A Cost Effective and Reliable Zero Carbon Replacement Strategy for Diablo Canyon Power Plant

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Disclaimer

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This report and all conclusions drawn represent views of the authors alone and do not represent the views of FOE, NREL, and the Low Carbon Grid Study

Introduction

With the recent passage of SB 350, California has initiated the next phase in the deep decarbonization of its electric system. The result will be an increase in the renewable content of California's electricity generation portfolio from 33+% in 2020 to 50+% in 2030 and a concomitant reduction in carbon emissions by some 40-45 MMTCO2 per year -- roughly half of current electric sector emissions. We now face another resource decision with large carbon emission implications – whether to extend the operating licenses for the Diablo Canyon nuclear power plant for twenty years. These licenses expire in 2024 (Unit 1) and 2025 (Unit 2).

The California Independent System Operator has stated: "The absence of the DCPP (Diablo Canyon) appears not to have negative impact on the reliability of the ISO transmission system with the assumption that there is sufficient deliverable generation within the ISO controlled grid."[1] That is, unlike Southern California Edison's San Onofre Nuclear Generating Station ("SONGS") retirement in 2012, DCPP's location and continued operation is not critical to grid reliability as long as its energy and capacity is replaced. The location and composition of this replacement portfolio is not critical for grid reliability. Given that the process to plan, procure, and construct new generation to replace a retiring DCPP or to complete the license extension process at both the State and Federal level[2] takes approximately seven years, the time to formally start the process for dealing with a potential DCPP retirement is at hand.

This study is intended to inform that process by comparing the cost to complete the license extension process plus the going forward operating, maintenance and incremental capital costs for DCPP operations from 2024 through 2045 (license extension period) to the cost of acquiring and operating a zero carbon replacement generation portfolio. The analysis will rely heavily on data submitted by Pacific Gas & Electric Company for its

[1] 2012-2013 Transmission Plan, CAISO March 20 2013, p. 169

[2] While the operating license extension itself is a discretionary action of the federal Nuclear Regulatory Commission, several CA State Agencies including but not limited to, the State Lands Commission, California Coastal Commission, State Water Resources Control Board, and especially the California Public Utilities Commission must take formal discretionary action to allow DCPP operation post 2024-2025 or, in the alternate, construct and operate alternative generation.

2017 General Rate Case,[3] and modeling work done for the Low Carbon Grid Study.[4] The Low Carbon Grid Study is a peer reviewed comprehensive analysis of the California electric grid in 2030 where DCPP has been retired and replaced with a range of new renewable portfolios that both replace DCPP and meet California policy objectives of a grid that supports long term decarbonization with an interim 2030 target of 50+% RPS and 40+% reduction in carbon emissions below 1990 levels.

The Grid and Diablo Canyon

DCPP is easily the largest single generation asset on the California grid and the second largest in the entire West after the Palo Verde nuclear plant in Arizona. Over the past six years, it has provided 2240 MW of net capacity at a 90.0% capacity factor for an annual average energy production of 17,662 GWh/yr.

A major pillar of reliability requires that the electric grid be capable of withstanding the sudden loss of its largest single producing element without loss of load. This event is called an "N-1 contingency" and Federal, regional and State rules all require that this event be mitigated by holding so called "spinning reserve[5]" equal to or greater than its 2240 MW capacity any time that DCPP is operating. This quantity of spinning reserve is called the "MSSC" (Maximum System Single Contingency) in the CAISO tariff. Thus DCPP must have "one for one backup" for its energy and capacity at all times and this backup must be dedicated to reserve duty in case of an outage. Thus facilities supplying these spinning reserves are unavailable to perform other useful functions on the grid – such as flexibility to help shape net system load with deep penetrations of wind and solar generation.

When DCPP was constructed some 30 years ago, PG&E also built the Helms Pumped Storage Plant[6] about 50 miles east of Fresno to be the cornerstone of the spinning reserve package for DCPP. Rated at 1212 MW

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[3] 2017 Pacific Gas and Electric General Rate Case www.dra.ca.gov/general/aspx?id=2034

[4] See www.lowcarbongrid2030.org/PhaseII/results (2015)

[5] In order to qualify for spinning reserve, the facility held in reserve must be on line, synchronized with the grid, and be capable of ramping up to its full capacity within 10 minutes. If the event does occur and the spinning reserve is "called," the grid operator then has one-half hour to replace that reserve to prepare for any subsequent loss of the next N-1 element. This second level of reserves is often called "operating reserves."

[6] see Helms Pumped Storage Plant, Wikipedia for a description and history of the facility.

of capacity, Helms is normally "self-scheduled" by PG&E to provide the bulk of the DCPP spin requirement.

The consequence of not being fully prepared for a trip of large nuclear facilities was graphically demonstrated in what is called the "Great Blackout of 2011"[7] -- the largest power failure in California history. When Units 2 and 3 of the San Onofre Nuclear Generating Stations ("SONGS") tripped off line during a grid disturbance that began in Arizona on the afternoon of September 8, 2011, almost seven million people were left without power for as much as twelve hours. Ensuring grid reliability in the event of loss of so much power in a single location is indeed serious business -- even if DCPP is not the original source of the problem.

The alternative to using Helms for spinning reserve is to start up and synchronize to the grid, but then leave "idling" some of the otherwise surplus natural gas plants in the state[8]. However, this alternative has several negative consequences that make using Helms to provide spin for DCPP the better solution. First, similar to an automobile in heavy city traffic vs. highway driving, the efficiency of most natural gas plants at idle or near idle is significantly less than when operated at full load.[9] Thus natural gas is wasted and greenhouse gas (GHGs) emissions to maintain grid reliability are increased. Second, during light load hours in the fall, winter and spring, the energy produced at idle by the gas plants supplying spinning reserves for DCPP is not needed to serve load, and their presence crowds out other energy that is cheaper to produce and that emits less GHG – such as wind and/or solar. These zero carbon resources must then be "curtailed" to maintain the system load/resource balance[10]. Helms, whose replacement cost today is over $2B, was constructed specifically 30 years ago to save these costs.

Should DCPP retire, the next largest generation asset on the CAISO system is the Delta Energy Center in Pittsburg at 880 MW and the system spinning

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[7] See 2011 Southwest blackout, Wikipedia
[8] The MW output difference between a plant operating at minimum load or idling (called Pmim) and the plant output at full throttle (called Pmax) qualifies as spinning reserve.
[9] In general, the efficiency of a relatively modern combined cycle natural gas plant is reduced by over 40%, and the plant idles at as much as 40% of maximum load.
[10] It would take about 3700 MW of natural gas plants idling at Pmin to supply 100% of the spinning reserves for DCPP. Those plants would emit over 1.6 MMTCO2e/yr in performing this duty.

reserve requirement would then become the larger of 880 MW or 3% of the load on the system at that point in time. Thus, when DCPP retires, the system requirement for spinning reserve will be cut significantly, and at least a portion of Helms would then be available to supply system flexibility without restriction.

If the DCPP outage is unexpected, or planned for only a short duration, then PG&E would replace the lost energy with so called "system power" from other units somewhere in the West that have spare capacity. This system power, generally speaking, comes from otherwise surplus gas-fired generation with an average carbon emission rate of about 950 lb/MWh. So, if DCPP were to shut down for one year and the energy replaced with system power, CA electric sector carbon emissions would increase by roughly 7.6 million metric tons or about 8% of emissions today and about 38% of projected 2045 electric sector emissions if California meets its long-term carbon reduction goals. When DCPP finally retires, unless and until new carbon-free resources whose energy output equals the energy produced by DCPP are constructed, and those new resources are in addition to whatever resources are constructed for other reasons[11] an increase in this system power output will be the result. This was the result when SONGS (which was only slightly smaller than DCPP) unexpectedly but permanently shut down in early 2012. CA electric sector carbon emissions increased by roughly 7 MMTCO2e in 2012 due to the SONGS shutdown.[12]

Replacing DCPP energy with only the very best, most efficient natural gas generation is little better. The most efficient natural gas plant operated in the most efficient manner (full load in cool weather at sea level) has a carbon emission rate of, at best, 800 lb/MWh, so the increased carbon emissions are "only" 6.4 million metric tons or 32% of the total long term emissions target.

Given the high cost of extending the NRC licenses, the high cost of continued operations at DCPP, and the risk of catastrophic failure of an aging plant on a seismically active site, the state of California needs to have a plan for retirement of DCPP. The plan must be to replace DCPP with zero GHG renewable energy and Energy Efficiency, both of which are

[11] Including, e.g., meeting established RPS targets such as those contained in SB 350.
[12] http://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/2008-2012-ghg-summary-2013-11-04.pdf

incremental to existing policy initiatives and programs. As stated above, the time for that plan is now.

The alternate portfolios

The purpose of this study is to evaluate the feasibility of a cost-effective, reliable, zero GHG alternative to a license extension at DCPP. This requires a calculation of the cost of continuing to operate DCPP past its current license term vs. the cost of a replacement portfolio of capacity and energy to serve California electric load if and when DCPP retires. In order to do so, it is critical to understand the overall context of utility procurement over the next 10-30 years. There is no question that the dominant policy driver in this timeframe is the need to decarbonize the production of electricity to achieve critical climate policy goals. The decision to retire the plant or extend the DCPP license is an important decision but hardly constitutes the major procurement decision facing California.

With the passage of SB 350, California utilities will be procuring 36-40 TWh of new bulk renewables (roughly 2 and one half times DCPP output) between now and 2030 to comply with the 50% Renewable Portfolio Standard ("RPS"). Plus, they will be acquiring all cost effective energy efficiency and accommodating a projected very significant expansion in customer sited and financed "rooftop solar" which does not count towards RPS compliance but clearly is a significant GHG reduction measure.

The definition of "all cost effective energy efficiency" deserves some explanation. Currently, utility plans and other state agency programs such as the Title 24 Codes and Standards work at the California Energy Commission are geared to acquire additional achievable energy efficiency ("AAEE") up to the "Mid-Mid Scenario" level[13]. Additional energy efficiency, given today's technology, is available at additional cost up to the so-called "High-Mid Scenario" level. However, there are currently no plans or programs to acquire this additional incremental level of energy efficiency. The passage of SB 350 also mandates a doubling of Energy Efficiency procurement and new plans and programs will be at least proposed by the end of 2016.

It is widely recognized that this is only the next step in a long process to ultimately decarbonize the electric grid by 2050 and that SB 350 plus carbon free replacement for DCPP together represents less than half of the total

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[13] 2015 Integrated Energy Policy Report (IEPR) CEC Pub #CEC-100-2015-001-CMD

procurement required over the next 30 plus years to both decarbonize the electric grid and electrify the transportation and building sectors in pursuit of long term climate policy goals.

To avoid backsliding on the long-term greenhouse gas target, carbon free replacement energy and capacity for a DCPP retirement must be additive to the SB 350 procurement. If the DCPP replacement energy and capacity is included in the 36-40 TWh of SB 350 procurement, then, on balance, DCPP has been replaced with 100% gas from "system power." If the State is to remain on track for meeting its climate policy goals when DCPP retires, it needs to procure roughly 55 TWh of new renewables (36-40 TWh for SB 350 plus 17.6 TWh for DCPP)[14], and the grid would be powered by roughly 57% renewable energy by about 2030.

In addition, the State must acquire all cost effective energy efficiency (i.e., the "High-Mid Scenario"), which the California Energy Commission estimates[15] at 20 TWh/yr over and above the current plans and is equivalent to one half of the new bulk renewables procurement necessary to achieve the legislatively mandated 50% RPS.

Customer sited and financed small "behind the meter" rooftop solar installations, which are an important arrow in the quiver of greenhouse gas reduction measures, will proceed without regard as to whether DCPP retires or not. New storage investments such as batteries or new pumped storage facilities, whether installed in conjunction with rooftop solar or as stand-alone facilities are important tools for flexibility in the new carbon constrained future but do not, in and of themselves, produce energy.

Several studies have been conducted[16] on achieving large carbon reductions on California's electric grid. Broadly speaking, they agree that the policy can

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[14] It is highly unlikely that any other form of carbon free electric energy such as new nuclear or hydroelectric or carbon sequestration and storage will be available in the quantities required in the next 15-20 years. All cost effective energy efficiency and rooftop solar should be acquired whether DCPP operates or not. Therefore, bulk renewables such as wind, solar PV, concentrating solar power ("CSP"), etc. become the only possible incremental carbon free resource additions.

[15] 2015 CEC IEPR op cit

[16] See, e.g., "California Pathways: GHG Scenario Results," Energy +Environmental Economics, April 6, 2015 or "Investigating a Higher Renewables Portfolio Standard in California," Energy + Environmental Economics, 2015, or "Integrating High Levels of

be accomplished without compromising reliability, and that a number of "mitigation measures" need to be taken to deal with over-generation in the middle of the day during, primarily, light load spring months. The Low Carbon Grid Study is more squarely aimed at the timing and renewable resource and incremental Energy Efficiency investments associated directly with DCPP retirement.

The Low Carbon Grid Study is a comprehensive, peer reviewed look at California's electric grid in 2030 without DCPP. The RPS penetration is roughly 57%, and the study includes acquisition of all cost effective energy efficiency and a complete build-out of potential rooftop solar. It also assumes electricity load growth to accommodate the charging of 3.3 million electric cars and the high-speed rail project. The results are summarized below.[17]

Table 1
Summary of Low Carbon Grid Study Results

Case	Net Cost % of Rev Req.	Carbon Emissions MMTCO2e/yr.	Renewable Curtailment,%
Diverse/Enhanced	0.6	41.1	0.2
High Solar/Enhanced	2.2	42.2	0.5
Diverse/Conventional	2.3	45.0	4.2
High Solar/Conventional	4.1	46.8	9.7

"Diverse" refers to a geographically and technologically diverse new renewable investment portfolio, "High Solar" refers to a renewable portfolio that has a higher photovoltaic percentage and less diversity, "Enhanced" refers to a package of new mitigation measures that provide flexibility to the grid without fossil fuel combustion, while "Conventional" refers to grid operations that resemble today's reliance on natural gas to provide flexibility. "Net Cost" is the customer rate impact of the incremental investment in RE

Variable Energy Resources in California," GE Energy Consulting, Schenectady, NY, 2015, or "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future," A CPUC Staff White Paper, Nov 25, 2015

[17] www.lowcarbongrid2030.org/PhaseII results

and EE expressed as a percentage of the total utility annual revenue requirement in the year 2030. These economic results are for $6/MMBTU gas. For $5/MMBTU gas, the net cost ranges from 1.8% to 8.5% of utility revenue requirement. For $8/MMBTU gas, the net cost ranges from -4% to +4% of utility revenue requirement.[18] For reference, 2013 carbon emissions from the electric sector were 97.5 MMCO2e.

The purpose here is not to dwell on the details of these results, but simply to point out that the policy objective of cost-effective deep carbon reductions can be met with a variety of renewable portfolios and grid operational enhancements. This result is robust across a broad range of variables, but how it is accomplished has important cost implications.

What is critical for the purpose of this work is to develop a range of plausible renewable/efficiency portfolios to replace the energy and capacity from DCPP, and compare the cost of acquisition and operation of those portfolios to the cost of the license extension and operation of DCPP during the 20-year license extension period. For that, we again turn to the Low Carbon Grid Study ("LCGS") for much of the raw data.

Four portfolios were constructed to bookend the range of possibilities for a zero carbon replacement portfolio. We constructed these portfolios that directly replace DCPP to demonstrate the wide range of GHG free resources available for the cost effective, reliable alternative to the nuclear plant.

First, we simply grossed up the DCPP load ratio share of the "diverse" portfolio from the LCGS that has very little incremental utility scale solar PV beyond what is contemplated between now and 2020.

Second we did the same with the "high solar" LCGS portfolio which is roughly 50% incremental solar PV from 2020 to 2030, and,

Third, we constructed a portfolio that is almost completely utility scale solar PV in the Central Valley PG&E service territory to give a "local" alternative. Table 2 below gives these three portfolios by energy and capacity.

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[18] generally accepted wisdom today is that natural gas prices will probably range between $5-8/MMBTU in 2030. See e.g., Annual Energy Outlook 2015, EIA 4/14/2015

Fourth, we combined 75% of the "diverse" portfolio with a new Energy Efficiency program for PG&E service territory that provides the other 25% replacement energy and is incremental to current CPUC regulated Energy Efficiency programs. This amount of incremental energy efficiency is equivalent to acquiring toughly 85% of the difference in technical potential between the CEC Mid-Mid and High-Mid scenarios in PG&E's service territory.

Table 2
DCPP Replacement Renewable Portfolios

	Diverse		**High Solar**		**Valley**	
Technology	**Energy** Gwh/yr	**Capacity** MW	**Energy** Gwh/yr	**Capacity** MW	**Energy** Gwh/yr	**Capacity** MW
Valley Project	858	120	185	25	1818	250
CSP	1392	335	423	100	-	-
Geothermal	3805	470	655	80	-	-
PV	1220	460	8484	3225	16370	6230
Wind, CA	4910	1440	4684	1485	-	-
Wind, WY	5570	1270	3607	825	-	-
Totals	17,760	4,095	18,038	5,740	18,188	6,480

For the "diverse" and "high solar" portfolios, the portfolios developed for the Low Carbon Grid Study were simply scaled to provide the energy lost by the DCPP retirement as a percentage of the energy required to both replace DCPP and, in addition, to achieve a 50% reduction in greenhouse gas emissions. The total new renewable energy in the Low Carbon Grid Study portfolios is 55 TWh/yr and the DCPP retirement portion of that is 17.76 TWh/yr or 32%.

The Valley portfolio was constructed by first counting the 250 MW of plant capacity that will be constructed in the Central Valley mandated by SB 1122 (Rubio) and called the "Valley Project." Then, the remainder of the energy to replace DCPP was supplied from newly constructed utility scale PV plants in the greater Central Valley.

These three renewable portfolios are not equivalent in their impact on grid operations or transmission requirements. There are four principal impacts that need to be quantified in order to compare these portfolios with continued operation of DCPP:

- Requirements for additional storage to mitigate over-generation in the middle of light load days as a function of the percentage of incremental energy supplied by PV.
- Even after additional storage is acquired, there will be increased amounts of renewable energy "curtailment" during, at least, extreme light load spring days, again as a function of the percentage of PV added, that is simply not economic to reduce with additional storage.
- The portfolios could have different capacity values.
- The portfolios will have different transmission requirements.

We discuss each of these issues in turn, relying on the numerous scenarios and sensitivities included in the Low Carbon Grid Study as a guide for quantification of these impacts.

Storage

At the solar PV penetration levels envisioned in all scenarios of 50% or greater RPS, whether DCPP is operating or not, most studies, including the Low Carbon Grid Study, have found some new bulk storage facilities to be cost effective "mitigation measures." These facilities operate on a daily cycle of charging during the middle of the day when the sun is shining and discharging in the early evening as the sun sets, shifting the "net load" curve to reduce over-generation and contribute to serving the evening load ramp without combusting natural gas.

For the purpose of this study, we assumed that this additional bulk storage would come from some fraction of the 5000 MW (six projects total) of new hydro pumped storage facilities under development in California that could be owned by PG&E. No attempt was made to specify which of these projects would/should be constructed. This decision, including provisions for an alternate advanced battery storage option, is best left to a robust competitive procurement process.

For the duty cycle involving large quantities of 4-6 hr storage per day, operating on many days of the year, pumped storage is roughly a factor of three more cost effective than the most advanced battery systems commercially available today. With today's battery technology, it is unlikely that this situation will change in the next 15-20 years. If, for some reason, a true breakthrough in battery technology were to occur, it would only make the renewable replacement portfolios more cost effective.

Because the Low Carbon Grid Study examined several levels of storage for different portfolios, it is possible to interpolate those results to approximate the amount of storage that would be cost effective in mitigating over-generation for our portfolios. If we take DCPP continued operations as a base, the High Solar portfolio is estimated to accommodate an additional 500 MW of cost effective 4-6 hr. bulk storage, and the Valley Solar portfolio is estimated to accommodate an additional 1000 MW of cost effective 4-6 hr. bulk storage. The Diverse portfolio does not warrant any additional bulk storage compared to the DCPP continued operations case due to the ability to lay off a small percentage (<10%) of the Wyoming wind and other out of state renewables in the Diverse portfolio to serve out of state local or regional load during those critical spring hours with a large "surplus" of renewable energy.

Even with the additional bulk storage and the ability to lay off some of the out of state wind during surplus hours in California, The High Solar and Valley Solar cases will show a small amount of increased renewable curtailment vs. either the Diverse case or continued operation of DCPP as the most cost effective solution to the over-generation issue. "Curtailment" is simply another word for "Dispatch" of renewables in hours during which they are not needed to serve CA load, and it is expensive to first import these renewables, balance them against load in CA, and then turn around and re-export the "surplus" right back to the same region where they were produced in the first place. "Over-generation" is simply another word for "potential exports."

Based on interpolation of the production cost modeling done for the Low Carbon Grid Study, this additional curtailment is calculated to be an additional 0.5% for the High Solar case and an additional 3% for the Valley Solar cases. For the purposes of this study, we simply grossed up the High Solar and Valley Solar portfolios to supply the same net energy to the grid after this curtailment. Once the overall policy is adopted and the procurement process has begun in earnest, these approximations of the amount of storage that is cost effective and what the residual curtailment levels would be should be calculated more precisely

Capacity Value

Somewhat by chance, all three alternate renewable portfolios have essentially the same capacity value at roughly 1750 MW of system Resource Adequacy ("RA") value once the portfolios are adjusted for the capacity value of the added bulk storage. This compares favorably with the actual 1250 MW of capacity made available if the 2240 MW of RA capacity value of DCPP reduced by the 990 MW of additional spinning reserve required to operate DCPP. At today's RA prices of roughly $40/kW-yr,[19] this additional capacity is worth some $40M/yr if DCPP is retired. This capacity value was calculated by the existing CPUC protocols for calculating "System RA" adjusted for the likely revisions to wind and solar "Net Qualifying Capacity" based on new modeling that is ongoing in the CPUC Resource Adequacy proceeding.

Much like the discussion on storage above, this assumption should be revisited once the procurement process has refined the portfolio options more definitively.

Transmission

To assess the transmission requirements of the alternate portfolios, we used the results of the Low Carbon Grid Study for the Diverse and High Solar portfolios. These portfolios were deliberately picked to utilize as much existing and previously planned transmission expansion as practical. Only the load ratio share[20] of the major new tie line for Wyoming wind needs to be assessed against these portfolios for cost comparison purposes. All other planned transmission expansions, such as the West of Devers and Gates/Gregg projects in California, are designed to reach a 50% RPS whether DCPP continues to operate or not.

The Valley Solar portfolio is a different story. Constructing 6,500 MW of new solar generation in the Central Valley will clearly require significant new transmission investment even after allocating the transmission now used by DCPP to the new portfolio.

The first major transmission upgrade required for this Valley Solar development is the proposed 62 mile 500 kV San Luis Transmission Project to strengthen the connection between the Western Area Power

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[19] CPUC , *2013-2014 Resource Adequacy Report*, p.24

[20] The share of the Diverse portfolio assigned to DCPP replacement energy that is additional to the procurement for the 50% RPS obligation.

Administration grid and the CAISO grid.[21] This project would allow full build-out of the proposed Westlands Water District solar project plus significantly improve N-S and E-W transfers throughout the Valley. The second major transmission upgrade required is to relieve the Path 26 bottleneck (the old seam between the PG&E and SCE balancing authorities predating the formation of the CAISO). The best way to accomplish this in conjunction with the Valley Solar generation build-out is to designate some of the required bulk storage investment to the Bison project near Tehachapi that sits astride Path 26, and to connect this project at 500 kV to both sides of Path 26 (Midway substation to the North, and Windhub substation to the South). Locating the remainder of the bulk storage in far northern California at Swan Lake will also provide additional N-S transfer capacity. Together, all these projects will provide roughly 5000 MW of new "deliverable capacity" from the Valley. The remainder of the solar generation can be interconnected using existing transmission and "energy only" interconnections as explained below.

The CPUC and CAISO are conducting a Special Study [22] to explore the potential for energy only interconnections to minimize the need for new transmission investments at a 50% or above RPS. "Energy Only Interconnections" depend on the CAISO's existing transmission congestion management system to allocate limited space on the grid. However, no incremental capacity or "RA" value can be assigned to a new generator that takes an energy only interconnection because some existing RA capacity would need to be constrained off-line by the congestion management system in order to allow the new generation to flow during peak demand hours. Thus, no net new peak capacity is added to the system if the transmission is interconnected using this process. This study has preliminarily found that some 7140 MW of energy only interconnections could be accomplished in the greater Central Valley region of PG&E's service territory without "major" impacts on congestion utilizing only the current grid[23].

Other potential projects that would assist in interconnecting the very large Valley Solar generation could be: upgrading the planned Gates/Gregg project from 230 kV to 500 kV, or constructing the proposed NCPA/TANC

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[21] San Luis Transmission Project Fact Sheet, WAPA Feb 2015
[22] "50% RPS Energy Only Special Study Update", Energy+Environmental Economics, June 29, 2015. The final study is due to be published in the 1st Quarter of 2016.
[23] ibid p.9

project to augment Path 15 transfer capacity[24]. In addition, it is highly likely that the so called "SWIP-N" project connecting southern Idaho to central Nevada[25] will be constructed quite apart from whether DCPP is retired or not. This project significantly improves the general circulation throughout the 11 western states. It is touted as important for achieving the 50% CA RPS target utilizing Wyoming wind and taking advantage of the emerging West-wide Energy Imbalance Market or "EIM." The EIM significantly improves trading opportunities and eases renewable integration issues around the West. As an additional benefit and relevant to this study, this SWIP-N project will increase the Path 26 capacity rating by roughly 500 MW by providing a strong parallel path to deal with contingency outage constraints that limit transfer capacity today.

In short, there are multiple viable transmission solutions that would allow the very large Valley Solar generation portfolio to provide energy and capacity to replace DCPP.

The precise package of transmission upgrades that is most cost effective and would best achieve all policy objectives would require decisions about precise locations and sizes of the solar PV projects among many other variables only peripherally related to DCPP retirement. The CAISO and PG&E are capable of making these decisions in a reasonable timeframe with competitive bids for the generating projects in hand if this overall plan were to be chosen to replace the energy and capacity from DCPP. If any of the transmission projects chosen become longer lead-time than the generation projects, temporary connection of the generation using the energy only scheme is certainly available. Such temporary interconnections would have minimal impact on the long term cost effectiveness of the generation portfolio.

For cost comparison purposes here, we allocate the cost of the San Luis Transmission Project, the incremental cost of upgrading the planned Gates/Gregg project, and the incremental network upgrades to provide a Path 26 uprating associated with the Bison pumped storage project to the

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[24] The Northern California Public Power Association ("NCPA") and its transmission arm Transmission Authority of Northern California ("TANC") have proposed an expansion of its existing transmission system between Northern California and the Bonneville Power Authority system in Oregon.

[25] see www.lspower.com/index.htm "One Nevada Transmission Project"

Valley Solar portfolio. This package, or some similarly sized package, in conjunction with some utilization of available energy only interconnections using the existing grid, plus the capacity freed up by retiring DCPP provides a reasonable estimate of the cost of added transmission what would be required if the Valley Solar alternative to DCPP were to be chosen.

The three portfolios are shown as pie charts for both energy and capacity below to graphically illustrate the differences.

Figure 1
Incremental Energy for High Solar Portfolio

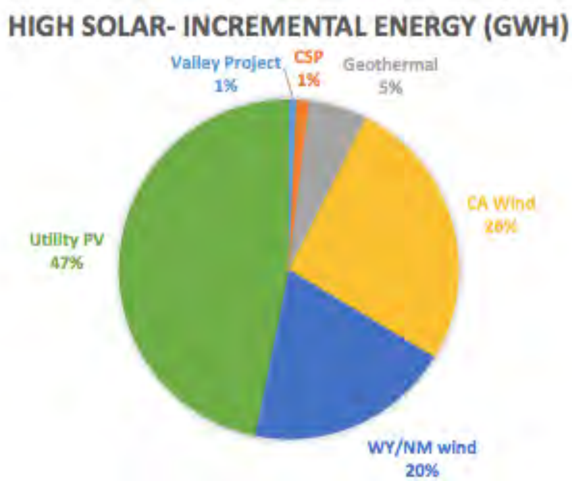


Figure 2
Incremental Capacity for High Solar Portfolio

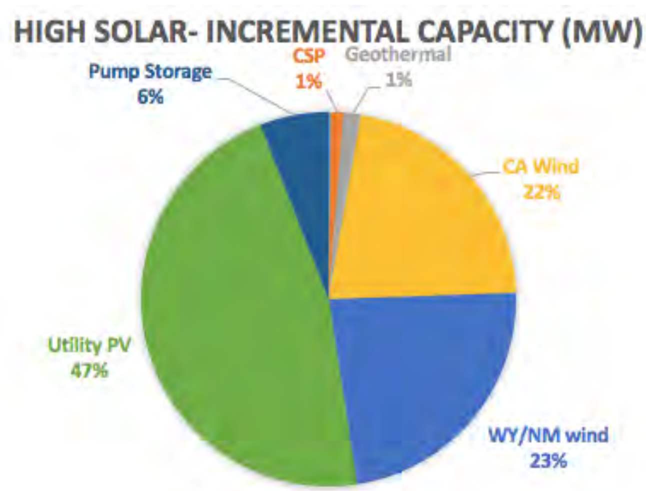


Figure 3
Incremental Energy for Diverse Portfolio

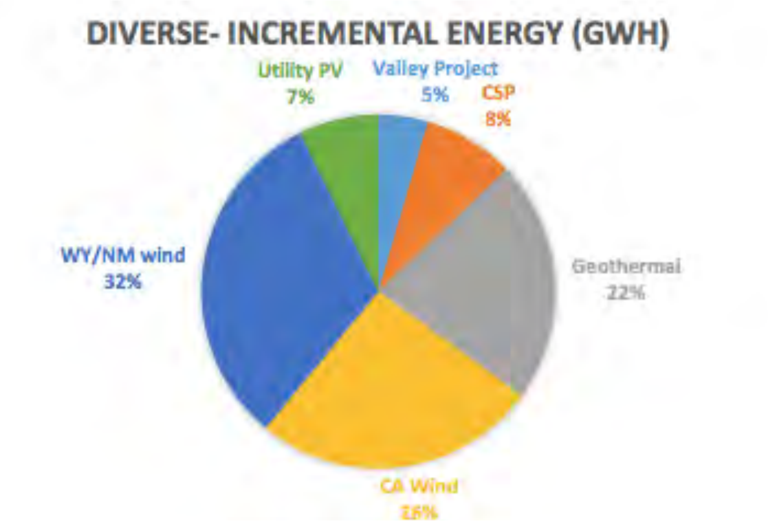


Figure 4
Incremental Capacity for Diverse Portfolio

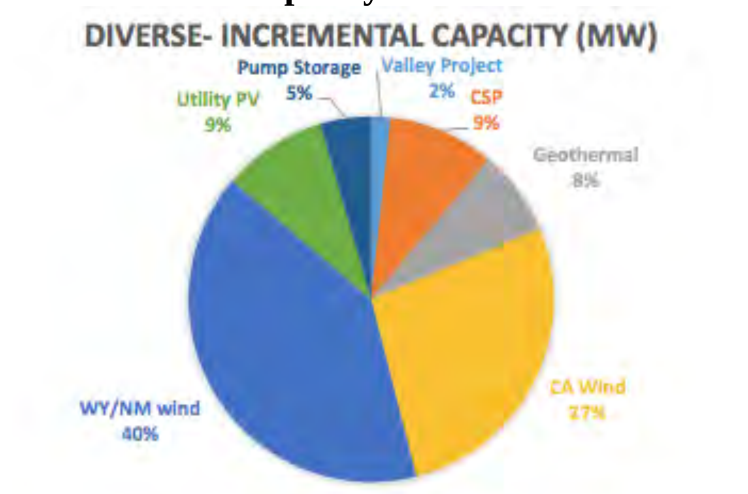


Figure 5
Incremental Energy for Valley Solar Portfolio

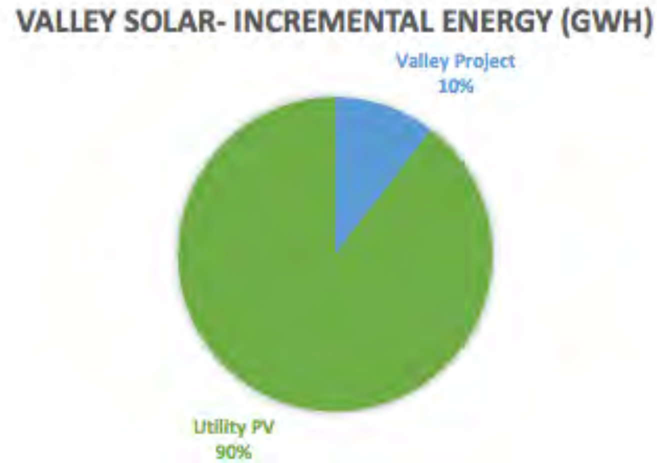
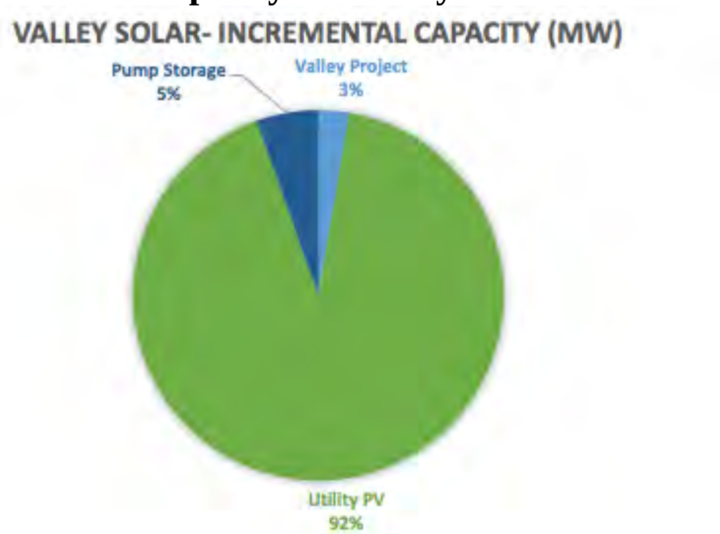


Figure 6
Incremental Capacity for Valley Solar Portfolio



Opportunities to Achieve Additional Energy Efficiency

The Low Carbon Grid Study took a detailed look at the availability and cost of incremental energy efficiency (called "AAEE" or Additional Achievable Energy Efficiency) beyond levels acquired with existing programs and expenditure levels[26] over the next fifteen years using current commercially available technology. As noted previously, the study found that energy efficiency at the level of CEC High-Mid Scenario as opposed to current program and expenditure level targets at CEC Mid-Mid Scenario or some 20 TWh/yr of AAEE statewide is achievable with current technology. Costs to acquire this enhanced level of energy efficiency were estimated to be roughly double the average cost per net kwh of current programs with marginal costs to achieve the full High-Mid Scenario roughly equivalent to the acquisition cost of new renewable resources. This equates to an added statewide expenditure level of over $600M/yr to achieve 12 TWh/yr of AAEE in 2024 and 20 TWh/yr of AAEE in 2030.[27]

Underlying the cost assumptions for any forecast of energy efficiency potential is the recognition that efficiency is a finite resource where the relationship between the costs and savings is determined by technology, market, and regulatory conditions and limitations. The supply/cost curves associated with this potential show increasing costs at increased resource acquisition and these cost increases are quite steep as the full technical potential is approached. Furthermore, both quantities and costs are relatively uncertain as compared to a "business as usual" scenario and this uncertainty is only partially resolved by state of the art, costly measurement and verification programs. While technology continues to advance – pushing these supply curves further out on the scale of increased AAEE at lower cost, there are also very real costs and long lead times associated with converting newly discovered technology into commercially available products that tempers the impact of technology advances on AAEE resource acquisition programs.

Much like renewable resources procured to increase the statewide RPS levels from 33% to 50% as per SB 350, the state has pledged to procure "all cost effective energy efficiency" quite apart from a decision to retire DCPP. Therefore, the question of additionality of any Energy Efficiency program deemed to be part of a replacement package for DCPP is an important consideration.

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[26] a full description of this potential can be found at www.lowcarbongrid2030.org/PhaseII results, *Guidance on Interpreting the Forecast and Production Cost Model for Energy Efficiency,* Tierra Resource Consultants, August 7, 2015
[27] www.lowcarbongrid2030.org/Phase II results, *Comparison of 2030 Fixed Costs of Renewables, Efficiency, and Integration with Production Cost Savings,* JBS Energy, Inc 2015 p. 37-39

However, incremental EE programs as part of the overall package to replace the energy and capacity now supplied by DCPP are clearly essential. California's experience over the past several decades makes it abundantly clear that pursuit of "stretch goals" for AAEE is a wise policy and optimism about eventual results is virtually certain. Even at double today's acquisition cost for EE, there is clearly a significant amount of additional AAEE available to contribute to filling the gap created by DCPP retirement. Setting a target of achieving High-Mid levels of AAEE in PG&E service territory as opposed to Mid-Mid AAEE means that roughly 25% of the DCPP energy can and should be procured with Energy Efficiency.

ON GOING COSTS TO EXTEND DCPP LICENSES PLUS COST TO OPERATE DCPP DURING THE LICENSE EXTENSION PERIOD

General Method of Analysis

The following costs required to operate DCPP from 2024 to 2044 were evaluated:

1. Operations and maintenance (O&M) costs aside from refueling outages and spent fuel disposal.
2. Refueling outage operations and maintenance (O&M) costs
3. Pensions, post-retirement benefits, long-term disability, and workers compensation, which are not included in PG&E's benefits loading factor, and other administrative overheads.
4. Property and liability insurance costs.
5. Fuel expenses.
6. Spent fuel disposal costs (incremental costs of disposal of future fuel only).
7. Return and associated taxes on inventories of materials and supplies required to keep the plant operating efficiently.
8. Return and associated taxes on fuel inventory.
9. Revenue requirement on incremental capital additions (long-lived investments required to maintain the plant in operating conditions), return, depreciation, income taxes, and property taxes.
10. License extension costs.

Cost Analysis

Economic Environment

Costs were analyzed in both real 2014 dollars and in nominal dollars. The economy-wide inflation rate used to develop nominal dollars from 2014 dollars was 1.74% through 2020 (the level of increase in the GDP implicit price deflator in recent years) and 2% thereafter (the long-term target of the Federal Reserve Board). The current PG&E rate of return and current income tax and property tax laws were used to develop the revenue requirement associated with capital expenses. Those are given below.

Any temporary tax credits or bonus depreciation provisions expiring before 2024 were assumed to not be renewed. The domestic production activities deduction (DPAD, otherwise known as "manufacturer's tax deduction"), which reduces federal taxable income from DCPP by 9%, was assumed to continue through the period.

PG&E's current rate of return[28] was used to represent future conditions. This is shown below. The rate of return including the income tax gross-up for common and preferred stock is 11.82%. The chart below shows the derivation.

Table 3
PG&E Capital Structure and Rate of Return

RETURN	8.06%	
DEBT	5.52%	47.00%
COMMON	10.40%	52.00%
PREFERRED	5.60%	1.00%

For consistency when comparing to the cost of renewable resources, the Low Carbon Grid Study mid-case set of economic conditions were used[29], which is generally consistent with current utility return parameters and with an inflation rate for the general economy in the vicinity of 2%.

Method of Analysis for Diablo Canyon

The analysis started by developing a BASE CASE The base case DCPP costs are a reflection of what would occur under business as usual conditions with no major capital additions for safety or environmental protection, no systematic cost changes, and relatively high performance. Costs were

[28] Adopted in CPUC Decision No. 12-12-034.
[29] op cit. www.lowcarbongrid2030.org/materials

assumed to increase modestly above inflation to maintain performance. A base case analysis generally starts with current levels of costs. The analysis assumed increases of 2% above inflation for O&M expenses other than refueling and for capital additions and 2.3% for refueling expenses. A baseline capacity factor was assumed for the plant equal to that achieved from 2011-2014 (90.0%). Base case parameters are identified and discussed in more detail below.

A CAPITAL ADDITIONS case was examined beyond the base case that involved the impacts of large lump-sum costs for extra capital additions and significant outages in given years. The cases with large lump sum costs can be parameterized to scale for different sizes of large events.

A GRADUAL ADVERSE CHANGE set of analyses tested the costs of Diablo Canyon in the event of more gradual or fluctuating adverse changes in cost and/or capacity factor,

The purpose of both of these types of sensitivity analyses was to determine the extent to which DCPP's economics would change if "business as usual" did not persist.

DCPP Base Case Parameters
Base O&M without Refueling

Base O&M costs start with PG&E's total O&M costs[30] excluding refueling outage costs computed below. excluding costs of the long-term seismic program which is assumed to be non-recurring, and excluding employee benefits which are estimated separately.[31]

We started with PG&E's recorded costs from 2011-2014 and forecast costs from 2015-2017 from its recently filed 2017 Test Year general rate case.[32] The average of these costs in 2014 dollars after removing seismic costs and employee benefits was $295 million. It is assumed that costs will escalate at 2% real per year. This increase is comprised of three items – the fact that PG&E's expenses have been escalating faster than inflation as measured by the gross domestic product implicit price deflator (mainly because labor

[30] From PG&E Ex05Ch3_ExpenseAutoWPs deflated using the GDP implicit price deflator to 2014 dollars. These expenses include payroll taxes and benefits paid to current employees (medical, 401k, etc.)
[31] We included payroll taxes in the overall costs from the GRC.
[32] 2010 costs were not used, because they reflect some of the one-time costs and savings arising from the steam generator replacement project.

costs have exceeded inflation in recent years); the need for training and other costs to replace an aging workforce for 20 more years of operations; plus additional escalation due to aging plant.

Refueling O&M

Refueling outages are estimated at $55.5 million per outage in 2014 dollars. The refueling costs are based on PG&E's estimates of refueling outage costs from 2013-2019, adjusted to real 2014 dollars.[33] Our estimate is the cost of the 2019 outage in 2014 dollars. PG&E has projected that its costs of refueling outages would increase at an average of 2.28% above inflation from 2013-2019. We carried the projection forward through the license extension period.

PG&E can be expected to have five refueling outages every four years.

Administrative Overhead

In 2017, PG&E forecasts $587.6 million of utility-wide administrative overhead expenses (excluding insurance, workers' compensation, and pensions and benefits in FERC Accounts 924-926, and short-term incentives and vacation payoffs in Account 920). These costs are found in the remainder of FERC Account 920 as well as Accounts 921-923, 930, and 935. PG&E's rate case allocates most administrative expenses to functions (including Diablo Canyon) by labor. Approximately 15.86% of these total expenses are assigned to Diablo Canyon using this method, or $93.2 million.[34]

However, only a portion of these administrative overhead expenses are incremental and would be reduced in the long run if Diablo Canyon were closed. In the 1990s, several studies by PG&E and other intervenors filed in general rate cases from Test Years 1993, 1996, and 1999 showed that 10-11% of administrative and general expenses were in fact assigned to Diablo Canyon on a department specific basis at that time.[35] Given the expansion of other activities on the PG&E system since the late 1990s, we estimate department-specific expenses related to Diablo Canyon avoidable with plant

[33] From TURN DR 3-11 in PG&E 2017 TY general rate case.
[34] PG&E 2017 TY GRC Workpapers to Exhibit PG&E-10, O&M Labor Tab.
[35] See for example, Prepared Testimony of Gayatri M. Schilberg for TURN in A. 94-12-055. Prepared Testimony of William B. Marcus for TURN in A. 97-12-020.

closure as 8% of A&G expenses (roughly half of the expenses allocated to Diablo Canyon) for purposes of this study. That figure is $47.0 million in 2017 nominal dollars. We escalate administrative overhead expenses at inflation even though wages at PG&E rise slightly faster than general inflation.

Pensions and Benefits and Payroll Taxes

PG&E's total pensions and benefits are $214 million in pension expense, not recovered through the rate case mechanism and $344 million of other benefits, including $224 million of healthcare costs and $120 million of other costs. The 15.86% labor share of these benefits is $36.97 million for pensions and $53.03 million for other benefits. In addition, costs of PG&E's Short-Term Incentive Program (STIP), workers' compensation, and vacation payoffs to departing employees must are part of the employee-related cost of Diablo Canyon.

This figure must be reduced because a portion of the benefits includes benefits associated with A&G labor costs allocated to Diablo Canyon in excess of those A&G costs that are avoidable in the longer term if Diablo Canyon closes. We calculate that non-incremental amount as 8.59% of total benefits.[36] Thus we multiply the benefits allocated to Diablo Canyon (except workers compensation) by 91.41% to obtain the benefits which would be avoided if Diablo Canyon were to close. The table below gives the results for 2017.

Table 4
Pensions, Benefits, and Other Labor Related Costs 2017 GRC ($'000)

	PG&E Total Company	Allocated to Diablo Canyon in GRC	Incremental Diablo Canyon Employee Benefits in this Study
Total GRC benefits	$ 334,338	$ 53,039	$ 48,483
Pensions	$ 233,036	$ 36,971	$ 33,795
Short-Term Incentives	$ 96,982	$ 15,385	$ 14,063
Payout of remaining vacation	$ 4,192	$ 665	$ 608
Workers compensation *	$ 36,638	$ 5,812	$ 5,812
Total Diablo Canyon benefits with incremental overhead	$ 705,186	$ 111,872	$ 102,761

[36] Diablo Canyon labor of $207.39 million + 8% incremental to Diablo Canyon X $274.02 million of administrative labor = $229.31 million. Diablo Canyon labor plus 15.86% of Administrative labor allocated to Diablo Canyon ($43.47 million) = $250.86 million. $229.12 million divided by $250.86 million = 91.41%.

For purposes of escalation, we divide benefits into three parts, medical, pension, and all other. Medical benefits are increased on a declining trend from 7.5% nominal in 2017 to 5% nominal after 2025. This is generally consistent with, though slightly higher in the long term than PG&E's forecasts used to plan its retiree healthcare costs. Pension costs are held flat in nominal dollars through 2024, then are cut in half (to reflect the end of extra payments from past under-funding) but increase from that point with wages. Under our base case scenario, 1% real escalation generally reflects higher future real levels of expenses at Diablo Canyon together with wage growth in PG&E as a whole in excess of inflation. This reflects that PG&E is making extra pension contributions now because its pension is underfunded, but eventually the underfunding will be taken care of and pension payments will then be lower but will grow approximately with wages.[37] Other benefits are increased at 1% per year above inflation for the same reason. Payroll taxes are included in the O&M costs of Diablo Canyon that we have used and are not estimated separately.

Property and Liability Insurance

Nuclear property insurance is projected to rise at 8.78% nominal (or 7% above inflation) from 2014-2017.[38] We continue a 5% real escalation rate from the $5.7 million figure in 2017. Total liability insurance is relatively flat from 2014-2017. We project $1.5 million in nuclear liability insurance flat in real terms, given the subsidies provided to nuclear entities by the Price-Anderson Act.[39] It is assumed that assessments that could be charged to nuclear utilities in the event of an accident at another utility's facility,[40] would not occur during the license extension period.

Fuel Cost

[37]Pension contributions also fluctuate with financial market returns, but we have no basis on which to consider those fluctuations in this analysis. This analysis essentially smooths out such fluctuations.

[38] Exhibit PG&E-9 (2017 GRC), Table 3-4, p. 3-28. See also PG&E, WP 3-189, Exhibit (PG&E-9) – January 2014 memo from NEIL to its members.

[39] " The average annual premium for a single-unit reactor site is approximately $1.1 million. The premium for a second or third reactor at the same site is discounted to reflect a sharing of limits. http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/nuclear-insurance.pdf

[40] http://www.naic.org/cipr_topics/topic_nuclear_liability_insurance.htm

Nuclear fuel costs were assumed to be $0.81 per MMBtu in 2014 dollars in the period following 2024 consistent with nuclear fuel assumptions used for transmission expansion planning throughout the Western United States[41] With DCPP's plant heat rate of 10,300 Btu/kWh derived from FERC Form 1 data, that amounts to $8.34 per MWh. Nuclear fuel costs in the base case assumed a 90% capacity factor. They were reduced in the sensitivity cases that had a lower capacity factor.

Materials and Supplies Inventory

DCPP, like other nuclear plants, has considerable amounts of inventory in both non-fuel materials and supplies, and in nuclear fuel. This inventory earns a return before it is used, and that return is part of the cost of nuclear power.

PG&E projects that its materials and supplies inventory at DCPP will increase at 2.5% per year in nominal terms (about 0.8% in real terms) from 2014-2017. The 2017 forecast inventory is $92.9 million in 2014 dollars. The value of inventory is assumed constant in real dollars despite limited real escalation in recent years. PG&E earns a return on outstanding inventory. We assume that return to be the current rate of return on rate base plus associated income taxes or 11.82%. Materials and supplies are also subject to property tax. Using PG&E's property tax parameters,[42] the tax rate on this inventory is 1.12%.

Our analysis of M&S inventory is based on the assumption that PG&E will use up a significant portion of its inventory (approximately 75%) if the plant is retired when the current plant license expires, but will maintain its inventory if the plant license is extended and will use up 75% of the inventory at the end of the extended license period. The difference in return and property taxes between maintaining 100% of inventory from 2020-2024 and using the M&S inventory during that period (for license extension) and the percentages above are economically part of the costs of license extension.

The remaining unused inventory is expensed in the last year of license operation. That expense in 2024 is not incurred with license extension but is instead incurred in 2044. Thus, there is a credit in 2024 for expensed M&S

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[41] WECC TEPPC 2024 Common Case.

[42] Historical cost less depreciation X 77.023% X 1.44585% tax rate = 1.12% tax rate on cost less depreciation.

inventory and a cost in 2044 in the case where the plant receives an extended license.

Fuel Inventory

A nuclear power plant requires fuel inventory in various stages of processing, starting with raw fuel, then incorporated into fuel rods, placed into the power plant, and burned to produce energy. Since fuel prices are not increasing in real dollars it was assumed that fuel inventory would be the same in real 2014 dollars as the 2014 recorded inventory ($472.6 million).[43]

Fuel inventory is assumed to be used up in the five years prior to plant closure. This results in a reduction in inventory from 2020-2024 if the plant license is not extended and from 2040-2044 if the plant license is extended. The difference in return and property taxes between maintaining 100% of inventory from 2020-2024 and using the inventory during that period (for license extension) and the percentages above are economically part of the costs of license extension. Similarly, in the analysis of costs with license extension, fuel inventory is reduced by the same percentages in 2040-2044.

The return on fuel inventory at the present time is based on the commercial paper rate because of its exact recovery in ERRA and low risk. We assume a long-term average commercial paper rate of 2.5% in the period of analysis (slightly above projected inflation and consistent with long-term debt rates in the range of 4-5%), even though the commercial paper rate is presently below 0.5% given current Federal Reserve interest rate policy.

However, PG&E is also requesting that the Commission review its policy of providing a commercial paper return to nuclear fuel and instead include it in rate base (with a return of 11.82% including associated income taxes).[44] The difference in cost between those two policy options for return on nuclear fuel is considerable (adding close to 4% to the cost of operating DCPP from 2025-2044).

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[43] PG&E 2014 FERC Form 1.

[44] PG&E 2017 TY GRC, Exhibit PG&E-10, p. 14-4; citing D. 14-08-032, Conclusion of Law 33.

We also estimate that approximately half of nuclear fuel inventory is subject to property taxes.[45] Using PG&E's property tax parameters described above, the tax rate on total inventory is 0.56%. That amount is added to the rate of return under either of the options.

Capital Additions

One of the largest components of the cost of nuclear power, and one which has not been well analyzed in the past, involves routine capital additions at nuclear power plants. Our best estimate is that PG&E has added $2.9 billion of net plant due to capital additions at DCPP from 1986-2014 compared to a plant construction cost of $5.4 billion as of the end of 1986.[46]

There are two approaches to estimating capital additions: one is "bottom up" that is identifying the type of projects on which money will be spent. The other "top down" method examines historical data and information from other power projects.

We have conducted a top-down analysis for two reasons. First, we do not know the size and number of specific projects on which PG&E would need to spend money in the period of time from 2025-2044. More importantly, we do not believe that PG&E has that information either. What PG&E will do in the distant future will depend both on ordinary needs for maintenance capital as well as on emerging issues and unknown projects. The fact that PG&E has done large amounts of work to solve known issues in recent years does not mean that it is finished investing money to solve new problems for another 20 years simply because what is known today has been addressed.

For the base case analysis, we have used PG&E's average amount of recorded and forecast capital additions from 2012 to 2018, subtracting out

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[45] $238 million of taxable fuel inventory in 2014 from PG&E 2017 TY GRC, Exhibit PG&E-10, Workpaper 12-65 versus $472 million of total fuel inventory from the 2014 FERC Form 1. The lower tax rate on fuel inventory is likely because some of PG&E's inventory before fabrication into fuel rods is not physically located in the state of California.

[46] Diablo Canyon gross plant costs were $5.40 billion in the 1986 FERC Form 1; they are $7.32 billion at the end of 2014 (excluding asset retirement obligations, which are non-cash future obligations). There were $2.69 billion in capital additions and $1.02 billion in retirements from 1989-2014. Over half of the retirements related to the steam generator replacements. Additionally, capital additions were expensed from 1996-2001 and are not included in PG&E's rate base today. They totaled about $62 million.

costs for ISFSI (on site dry cask spent fuel storage),[47] That figure is $186 million (2014 dollars).

We add 5% in the aggregate to this figure for allowance for funds used during construction (AFUDC) because our source data (the figures provided by PG&E in rate cases) do not include AFUDC. AFUDC is calculated monthly to compensate for interest and equity return during construction and it is recovered, with a rate of return, over the life of the plant. The 5% figure is judgmental but reflects that some projects have minimal AFUDC (completed in a few months) but other larger projects have considerably more AFUDC as their progress from inception to completion may be several years. Thus our estimate of capital additions with AFUDC is $195.3 million in 2014 dollars before escalation.

These costs are assumed to escalate at 2% above inflation over the relicensing period to reflect that PG&E's labor costs are likely to escalate faster than inflation and that that many parts of the plant have limited life spans and may need replacement in the 20-year period.

Our analysis assumes that capital additions are reduced near the end of the project's life to only those items that must be done for safety reasons or are economic over the very short period of time until the plant closes. Thus, in the case when the license is relinquished in 2024, we estimate that capital additions decline by 20% in each of the years 2020-23 and become zero in the year of closure. The difference between 100% of capital additions (if license extension occurs) and the percentages above are economically part of the costs of license extension. Similarly, in the analysis of costs with license extension, capital additions are reduced by the same percentages in 2040-2044.

We analyze the impact of large unforeseen expenses (e.g., embrittlement mitigation, cooling towers or other mitigation for once-through cooling, a third steam generator, etc.) in the CAPITAL ADDITIONS CASE . These costs are not included in the base case. Examples of large unforeseen

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[47] 2019 data were not used because it is closer to relicensing and may reflect lower costs. PG&E's estimates of 2017-2019 costs have been declining in recent years (TURN DR 3-22 and 5-4 in PG&E's 2017 GRC) ISFSI costs were subtracted because some of the costs may result from past fuel and because fuel disposal costs are estimated separately in this report.

expenses include: shutting down unit 1 or the cost of annealing the reactor vessel to deal with significant embrittlement issues, cooling towers to address once-through cooling, strengthening the plant to withstand earthquakes and the potential for items with a 25-year life (e.g., steam generators) to be required during the license extension period.

Fuel Disposal

We analyzed incremental fuel disposal costs (for the fuel used after 2024/2025) based on work done by Alvarez (2015).[48] He estimates a range of costs of $13.2 million to $22.5 million in 2013 dollars per year of operation as the incremental cost of dealing with the fuel generated during the relicensing period. This does not include costs such as removing spent fuel during refueling (which is simply part of the refueling O&M cost) but does include required wet and dry storage costs.

License Extension Costs

We have treated license extension costs similar to hydroelectric relicensing, with costs capitalized and amortized over the new term of the license. Our base case estimate of license extension costs is $100 million (2014 dollars) before AFUDC over the licensing period. The gross nominal dollar cost with AFUDC used in this study is $148 million, which is amortized from 2025-2044.

Gas and Carbon Costs for Short-Term or Limited Amounts of Replacement Power

While not needed in the base case, in some of the sensitivity cases, adjustments were required to add the incremental cost of gas-fired generation (fuel, variable O&M, and carbon costs) that had to be generated because the base case 90% capacity factor was not attained (either due to a large capital spending event in a given year, or due to much smaller but more persistent reductions in capacity factor). When those adjustments were made, we used fuel and carbon costs generally consistent with the 2030 Low Carbon Grid Study. The gas prices were from the CPUC Renewable Portfolio Standard (RPS) calculator v.6.1, escalated at 2.06% after 2030 (same rate of escalation as before 2030). The carbon price used was the LCGS mid-case ($32/ton in 2014 dollars in 2030), with 2% real escalation

[48] Robert Alvarez, "The Cost for the Management, Operating and Disposal of Spent Nuclear Fuel at the Diablo Canyon Power Plant," November 19, 2015.

before and after 2030. A market heat rate for baseload replacement power of 7500 Btu/kWh was used.

BASE CASE

Three different sets of costs for Diablo Canyon must be analyzed here. The first are the costs from 2025-2044 incurred during the license extension. The second set of costs are those incurred from 2020-2024 for operation during the license extension period that would not be incurred if the license were to be relinquished. These costs include the fuel and M&S inventories that would be used up in 2020-2024 (discussed above) as well as the portion of capital additions costs that would be incurred if the license were extended, minus the smaller amount of capital additions incurred if the license were not to be extended. The third item is an end-effect credit in 2045 for tax effects resulting from the plant closure.

Table 5 below summarizes the present value of base case costs as of 2025 for DCPP for the years 2020-2045 in real and nominal dollars. The discount rates used were 6 percent real and 8 percent nominal. It shows a present value of costs of $14.1 billion to $14.8 billion in 2014 dollars depending on the ratemaking treatment of fuel inventory and the level of costs required for fuel disposal. PG&E's requested ratemaking treatment for fuel inventory alone would add $586 million, which is more than 4% of the cost of license extension without that ratemaking change. The nominal dollar figures are higher in magnitude but similar directionally.

TABLE 5
Diablo Canyon Base Case by Type of Cost ($ Million)

	Real 2014 $		Nominal $	
Base Case	NPV at 6%		NPV at 8%	
	in 2025		in 2025	
refueling O&M	$	1,087	$	1,218
base O&M	$	4,646	$	5,634
employee benefits	$	1,266	$	1,536
administrative overhead	$	515	$	624
fuel	$	1,689	$	2,048
insurance	$	163	$	197
fuel disposal	$	154	$	186
M&S inventory	$	139	$	168
fuel inventory	$	192	$	233
capital additions	$	4,102	$	4,978
relicensing	$	149	$	180
Low base case	$	14,101	$	17,001
2020-2024 extra pre-closure costs from license extension	*$*	*630*	*$*	*755*
2025-2044 operating costs from license extension	*$*	*13,513*	*$*	*16,298*
2045 tax end effect from license extension	*$*	*(42)*	*$*	*(51)*
adjustments to base case				
High fuel disposal cost	$	108	$	131
Return on rate base for fuel inventory	$	586	$	708
High base case	$	14,795	$	17,840

The low base case cost is equivalent to 6.9 cents per kWh (2014 dollars) at expected production levels for every kilowatt-hour produced from 2025-2044, while the high base case is just over 7.2 cents per kWh. In nominal dollars, the cost of the kWh produced from 2025-2044 is 9.7 cents per kWh in the low base case and 10.2 cents per kWh in the high base case.

CAPITAL ADDITIONS CASE

A set of evaluations were run based on significant capital expenditures either as a condition of license extension or in the middle of the new license period. Again, in this top down analysis, no specific project is identified. However, there are a number of pending known concerns that could have very large costs, such as OTC compliance, seismic risks, embrittlement of unit 1, fire hazard repair to address faulty cable installation, etc. Other large but unforeseen costs could also arise, such as replacing equipment a second time that needed initial replacement after 20-25 years in service (e.g., steam generators).

To parameterize the effects of levels of capital costs, capital expenditures costs from $250 million to $2 billion (real 2014 dollars) were assumed at two points in the project's life – 2024 as a relicense condition and 2034 as an unexpected mid-license cost. For events that could cause costs above $1.5 to $2 billion it is very likely that the plant would close as this expenditure would be clearly uneconomic, particularly if some or all of the plant had to be shut down for a significant period of time to make the repairs, so we did not analyze these higher levels of cost explicitly.

The results are given below in Table 6 in real and nominal dollars.

TABLE 6
Sensitivity of Costs to One-Time Capital Addition ($ Million)

	real 2014 dollars		nominal dollars	
	event in 2024	event in 2034	event in 2024	event in 2034
$250 million capital addition	$ 327	$ 178	$ 395	$ 218
$500 million capital addition	$ 653	$ 357	$ 789	$ 435
$1 billion capital addition	$ 1,306	$ 714	$ 1,578	$ 870
$1.5 billion capital addition	$ 1,960	$ 1,071	$ 2,367	$ 1,305
$2 billion capital addition	$ 2,613	$ 1,428	$ 3,156	$ 1,740
replacement power costs for large capital spending project				
capacity factor 60% for one year	$ 360	$ 258	$ 432	$ 319
capacity factor zero for one year	$ 1,081	$ 774	$ 1,297	$ 958

A single large capital expenditure at the $500 million level (with an accompanying loss of production of a 30% capacity factor) could cost an extra $1,013 million (net present value 2014 real dollars) in 2024 and $615 million in 2034. Costs would rise if the expenditure were larger or if the outage to install new equipment were longer. A very expensive project costing $1.5 billion with a year's outage would have a net present value of cost in 2014 dollars of $3.0 billion in 2024 and $1.8 billion in 2034.

Sensitivity to Smaller Cost Increases or Capacity Factor Decreases
In addition to capital additions, other sensitivities were run to capture either increases in costs (estimated as increased amounts of real escalation) or relatively small but persistent decreases in capacity factor that would not cause plant closure but would require replacement power and carbon offsets in some hours of the year. The decreases in capacity factor were modeled as either ongoing due to aging or fluctuations that simply reduced the average capacity factor below the base case 90% assumption. (Table 7)

TABLE 7
Cost Increases from Capacity Factor Loss and Real Escalation ($ Million)

	Real 2014 $ NPV at 6% in 2025		Nominal $ NPV at 8% in 2025	
capacity factor drops 0.5% per year 2025-2044	$	621	$	956
capacity factor drops 1% per year 2035-2044	$	264	$	441
average capacity factor 89%	$	140	$	202
average capacity factor 88%	$	278	$	398
average capacity factor 87%	$	412	$	591
average capacity factor 86%	$	542	$	778
average capacity factor 85%	$	668	$	959
real escalation increases by 0.5%	$	610	$	732
real escalation increases by 1%	$	1,449	$	1,743

These cases show that, increases in plant costs or reduction in performance on a slow sustained basis would also have significant costs. There would be a $610 million increase (real 2014 dollars) if real cost escalation increased by 0.5%. If the expected capacity factor declined by 0.5% per year from 2025-2044, the replacement power bill would be an unforeseen $621 million above the base.

Year-by-Year Costs of License Extension under Several Scenarios
Table 8 shows the year-by-year costs of several of the scenarios discussed above in real 2014 dollars.

TABLE 8
Scenario Analysis (Real 2014 $'000)

	low base case Diablo	high base case Diablo	0.5% loss of capacity factor per year	0.5% more real escalation	$1 billion more 2024 *	$500 million more 2034 *
2020	$ 15,110	$ 19,081	$ 19,081	$ 29,081	$ 19,081	$ 19,081
2021	$ 49,283	$ 62,496	$ 62,496	$ 80,669	$ 62,496	$ 62,496
2022	$ 107,276	$ 129,297	$ 129,297	$ 153,041	$ 129,297	$ 129,297
2023	$ 209,160	$ 239,990	$ 239,990	$ 264,975	$ 239,990	$ 239,990
2024	$ 209,576	$ 249,215	$ 249,215	$ 271,178	**$ 780,356**	$ 249,215
2025	$ 819,198	$ 872,641	$ 878,784	$ 888,290	$ 1,032,524	$ 872,641
2026	$ 883,292	$ 936,735	$ 949,303	$ 955,943	$ 1,086,119	$ 936,735
2027	$ 993,287	$ 1,046,730	$ 1,066,017	$ 1,070,811	$ 1,186,320	$ 1,046,730
2028	$ 969,879	$ 1,023,322	$ 1,049,629	$ 1,047,214	$ 1,153,750	$ 1,023,322
2029	$ 1,012,757	$ 1,066,200	$ 1,099,838	$ 1,092,793	$ 1,188,044	$ 1,066,200
2030	$ 1,055,582	$ 1,109,025	$ 1,150,315	$ 1,138,571	$ 1,222,895	$ 1,109,025
2031	$ 1,171,319	$ 1,224,762	$ 1,274,033	$ 1,261,910	$ 1,331,106	$ 1,224,762
2032	$ 1,141,729	$ 1,195,172	$ 1,252,763	$ 1,231,420	$ 1,294,223	$ 1,195,172
2033	$ 1,185,351	$ 1,238,794	$ 1,305,056	$ 1,275,332	$ 1,330,770	$ 1,238,794
2034	$ 1,229,645	$ 1,283,088	$ 1,358,382	$ 1,323,945	$ 1,368,221	**$ 1,852,272**
2035	$ 1,354,603	$ 1,408,046	$ 1,492,742	$ 1,459,994	$ 1,486,545	$ 1,507,477
2036	$ 1,321,699	$ 1,375,142	$ 1,469,623	$ 1,425,574	$ 1,447,229	$ 1,467,168
2037	$ 1,370,555	$ 1,423,998	$ 1,528,658	$ 1,479,730	$ 1,489,874	$ 1,509,049
2038	$ 1,422,463	$ 1,475,906	$ 1,591,149	$ 1,537,323	$ 1,535,783	$ 1,554,373
2039	$ 1,551,874	$ 1,605,318	$ 1,731,561	$ 1,681,777	$ 1,658,647	$ 1,677,561
2040	$ 1,494,737	$ 1,543,776	$ 1,681,450	$ 1,617,830	$ 1,591,585	$ 1,610,173
2041	$ 1,512,483	$ 1,552,713	$ 1,702,259	$ 1,633,677	$ 1,596,686	$ 1,613,554
2042	$ 1,518,884	$ 1,550,305	$ 1,712,179	$ 1,638,518	$ 1,590,575	$ 1,605,775
2043	$ 1,605,104	$ 1,627,717	$ 1,802,386	$ 1,735,268	$ 1,664,410	$ 1,677,989
2044	$ 1,490,874	$ 1,504,678	$ 1,692,626	$ 1,607,805	$ 1,537,921	$ 1,549,932
2045 tax effects	$ (142,179)	$ (142,179)	$ (142,179)	$ (136,533)	$ (154,324)	$ (157,892)
NPV at 6% real	$ 14,100,723	$ 14,794,620	$ 15,580,105	$ 15,404,719	$ 16,461,207	$ 15,409,557
pre-closure extra cost 2020-2024 with license extension	*$ 629,594*	*$ 747,406*	*$ 747,406*	*$ 856,800*	*$ 1,278,548*	*$ 747,406*
License extension years 2025-2044	*$ 13,512,953*	*$ 14,089,036*	*$ 14,874,521*	*$ 14,588,080*	*$ 15,228,055*	*$ 14,708,595*
value of resources with > 20 year life and tax end effects	*$ (41,823)*	*$ (41,823)*	*$ (41,823)*	*$ (40,162)*	*$ (45,395)*	*$ (46,445)*
	* Includes 30% reduction in capacity factor in the year with the capital spending.					

Table 9 shows a corresponding analysis of these cases in nominal dollars.

TABLE 9
Scenario Analysis (Nominal $ '000)

	low base case Diablo	high base case Diablo	0.5% loss of capacity factor per year	0.5% more real escalation	$1 billion more 2024 *	$500 million more 2034 *
2020	$ 16,758	$ 21,162	$ 21,162	$ 32,252	$ 21,162	$ 21,162
2021	$ 55,751	$ 70,698	$ 70,698	$ 91,255	$ 70,698	$ 70,698
2022	$ 123,781	$ 149,190	$ 149,190	$ 176,587	$ 149,190	$ 149,190
2023	$ 246,166	$ 282,451	$ 282,451	$ 311,857	$ 282,451	$ 282,451
2024	$ 251,590	$ 299,175	$ 299,175	$ 325,541	**$ 888,438**	$ 299,175
before 2024 NPV	$ 754,856	$ 896,087	$ 896,087	$ 1,027,152	$ 1,485,351	$ 896,087
2025	$ 1,003,091	$ 1,068,531	$ 1,076,052	$ 1,087,693	$ 1,264,304	$ 1,068,531
2026	$ 1,103,203	$ 1,169,952	$ 1,185,649	$ 1,193,943	$ 1,356,528	$ 1,169,952
2027	$ 1,180,660	$ 1,248,744	$ 1,273,314	$ 1,276,050	$ 1,426,574	$ 1,248,744
2028	$ 1,260,286	$ 1,329,731	$ 1,363,916	$ 1,360,778	$ 1,499,214	$ 1,329,731
2029	$ 1,434,548	$ 1,505,383	$ 1,549,967	$ 1,545,239	$ 1,666,876	$ 1,505,383
2030	$ 1,427,066	$ 1,499,317	$ 1,555,137	$ 1,539,261	$ 1,653,261	$ 1,499,317
2031	$ 1,514,828	$ 1,588,524	$ 1,656,467	$ 1,633,701	$ 1,735,168	$ 1,588,524
2032	$ 1,605,889	$ 1,681,059	$ 1,762,063	$ 1,732,043	$ 1,820,378	$ 1,681,059
2033	$ 1,700,590	$ 1,777,263	$ 1,872,328	$ 1,829,683	$ 1,909,219	$ 1,777,263
2034	$ 1,913,393	$ 1,991,600	$ 2,101,782	$ 2,060,039	$ 2,116,180	**$ 2,838,045**
2035	$ 1,903,022	$ 1,982,793	$ 2,109,213	$ 2,050,683	$ 2,099,963	$ 2,131,206
2036	$ 2,012,267	$ 2,093,633	$ 2,237,479	$ 2,170,416	$ 2,203,384	$ 2,233,742
2037	$ 2,128,383	$ 2,211,377	$ 2,373,906	$ 2,297,924	$ 2,313,677	$ 2,343,455
2038	$ 2,253,173	$ 2,337,827	$ 2,520,370	$ 2,435,110	$ 2,432,670	$ 2,462,117
2039	$ 2,507,323	$ 2,593,669	$ 2,797,638	$ 2,717,203	$ 2,679,832	$ 2,710,391
2040	$ 2,463,308	$ 2,544,123	$ 2,771,008	$ 2,666,162	$ 2,622,912	$ 2,653,544
2041	$ 2,542,403	$ 2,610,028	$ 2,861,408	$ 2,746,124	$ 2,683,945	$ 2,712,299
2042	$ 2,604,226	$ 2,658,100	$ 2,935,644	$ 2,809,347	$ 2,727,145	$ 2,753,208
2043	$ 2,640,249	$ 2,679,796	$ 2,985,268	$ 2,847,171	$ 2,743,968	$ 2,767,715
2044	$ 2,659,472	$ 2,684,096	$ 3,019,364	$ 2,868,057	$ 2,743,396	$ 2,764,821
2045 end effect (tax)	$ (258,697)	$ (258,697)	$ (258,697)	$ (248,424)	$ (280,795)	$ (287,285)
Net Present Value at 8%	$ 17,001,398	$ 17,840,349	$ 18,796,808	$ 18,572,388	$ 19,802,416	$ 18,594,777
pre-closure extra cost 2020-2024 with license extension	*$ 754,856*	*$ 896,087*	*$ 896,087*	*$ 1,027,152*	*$ 1,485,351*	*$ 896,087*
License extension years 2025-2044	*$ 16,297,934*	*$ 16,995,654*	*$ 17,952,112*	*$ 17,594,588*	*$ 18,372,847*	*$ 17,755,761*
value of resources with > 20 year life and tax end effects	*$ (51,392)*	*$ (51,392)*	*$ (51,392)*	*$ (49,351)*	*$ (55,781)*	*$ (57,071)*
	* Includes 30% reduction in capacity factor in the year with large capital spending					

Renewable Replacement Portfolio Costs

We now turn to the cost of the three potential renewable replacement portfolios. In the Low Carbon Grid Study, these costs were calculated as an annual utility revenue requirement in the year 2030 and compared to a case that kept the renewable portion of total resources at a 33% RPS level. Here, consistent with the DCPP going forward cost analysis detailed above, we analyze them in both real 2014 dollars and in nominal dollars with consistent macro-economic variables such as inflation.[49] The bulk of the renewable procurement is assumed to be through 20-year fixed price PPAs between PG&E and third parties covering the license extension period. The storage and transmission investments are assumed to be made by PG&E. As before, the result will be expressed as the net present value at a 6.15% discount rate from 2025 to 2045 adjusted for the residual value in 2045 of those portions of the portfolio such as long life transmission investments and utility rate based pumped storage facilities whose useful life exceeds 20 years.

For a base, we used the LCGS mid-case set of technology cost/performance parameters which are generally consistent with version 6.1 of the CPUC RPS Calculator used for planning purposes by the state energy agencies[50]. The capital costs of the various technologies are shown below in Table 10. Later, we will adjust these base costs for other factors and develop sensitivities to these and other assumptions.

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[49] Although, in general, renewable resources under fixed price PPAs are not affected by changes in the inflation assumption once constructed, we still need an inflation assumption to account for minor going forward costs such as O&M past 2045, potential timing of the resource build-out, and the comparison of nominal dollar figures.

[50] Major exceptions to this equivalency are confined to (a) mid case estimates for geothermal capital cost which increased by 30% in v6.1 over previous estimates. Available evidence is much more consistent with treating the data point used as justification for raising geothermal capital cost as an outlier representative of “High Case” costs instead of average costs, and (b) wind capacity factors whose mid case estimates in v6.1 are too low by approximately 15% due to using the power curve for an early generation wind turbine to convert wind speed to output. Using current generation variable pitch turbine power curves yields capacity factors roughly 15% higher and in line with recently signed PPAs throughout the United States.

TABLE 10
Base Case Capital Costs for Renewable Resources
2014 $

Technology	Capital Cost, $/kw
Valley Project	5,224
CSP w/ storage	6,228
Geothermal[51]	5,986
PV (1 axis tracking)	2,185
Wind, CA[52]	1,516
Wind WY	1,716
Pumped storage	1.898

The present value of the base renewable resource costs during the license extension period plus the associated transmission[53] and storage investments adjusted for residual value in 2045 are shown in Table 11. End effects arise because geothermal, pumped storage, and transmission projects have a project life longer than the 20-year license extension.[54]

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[51] 30 yr project life

[52] Most of the CA wind is assumed to be repowerings of the 30+ year-old facilities in the Altamont, Tehachapi, and San Gorgonio areas. The capacity factor of this repowered CA wind is adjusted to net out the energy from the existing facilities.

[53] The transmission investments are $1.0B, $640M, and $1.4B for the Diverse, High Solar and Valley Solar portfolios respectively.

[54] We valued the end-effects as replacement cost new less depreciation as of 2045, with an assumed one third of the life of geothermal and half the life of transmission lines and pumped storage projects remaining.

TABLE 11
Base Real 2014 Dollars NPV @6% 2025-2044 ($ Millions)

Cost Element	Diverse	High Solar	Valley Solar
NPV 2025-2044	14,611	15,101	19,214
End Effects	(177)	(115)	(239)
Base Net Cost	14,433	14,985	18,976

Adjustments to Base Costs
Clearly, at these Base costs, the Valley Solar portfolio is significantly more expensive than the other options and probably would not be chosen under these circumstances. The combination of the lack of low cost, high capacity factor out of state wind, higher transmission costs, increased storage, and increased curtailment due to over-generation in winter and light load spring hours renders the Valley Solar portfolio not cost competitive with the other portfolio options. However, base projected costs represent only a snapshot in time during a period of rapidly declining renewable resource costs – especially for solar PV.

As an initial adjustment, we assume that PV installed costs continue on their current decline curve until they reach the ambitious but clearly plausible Department of Energy "Sun Shot" targets for the 2020 timeframe.[55] These costs are equivalent to the "low tech case" estimates from the Low Carbon Grid Study at a capital cost for tracking PV in CA of $1,516/kw instead of the base cost of $2,185/kw from Table 10. If this scenario were to occur, the 2024-2044 NPV for the Valley Solar portfolio becomes $14,503B with an end effect adjustment of ($194M) for a net license extension period cost of $14,309B for the Valley Solar portfolio – in line with the base case Diverse and High Solar portfolios.

In contrast to the DCPP cost trends, most adjustments for renewable resource procurement tend to be in the downward direction rather than potential increses in cost from base case estimates.

[55] http://energy.gov/eere/sunshot/sunshot-initiative

First, solar PV is not the only renewable technology whose costs are declining. Wind costs are also on a steep "learning curve" decline as field experience is gained and supply chains become more robust with exploding volumes world wide. Reported wind costs have declined by 37% over the past five years[56] and the wind industry has its own abbitious research and development program equivalent to the Sun Shot program – called Wind Vision. Wind Vision lays out an ambitious but plausible target of 30% improvement by 2025 in cost/performance for wind[57].

Second, the above base analysis unnecessarily assumes that current renewable resource tax incentives such as the wind Production Tax Credit, other renewables 30% Investment Tax Credit, bonus depreciation measures associated with the stimulus package enacted in the wake of the financial meltdown of 2008, and California's property tax exemption for solar all expire prior to procurement of the DCPP replacement portfolio.

This assumption is not just very conservative, it is incorrect. Congress recently extended many of the incentives due to expire in 2016 for an additional five years on a declining scale[58]. There is good reason for the bulk of the DCPP replacement portfolio to be procured before the expiration of these extended credits. Furthermore, there is no reason to believe that NO tax incentives to invest in renewables will be available after 2020.

The intersection of climate change concerns from the left with anti-tax of any kind sentiment from the right that resulted in the passage of the recent "tax extender" package remains a strong political force. One idea that has some political traction is to extend to renewables the same tax incentive now available to oil and gas and real estate investments called "Master Limited Partnerships."[59] This incentive which has been extensively used by the fossil fuel industry to finance production plays as well as virtually all so called "mid-stream" oil and gas investments such as storage, pipelines, and processing facilities for at least the last decade is, by many accounts, equivalent in financial impact to the Renewable Investment Tax Credit. [60]

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[56] http://energy.gov/eere/wind/wind-vision p. 29
[57] Wind Vision, op cit p.149
[58] www.chadbourne.com/tax-credit-extensions-clear-congress_12/18/15
[59] www.bakerbotts.com/ideas/publications/2015/06/mlp-update
[60] *Id.*

Finally, we would note that the capital cost estimates for renewable technologies tend to represent regional average costs and all of the technologies have a robust supply curve with numerous individual projects whose actual cost is below average at the penetration levels contemplated here. As has been demonstrated time and again over the past decades, under these circumstances, well designed, properly planned and executed competitive procurement processes yield multiple projects whose costs are significantly below the projected averages.

As with the DCPP adjustments analyzed in the previous section, we choose to not confuse precision with accuracy when projecting this far into the future and, instead, adopt a "top down" adjustment to the base case estimate for renewable replacement portfolio costs.

Table 12 shows the year-by-year costs in real dollars for several of the renewable scenarios discussed above. Because costs are levelized in nominal dollars, they decline in real dollars over the life of the project.

TABLE 12
Renewable Portfolios, Mid and Low Cost Cases (2014 Real $'000)

	diverse renewable mid cost	high solar mid cost	Valley solar mid cost	diverse renewable low cost	high solar low cost	Valley solar low cost
2025	$ 1,472,070	$ 1,521,398	$ 1,935,801	$ 1,273,329	$ 1,227,501	$ 1,477,007
2026	$ 1,443,206	$ 1,491,567	$ 1,897,844	$ 1,248,361	$ 1,203,432	$ 1,448,046
2027	$ 1,414,908	$ 1,462,320	$ 1,860,631	$ 1,223,884	$ 1,179,836	$ 1,419,653
2028	$ 1,387,165	$ 1,433,647	$ 1,824,148	$ 1,199,886	$ 1,156,702	$ 1,391,817
2029	$ 1,359,965	$ 1,405,536	$ 1,788,380	$ 1,176,359	$ 1,134,021	$ 1,364,526
2030	$ 1,333,299	$ 1,377,977	$ 1,753,314	$ 1,153,293	$ 1,111,785	$ 1,337,771
2031	$ 1,307,156	$ 1,350,958	$ 1,718,935	$ 1,130,679	$ 1,089,986	$ 1,311,540
2032	$ 1,281,526	$ 1,324,468	$ 1,685,231	$ 1,108,509	$ 1,068,613	$ 1,285,824
2033	$ 1,256,398	$ 1,298,498	$ 1,652,187	$ 1,086,774	$ 1,047,660	$ 1,260,612
2034	$ 1,231,763	$ 1,273,038	$ 1,619,791	$ 1,065,465	$ 1,027,118	$ 1,235,894
2035	$ 1,207,610	$ 1,248,076	$ 1,588,031	$ 1,044,573	$ 1,006,978	$ 1,211,660
2036	$ 1,183,932	$ 1,223,604	$ 1,556,893	$ 1,024,091	$ 987,234	$ 1,187,902
2037	$ 1,160,717	$ 1,199,612	$ 1,526,366	$ 1,004,011	$ 967,876	$ 1,164,610
2038	$ 1,137,958	$ 1,176,090	$ 1,496,437	$ 984,325	$ 948,898	$ 1,141,775
2039	$ 1,115,645	$ 1,153,029	$ 1,467,095	$ 965,024	$ 930,292	$ 1,119,387
2040	$ 1,093,770	$ 1,130,421	$ 1,438,328	$ 946,102	$ 912,051	$ 1,097,438
2041	$ 1,072,323	$ 1,108,256	$ 1,410,126	$ 927,551	$ 894,168	$ 1,075,920
2042	$ 1,051,297	$ 1,086,525	$ 1,382,476	$ 909,364	$ 876,635	$ 1,054,823
2043	$ 1,030,684	$ 1,065,221	$ 1,355,369	$ 891,533	$ 859,446	$ 1,034,141
2044	$ 1,010,474	$ 1,044,334	$ 1,328,793	$ 874,052	$ 842,594	$ 1,013,863
NPV at 6% real	$ 14,433,880	$ 14,985,441	$ 18,975,648	$ 12,482,148	$ 12,080,126	$ 14,445,136
License extension years 2025-2044	*$ 14,611,342*	*$ 15,100,954*	*$ 19,214,194*	*$ 12,638,691*	*$ 12,183,818*	*$ 14,660,347*
End effects - Value of resources with > 20 year life	*$ (177,462)*	*$ (115,513)*	*$ (238,547)*	*$ (156,544)*	*$ (103,692)*	*$ (215,211)*

Table 13 shows the same costs in nominal dollars.

TABLE 13
Renewable Portfolios, Mid and Low Cost Cases (Nominal $'000)

	diverse renewable mid cost	high solar mid cost	Valley solar mid cost	diverse renewable low cost	high solar low cost	Valley solar low cost
2025	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2026	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2027	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2028	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2029	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2030	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2031	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2032	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2033	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2034	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2035	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2036	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2037	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2038	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2039	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2040	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2041	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2042	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2043	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
2044	$ 1,802,519	$ 1,862,919	$ 2,370,347	$ 1,559,164	$ 1,503,049	$ 1,808,564
Net Present Value at 8%	$ 18,177,884	$ 18,868,801	$ 23,898,024	$ 15,720,058	$ 15,211,167	$ 18,194,091
License extension years 2025-2044	*$ 18,391,673*	*$ 19,007,959*	*$ 24,185,401*	*$ 15,908,646*	*$ 15,336,085*	*$ 18,453,355*
End effects - Value of resources with > 20 year life	*$ (213,789)*	*$ (139,158)*	*$ (287,377)*	*$ (188,588)*	*$ (124,918)*	*$ (259,264)*

Expected Costs

The foregoing analysis laid out base costs and then some potential adjustments to that base. Not all of the adjustments will necessarily occur in the future, but it is a virtual certainty that many will. There is almost no upside to the DCPP going forward costs and there is almost no downside to the replacement portfolio costs. Here, we make the following assumptions about the future potential costs to arrive at a single best estimate of future life cycle costs of the various options:

- DCPP will be faced with $1-3B of "unexpected capital costs as the plant ages.
- Renewable tax credits will be extended past current expiration dates by extending Master Limited Partnership tax treatment similar to oil and gas and real estate investments.

With these adjustments, the expected costs of the various portfolios are shown in Table 14 below:

Table 14
Expected Life Cycle Costs of Alternatives

Diablo Canyon License Extension	**$17+ B**
Portfolio A: Diverse Renewables	**$13- B**
Portfolio B: High Solar Renewables	**$13 B**
Portfolio C: Central Valley Solar	**$15- B**
Portfolio D: 75% Diverse Renewables, 25% Energy Efficiency (PG&E only)	**$12- B**

Conclusion

The strong conclusion from the foregoing analysis is that it is clearly in the interest of California ratepayers to replace DCPP with a renewable portfolio in an orderly transition on a timetable that will enable ratepayers to benefit from the renewable tax credits that may expire in 2020. These renewable resources will be additive to the recently adopted policy of a 50% RPS by 2030. It is also in ratepayer interests to overhaul and expand current energy efficiency programs to bear part of the load caused by retirement of DCPP.

We can confidently state that on a life cycle basis the investment in renewables and efficiency will, over time, provide consumers with lower cost electricity than DCPP, will be more reliable, and will eliminate the real financial and safety risks inherent in operating nuclear reactors that are 40 to 60 years old.

Our conclusion is based on our analysis that: (a) the base, conventional wisdom estimate of DCPP license extension period costs at more than $14B is roughly the same as the base, conventional wisdom procurement and operating costs of a robust range of renewable resources and incremental energy efficiency that embody the true meaning of “least cost/best fit.”; (b) there is a near certainty that the base costs for DCPP life extension are low by at least 10% and probably more to cover either unforeseen issues during the license extension period, or conditions attached to the license extension to deal with issues such as seismic retrofits and/or once through cooling mitigation measures; the need to close unit 1 by 2023 due to embrittlement; the need for new steam generators, etc., (c) there is strong evidence to believe that the renewable replacement portfolio can be procured for at least 10% less than the base estimate; (d) that the retirement of DCPP will reduce required spinning reserves and relieve the Helms pumped storage plant, which is worth in excess of $2B, for a higher duty of providing flexibility to the grid to accommodate ever increasing penetrations of zero variable cost, zero carbon emitting renewable resources onto California’s electric grid.

In addition, the DCPP costs are uncertain and subject to inflation. The renewable alternative costs are largely fixed. They have no fuel costs and little maintenance exposure. They are low risk inflation hedges and they eliminate the awesome enterprise level risks inherent in running nuclear reactors in a seimically active region.