2 unit by assuming that the unit will be able to sell into the CAISO SP15 wholesale market if it is economic to do so, subject to its operating constraints.

3.1.1 Glenarm GT2 Repair Estimate

PWP hired several firms to provide an estimate of the repair costs consisting of contract work, contingency, and administrative costs. The firms that provided those estimates to perform the contract work to repair the unit are kept confidential for the purposes of this report. The scope of the repair work included the main contract work along with contingency and administrative costs that PWP will be responsible for. The two estimates provided to PWP ranged from a low of $9.9 million to a high of $13.3 million.

Table 3-1 Glenarm GT2 Repair Estimate

RESPONSIBLE	CATEGORY	ESTIMATE TYPE	LOW	HIGH
Contractor	Contract Work	Contract Work	$7,500,000	$10,900,000
PWP		Remote Laydown	$300,000	$300,000
	Contingency	Contingency	$1,635,000	$1,635,000
	Administrative Costs	PWP Staff & Labor	$450,000	$450,000
		Air Permit	$27,000	$27,000
		Building Permit	$15,000	$15,000
Total Contract Work, Contingency, Admin Costs			$9,927,000	$13,327,000
	Repair Cost $/kW		**$451**	**$606**

Source: Pasadena Water & Power

On a unitized based the cost to repair the 22 MW Glenarm GT2 unit would range from $451/kW to $606/kW.

3.1.2 Replacement Costs

The Pratt & Whitney GG4C-1DF gas generator and Curtiss-Wright CT2 power turbine technology used in the Glenarm GT2 is no longer commercially available today. There are similar, newer manufactured turbines today that can provide a similar level of operations but with better efficiency. Unfortunately, there has not been a lot of peaking natural gas power plants built in California over the last 7-9 years. Currently, the 300 MW Pio Pico Energy Center is under construction in San Diego, CA. Pio Pico utilizes the General Electric LMS100 technology and is not a direct comparison to the replacement cost of Glenarm GT2. Table 3-2 below lists some of the more recent peaking natural gas plants that have been proposed in California since 2009. Many of these proposed plants have since been cancelled; however it is informative to review the pipeline of plants and their estimated costs. Many of the costs reported by Energy Velocity are based upon press releases and come from a variety of sources. Most of the costs listed for the power plants are more than likely an EPC estimate, rather than a total all-in cost, which would also include owner's costs and interest accrued during construction.

Table 3-2 Recent Proposed Peaking Natural Gas Turbines in California

PLANT NAME	PLANT COUNTY	PHASE STATUS	PHASE ONLINE DATE	NET CAPACITY MW	TOTAL [4]COST ($ MILLIONS)	COST UNIT ($/KW)
Watson Cogeneration Co	Los Angeles	Postponed	2017	94.2		
SDG&E Camp Pendleton Power Plant	San Diego	Feasibility	2017	1000		
Jasmin Power III – SD 6000	Kern	Proposed	2017	92.584		
Pio Pico Energy Center	San Diego	Under Const	2016	321	$300	$935
Kimberlina Power Plant	Kern	Canceled	2016	50	$90	$1,800
Quail Brush Generation Project	San Diego	Canceled	2015	99		
Wellhead Power Helm LLC	Fresno	Canceled	2015	48		
Sun Valley Energy Project	Riverside	Canceled	2015	520	$250	$481
Escondido	San Diego	Operating	2014	49.9		
Ocotillo Energy Project	Riverside	Canceled	2013	455		
Haynes	Los Angeles	Operating	2013	649.2	$782	$1,205
Walnut Creek Energy Park	Los Angeles	Operating	2013	500.5	$500	$999
CPV Sentinel Energy Project	Riverside	Operating	2013	318.75	$337	$1,057

[4] Costs are reported by Energy Velocity do not identify if costs are EPC or all in costs.

PLANT NAME	PLANT COUNTY	PHASE STATUS	PHASE ONLINE DATE	NET CAPACITY MW	TOTAL [4]COST ($ MILLIONS)	COST UNIT ($/KW)
Marsh Landing Generating Station	Contra Costa	Operating	2013	828	$700	$845
CPV Sentinel Energy Project	Riverside	Operating	2013	531.75	$563	$1,059
San Francisco Electric Reliability Project (Intl Airport)	San Mateo	Canceled	2012	48	$38	$792
Oxnard Peaker	Ventura	Operating	2012	49.8	$50	$1,004
Mariposa Energy	Alameda	Operating	2012	199.6	$185	$927
Almond Power Plant	Stanislaus	Operating	2012	174	$200	$1,149
Wellhead Power Delano	Kern	Operating	2012	48.5		
Carlsbad Energy Center	San Diego	Canceled	2011	300	$500	$1,667
Canyon Power Project	Orange	Operating	2011	50	$65	$1,300
Canyon Power Project	Orange	Operating	2011	50	$65	$1,300
French Valley Energy Center	Riverside	Canceled	2011	49	$50	$1,020
Pastoria Energy Facility	Kern	Canceled	2011	160		
Canyon Power Project	Orange	Operating	2011	50	$65	$1,300
Canyon Power Project	Orange	Operating	2011	50	$65	$1,300
Riverside Energy Resource Center	Riverside	Operating	2011	96	$100	$1,042
Bullard Energy Center	Fresno	Canceled	2010	200	170	$850
El Cajon Energy Center Peaker	San Diego	Operating	2010	49.9		
Highgrove Power Plant	San Bernardino	Canceled	2010	300	200	$667
Orange Grove Project	San Diego	Operating	2010	118	120	$1,017

PLANT NAME	PLANT COUNTY	PHASE STATUS	PHASE ONLINE DATE	NET CAPACITY MW	TOTAL [4]COST ($ MILLIONS)	COST UNIT ($/KW)
Larkspur Energy Facility	San Diego	Canceled	2010	47		
Miramar Peaking Facility	San Diego	Operating	2009	53	56.5	$1,066
Panoche Energy Center	Fresno	Operating	2009	432	300	$694
Chula Vista	San Diego	Canceled	2009	94	80	$851
San Francisco Electric Reliability Project (Potrero Hill)	San Francisco	Canceled	2009	135	230	$1,704

Source: Energy Velocity

In 2010, PWP contracted with an engineering firm to conduct a repowering options study for the local plants. The cost estimate in the study to replace Glenarm GT1 with General Electric LM 2500 with net output of 28 MW was $968/kW. Black & Veatch estimates a comparable new General Electric 7FA simple cycle natural gas turbine would cost between $715 -$813/kW installed. A more flexible General Electric LMS100 is estimated around $1,372/kW installed. Since 2010 Black & Veatch has observed that the cost for constructing power plants has come down worldwide due to lower cost of materials. The repair estimate for Glenarm GT2 ranged from $451-606/kW for EPC only. The estimate to repair an existing facility without having to procure new permits and satisfying the EPA New Source Review appears to be reasonable relative to Black & Veatch's estimate of current simple cycle EPC costs. According to publicly available documents, costs for building new proposed gas turbine power plants appears to be significantly higher than the cost to repair Glenarm GT2. Black & Veatch new build estimates are also higher than the repair cost. The reported cost of new build may vary greatly due to differences in technology, location, size, and EPC firm.

3.1.3 Net Energy Revenue Forecast

Black & Veatch performed a dispatch analysis to determine the performance and net energy revenue of the plant from 2017-2040. Black & Veatch dispatched the Glenarm GT2 unit against hourly projected prices in the SP15 market for the next 25 years. Table 3-3 shows the forecasted net energy revenue for the sale of energy from Glenarm GT2.

Table 3-3 Glenarm GT2 Merchant Net Energy Revenue Forecast

YEAR	MW	GENERATION (GWH)	CF	# OF STARTS	ENERGY REVENUE ($ 000)	OPERATING COST ($ 000)	GROSS MARGIN ($ 000)
2017	22.07	123.21	1%	4	$13,167	$13,142	$25

YEAR	MW	GENERATION (GWH)	CF	# OF STARTS	ENERGY REVENUE ($ 000)	OPERATING COST ($ 000)	GROSS MARGIN ($ 000)
2018	22.07	261.77	2%	8	$29,060	$27,134	$1,927
2019	22.07	129.35	1%	5	$17,643	$15,284	$2,358
2020	22.07	107.28	1%	3	$12,797	$12,696	$101
2021	22.07	161.21	1%	6	$22,657	$22,201	$456
2022	22.07	0	0	0	0	0	0
2023	22.07	0	0	0	0	0	0
2024	22.07	0	0	0	0	0	0
2025	22.07	0	0	0	0	0	0
2030	22 07	0	0	0	0	0	0
2040	22.07	0	0	0	0	0	0

Source: Black & Veatch

As expected the Glenarm GT2 unit has very little underlying energy value because it is an inefficient, high heat rate unit. The forecasted operation of the plant is expected to be similar to historical operations. Glenarm GT2 will likely only operate during summer peak load hours or in the event of generation or transmission contingency. As the percentage of renewables increase over time the Glenarm GT2 unit is expected to operate less. In real world conditions the Glenarm GT2 may operate more than forecasted due to unforeseen system contingencies, such as the loss of the TM Goodrich transmission line, and market volatility. Volatility in real time market pricing can also offer opportunities for Glenarm GT2 to operate during very high price hours.

3.2 RESOURCE ADEQUACY

The value of the Glenarm GT2 unit is embedded in is location within the PWP service territory. As previously mentioned PWP is only connected to the CAISO system by the 220kV transmission line at TM Goodrich. PWP forecasted system peak is around 316 MW and is expected to remain fairly flat in the future. Under peak load conditions the loss of the TM Goodrich line would result in the loss of around 245 MW of import capability. Under this transmission contingency the Glenarm GT2 unit would be able to serve load and possibly mitigate some blackouts. The market for local, system, and flexible resource adequacy is very depressed over the past few years and is expected to remain depressed for the next several years as more renewables continue to enter the market. Black & Veatch assumes that Glenarm GT2 would qualify to meet system, local and flexible resource adequacy requirements.

3.2.1 System Level Resource Adequacy

The California Resource Adequacy (RA) program is designed to meet reliability requirements by requiring California Public Utilities Commission (CPUC) jurisdictional load serving entities (LSEs) to procure capacity 15% above the forecasted monthly peak load. The California RA program has multiple layers of complexity to meet reliability requirements. The 15% capacity requirement above forecast system peak load is the system level requirement based upon the 1 in 2 peak load forecast for the LSE. Capacity can be located anywhere on the system as long as it can meet deliverability requirements to serve the monthly peak load. California is long on system level RA and may be permanently long on system level RA due to the large and growing amounts of solar generation. Publicly available information on RA prices is difficult to obtain because the RA contracts are negotiated bilaterally between the LSE and generation owners.

Black & Veatch forecasts system level RA to be either zero or a small value enough to cover the annual fixed O&M costs of an existing generator to prevent those units from exiting the market (i.e. retire). Table 3-4 list some RA prices based upon a survey of RA contracts collected by the CPUC in 2015. The posted price for system level RA is expected to remain low in the foreseeable future and is consistent with Black & Veatch's outlook on system RA prices.

Table 3-4 Resource Adequacy Capacity Prices (2013-2017)

Table 11. Aggregated RA Contract Prices, 2013-2017

	All RA Capacity Contracts			Local RA Capacity Contracts			CAISO System RA Capacity Contracts		
	Total	NP-26	SP-26	**Subtotal**	NP-26	SP-26	**Subtotal**	NP-26	SP-26
Weighted Average Price ($/kW-month)	**$3.23**	$2.66	$3.60	**$3.39**	$2.44	$3.65	**$2.86**	$2.79	$3.17
Average Price ($/kW-month)	**$3.20**	$2.65	$3.61	**$3.43**	$2.88	$3.73	**$2.41**	$2.26	$2.76
Minimum Price ($/kW-month)	**$0.09**	$0.11	$0.09	**$0.09**	$0.90	$0.09	**$0.11**	$0.11	$0.14
Maximum Price ($/kW-month)	**$26.54**	$14.85	$26.54	**$26.54**	$8.62	$26.54	**$18.99**	$14.85	$18.99
85th Percentile ($/kW-month)[25]	**$5.80**	$3.50	$8.20	**$6.48**	$3.17	$8.47	**$4.49**	$4.49	$7.30
Contracted Capacity (MW)	**372,623**	148,417	224,207	**256,562**	54,590	201,972	**116,061**	93,827	22,234
Percentage of Total Capacity in Data Set	**100%**	40%	60%	**69%**	15%	54%	**31%**	25%	6%
Number of Monthly Values	**3,556**	1,516	2,040	**2,748**	956	1,792	**808**	560	248

Source: CPUC 2013-2014 Resource Adequacy Report – August 2015

Black & Veatch does not anticipate system RA prices to recover to the cost of new entry throughout the study horizon. Over the study period system level RA prices will remain low, but new entry into the market will be driven by local and Flex RA requirements, rather than system RA.

3.2.2 Local Resource Adequacy

The RA program also has a local RA sub-requirement that requires a certain amount of capacity be located within a transmission constrained zone. The Glenarm power plant is located in the LA Basin and is part of the LA Basin Local Capacity region in the CAISO. There are ten local reliability zones in the CAISO. Capacity requirements in the local capacity zones are higher because planning requirements are based upon a 1 in 10 peak load rather than a 1 in 2 peak load. Local RA requirement also factor in operating contingencies such as the loss of generation or transmission line that would impact the local area. PWP has a compliance obligation to demonstrate resource adequacy showings for system, local, and flexible RA requirements allocated based upon load. Figure 3-1 illustrates the Local Capacity zones

Figure 3-1 Local Capacity Requirements

Source: CAISO

Some of the CAISO local zones have sub-areas that reflect local transmission issues within the larger local area. Currently the PWP transmission issue is not captured as a sub-area within the LA Basin.

The LCR requirements calculated by the CAISO are complex because it incorporates planning and operating reliability protocols. The LCR from a planning perspective is based upon a 1 in 10 peak load forecast. It also takes into account possible operating contingencies such as the loss of a generator or a transmission line, referred to as the N-1 (Category B) and N-1-1 (Category C), which is the next stringent contingency.

Table 3-5 below lists the latest LCR analysis performed by the CAISO for 2017. The CAISO does not project any local RA deficiencies in the LA Basin for 2017, therefore new build capacity is not requirement. However, as load grows, units retire, the need for more capacity to satisfy local RA may be required. Currently Black & Veatch estimates that local RA may be required in the 2020 time frame, however the need for that capacity is related to the retirement of once-through cooling units in the LA Basin. The LCR determination process is an annual process and does not perform a forward look ahead. One of the main criticisms of the California RA program is the lack of a longer term forward RA procurement process. The investor owned utilities (IOUs) do however have a somewhat separate Long Term Procurement Plan (LTPP) that ties into the CPUC RA program.

Table 3-5 LA Basin 2017 Local Capacity Requirement

2017 Local Capacity Requirements

	Qualifying Capacity			2017 LCR Need Based on Category B[1,2]			2017 LCR Need Based on Category C[2,3] with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	20	198	218	110	0	110	157	0	157
North Coast / North Bay	128	722	850	721	0	721	721	0	721
Sierra	1176	890	2066	1247	0	1247	1731	312*	2043
Stockton	149	449	598	340	0	340	402	343*	745
Greater Bay	1070	8792	9862	4260	232*	4492	5385	232*	5617
Greater Fresno	231	3072	3303	1760	0	1760	1760	19*	1779
Kern	60	491	551	137	0	137	492	0	492
LA Basin	1615	8960	10575	6873	0	6873	7368	0	7368
Big Creek/ Ventura	543	4920	5463	1841	0	1841	2057	0	2057
San Diego/ Imperial Valley	239	5071	5310	3570	0	3570	3570	0	3570
Total	5231	33565	38796	20859	232	21091	23643	906	24549

Source: CAISO

Interpreting the LCR requirements in Table 3-5 above is more complicated than simply checking if the maximum qualifying capacity is greater than the LCR need based upon Category B and C requirements. The LCR zones have sub-regions in which constrained transmission is problematic and may require new build to solve those load pocket issues:

- El Nido sub-area;
- Western Sub-Area;
- West of Devers Sub-area;
- Valley-Devers Sub-Area;
- Valley Sub-area;
- Eastern LA Basin Sub-area;
- LA Basin Area and San Diego Sub-area Combined.

PWP's single transmission line connection at TM Goodrich to the CAISO is an example of a possible sub-area within the LA Basin, but currently the CAISO does not carve out a sub-region for PWP. For the LA Basin as a whole there is enough excess capacity to meet LCR by a substantial margin and new build does not appear to be required in the foreseeable future. Therefore if there is no deficiency in LCR it is reasonable to assume that local capacity prices will remain low and will not converge towards the cost of a new entry. Table 3-6 below lists the surveyed local RA prices contracted from 2013-2017. The weighted average price of local RA was $3.63/kW-mo. and the maximum price was $24.36/kW-yr., which is likely represented by a brand new power plant.

Table 3-6 LA Basin 2017 Historical Local RA Contract Prices

Table 12. Capacity Prices by Local Area, 2013-2017

	Big Creek-Ventura	LA Basin	Bay Area	Other PG&E Local Areas	San Diego - IV	CAISO System (no Local Area)
Weighted Average Price ($/kW-month)	$3 41	$3.63	$2 37	$3 01	$4.08	$2 86
Average Price ($/kW-month)	$3 39	$3.95	$2 79	$2 97	$3 78	$2 41
Minimum Price ($/kW-month)	$0 12	$0.11	$0 90	$0 90	$0 09	$0 11
Maximum Price ($/kW-month)	$21 77	$24.26	$4 51	$8 62	$26.54	$18 99
85th percentile ($/kW-month)	$7 53	$8 58	$3 12	$3 25	$11.10	$4.49
Contracted Capacity (MW)	79,154	73,922	49,142	5,448	48,896	116,061
Percentage of Total Capacity in Data Set	21 2%	9 8%	13 2%	1 5%	13 1%	31 1%

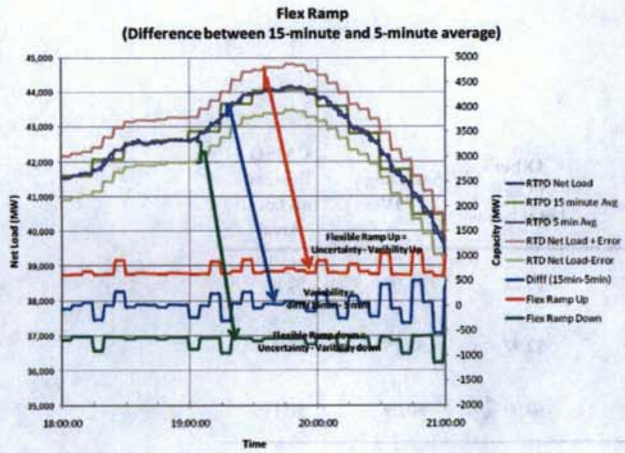
Source: CPUC 2013-2014 Resource Adequacy Report – August 2015

3.2.3 Flexible Resource Adequacy Capacity (FRAC)

In order to meet the 50% RPS requirement PWP will need to procure additional wind and solar resources to meet those goals by 2030. As PWP adds more wind and solar PWP will be responsible for procuring the associated flexible capacity based upon the FRAC formula[5] used by the CAISO. As a member of the CAISO, PWP is also able to participate in the Energy Imbalance Market (EIM). The EIM is an automated 15 minute optimization and 5 minute dispatch market that provides imbalance energy to help integrate renewable resources. The Glenarm GT2 should contribute to PWP's flexible capacity requirement which is a function of the amount of intermittent renewables that PWP contributes to the entire EIM footprint. Under the third layer of the RA program, PWP has a Flexible Resource Adequacy Capacity Must Offer Obligation (FRAC-MOO). Figure 3-2 below shows the definition of the flexible ramping requirement, which is the change in the net load from the 15 minute interval to 5 minute interval.

[5] FRAC-MOO is calculated on a monthly basis using the maximum change in the 1 minute net load data over a 3 hour period plus 3.5% of the peak load for the CAISO system. LSE's are then allocated a share of the total FRAC requirement based upon their contribution from load and renewables.

Figure 3-2 Flexible Capacity Requirements



Source: CAISO

Resources that can respond within 10 minutes should be able to qualify for flexible ramping in the CAISO market. The Glenarm GT2 unit will likely be able to contribute to FRAC-MOO but it is unlikely to be dispatched since it is an expensive, high heat rate unit to operate. Black & Veatch assumes that the flexible RA value of the plant should be the same as the local value of the plant because Glenarm GT2 can simultaneously be able to qualify to meet local and flexible RA requirements.

3.2.4 CAISO Capacity Procurement Mechanism (CPM)

Another data point in attempting to understand the capacity value of the Glenarm GT2 unit is to look at the capacity backstop procurement price calculated by the California Energy Commission (CEC). In February 2016 the CAISO started to transition to a new Capacity Procurement Mechanism (CPM) to procure either system, local, or flexible capacity required for reliability that was not designated for Resource Adequacy (RA). Given that RA prices in California are very low due to supply exceeding demand, Black & Veatch believes that the CPM provides an administrative pricing ceiling signal to the cost of capacity using existing generation as a proxy.

The CEC estimated levelized going-forward fixed costs[6] for a mid-cost, 550 MW combined cycle with duct firing resource in 2013 plus 20%. This equals $75.68/kW- year ($6.31/kW-month) using the CEC draft report estimates for insurance, ad valorum, and fixed operation and maintenance costs. This price can be used as a soft offer cap price for all capacity types (system, local, flexible) and all competitive solicitation processes (annual, monthly, intra-monthly). The CAISO CPM is not a market price signal that can be transacted on, but it does provide a ceiling price that the CAISO would be willing to pay in the event existing capacity is required on the system to meet either system, local, or flexible capacity requirements.

3.2.5 Capacity Value for Glenarm GT2

It is difficult to identify a single price point for the capacity value of Glenarm GT2 should it be repaired and returned into service. The short term value of Glenarm GT2 is probably close to zero

[6] Going forward costs are reviewed every four years by the CEC.

for the next 3-5 year horizon due to oversupply of system, local, and flexible capacity on the system. As more units begin to retire, more renewables come online, and load growth starts to pick up, the local and flexible RA values should increase. Black & Veatch assumes the flex RA value will be the same as the local RA value. Glenarm GT2 can qualify for both RA requirements but would not get paid twice for the same capacity. Using the weighted average local RA price in the LA Basin from 2013-2017 of $3.63/kW-mn or $43.56/kW-yr, Black & Veatch believes this represents a reasonable mid-point value for the capacity for Glenarm GT2. The low estimate would be zero or the actual annual fixed O&M cost for the Glenarm GT2. Black & Veatch assume $1/kW-mn would be a reasonable estimate of fixed O&M costs for Glenarm GT2. The high range estimate would be the CPM price of $75.68/kW-yr

Table 3-7 Glenarm GT2 Capacity Value Range

CAPACITY VALUE	PRICE	LOW	MID	HIGH
Glenarm GT Capacity Value	$/kW-mn	$1	$3.63	$6.31
	$/kW-yr	$12	$43.56	$75.68

Source: Black & Veatch

4 Recommendation

Black & Veatch believes that PWP should consider repairing the unit primarily to support system reliability because the Glenarm GT2 has locational value that is specific to PWP due to reliance on a single transmission line connection at TM Goodrich to the CAISO system. Based upon the estimated repair cost estimates for Glenarm GT2 that ranges from $9.9 million to $13.3 million the repair costs is likely lower than the cost of a new build. It is unlikely that PWP will need to acquire new capacity until the retirement of the Intermountain Power Plant in 2025. The replacement cost of purchasing flex or local RA in the market will likely be more expensive over the long term than the alternative of repairing Glenarm GT2. Table 4-1 below lists the range of energy and capacity values for Glenarm GT2. Although the Black & Veatch deterministic simulation of Glenarm GT2 did not forecast the plant to operate due to its high operating costs over the long term, Black & Veatch assumes $500,000 of annual net energy revenue that can be derived by real time market opportunities, which would require the unit to operate at around 1% CF annually. Table 4-1 is Black & Veatch's estimated range of energy and capacity value for the Glenarm GT2 unit.

Table 4-1 Annual Net Revenue Estimate

NET ANNUAL REVENUE 2016 $ 000			
Glenarm GT2	Low	Mid	High
Annual Capacity Revenue	$264	$958	$1,665
Annual Net Energy Revenue	$500	$500	$500
Total Annual Net Revenue	**$764**	**$1,458**	**$2,165**

Source: Black & Veatch

Using the average repair cost of $11.6 million and the average annual net revenue for Glenarm GT2 of $1.5 million, Black & Veatch projects that cost recovery[7] for the plant can be done within 10 years. Under the worst case scenario of low annual net revenue and high repair estimate the recovery of the repair costs could take up to 17 years. The financial risks for repairing Glenarm GT2 are asymmetrical. The downside risk is fairly low especially if PWP will require local and flex reserves in the future to replace capacity lost from IPP and may need that capacity to meet future FRAC-MOO requirements. Looking at a long term investment horizon PWP will need to determine if they should acquire capacity by repairing Glenarm GT2, build a new plant, or rely on the market. Of those alternatives it would appear that repairing Glenarm GT2 would be the best option given its location within the PWP load pocket to provide emergency power in the event the transmission line at TM Goodrich goes down. From both a reliability and economic perspective the repair of Glenarm GT2 is the best option given the alternatives and other mitigating factors. The repair of Glenarm GT2 does not need to be performed immediately given that market conditions for capacity is still soft and PWP is currently not in need of additional capacity in the next several years.

Although the CAISO LCR process does not currently recognize the TM Goodrich transmission constraint within the LA Basin local area, PWP's local transmission constraint is real and is best addressed by repairing Glenarm GT2 and putting it back into service to maintain system reliability.

[7] Black & Veatch made some high level assumptions to recover repair costs and did not assume any financing costs for the repairs to provide a high level estimated payback period.

Repair of Glenarm GT2 is also advantageous to PWP because the existing permits can be used instead of having to acquire new permits and go through the EPA New Source Review. If PWP were to build a new plant at a different location the plant would likely need to acquire two NSR permits for Prevention of Significant Deterioration (PSD) and Non-Attainment NSR permits given that the Glenarm GT2 plant is located in the South Coast Air Quality Management District (SCAQMD). The NSR permit would require approval from either the SCAQMD or from the EPA. The cost of undergoing the NSR permitting process has not been included in the analysis for examining alternative resources. Choosing to build a new plant instead of repairing Glenarm GT2 introduces an unnecessary risk that the NSR permits would not be issued for one reason or another. Repair of Glenarm GT2 represents PWP's best long term resource option when factors such as system reliability, economics, and NSR permitting risk are taken into account.