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Research Commentary

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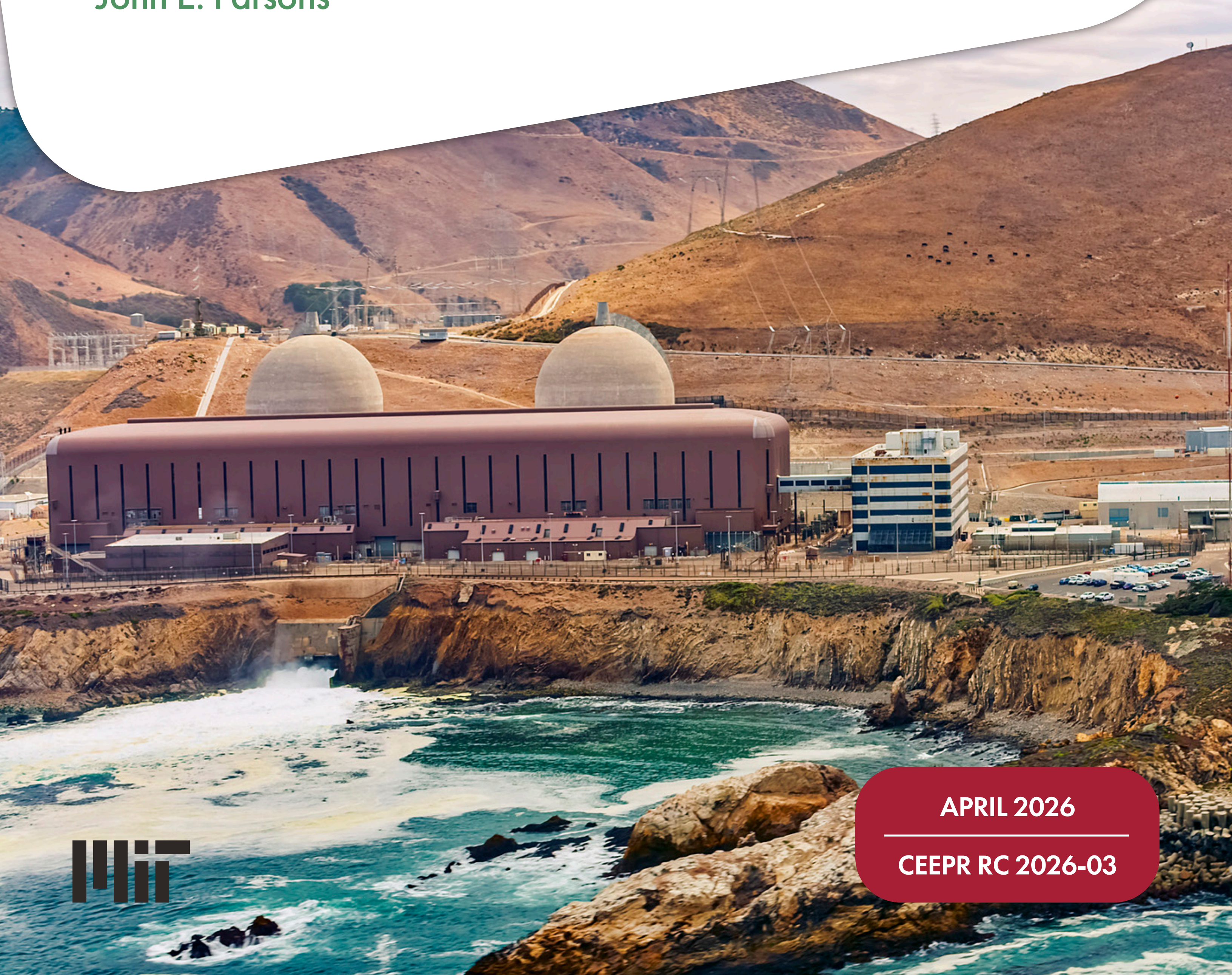

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The Economics of Continued Operation of the Diablo Canyon Nuclear Power Plant, 2030-2045

John Parsons*

April 20 2026

1 Introduction

Should the Diablo Canyon Nuclear Power Plant's (DCPP) operating life be extended to 2045? In 2022, Senate Bill 846 (SB 846) authorized a potential five year extension from 2025 to 2030. However, on April 2, 2026 the Nuclear Regulatory Commission (NRC) approved a twenty year license extension to 2045. The question is whether the state should agree to extend the plant's operation to 2045 in alignment with its NRC license.[1]

This Research Commentary is written to inform public deliberation on such an extension. This analysis focuses on the economic costs and benefits of continued plant operation, understanding that these are only one aspect of the larger question.

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[1] DCPP has two reactors, and in each revision of the life of the plant the specified retirement dates of the two units are staggered. Unit 1 had originally been licensed to operate to November 2024 and Unit 2 to August 2025. Pursuant to a multiparty settlement agreement in 2016 and a succeeding decision of the California Public Utility Commission, no license extension was to happen and the reactors were to each each shut down at expiration of the original licenses. SB 846 established new retirement dates of October 31, 2029 for Unit 1 and October 31, 2030 for Unit 2. The term of the NRC's April 2026 license renewal extends to November 2, 2044 for Unit 1 and to August 26, 2045 for Unit 2.

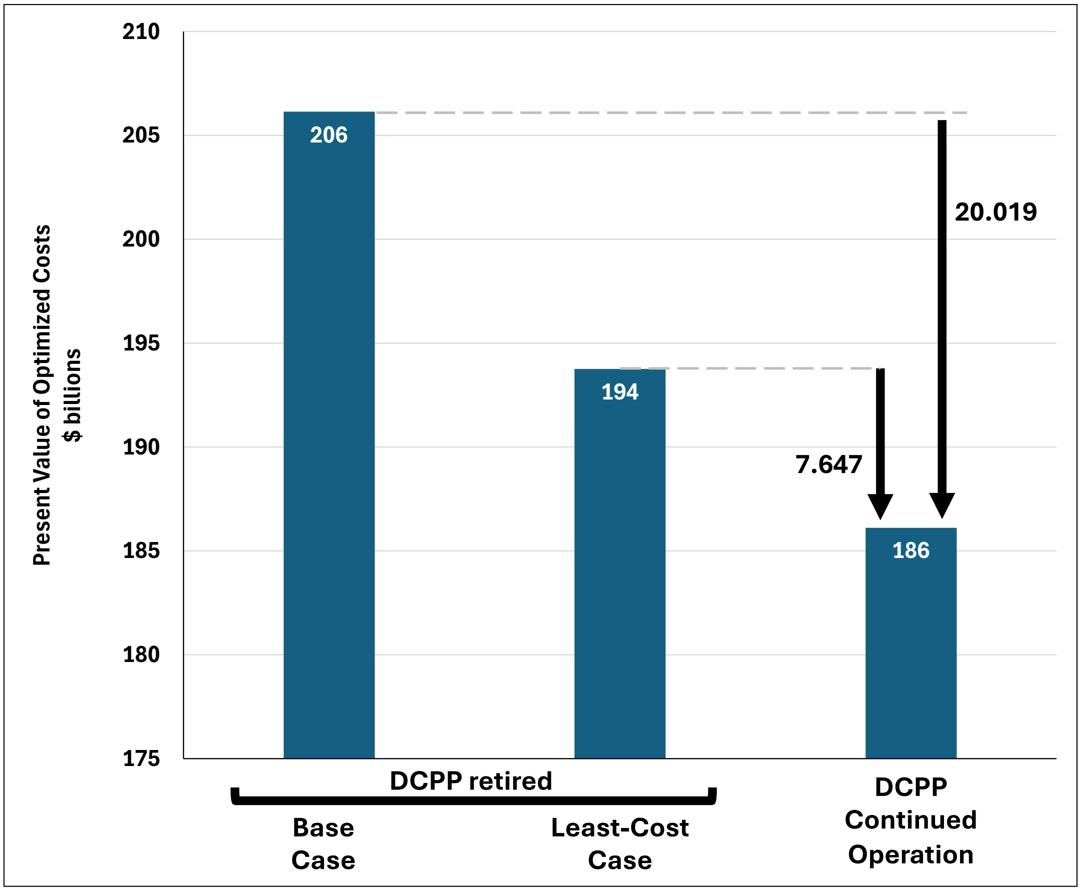

Figure 1: Present Value of Optimized Costs With Diablo Canyon Power Plant Retired Compared Against the Present Value of Optimized Cost With Diablo Canyon's Continued Operation.

2 Summary of Results

Extending the life of the Diablo Canyon Nuclear Power Plant to 2045 can help reduce the cost of California's electricity. The plant provides reliable capacity which is a valuable contribution to California's system. It displaces capacity from existing natural gas power plants, offers California the opportunity to deploy in-state renewable resources more economically, and delays the need for costly transmission upgrades.

The amount of savings depends upon the portfolio of resources California relies on in the absence of DCPP. At a minimum, continued operation of the Diablo Canyon Nuclear Power Plant from 2030 to 2045 earns savings net of capital and operating costs totaling more than $7.6 billion in present value, or more than $500 million per year of continued operations.

The savings more than double when calculated relative to the current portfolio of alternatives mandated pursuant to Assembly Bill 1373 (AB 1373). In that case, the total present value of savings for extending the life of DCPP exceed $20 billion, or more than $1.3 billion per year.

3 The CPUC's RESOLVE Modeling

In order to evaluate whether a generation asset like DCPP is cost-efficient, a common tool of analysis is a capacity expansion and dispatch model. At MIT, one widely used model is known as 'GenX'. It was developed at the MIT Energy Initiative in partnership with Princeton University's Zero Lab and New York University's Sustainable Energy Transitions group, and has been employed by many research teams for policy studies and peer-reviewed published research.[2] The 2021 joint Stanford-MIT study on Diablo Canyon used the 'urbs' model.[3] However, this Commentary relies on modeling reported by the California Public Utilities Commission (CPUC) in the course of its 2024-2026 Integrated Resource Planning (IRP) process, which develops inputs to the 2026-2027 Transmission Planning Process. The CPUC employed the RESOLVE model, which is a product supplied by the consulting firm E3.[4] The model includes a very detailed and granular representations of the California electric grid and neighboring systems that would be difficult to replicate. Moreover, the inputs to the model were developed by the CPUC in the course of a very transparent public process, so that results produced using the model can be assessed and appreciated within the frame of the current public discussion in California.[5] Finally, and most importantly, the value of the model for our purposes also depends on whether it can be used to address the question at hand, which is the contribution of DCPP to the grid. As it happens, RESOLVE model results reported by the CPUC in October 2025 do exactly that.[6] The CPUC Energy Division also produced a summary discussion.[7] Therefore, this Commentary delves into those results and synthesizes them here, extracting the information relevant to the extension period 2030-2045 rather than the full period 2026-2045 covered by the CPUC analysis.

The inputs to the RESOLVE modeling include an itemization of existing generation and storage assets as well as the topology of the transmission network. This is called the Baseline portfolio. The inputs also include a specification of available new generation technologies and transmission upgrade options over future years, together with forecasted costs for each option in future years. Finally, the inputs include forecasted load in future years and specific assumptions about policies, such as the planning reserve margin, greenhouse gas emission reductions, and so on.

Given those inputs, RESOLVE optimizes the remaining investments in generation, storage and transmission assets. This analysis focuses on three of the October 2025 runs of the model reflecting different additional assumptions about planned investments beyond the Baseline portfolio:

- A Least-Cost Comparison Case (hereafter Least-Cost Case), which optimizes all investments beyond the Baseline, but excluding DCPP as an option;
- A proposed Base Case (hereafter Base Case), which adds to the Baseline certain procurements related to AB 1373, notably offshore wind and long duration storage, and optimizes all remaining investments, but also excluding DCPP as an option; and
- A DCPP Extension Case (hereafter DCPP Case), which adds to the Baseline life extension for DCPP out to 2045, and optimizes all remaining investments.

For each of the three cases, the RESOLVE model's logic assures that the resulting portfolio of investments generates enough electricity to serve California's load each year.[8] Each portfolio also has sufficient capacity to meet California's specified planning reserve margin which assures grid reliability. Consequently, the

[2] Bonaldo, Luca et al. (2025). "GenX". In: DOI: 10 . 5281 / zenodo . 10846070. https://github.com/GenXProject/GenX.jl.

[3] Aborn, Justin et al. (Nov. 2021). An Assessment of the Diablo Canyon Nuclear Plant for Zero-Carbon Electricity, Desalination, and Hydrogen Production. Tech. rep.

[4] https://www.ethree.com/tools/resolve/, and https://github.com/e3-/resolve

[5] California Public Utilities Commission (Feb. 2025). Inputs Assumptions, 2024-2026 Integrated Resource Planning (IRP).
CPUC Energy Division (Feb. 2025) Draft 2025 Inputs and Assumptions for the 2024-2026 IRP Cycle.

[6] E3 (2025) Resolve RV - DCPP Extension.xlsx.
E3 (2025) Resolve RV - Least Cost Comparison.xlsx.
E3 (2025) Resolve RV - Proposed Base Case.xlsx.

[7] CPUC Energy Division (Sept. 2025). 26-27 Transmission Planning Process RESOLVE Modeling Results (Updated).

[8] California's electricity system is a mix of public and private ownership and different governing authorities. The focus of the CPUC's IRP RESOLVE modeling is developing portfolios of generation to serve the 80% of California load for which the California Independent System Operator (CAISO) is the balancing authority. This also roughly corresponds to the electric load in the territories of the three largest investor-owned utilities which the CPUC regulates, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDGE).

Table 1: Cumulative Nameplate Capacity (GW) of New Resources in the Least-Cost Case.

Resource Type	2026	2028	2031	2036	2041	2045
Geothermal	0.1	0.4	1.2	3.4	3.4	4.0
Geothermal (Enhanced)				1.8	1.8	1.8
In-State Wind	0.3	0.8	2.0	2.6	4.8	7.7
Out-of-State Wind	1.4	2.9	5.5	8.8	19.0	19.0
Offshore Wind				0.0	0.0	0.0
Solar	4.0	15.0	35.2	47.3	56.2	71.5
Li-ion Battery (4-hr)	3.9	6.7	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	0.2	1.0	10.4	14.4	14.4	21.1
Location Constrained Storage (12-hr)			1.6	5.4	5.4	5.4
Generic Long Duration Storage (24-hr)				0.0	0.0	0.0
Existing Natural Gas Capacity	(1.3)	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)

Source: E3 (2025) Resolve RV - Least Cost Comparison.xlsx.

defining difference between the three portfolios is the cost.[9] I will first contrast the cost of the DCPP Case against that of the so-called Least-Cost Case. I will then also contrast the cost of the DCPP Case against that of the Base Case.[10]

3.1 DCPP Case Contrasted with the Least-Cost Case

While SB 846 authorized up to a 5-year extension to October 31, 2029 for Unit 1 and October 31, 2030 for Unit 2, it simultaneously required that the Integrated Resource Plan assume retirement in 2025. This misalignment has state authorities attempting to meet future load at lowest cost while diligently procuring replacement capacity for DCPP even as the plant continues in operation. Therefore, when the CPUC describes this as the Least-Cost Case, it means within the bounds set by the legislature, among other things, taking closure of DCPP as given. As the modeling shows, extending the life of DCPP lowers the system cost below the Least-Cost Case.

3.1.1 Portfolio Changes

When DCPP is excluded as a resource, as it is in the Least-Cost Case, the RESOLVE model identifies one set of resources needed to serve forecasted load throughout the year and to meet the reliability and policy constraints, including the state's greenhouse gas emission targets. When DCPP is included as a resource, the RESOLVE model chooses a different set of resources. Including DCPP makes it easier to meet hourly load without as much new investment. Including DCPP also makes it easier to meet the planning reserve margin. Finally, since DCPP's generation is all carbon-free, including the plant also makes it easier to meet the state's greenhouse gas emissions targets. Therefore, the DCPP Case portfolio reduces or delays investments in capacity of a number of other technologies which would otherwise increase system costs.

Table 1 shows the cumulative nameplate capacity of new resources in the Least-Cost Case portfolio at key years from 2026 through 2045. Table 2 shows the same information for the DCPP Case portfolio. Table 3 and Figure 2 show the differences between the two, which are:

- 1.3 GW of existing natural gas capacity is displaced;

[9]With much of the system being legacy assets, and with significant investments being mandated under various policies, the RESOLVE modeling only chooses a fraction of total system assets and therefore costs. In the earliest year of the RESOLVE model Base Case run, 2026, the optimized costs only account for 13% of the total system costs for the Base Case portfolio. In the latest year, 2045, they still only account for 29%–see the 'Costs' page in E3 (2025) Resolve RV - Proposed Base Case.xlsx.

[10]These contrasts are comparable to the exercise contained in Chapter 1 of the 2021 joint Stanford-MIT study on Diablo Canyon

Table 2: Cumulative Nameplate Capacity (GW) of New Resources in the DCPP Case.

Resource Type	2026	2028	2031	2036	2041	2045
Geothermal	0.1	0.1	1.2	3.4	3.4	3.4
Geothermal (Enhanced)				1.8	1.8	1.8
In-State Wind	0.1	0.8	2.3	2.7	5.6	8.3
Out-of-State Wind	0.5	2.9	5.5	7.0	18.0	19.0
Offshore Wind						
Solar	2.8	15.0	27.1	41.8	49.5	65.9
Li-ion Battery (4-hr)	3.9	6.7	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	0.2	1.0	5.9	11.8	11.8	18.3
Location Constrained Storage (12-hr)			1.6	5.4	5.4	5.4
Generic Long Duration Storage (24-hr)						
Existing Natural Gas Capacity	(3.1)	(3.1)	(3.1)	(3.1)	(3.1)	(3.1)

Source: E3 (2025) Resolve RV - DCPP Extension.xlsx.

Table 3: Difference in Cumulative Nameplate Capacity (GW) of New Resources, DCPP Case Minus Least-Cost Case.

Resource Type	2026	2028	2031	2036	2041	2045
Geothermal	(0.0)	(0.3)	0.0	0.0	0.0	(0.6)
Geothermal (Enhanced)				(0.1)	(0.1)	(0.1)
In-State Wind	(0.2)	(0.0)	0.3	0.1	0.8	0.6
Out-of-State Wind	(0.9)	0.0	0.0	(1.7)	(1.0)	0.0
Offshore Wind				0.0	0.0	0.0
Solar	(1.2)	0.0	(8.1)	(5.5)	(6.7)	(5.5)
Li-ion Battery (4-hr)	0.0	0.0	0.0	0.0	(0.0)	(0.0)
Li-ion Battery (8-hr)	0.0	0.0	(4.4)	(2.6)	(2.6)	(2.9)
Location Constrained Storage (12-hr)			0.0	0.0	0.0	0.0
Generic Long Duration Storage (24-hr)			0.0	0.0	0.0	0.0
Existing Natural Gas Capacity	(1.8)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)

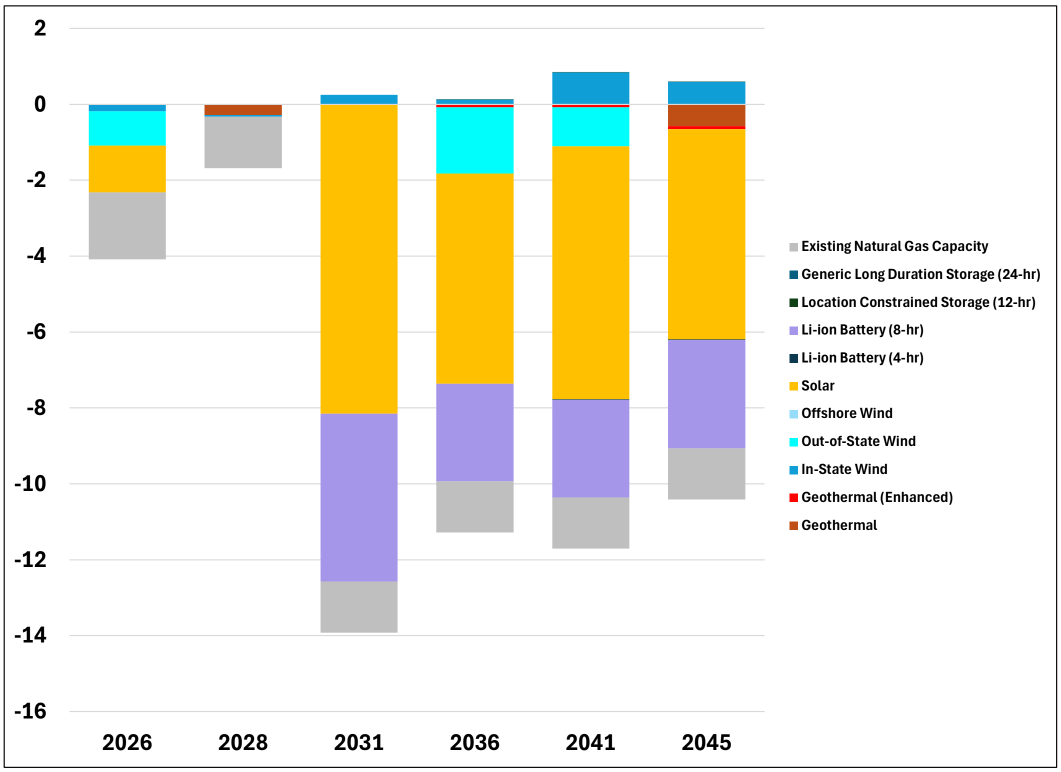

Figure 2: Difference in Cumulative Nameplate Capacity (GW) of New Resources, DCPP Case Minus Least-Cost Case.

Table 4: Difference in Annual Generation (TWh) of Resources, DCPP Case Minus Least-Cost Case.

Resource Type	2026	2028	2031	2036	2041	2045
Nuclear	18.1	18.1	18.1	18.1	18.1	18.1
Geothermal	(0.3)	(2.3)	0.7	3.7	3.6	3.1
Geothermal (Enhanced)				1.1	1.7	0.6
In-State Wind	(1.3)	(0.6)	0.5	0.7	0.1	0.8
Out-of-State Wind	(3.1)	0.0	1.2	2.3	10.0	7.9
Offshore Wind				(9.9)	(16.5)	(16.0)
Solar	(6.8)	(8.3)	(22.9)	(18.4)	(18.2)	(14.9)
Li-ion Battery (4-hr)	(0.0)	0.1	0.0	(0.0)	0.4	(0.0)
Li-ion Battery (8-hr)	0.0	(0.0)	1.7	0.5	0.4	0.1
Location Constrained Storage (12-hr)			0.0	0.2	(0.6)	(0.1)
Generic Long Duration Storage (24-hr)			0.0	0.5	0.5	0.5
Existing Natural Gas Capacity	(9.0)	(6.6)	(0.6)	(1.1)	(1.7)	(0.6)
Other	0.0	(1.0)	(0.3)	0.0	(0.2)	(0.1)
Net Imports	2.4	0.5	1.5	2.2	2.4	0.6
Total	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)

Source: E3 (2025) Resolve RV - Least Cost Comparison.xlsx and E3 (2025) Resolve RV - DCPP Extension.xlsx.

- California's solar and storage buildout is shifted out to later years, and as of 2045, there is 5.5 GW less solar capacity installed and 2.9 GW less of 8-hour batteries;
- geothermal capacity by 2045 is decreased by 0.6 GW;
- out-of-state wind capacity growth is delayed, and in-state wind capacity by 2045 is increased by 0.6 GW.

In addition to these, there are some changes in the set of transmission upgrades. Additional upgrades totaling 76 MW of capacity are made across 2 lines, and avoided upgrades totaling more than 2.4 GW of capacity occur across 5 other lines.

3.1.2 Changes to Generation Dispatch

Table 4 shows the differences in the generation dispatch of the various types of resources between the two runs. The top row of the table shows the 18 TWh of generation from the Diablo Canyon nuclear power plant. The remaining rows show how this is offset by reductions from various combinations of resources in the different years. The two major offsetting sources are reductions in solar generation and in natural gas generation. There are also some reductions in wind generation in some years. We also see some increases in storage. However, storage is not a source of generation, so the apparent increased generation from storage is avoided losses due to lower utilization. The table also shows an increased reliance on imports.

Even as we note these differences, it is useful to keep them in perspective. In both the DCPP Case and the Least-Cost Case, California continues to massively expand renewable generation. Figure 3 shows annual generation and import by resource type in the modeled years for the DCPP Case. By 2045, solar generation accounts for more than 50% of total generation, and generation from renewables accounts for almost 95%. Generation from Diablo Canyon–which appears in the beige band near the bottom of each column–accounts for just less than 4% of total generation. Its displacement of some solar generation is a change on the margin of a still necessary large scale investment in solar, storage and other renewables.

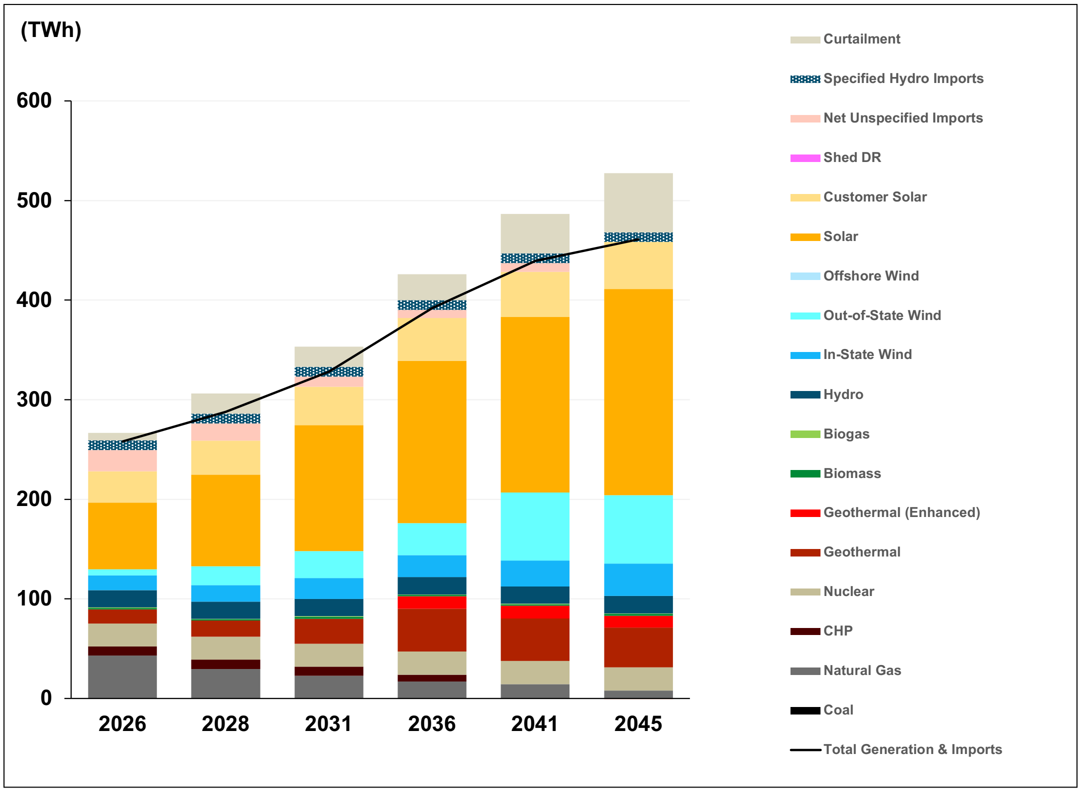

Figure 3: Annual Generation and Imports by Resource Type, in the DCPP Case.

Source: E3 (2025) Resolve RV - DCPP Extension.xlsx.

Table 5: Cost Savings ($ million) from Continued Operation of DCPP Relative to the Least-Cost Case by Resource Type.

	Resource Type	2026	2028	2031	2036	2041	2045
[1]	Nuclear	1,198	1,198	1,198	1,198	1,198	1,198
[2]	Geothermal	(5)	(206)	(9)	(7)	(7)	(543)
[3]	Geothermal (Enhanced)	0	0	0	(73)	(73)	(73)
[4]	In-State Wind	(25)	(0)	(0)	(13)	(5)	(1)
[5]	Out-of-State Wind	(195)	(2)	(2)	(610)	(309)	(26)
[6]	Offshore Wind	0	0	0	0	0	0
[7]	Solar	(138)	(38)	(1,094)	(798)	(917)	(758)
[8]	Li-ion Battery (4-hr)	0	(0)	(0)	(0)	(3)	(3)
[9]	Li-ion Battery (8-hr)	(0)	0	(988)	(604)	(604)	(663)
[10]	Location Constrained Storage (12-hr)	(0)	(0)	0	2	2	2
[11]	Generic Long Duration Storage (24-hr)	0	0	0	0	0	0
[12]	Existing Natural Gas Capacity	(560)	(481)	(129)	(144)	(180)	(185)
[13]	Other Generation	1	(150)	(56)	1	(93)	(10)
[14]	Transmission	0	0	(0)	(0)	(134)	(375)
[15]	Market Purch less Revs plus Carbon	(163)	(941)	164	157	57	190
[16]	Total	113	(618)	(917)	(892)	(1,069)	(1,245)
[17]	Present Value Factors, 2026-2045	1.339	2.026	2.760	2.797	2.003	5.281
[18]	Present Value	151	(1,252)	(2,530)	(2,496)	(2,142)	(6,576)
[19]	Total PV, 2026-2045	(14,845)					
[20]	Present Value Factors, 2031-2045	0.000	0.000	2.001	2.797	2.003	0.943
[21]	Present Value	0	0	(1,834)	(2,496)	(2,142)	(1,175)
[22]	Total PV, 2031-2045	(7,647)					

Source: E3 (2025) Resolve RV - Least Cost Comparison.xlsx and E3 (2025) Resolve RV - DCPP Extension.xlsx.

3.1.3 Savings

Table 5 translates the portfolio and dispatch changes into monetary savings across the different resources. In the first modeled year, 2026, the costs for Diablo are slightly higher than the savings on other resources, so we see in row [16] the total costs initially rise by $113 million. However, this relationship reverses in the other modeled years. In 2028 the total costs fall significantly and the savings are $618 million. By 2045, the savings rise to $1.245 billion.

3.1.4 Present Values

To sensibly add together the savings from different years, a present valuation is applied using a discount rate. The CPUC used a real discount rate of 5%, and calculated a present value factor for each of the modeled years as shown in row [17] of Table 5. Row [18] calculates the present value of the savings for each modeled year. The total present value of savings is $14.845 billion.

The CPUC's RESOLVE modeling covers the years 2026-2045, consistent with its legislative mandate to assume DCPP had been shut down in 2025. However, in fact, DCPP has already had its operation extended to 2030. For the purpose of this Commentary, we want to know the cost savings for a *further* extension of operations from 2031 to 2045. Accordingly, this analysis calculates a revised set of present value factors to reflect this different time window. These are shown in row [20] of Table 5. For example, the present value factors for 2026 and 2028 are set equal to zero. This analysis also reduced the present value factors for 2031 and 2045, as explained momentarily. The revised Total Present Value of savings for the window 2031-2045 is $7.647 billion, or just over $500 million per year.

Table 6: Detailed Calculation of the Annual Savings and Total Present Value ($ millions).

	Savings				PV	Present Value	
Year	Modeled	Interpolated	Total	Revised	Factor	Total	Revised
2026	113		113	0	0.907	102	0
2027		(253)	(253)	0	0.864	(218)	0
2028	(618)		(618)	0	0.823	(509)	0
2029		(718)	(718)	0	0.784	(562)	0
2030		(817)	(817)	0	0.746	(610)	0
2031	(917)		(917)	(917)	0.711	(651)	(651)
2032		(912)	(912)	(912)	0.677	(617)	(617)
2033		(907)	(907)	(907)	0.645	(585)	(585)
2034		(902)	(902)	(902)	0.614	(554)	(554)
2035		(897)	(897)	(897)	0.585	(525)	(525)
2036	(892)		(892)	(892)	0.557	(497)	(497)
2037		(928)	(928)	(928)	0.530	(492)	(492)
2038		(963)	(963)	(963)	0.505	(486)	(486)
2039		(998)	(998)	(998)	0.481	(480)	(480)
2040		(1,034)	(1,034)	(1,034)	0.458	(474)	(474)
2041	(1,069)		(1,069)	(1,069)	0.436	(466)	(466)
2042		(1,113)	(1,113)	(1,113)	0.416	(463)	(463)
2043		(1,157)	(1,157)	(1,157)	0.396	(458)	(458)
2044		(1,201)	(1,201)	(1,201)	0.377	(453)	(453)
2045	(1,245)		(1,245)	(1,245)	0.359	(447)	(447)
2046-2064		(1,245)	(1,245)	0	4.338	(5,402)	0
Total						(14,845)	(7,647)

Table 6 helps clarify how the RESOLVE model calculated the present value factors, and explains the principles behind the revised calculation. The second column shows the savings calculated for the modeled years: 2026, 2028, 2031, 2036, 2041, and 2045. For the non-modeled years, savings are assumed to be interpolated from the modeled year as shown in the third column. So, the interpolated savings for 2027 is calculated as 50% of the savings for 2026 and 50% of the savings for 2028. The fourth column shows the total savings, whether modeled or interpolated. The fifth column shows the revised savings, which zeroed out the savings for 2026-2030. The sixth column shows the annual present value factor, which can be readily calculated from the 5% discount rate using the familiar formula. The present values shown in columns seven and eight equal the savings, whether total or revised, multiplied times the present value factor.

Table 5 only shows present factors for the modeled years, whereas Table 6 implements the present value for both modeled and interpolated year. The two tables yield the exact same total present values, both for the longer window of 2026-2045 and for the shorter window of 2030-2045. This clarifies that the present value factors shown in Table 5 were calculated to capture the values from the interpolated years.[11]

Near the bottom of Table 6 there is a row for the nineteen years 2046-2064. The RESOLVE model extends its valuation of savings beyond the final model year of 2045. It calculates a terminal value for 2045 assuming the savings continue for another nineteen years to 2064. That is why in Table 5 the present value factor for 2045 is so large. However, in this exercise, it is assumed that operations at Diablo Canyon are extended only to 2045, and not beyond.Therefore, in addition to zeroing out the savings for 2026-2030, this analysis has also zeroed out the contribution to the terminal value from years 2046-2064. Accordingly, the revised present value factor for 2045 shown in Table 5 is much smaller.

Table 7 provides an alternative breakdown of changes in system cost into 4 categories:

- $8.445 billion in net avoided and delayed investment and fixed operating and maintenance costs due to changes in the portfolio of generation assets;

[11] See also the documentation for RESOLVE at https://docs.ethree.com/projects/resolve/en/latest/user_guide/settings.html

Table 7: Cost Savings from Life Extension of DCPP Relative to the Least-Cost Case by Type of Cost.

Source of Savings	NPV 2026-2045 $ million 2024$	NPV 2030-2045 $ million 2024$
Avoided and delayed investment and fixed O&M costs for generation assets	-11,950	-8,445
Avoided and delayed investment and fixed O&M costs for transmission upgrades	-2,250	-624
Reduced variable O&M and fuel costs for generation	-532	362
Reduced cost net of revenue from purchase and sale of electricity, incl. carbon costs	-112	1,061
Total	-14,845	-7,647

- $624 million in net avoided and delayed investment and fixed operating and maintenance costs due to changes in the portfolio of transmission upgrades;
- $362 million in additional variable operating and maintenance costs, as well as net reduction to the fuel costs, as a result of the different dispatch of the new versus the old portfolio of generation assets; and
- $1.061 billion in added net costs from market purchases and sales of electricity, inclusive of carbon costs.

3.2 DCPP Case Contrasted with the Base Case

In this subsection, the analysis shifts from measuring the cost savings relative to the Least-Cost Case to measuring it relative to the Base Case.

3.2.1 Portfolio Changes

Table 8 shows the new nameplate capacity of various newly installed technologies at key years from 2026 through 2045 for the Base Case portfolio. A distinguishing feature of the Base Case portfolio is the inclusion of offshore windfarm capacity at Morro Bay starting in 2036 and at Humboldt Bay starting in 2041. These are very expensive resources and therefore do not appear in the Least-Cost portfolio. Similarly, the Base Case portfolio includes a small amount of 24-hour duration storage which is also expensive and not included in the CPUC Least-Cost portfolio. These options are elements of the procurement amounts considered in CPUC Docket 24-08-064 pursuant to legislation AB 1373, albeit at extended online dates.[12] Offsetting these additional resources, the resulting optimized investments in the Base Case portfolio includes less out-of-state wind, less solar, and less 8-hour battery storage capacity relative to the Least-Cost Case.

Table 9 and Figure 4 show the differences between the Base Case portfolio of new resources and the DCPP portfolio, the most significant of which are:

- 4.5 GW of offshore wind capacity is not built;
- California's solar and storage buildout is shifted out to later years, and as of 2045, there is 2.6 GW less solar capacity installed and 0.8 GW less of 8-hour batteries and long-duration storage;
- 1.4 GW of existing natural gas capacity is displaced.

[12] CPUC Energy Division (Sept. 2025). 26-27 Transmission Planning Process RESOLVE Modeling Results (Updated), p. 7.

Table 8: Cumulative Nameplate Capacity (GW) of New Resources in the Base Case.

Resource Type	2026	2028	2031	2036	2041	2045
Geothermal	0.1	0.3	1.2	3.4	3.4	3.4
Geothermal (Enhanced)				1.7	1.7	1.7
In-State Wind	0.3	0.8	2.0	2.6	4.8	7.7
Out-of-State Wind	1.4	2.9	5.5	7.0	17.0	19.0
Offshore Wind				2.9	4.5	4.5
Solar	4.0	15.0	35.9	47.5	53.7	68.5
Li-ion Battery (4-hr)	3.9	6.7	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	0.2	1.0	10.0	13.2	13.2	18.6
Location Constrained Storage (12-hr)			1.6	5.4	5.4	5.4
Generic Long Duration Storage (24-hr)				0.5	0.5	0.5
Existing Natural Gas Capacity	(1.3)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)

Source: E3 (2025) Resolve RV - Proposed Base Case.xlsx.

Table 9: Difference in Cumulative Nameplate Capacity (GW) of New Resources,
DCPP Extension Case Minus Base Case.

Resource Type	2026	2028	2031	2036	2041	2045
Geothermal	(0.0)	(0.2)	0.0	0.0	0.0	0.0
Geothermal (Enhanced)				0.0	0.0	0.0
In-State Wind	(0.2)	0.0	0.2	0.2	0.9	0.6
Out-of-State Wind	(0.9)	0.0	0.0	0.0	1.0	0.0
Offshore Wind				(2.9)	(4.5)	(4.5)
Solar	(1.2)	0.0	(8.8)	(5.7)	(4.2)	(2.5)
Li-ion Battery (4-hr)	0.0	0.0	0.0	0.0	0.0	0.0
Li-ion Battery (8-hr)	0.0	0.0	(4.1)	(1.4)	(1.4)	(0.3)
Location Constrained Storage (12-hr)			0.0	(0.0)	(0.0)	(0.0)
Generic Long Duration Storage (24-hr)			0.0	(0.5)	(0.5)	(0.5)
Existing Natural Gas Capacity	(1.7)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)

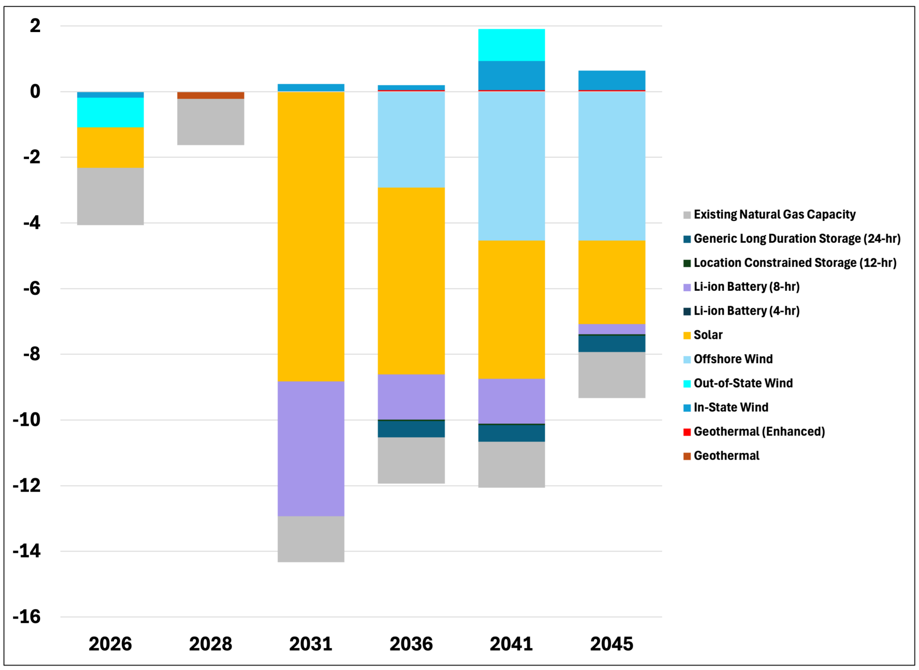

Figure 4: Difference in Cumulative Nameplate Capacity (GW) of New Resources, DCPP Extension Case Minus Base Case.

Table 10: Difference in Annual Generation (TWh) of Resources,
Diablo Canyon Extension Case Minus Base Case.

Resource Type	2026	2028	2031	2036	2041	2045
Nuclear	18.1	18.1	18.1	18.1	18.1	18.1
Geothermal	(0.3)	(2.3)	0.7	3.7	3.6	3.1
Geothermal (Enhanced)				1.1	1.7	0.6
In-State Wind	(1.3)	(0.6)	0.5	0.7	0.1	0.8
Out-of-State Wind	(3.1)	0.0	1.2	2.3	10.0	7.9
Offshore Wind				(9.9)	(16.5)	(16.0)
Solar	(6.8)	(8.3)	(22.9)	(18.4)	(18.2)	(14.9)
Li-ion Battery (4-hr)	(0.0)	0.1	0.0	(0.0)	0.4	(0.0)
Li-ion Battery (8-hr)	0.0	(0.0)	1.7	0.5	0.4	0.1
Location Constrained Storage (12-hr)			0.0	0.2	(0.6)	(0.1)
Generic Long Duration Storage (24-hr)			0.0	0.5	0.5	0.5
Existing Natural Gas Capacity	(9.0)	(6.6)	(0.6)	(1.1)	(1.7)	(0.6)
Other	0.0	(1.0)	(0.3)	0.0	(0.2)	(0.1)
Net Imports	2.4	0.5	1.5	2.2	2.4	0.6
Total	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)

A very small additional amount of Enhanced Geothermal is built as well as a small additional amount of In-State wind. The timing of some Out-of-State wind capacity shifts later, as does the timing of traditional geothermal and a small amount of In-State wind.

In addition to these changes in the portfolio of generation and storage capacity, there are some changes in the set of transmission upgrades. Additional upgrades totaling 2.2 GW of capacity are made across 4 lines, and avoided upgrades totaling more than 4.8 GW of capacity occur across 4 other lines.

3.2.2 Changes to Generation Dispatch

Table 10 shows the differences in the generation dispatch of the various types of resources between the two runs. The top of the table shows the 18 TWh of generation from the Diablo Canyon nuclear power plant. This is offset by reductions from various combinations of resources in the different years. Initially, in 2026 we see less generation from natural gas, solar, wind and geothermal. Later, in 2036, 2041 and 2045, the two main resources generating less are offshore wind and solar. Indeed, there are other resources increasing their generation, such as geothermal and in-state and out-of-state wind. There are also some avoided losses due to lower utilization of storage. The availability of Diablo Canyon's generation, and the accompanying decision not to procure offshore wind, relaxes a variety of constraints and creates a shuffling of generation resources beyond a simple one-for-one displacement of Diablo's generation.

Again, these contrasts should be appreciated in context: both the Base Case and the DCPP Case involve a massive expansion of renewable generation. The differences are on the margin, which nevertheless produce significant savings.

3.2.3 Savings

Table 11 translates the portfolio and dispatch changes into monetary savings across the different resources for the Base Case comparison. Just as in the comparison against the Least-Cost Case, in the first modeled year, 2026, the costs for Diablo are slightly higher than the savings on other resources, so we see in row [16] that the total costs rise by $113 million, but this relationship reverses in the other modeled years. In the years 2036, 2041 and 2045, the savings average more than $3 billion per year, primarily by avoiding expensive offshore wind investments.

Table 11: Cost Savings from Life Extension of Diablo Canyon NPP Relative to the Proposed Base Case by Resource Type.

	Resource Type	2026	2028	2031	2036	2041	2045
[1]	Nuclear	1,198	1,198	1,198	1,198	1,198	1,198
[2]	Geothermal	(5)	(162)	(6)	(6)	(6)	(6)
[3]	Geothermal (Enhanced)	0	0	0	46	46	46
[4]	In-State Wind	(25)	(0)	39	26	139	96
[5]	Out-of-State Wind	(195)	(2)	(2)	(2)	274	5
[6]	Offshore Wind	0	0	0	(2,592)	(3,805)	(3,805)
[7]	Solar	(139)	(39)	(1,197)	(841)	(686)	(526)
[8]	Li-ion Battery (4-hr)	0	(0)	(0)	(0)	(0)	0
[9]	Li-ion Battery (8-hr)	(0)	0	(919)	(354)	(354)	(92)
[10]	Location Constrained Storage (12-hr)	(0)	(0)	(0)	(8)	(8)	(8)
[11]	Generic Long Duration Storage (24-hr)	0	0	0	(232)	(232)	(232)
[12]	Existing Natural Gas Capacity	(560)	(500)	(111)	(158)	(231)	(189)
[13]	Other Generation	1	(209)	(98)	1	(36)	(20)
[14]	Transmission	0	0	(0)	(6)	122	(110)
[15]	Market Purch less Revs plus Carbon	(163)	(917)	207	92	173	(57)
[16]	Total	113	(631)	(888)	(2,835)	(3,406)	(3,698)
[17]	Present Value Factors, 2026-2045	1.339	2.026	2.760	2.797	2.003	5.281
[18]	Present Value	152	(1,277)	(2,451)	(7,931)	(6,823)	(19,528)
[19]	Total PV, 2026-2045	(37,859)					
[20]	Present Value Factors, 2031-2045	0.000	0.000	2.001	2.797	2.003	0.943
[21]	Present Value	0	0	(1,777)	(7,931)	(6,823)	(3,488)
[22]	Total PV, 2031-2045	(20,019)					

3.2.4 Present Values

The bottom two panels of Table 11 show the present value of savings. First, rows [17]-[19] show the present value as calculated by the CPUC for the years 2026-2045, coming to $37.859 billion. Second, rows [20]-[22] show the present value for the shorter window of 2030-2045, coming to $20.019 billion, or more than $1.3 billion per year.

4 The Cost of Operating Diablo Canyon

Of course the value of the RESOLVE model runs depends upon the quality of the inputs. A key input is the cost of operating Diablo Canyon. There are two cost inputs, (i) the fixed O&M cost of operating the plants, and (ii) the fuel cost per unit of generation. This analysis examines these two inputs in turn.

4.1 Fixed O&M Cost

The CPUC staff determined an annual fixed operating and maintenance cost of $1.054 billion or $450/kW-yr, exclusive of fuel cost "based on PG&E testimony on the costs of extending and operating DCPP through 2030".[13]

This analysis benchmarks this estimate against two sources of data. The first source is PG&E's testimony on forecasted costs for DCPP. The second source is the historical costs of operating and maintaining DCPP found in PG&E's Annual Report to the Federal Energy Regulatory Commission (FERC) known as Form 1.

4.1.1 PG&E Forecasted O&M Costs

Table 12 reproduces data provided by PG&E in July 2025 as testimony before the CPUC. A number of ideosyncracies of the proceedings must be understood in order to use the data in the table. First, row [6] is the A&G Allocation (Administrative and General). These are overhead costs which are allocated. They do not appear before 2027 because an A&G allocation charge had already been filed for those early years under a different regulatory proceeding, and so no new charge was estimated for the life extension. Second, the figures in 2030 are substantially smaller than the prior year because one of the two reactor units is retired and not operating at all in 2030. Indeed, the figures in 2029 reflect one unit operating the full year and one operating for ten months of the year. Therefore, this analysis focuses on the years 2027-2029, which contain substantially all of the annual costs of a fully operational plant. However, in calculating an annual average, this analysis adjusts the 2029 figure upwards to account for the missing two months of operation of one of the two reactor units. Third, and finally, the numbers are reported in nominal dollars based on projected inflation factors. Different inflation factors are used for different line items. For example, PG&E's contract with its unions includes a 3.5% annual escalation, which enters into the labor rates for the work included in the table. In contrast, the fuel cost, which is already contracted, is amortized straight line and therefore constant. In row [11] I show the index PG&E used for row [5].

Unfortunately, the full set of factors used for all lines is not available. Therefore, this analysis uses the index in row [11] as a rough benchmark with which to deflate row [10] to 2024$ as shown in row [12]. The resulting average annual expenses for the three years 2027-2029, exclusive of fuel, is $991 million, which is slightly below the CPUC staff's input to the RESOLVE model. This validates the input used in the RESOLVE model.

[13] CPUC Energy Division (Sept. 2025). 26-27 Transmission Planning Process RESOLVE Modeling Results (Updated), p. 94.

Table 12: DCPP 2023–2030 Extended Operations Costs, $ millions.

	2023 A	2024 A	2025 A	2026 F	2027 F	2028 F	2029 F	2030 F	2027-2029 Weighted Average
DCPP Direct Costs									
[1] Expense O&M and Projects	17,025	63,586	417,724	563,934	551,866	585,304	429,956	338,607	
[2] Nuclear Fuel Expense Amortization			134,002	135,734	135,734	135,734	135,734	135,734	
[3] Spent Nuclear Fuel Management				(12,587)	(9,154)	(18,287)	(21,405)	(1,796)	
Statutory Fees									
[4] Fixed Payment		7,869	66,479	113,997	116,467	118,741	110,894	51,478	
[5] Volumetric Performance Fee		19,467	147,638	266,567	273,580	265,332	276,827	113,736	
Results of Operations Items									
[6] A&G Allocation					153,407	149,524	122,422	54,123	
[7] Taxes	1,928	5,211	17,573	23,659	24,431	26,939	21,955	18,782	
[8] Revenue Fees and Uncollectables	271	787	8,823	5,948	5,183	6,223	2,463	1,412	
[9] Debt Financing Costs		173	2,925	2,918					
[10] Total, excl Fuel Exp Amort					1,115,780	1,133,776	943,112		1,095,660
[11] Index, S&P Q2 2025 capital gen esc		1.000	0.941	0.917	0.910	0.906	0.899		
[12] Total, excl Fuel Exp Amort, 2024$					1,015,404	1,027,045	847,948		991,731

Source: Annual figures in rows [1]-[9] are from Table 1-1 in PG&E (July 2025). Prepared Testimony, (Amending Testimony Served on March 18, 2025, Diablo Canyon Power Plant 2026 Cost Recovery Forecast to Support Operations as Directed by the State to Ensure Electric Reliability and to Reduce Greenhouse Gas Emissions for All California. CPUC 25-03-015.

4.1.2 DCPP Historical O&M Costs

Table 13 shows the historical cost of operations at the Diablo Canyon nuclear plant as reported by PG&E on its annual FERC Form 1 filing. The first five rows of the table show DCPP's historical cost as reported in the nominal dollars of the reporting year. Row [1] is the total production expenses, which does not include capital expenditures. Row [2] shows the additions to plant, which is the result of capital expenditures. Row [3] is the total. Since the CPUC broke their cost inputs into a fixed annual expense exclusive of fuel and a fuel expense, this analysis subtracts the fuel expense shown in row [4] to obtain a total cost exclusive of fuel shown in row [5]. To report these costs in a common currency of 2024 dollars, row [6] shows the implicit price deflator calculated by the U.S. Bureau of Economic Analysis and row [7] shows the resulting inflation adjustment for each year. Rows [8]-[10] restate the cost figures denominated in a common currency of 2024 dollars.

The nine year average cost of $613 is substantially below the CPUC's assumption for its RESOLVE modeling. Two factors should be taken into consideration. First, these data do not include certain central office overhead expense items. From the PG&E testimony, that could potentially add up to 16% on top of the reported figure, bringing it to $711 million, which is still substantially below. Second, the capital expenditures (additions to plant) in recent years have been unusually low. This may reflect that the plant was ostensibly coming to the end of its operating life and so large costs needed for a longer life would not be incurred. Still, looking back to earlier years when there were larger capital expenditures, the historical costs exclusive of fuel never reached $800 million. This second benchmarking also validates the input to the RESOLVE model. If anything it suggests it may be conservative.

4.2 Fuel Cost

Table 14 shows how data on generation and nuclear fuel costs evolve in the RESOLVE model across the modeled years. Row [1] is generation, which is constant. Row [2] is the heat rate–the unit of heat from the fuel per unit of electricity–which is also constant. Therefore, the fuel input each year–measured in units of heat–is also constant. Row [4] shows the annual expenditures on fuel, which decline very gradually. Therefore, the unit cost of fuel is declining. Row [5] shows the implied unit cost measured in dollars per

Table 13: DCPP Historical Cost of Operations, 2016-2024.

Historical Cost ($ million)		2016	2017	2018	2019	2020	2021	2022	2023	2024	9 yr Avg
[1] Total Production Expenses		509	498	532	612	522	586	551	461	569	
[2] Additions to Nuclear Plant		178	198	148	138	63	62	173	9	32	
[3] Total Cost		687	696	680	750	586	648	724	470	601	
[4] Fuel		128	125	129	114	111	122	111	106	143	
[5] Total Cost, excl Fuel		559	571	551	637	475	526	613	364	458	
[6] BEA Implicit Price Deflator		98	100	102	104	105	110	118	122	125	
[7] Inflation Factor (2024=1.0)		1.277	1.254	1.226	1.206	1.190	1.138	1.063	1.025	1.000	
[8] Total Cost	($2024)	877	873	834	905	697	738	769	482	601	753
[9] Fuel	($2024)	163	157	158	137	132	139	118	109	143	139
[10] Total Cost, excl Fuel	($2024)	714	716	676	768	565	599	651	373	458	613

Sources and Notes:

[1] FERC Form 1, Page 402, Total Production Expenses.
[2] FERC Form 1, Page 120, Total Additions to Electric Plant in Service.
[3] = [1]+[2].
[4] FERC Form 1, Page 402, Fuel Expense.
[5] = [3]-[4].
[6] US BEA, Table 1.1.9 Implicit Price Deflators for GDP. (2017=100)
[7] = [6,t=2024]/[6,t].
[8] = [3]*[7].
[9] = [4]*[7].
[10] = [5]*[7].

Table 14: Fuel Cost Inputs to the RESOLVE Model, Modeled Years 2026-2045, in 2024$

		2026	2028	2031	2036	2041	2045
[1] Generation	(TWh)	18.106	18.106	18.106	18.106	18.106	18.106
[2] Heat Rate	(MMBtu/MWh)	10.5	10.5	10.5	10.5	10.5	10.5
[3] Fuel Input	(MMBtu)	190.109	190.109	190.109	190.109	190.109	190.109
[4] Nuclear Fuel Cost	($ million)	144.802	144.776	144.735	144.668	144.603	144.549
[5] Unit Fuel Cost	($/MWh)	8.00	8.00	7.99	7.99	7.99	7.98
[6] Unit Fuel Cost	($/MMBtu)	0.7617	0.7615	0.7613	0.7610	0.7606	0.7603

Source: Rows [1]-[4] from E3 (2025) Resolve RV - DCPP Extension.xlsx.

Table 15: DCPP Forecasted Fuel Cost for Extended Operations, 2026-2030.

		2026	2027	2028	2029	2030	Sum 2026-2030
Nuclear Fuel Exp Amort	($ milllions)	113,997	116,467	118,741	110,894	51,478	511,577
Generation Forecast	(TWh)	18.224	18.288	17.329	17.652	7.068	78.562
Unit Cost	($/MWh)	6.26	6.37	6.85	6.28	7.28	6.51

Table 16: DCPP Historical Fuel Cost Statistics, 2016-2024.

		2016	2017	2018	2019	2020	2021	2022	2023	2024	9 yr Avg
Heat Rate	MMBtu/MWh	10.2	10.3	10.3	10.3	10.4	10.3	10.3	10.4	10.3	10.3
Cost of Fuel	$/MMBtu	0.657	0.674	0.682	0.680	0.653	0.712	0.611	0.576	0.753	
Inflation Factor		1.277	1.254	1.226	1.206	1.190	1.138	1.063	1.025	1.000	
Cost of Fuel	2024$/MMBtu	0.839	0.845	0.836	0.820	0.777	0.810	0.649	0.590	0.753	0.769

Source: FERC Form 1, Page 402, Production Expenses.

megawatt of electricity generated. Row [6] shows the implied unit cost measured in dollars per unit of heat input from the fuel which declines gradually towards $0.7603/MMBtu. [14]

4.2.1 PG&E Forecasted O&M Costs

Table 15 shows PG&E's forecasted fuel costs and forecasted generation for 2026-2030. The top row also appears in Table 12. The second row is the forecasted generation in each year. The third row expresses the fuel cost per unit of generation.

The fluctuating unit cost is a product of two factors. First, the fuel cost is amortized straight line over the life extension. Second, in years with a refueling outage, generation is reduced. Therefore, in these years the calculated unit cost increases. Third, in 2029 Unit 1 retires near the end of the year, which reduces generation and increases the calculated unit cost. Then, in 2030, when Unit 2 is the only unit operating, and it retires near the end of the year, generation is significantly reduced and the calculated unit cost rises dramatically. To abstract from these artificial fluctuations in the annual unit cost, this analysis totals all of the fuel expenditures for extended operation and totals all generation for extended operation, and calculates an overall average unit cost through extended operation. It is $6.51/MWh. This is markedly less than what is used in the RESOLVE modeling.

4.2.2 DCPP Historical Fuel Costs

Table 16 shows the comparable historical fuel data at the Diablo Canyon nuclear plant as reported by PG&E on its annual FERC Form 1 filing. The first row is the average heat rate, which on average has been slightly below the value used in the RESOLVE model. A lower heat rate is a more efficient thermal plant, so the RESOLVE model's is very slightly conservative as compared to the historical record. The second row is the average unit cost of fuel as reported. This analysis uses the inflation factor calculated in Table 13 to adjust these values to a common currency of 2024 dollars.[15] The average price has been only slightly higher than the $0.76/MMBtu used in the RESOLVE model runs. This validates this second input to the RESOLVE model.

[14] CPUC Energy Division (Sept. 2025). 26-27 Transmission Planning Process RESOLVE Modeling Results (Updated), p. 94, states a cost of $0.71/MMBtu. However, the model results I viewed contained the slightly higher numbers shown in the table.

[15] Nuclear fuel is generally purchased with long lead times, and the cost is amortized over the life of the fuel bundle–typically 4.5 years in this case. Therefore the reported cost level often lags short run dynamics in the uranium market.

5 Other Economic Considerations

5.1 Comparison of These CPUC-RESOLVE Results Against the Stanford/MIT 2021 Results

The 2021 Stanford/MIT studied the cost and benefits of continuing operation of DCPP past the 2024/2025 end of license dates to 2045.[16] The exercise was substantially similar in spirit to the exercise discussed in this Commentary: in one alternative, DCPP is closed, and a cost-efficient portfolio is chosen to meet forecasted load together with California policies on decarbonization, and in a second alternative the operating life of DCPP is extended, and an alternative cost-efficient portfolio is chosen to meet the balance of forecasted load together with California policies on decarbonization. Extending the commercial operation of DCPP had two main benefits.

First, in the near term, it accelerated the decarbonization of the electric grid: "The continued operation of Diablo Canyon would significantly reduce California's use of natural gas for electricity production from 2025 to 2035 by approximately 10.2 TWh per year. In doing so, Diablo Canyon would also reduce California carbon emissions by an average of 7 Mt CO2 a year from 2025-2035, corresponding to an 11% reduction in CO2 from the electricity sector relative to 2017 levels, for a cumulative total of 35 Mt CO2 from 2025-2030 alone."

Second, in both the near and long term, it would produce cost savings: "Maintaining Diablo Canyon to 2035 would also save $2.6 Billion in power system costs from 2025-2035. ... Over the longer term, [to 2045] ...keeping Diablo Canyon online would save the state $15-16 Billion."

The main difference between the 2021 Stanford/MIT study and the CPUC-RESOLVE is the policy counterfactual in the near term. In the long term, the policy target in both studies is a GHG emissions limit. However, in the near term, the policy target in the 2021 Stanford/MIT study was a renewable mandate, while in the CPUC-RESOLVE modeling it is a GHG emissions limit. Consequently, in the 2021 Stanford/MIT study continued operation of DCPP could produce GHG emission reductions additive to the renewable deployment, whereas in the CPUC-RESOLVE modeling emissions are nearly identical.[17] That leaves cost as the primary benefit of continued operation of DCPP.

The 2021 Stanford/MIT study and the CPUC-RESOLVE modeling make slightly different assumptions about the cost of technology options. As noted earlier, in most respects, the CPUC-RESOLVE modeling is also more granular. Nevertheless, the results relative to costs are generally quite consistent. The main effect of continuing operation of DCPP is to accelerate the displacement of natural gas generators and to delay some investments in solar and storage, with marginal effects on other technologies depending upon assumptions about California's procurements. In both studies, that is the source of the savings.

5.2 Continuing Operation at DCPP While Accelerating Decarbonization

Instead of allowing the continued operation of DCPP to delay investments in other low-carbon generation, the state could choose to maintain those procurements and use DCPP to accelerate decarbonization. The CPUC-RESOLVE modeling does not consider that option.

5.3 Baseload or Flexible

Historically, U.S. nuclear power plants have been operated as baseload generators, meaning they are operated constantly at full capacity except when they must be taken offline for refueling and/or maintenance. Since they are a very capital intensive asset as well as having a high share of fixed operating and maintenance costs, operating baseload amortizes the fixed costs over a larger volume of generation to produce the

[16] Aborn, Justin et al. (Nov. 2021). An Assessment of the Diablo Canyon Nuclear Plant for Zero-Carbon Electricity, Desalination, and Hydrogen Production. Tech. rep. See Chapter 1.

[17] While DCPP displaces some natural gas generation, which reduces those emissions, the modeled results include more imports with emissions so that the net change in emissions is minimal.

lowest per unit cost. Some people infer from this chosen duty cycle that nuclear power plants are technically incapable of adjusting their generation. This is an incorrect inference. In other countries, notably France, several nuclear power plants modulate their generation in response to the daily and weekly load cycles as well as to fluctuations in the hourly wholesale price of electricity. Executing this modulation requires planning and training, and there are specific constraints that must be attended to. The Diablo Canyon nuclear power plant's license recognizes its technical capability to modulate generation, although PG&E has not taken advantage of that technical possibility.

Some argue that a so-called baseload asset like DCPP is incompatible with high levels of renewable penetration on the grid, since the fluctuating renewable generation has to be accommodated by some combination of storage and net load-following dispatch of thermal generators. However, if we recognize the potential for a nuclear power plant to modulate its generation, then this supposed conflict is resolved.

The 2021 Stanford-MIT report on Diablo Canyon modeled a California grid with a high penetration of renewables, and explored the optimal dispatch of DCPP. We found that flexibility increased the value of DCPP.

The RESOLVE modeling of the DCPP case hard codes into its results the baseload operation of the plant. It does not entertain flexible operation. Nevertheless, extending the operation of DCPP produces savings for California. Or, conversely, eliminating DCPP from the portfolio because of its baseload characteristic would increase the cost of electricity to California.

In the future, PG&E, the CPUC and California should entertain the flexible operation of DCPP. Doing so could further increase the value of the plant and the savings it can provide to the state.

Contact.

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