PREPARED TESTIMONY OF
WILLIAM A. MONSEN

ADDRESSING COSTS OF THE DIABLO CANYON POWER PLANT

PUBLIC VERSION
REDACTED

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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DIRECT TESTIMONY OF WILLIAM A. MONSEN
ON BEHALF OF THE UTILITY REFORM NETWORK
ADDRESSING COSTS OF THE DIABLO CANYON POWER PLANT

I. Introduction and Summary of Findings and Recommendation

Q. Please state your name, position and business address.
A. My name is William A. Monsen. I am a Principal Consultant at MRW & Associates, LLC (MRW). My business address is 1736 Franklin Street, Suite 700, Oakland, California.

Q. Please describe you background, experience and expertise?
A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, energy consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including Arizona, Colorado, California, Nevada, New England, and Wisconsin. Prior to joining MRW, I worked at Pacific Gas and Electric Company (“PG&E”). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley, and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison.

Q. Have you previously testified as an expert witness?
A. Yes. I have previously testified before the California Public Utilities Commission (Commission) on behalf of TURN, the California Farm Bureau Federation, the City of San Diego, the City of Long Beach, Bear Mountain, Snow Summit, the Independent Energy Producers Association, the California Cogeneration Council, Duke Energy North America, the Alliance for Retail Energy Markets, the Center for Energy Efficiency and Renewable Technologies, the Local Governmental Commission Coalition, Clearwater Port, Commercial Energy, and The Vote Solar Initiative. I have also submitted testimony

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in proceedings before the Federal Energy Regulatory Commission as well as state utility commissions in Arizona, Colorado, Massachusetts, Oregon, and Nevada. I have also submitted expert reports in arbitration and court proceedings. Additional information about my qualifications is provided in Appendix 1.

Q. What is the purpose of your testimony in this proceeding?
A. My testimony reviews the forecasted costs of continued operation of the Diablo Canyon Power Plant (DCPP) based on information provided by Pacific Gas & Electric (PG&E) in Rulemaking (R.) 23-01-007 and other recent proceedings.¹

Q. How is your testimony organized?
A. My testimony consists of four sections and is organized as follows:

- Section I: Introduction and Summary of Findings and Recommendations.
- Section II: PG&E’s Proposed Costs for DCPP
- Section III: PG&E’s significant understatement of costs associated with continued operation of DCPP.
- Section IV: Brief conclusion to the testimony.

A. Summary of Findings and Recommendations

Q. Please summarize your findings and recommendations.
A. In this testimony, I make the following findings and recommendations on behalf of TURN:

1. PG&E’s Failure to Link Historic and Forecast Costs to Major Work Categories

**Concern:** PG&E provided both historic and forecast costs related to DCPP using categories adopted by the Electric Utility Cost Group (EUCG). In PG&E’s General Rate

Cases (GRCs), PG&E presents cost data using Major Work Categories (MWCs). Despite requests from TURN, PG&E refused to provide a useful cross-walk between the EUCG categories and MWCs even though PG&E does not intend to present cost data using EUCG categories in the future. PG&E’s refusal to provide transparent cost comparisons makes it very challenging to evaluate the reasonableness of their forecast.

**Recommendation:** The Commission should order PG&E to provide forecast data in this proceeding using the same MWCs that serve as the basis for reviews in both the General Rate Case and any future cost recovery proceeding. This approach would allow parties and the Commission to assess the reasonableness of PG&E’s forecasted costs as well as to compare and contrast PG&E’s forecasts across different proceedings.

2. **PG&E Fails to Link Historic and Forecast Costs to DCPP Results of Operations**

**Concern:** PG&E provided a very useful Results of Operation (RO) summary for DCPP in its most recent General Rate Case (GRC). This RO provides a clear, comprehensible summary of the costs and revenues related to DCPP under the current ratemaking paradigm. Parties generally have experience reviewing RO summaries. In its testimony in this proceeding, PG&E provided a completely different method of disaggregating costs that cannot easily be compared to historic or forecasted costs reviewed in any other Commission proceeding.

**Recommendation:** The Commission should order PG&E to provide a disaggregation of forecast costs that uses the same format as the RO summary in the GRC. This would provide the Commission and parties with a clear snapshot of the total forecasted costs and ratepayer obligations associated with the potentially new operating and ratemaking paradigm for DCPP during extended operations.
3. PG&E Fails to Include Numerous Costs of DCPP, Thereby Understating the Actual Costs of Extended Operation

Concern: PG&E ignores a number of costs that it will incur related to the continued operation of DCPP. PG&E acknowledged that a number of cost categories are excluded from its showing but refused to provide estimates for these line items. Because of PG&E’s refusal to include those costs in its estimates of the all-in costs of DCPP, PG&E significantly understates the true costs of continued operation of DCPP.

The following table summarizes whether certain costs identified in the DCPP RO were included in the historic costs (i.e., Table 1) or forecast costs (i.e., Table 2) presented in PG&E’s testimony:

**Table 1: Categories of Costs in DCPP RO Excluded from PG&E May 19th Testimony**

<table>
<thead>
<tr>
<th>Category</th>
<th>Excluded from Table 1 (Historic)</th>
<th>Excluded from Table 2 (Forecast)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Uncollectibles</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Administrative and General</td>
<td>Y/N</td>
<td>Y/N</td>
<td>Portion is in Capital line as capitalized A&amp;G. Contract A&amp;G is excluded</td>
</tr>
<tr>
<td>Franchise &amp; SFGR Tax Requirement</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Superfund Taxes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property Taxes</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Payroll Taxes</td>
<td>Y/N</td>
<td>Y/N</td>
<td>Payroll Taxes included in Support Services line; all other taxes excluded</td>
</tr>
<tr>
<td>Business Taxes</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Other Taxes</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>State Corporation Franchise Taxes</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Federal Income Taxes</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>Y</td>
<td>Y</td>
<td>During extended operations, PG&amp;E expects to expense all costs in the year they are incurred</td>
</tr>
<tr>
<td>Net for Return</td>
<td>Y</td>
<td>Y</td>
<td>PG&amp;E has not yet proposed to earn any return on capital or nuclear fuel during extended operations</td>
</tr>
</tbody>
</table>

Note that in the above table, a category that is denoted with a “Y” means that it was excluded from PG&E’s cost tables in this proceeding. As can be seen from the above table, there are a large number of line items from the DCPP RO that are not accounted for in the historic or forecast costs presented by PG&E in this proceeding. TURN conservatively estimates that the total of these excluded costs is approximately $3.79
billion from 2023-2030 (which would be incremental to PG&E’s estimate of $5.86 billion in costs over the same period).

In addition to the costs that have been identified in the DCPP RO that PG&E excluded from its cost estimates, it was unclear if PG&E also excluded certain other cost categories not specifically identified in the DCPP RO from the historic and forecast costs presented in its testimony. The following table summarizes those categories of costs:

Table 2: Categories of Other Costs Excluded from PG&E May 19th Testimony

<table>
<thead>
<tr>
<th>Category</th>
<th>Excluded from Table 1</th>
<th>Excluded from Table 2</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pensions and benefits</td>
<td>N</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Nuclear Property Insurance</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Nuclear Liability Insurance</td>
<td>N</td>
<td>N</td>
<td>Included in Support Services</td>
</tr>
<tr>
<td>Materials and Supplies Inventory</td>
<td>Y</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Mitigation Fees for SWCB to address entrainment</td>
<td>N</td>
<td>N</td>
<td>Included in Operations line</td>
</tr>
<tr>
<td>Refueling Outage Costs</td>
<td>N</td>
<td>N</td>
<td>Included In Outages</td>
</tr>
<tr>
<td>Employee Retention and Severance Payments</td>
<td>Y</td>
<td>Y</td>
<td>Will update in new application</td>
</tr>
<tr>
<td>Return, financing or carrying costs on nuclear fuel inventory</td>
<td>??</td>
<td></td>
<td>PG&amp;E is not proposing cost recovery to include return, financing or carrying costs on fuel inventory “in this proceeding” but leaves open the possibility that such items could be requested in a future cost recovery application.</td>
</tr>
<tr>
<td>Return, carrying or financing costs on capex or capital adds?</td>
<td>??</td>
<td></td>
<td>PG&amp;E claims that it is not proposing any return, carrying or financing costs relating to capital additions “in this proceeding” but leaves open the possibility that such costs could be requested in a future cost recovery application.</td>
</tr>
</tbody>
</table>

As can be seen from the above table, there are several items that are not accounted for in the historic or forecast costs presented by PG&E in this proceeding. TURN estimates that the costs associated with this set of excluded costs is approximately $329.8 million from 2023-2030. In some instances (i.e., return or carrying costs on nuclear fuel and capital), PG&E excluded items from its current forecasts but expressly held open the possibility that it could request additional ratepayer funds for these purposes in a future proceeding. TURN’s analysis does not attempt to estimate additional costs attributable to the carrying costs or return on nuclear fuel or capital additions.
Finally, PG&E has failed to include the various incentive payments that PG&E expects to receive associated with the extended operation of DCPP. These include both fixed payments, volumetric payments, employee retention costs, and the funding of a Liquidated Damages account. These payments are expected to amount to $2.72 billion from 2023-2030.

After including all costs that PG&E would likely incur to extend operations of DCPP as well as incentive payments made to PG&E from outside funding sources, TURN estimates that PG&E has understated the costs of DCPP for the period from 2023-2030 by over $6.84 billion. The following table presents the details of this estimate:

Table 3: Comparison of PG&E and TURN Cost Estimates for DCPP from 2023-2030
(nominal k$)

<table>
<thead>
<tr>
<th></th>
<th>Total PG&amp;E Costs</th>
<th>Costs Excluded from DCPP RO Model</th>
<th>Other Excluded DCPP Costs</th>
<th>Additional Incentive Payments to PG&amp;E</th>
<th>Total TURN Costs</th>
<th>Difference (PG&amp;E - TURN)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2023</td>
<td>735,836</td>
<td>659,493</td>
<td>50,300</td>
<td>-</td>
<td>1,445,629</td>
<td>(709,793)</td>
</tr>
<tr>
<td>2024</td>
<td>744,446</td>
<td>691,414</td>
<td>50,300</td>
<td>148,864</td>
<td>1,635,024</td>
<td>(890,578)</td>
</tr>
<tr>
<td>2025</td>
<td>893,139</td>
<td>715,945</td>
<td>70,687</td>
<td>470,679</td>
<td>2,150,450</td>
<td>(1,257,311)</td>
</tr>
<tr>
<td>2026</td>
<td>765,143</td>
<td>304,419</td>
<td>71,095</td>
<td>477,739</td>
<td>1,618,396</td>
<td>(853,253)</td>
</tr>
<tr>
<td>2027</td>
<td>751,995</td>
<td>348,335</td>
<td>21,211</td>
<td>447,530</td>
<td>1,569,071</td>
<td>(817,076)</td>
</tr>
<tr>
<td>2028</td>
<td>885,818</td>
<td>363,211</td>
<td>21,635</td>
<td>432,556</td>
<td>1,703,220</td>
<td>(817,402)</td>
</tr>
<tr>
<td>2029</td>
<td>773,477</td>
<td>402,036</td>
<td>22,068</td>
<td>470,010</td>
<td>1,667,591</td>
<td>(894,114)</td>
</tr>
<tr>
<td>2030</td>
<td>312,811</td>
<td>301,108</td>
<td>22,509</td>
<td>274,091</td>
<td>910,519</td>
<td>(597,708)</td>
</tr>
<tr>
<td>Total</td>
<td>5,862,665</td>
<td>3,785,961</td>
<td>329,805</td>
<td>2,721,469</td>
<td>12,699,899</td>
<td>(6,837,234)</td>
</tr>
</tbody>
</table>

Table 3 presents the “gross” costs of continuing to operate DCPP. Based on these costs, the levelized “gross” cost of power for DCPP is almost $98/MWh (2024 $).

PG&E expects to receive funding from DWR and DOE to offset some of the costs of extended operation of DCPP. Even if PG&E were to receive 100% of the funding from DWR and DOE, the levelized “net” costs of power for DCPP from 2023-2030 are still over $88/MWh.
Recommendation: The Commission should order PG&E to demonstrate that it has included all anticipated costs for DCPP that it intends to collect from either ratepayers or other sources (e.g., the federal/state governments) through 2030 in its presentation so that the total anticipated costs to ratepayers can be evaluated prior to issuing any authorization to proceed with extended operations.

II. PG&E’s Proposed Costs for DCPP

Q. What is the purpose of this section of your testimony?
A. This section summarizes PG&E’s presentation of historic and forecast costs associated with DCPP.

Q. What information does PG&E provide in its testimony related to the historic and forecast costs to operate DCPP?
A. PG&E presents two tables in its testimony that PG&E contends present (1) the historic costs of operation of DCPP (Table 1)\(^2\) and (2) the forecasted costs of operation of DCPP (Table 2)\(^3\). The costs in the PG&E tables are presented in nominal dollars. The following table combines PG&E’s tables and presents these costs for both the historic and forecast periods.

---

\(^2\) PG&E May 19\(^{th}\) Testimony, p. 7.
\(^3\) PG&E May 19\(^{th}\) Testimony, p. 9.
Table 4: Historic and Forecast Costs for DCPP as Presented by PG&E (nominal k$) [[CONFIDENTIAL]]

<table>
<thead>
<tr>
<th>Year</th>
<th>Engineering</th>
<th>Loss Prevention</th>
<th>Materials and Services</th>
<th>Fuel Management</th>
<th>Operations</th>
<th>Support Services</th>
<th>Training - Develop and Conduct</th>
<th>Work Management</th>
<th>Total Nuclear Operating Costs</th>
<th>Capital</th>
<th>Outage</th>
<th>Fuel</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>32,406</td>
<td>53,424</td>
<td>9,015</td>
<td>-</td>
<td>52,941</td>
<td>146,653</td>
<td>8,911</td>
<td>80,692</td>
<td>384,042</td>
<td>178,313</td>
<td>44,663</td>
<td>105,278</td>
<td>712,296</td>
</tr>
<tr>
<td>2011</td>
<td>32,765</td>
<td>58,989</td>
<td>6,016</td>
<td>-</td>
<td>55,982</td>
<td>143,618</td>
<td>7,772</td>
<td>86,295</td>
<td>391,436</td>
<td>229,839</td>
<td>43,019</td>
<td>127,942</td>
<td>792,236</td>
</tr>
<tr>
<td>2012</td>
<td>34,619</td>
<td>70,277</td>
<td>5,721</td>
<td>4,430</td>
<td>58,665</td>
<td>157,288</td>
<td>7,843</td>
<td>105,202</td>
<td>444,044</td>
<td>251,090</td>
<td>45,587</td>
<td>128,631</td>
<td>869,352</td>
</tr>
<tr>
<td>2013</td>
<td>38,509</td>
<td>64,850</td>
<td>8,917</td>
<td>5,987</td>
<td>61,427</td>
<td>134,566</td>
<td>10,987</td>
<td>96,973</td>
<td>422,216</td>
<td>209,296</td>
<td>45,289</td>
<td>133,152</td>
<td>809,953</td>
</tr>
<tr>
<td>2014</td>
<td>36,865</td>
<td>62,261</td>
<td>12,980</td>
<td>844</td>
<td>65,186</td>
<td>155,377</td>
<td>11,222</td>
<td>144,842</td>
<td>489,577</td>
<td>209,934</td>
<td>87,156</td>
<td>113,921</td>
<td>900,588</td>
</tr>
<tr>
<td>2015</td>
<td>36,783</td>
<td>63,045</td>
<td>8,499</td>
<td>1,053</td>
<td>55,839</td>
<td>151,291</td>
<td>9,335</td>
<td>157,413</td>
<td>483,257</td>
<td>217,443</td>
<td>52,333</td>
<td>125,134</td>
<td>878,167</td>
</tr>
<tr>
<td>2016</td>
<td>41,005</td>
<td>72,811</td>
<td>8,648</td>
<td>648</td>
<td>67,903</td>
<td>147,888</td>
<td>7,318</td>
<td>141,805</td>
<td>488,026</td>
<td>183,121</td>
<td>58,860</td>
<td>126,909</td>
<td>856,916</td>
</tr>
<tr>
<td>2017</td>
<td>48,129</td>
<td>69,343</td>
<td>3,811</td>
<td>300</td>
<td>73,457</td>
<td>104,299</td>
<td>7,700</td>
<td>120,992</td>
<td>428,031</td>
<td>161,871</td>
<td>64,584</td>
<td>124,061</td>
<td>778,547</td>
</tr>
<tr>
<td>2018</td>
<td>49,749</td>
<td>70,840</td>
<td>3,920</td>
<td>-</td>
<td>75,766</td>
<td>61,617</td>
<td>7,996</td>
<td>114,824</td>
<td>384,712</td>
<td>106,210</td>
<td>48,086</td>
<td>128,286</td>
<td>667,294</td>
</tr>
<tr>
<td>2019</td>
<td>50,033</td>
<td>74,045</td>
<td>6,000</td>
<td>554</td>
<td>77,567</td>
<td>98,313</td>
<td>10,343</td>
<td>137,884</td>
<td>454,739</td>
<td>102,476</td>
<td>81,928</td>
<td>112,605</td>
<td>751,748</td>
</tr>
<tr>
<td>2020</td>
<td>46,723</td>
<td>78,778</td>
<td>4,600</td>
<td>501</td>
<td>70,895</td>
<td>11,472</td>
<td>106,288</td>
<td>34,327</td>
<td>44,982</td>
<td>596,818</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td>39,542</td>
<td>72,659</td>
<td>4,976</td>
<td>832</td>
<td>71,340</td>
<td>9,072</td>
<td>104,519</td>
<td>34,360</td>
<td>41,466</td>
<td>581,344</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>31,990</td>
<td>72,755</td>
<td>8,468</td>
<td>808</td>
<td>77,593</td>
<td>7,551</td>
<td>112,109</td>
<td>12,995</td>
<td>63,274</td>
<td>644,111</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td>44,444</td>
<td>77,614</td>
<td>7,887</td>
<td>833</td>
<td>76,292</td>
<td>9,352</td>
<td>108,140</td>
<td>150,180</td>
<td>46,841</td>
<td>735,836</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td>44,767</td>
<td>78,178</td>
<td>7,944</td>
<td>839</td>
<td>76,847</td>
<td>9,420</td>
<td>108,926</td>
<td>150,052</td>
<td>46,841</td>
<td>744,446</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>39,047</td>
<td>68,189</td>
<td>6,929</td>
<td>732</td>
<td>67,028</td>
<td>8,216</td>
<td>191,968</td>
<td>150,094</td>
<td>96,961</td>
<td>893,139</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2026</td>
<td>39,786</td>
<td>69,479</td>
<td>7,060</td>
<td>746</td>
<td>68,296</td>
<td>8,371</td>
<td>142,588</td>
<td>154,312</td>
<td>50,177</td>
<td>765,144</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2027</td>
<td>41,178</td>
<td>71,911</td>
<td>7,308</td>
<td>772</td>
<td>70,687</td>
<td>8,664</td>
<td>147,579</td>
<td>119,785</td>
<td>51,933</td>
<td>751,996</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2028</td>
<td>42,619</td>
<td>74,427</td>
<td>7,563</td>
<td>799</td>
<td>73,161</td>
<td>8,968</td>
<td>206,495</td>
<td>123,977</td>
<td>107,502</td>
<td>885,818</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2029</td>
<td>44,111</td>
<td>77,032</td>
<td>7,828</td>
<td>827</td>
<td>75,721</td>
<td>9,282</td>
<td>158,091</td>
<td>96,237</td>
<td>55,632</td>
<td>773,478</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td>19,023</td>
<td>33,220</td>
<td>3,376</td>
<td>357</td>
<td>32,655</td>
<td>4,003</td>
<td>68,177</td>
<td>20,751</td>
<td>23,991</td>
<td>422,644</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: PG&E May 19th Testimony, Tables 1 and 2. Note that PG&E’s value in Table 1 for Capital in 2021 is “34,36.” TURN assumes that this value is $34,360.
The following figures present the data from Table 4 graphically:

**Figure 1: Historic and Forecast Costs for DCPP by Disaggregated EUCG Category**

Note: Data in figure are not confidential since one category aggregates two confidential categories: Support Services and Fuel.
Figure 2: Historic and Forecast Costs for DCPP by Aggregated EUCG Category

Note: Data in figure are not confidential since one category aggregates two confidential categories: Total Nuclear Operating Costs and Fuel

Q. Do you have any comments about the data presented by PG&E?

A. Yes. Based on the data provided by PG&E, annual total costs for DCPP declined from a high in 2014 of about $900 million to a low of $581 million in 2021 and are projected to jump to nearly nearly $900 million in 2025. The variation in total costs seen in the above figures is driven primarily by changes in historic and forecast capital spending. Less obvious but still important is to note the manner in which PG&E has chosen to aggregate the various costs in its testimony in this proceeding. PG&E uses categories defined by the Electric Utility Cost Group (EUCG)\(^4\) to present its historic and forecast data in this proceeding.

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\(^4\)To simplify the discussion, TURN’s testimony refers to the cost categories defined by EUCG as “EUCGs.”
Q. Is this the aggregation that PG&E typically uses to present its O&M and capital costs in other proceedings?

A. No. PG&E acknowledges that it typically presents its costs aggregated into Major Work Categories (MWCs). It also acknowledges that most intervenors are familiar with costs categorized by MWCs and not EUCGs. In response to a TURN data request, PG&E refused to map any of the presented costs to MWCs.

Q. Why did PG&E use this alternative presentation in this proceeding?

A. According to PG&E, it presented estimated future costs “…in the EUCG industry accounting format because the DOE required that CNC applications be submitted using that methodology.” This rationale is not persuasive since PG&E has longstanding experience presenting DCPP cost data using the traditional MWCs. PG&E should have a readily-available “crosswalk” between costs categorized using EUCGs and MWCs.

Q. Does PG&E plan to present DCPP costs using the EUCG breakdown in future Commission proceedings?

A. No. PG&E states that it “does not plan to use the EUCG accounting format for its future cost recovery application with the CPUC.” Instead, PG&E intends to use a completely different method of cost categorization for purpose of future cost recovery proceedings. This method, described at a high level in its June 9, 2023 testimony, would present O&M costs using the same MWCs that have been presented in GRCs. This fact demonstrates the absurdity of PG&E’s decision to use the EUCG accounting format for presenting forecasted costs in this proceeding. PG&E’s decision to use an atypical method of cost presentation in this proceeding (and, it should be noted, that will never be repeated in a future case) appears designed to frustrate any meaningful review of the forecast.

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5 PG&E May 19th Testimony, p. 3.
6 PG&E May 19th Testimony, p. 3.
7 PG&E response to TURN Data Request #4, Questions 1 and 2.
8 PG&E response to TURN Data Request #4, Question 2.
9 PG&E response to TURN Data Request #4, Question 2.
10 PG&E response to TURN Data Request #4, Question 2. See also PG&E June 9, 2023 Testimony, pages 3-3 through 3-4.
Q. How do PG&E’s estimate of Total Nuclear Operating Costs change relative to Capital, Outage, and Fuel over time?

A. The following table presents that comparison:

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Nuclear Operating Costs</th>
<th>Capital</th>
<th>Outage</th>
<th>Fuel</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>53.9%</td>
<td>25.0%</td>
<td>6.3%</td>
<td>14.8%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2011</td>
<td>49.4%</td>
<td>29.0%</td>
<td>5.4%</td>
<td>16.1%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2012</td>
<td>51.1%</td>
<td>28.9%</td>
<td>5.2%</td>
<td>14.8%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2013</td>
<td>52.1%</td>
<td>25.8%</td>
<td>5.6%</td>
<td>16.4%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2014</td>
<td>54.4%</td>
<td>23.3%</td>
<td>9.7%</td>
<td>12.6%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2015</td>
<td>55.0%</td>
<td>24.8%</td>
<td>6.0%</td>
<td>14.2%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2016</td>
<td>57.0%</td>
<td>21.4%</td>
<td>6.9%</td>
<td>14.8%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2017</td>
<td>55.0%</td>
<td>20.8%</td>
<td>8.3%</td>
<td>15.9%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2018</td>
<td>57.7%</td>
<td>15.9%</td>
<td>7.2%</td>
<td>19.2%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2019</td>
<td>60.5%</td>
<td>13.6%</td>
<td>10.9%</td>
<td>15.0%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2021</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2023</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2024</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2025</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2026</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2027</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2028</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2029</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>2030</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Source: Derived from PG&E May 19th Testimony, Tables 1 and 2

As seen in Table 5 above, Capital is a very small fraction of total costs in 2020-2022. This is not surprising since PG&E was expecting to shut down DCPP and had reduced capital expenditures under that assumption. However, Capital becomes a much larger fraction of PG&E’s estimate of DCPP costs starting in 2023.

Regarding longer-term trends, Fuel and Outage Costs have increased since 2010 at higher CAGRs ( and , respectively) than have Total Nuclear Operating Costs and Capital Costs ( and , respectively). In addition, the trends from 2020-2029
show Capital Costs growing at a very high CAGR of 9.3%, Fuel Costs growing a bit slower at [REDACTED], Outage Costs growing at 2.4%, and Total Nuclear Operating Costs growing at [REDACTED].

Q. How do PG&E’s cost estimates presented in its testimony compare to those PG&E presented for 2020-2023 in its last GRC?

A. They do not compare well. Section III highlights the wide disparities between the cost estimates presented in the testimony in this proceeding and what PG&E presented in its 2023 GRC.

III. PG&E Significantly Understates Total Costs for DCPP

Q. What is the purpose of this section of your testimony?

A. This section compares the costs that PG&E presented in this proceeding against TURN’s more complete forecast of the costs for extended DCPP operations. Based on TURN’s review of PG&E’s testimony in this proceeding, PG&E’s responses to TURN data requests, and PG&E’s prior showings regarding the costs for DCPP, TURN concludes that PG&E has significantly understated the costs of DCPP should it continue to operate past its currently projected closure dates.

Q. What information has PG&E presented to help gauge its prior estimates of the costs of owning and operating DCPP?

A. In PG&E’s last GRC, it presented a Results of Operation (RO) exhibit for the DCPP.11 This RO summary presents all of the costs and revenues for DCPP. The following presents this RO summary from the workpapers from the GRC:

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11 Workpapers to Exhibit PG&E-10 in A.21-06-021, pp. WP 17-94 to WP 17-98.
Figure 3: RO Results from PG&E’s 2023 Test Year GRC

[Table of Electric Generation - Diablo Canyon Power Plant]

Q. How do the values presented in PG&E’s DCPP RO model compare to the information that PG&E presented in its testimony in this proceeding?

A. While the “Production” line item is similar to the Total Nuclear Operating Costs line...
from PG&E’s testimony in this proceeding, there are numerous line items in the DCPP RO model that do not appear in PG&E’s testimony.

Q. Does that mean that PG&E excluded certain costs from its cost estimate in this proceeding that were included in the DCPP RO model?

A. Yes. TURN submitted data requests to PG&E to determine the extent to which some of the line items in the DCPP RO model were included in line items presented in PG&E’s testimony in this proceeding. In most cases, PG&E indicated that those costs from the DCPP RO model were not included in the costs in this proceeding. The following table summarizes PG&E’s responses to TURN data requests about whether PG&E included certain costs in its cost estimates for this proceeding:

Table 6: DCPP Costs from DCPP RO Model Possibly Excluded in PG&E May 19th Testimony

| Category                          | Excluded from Table 1 | Source  | Excluded from Table 2 | Source  | Notes                                                                 |
|-----------------------------------|------------------------|---------|------------------------|---------|                                                                      |
| Transmission                      | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Uncollectibles                    | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Administrative and General        | Y/N                    | TURN-2, Q2 | Y/N                    | TURN-2, Q3 | Portion is in Capital line as capitalized A&G. Contract A&G is excluded |
| Franchise & SFGR Tax Requirement  | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Superfund Taxes                   | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Property Taxes                    | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Payroll Taxes                     | Y/N                    | TURN-2, Q2 | Y/N                    | TURN-2, Q3 | Payroll Taxes included in Support Services line; all other taxes excluded |
| Business Taxes                    | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Other Taxes                       | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| State Corporation Franchise Taxes | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Federal Income Taxes              | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 |                                                                 |
| Depreciation                      | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 | During extended operations, PG&E expects to expense all costs in the year they are incurred |
| Net for Return                    | Y                      | TURN-2, Q2 | Y                      | TURN-2, Q3 | PG&E has not yet proposed to earn any return on capital or nuclear fuel during extended operations but may do so in a future application |

In the above table, the first column presents line items from the DCPP RO model, the second column indicates whether PG&E excluded those categories from its historic data

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12 PG&E Response to TURN Data Request 2, Questions 2 and 3.
in this proceeding (i.e., Table 1), the third column indicates the source for this
information (i.e., PG&E’s response to the TURN data request), the fourth column
indicates whether the line item is excluded from PG&E’s forecast data in this proceeding
(i.e., Table 2), the fifth column indicates the source for this information, and the sixth
column provides explanatory notes.

Q. What do you conclude from this table?

A. PG&E has excluded costs for at least 13 categories specifically called out in DCPP RO
model from the costs that it presented in this proceeding. Adding these excluded costs
causes the total cost of both historic and extended operation of DCPP to be much greater
than presented by PG&E in its testimony.

Q. Has TURN attempted to “fill in the blanks” in PG&E’s cost estimates from this
proceeding?

A. Yes. The following table presents TURN’s estimates for Total Operating Expenses for
2020-2030 in the same format as the DCPP RO summary:
### Table 7: TURN Estimate of Total DCPP Operating Expenses (nominal k$)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Adj Recorded Year</th>
<th>Estimated Year</th>
<th>Test Year</th>
<th>TRENDED OR FORECAST Year</th>
<th>Excluded from Tables 1 and 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>OPERATING EXPENSES:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Nuclear Fuel</td>
<td>44,982</td>
<td>41,466</td>
<td>63,274</td>
<td>50,177</td>
<td>35,812</td>
</tr>
<tr>
<td>3</td>
<td>Outage</td>
<td>34,327</td>
<td>34,360</td>
<td>12,995</td>
<td>150,180</td>
<td>150,052</td>
</tr>
<tr>
<td>4</td>
<td>Capital</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>Production</td>
<td>3,147</td>
<td>4,496</td>
<td>4,193</td>
<td>4,283</td>
<td>4,806</td>
</tr>
<tr>
<td>6</td>
<td>Transmission</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>Distribution</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>8</td>
<td>Customer Accounts</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>9</td>
<td>Uncollectibles</td>
<td>4,060</td>
<td>3,617</td>
<td>3,753</td>
<td>3,699</td>
<td>3,640</td>
</tr>
<tr>
<td>10</td>
<td>Customer Services</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>11</td>
<td>Administrative and General Franchise</td>
<td>155,931</td>
<td>185,140</td>
<td>213,627</td>
<td>124,987</td>
<td>142,557</td>
</tr>
<tr>
<td>12</td>
<td>Franchise &amp; SFGR Tax Requirement</td>
<td>9,319</td>
<td>9,168</td>
<td>10,035</td>
<td>9,547</td>
<td>9,905</td>
</tr>
<tr>
<td>13</td>
<td>Amortization</td>
<td>23,407</td>
<td>23,407</td>
<td>23,407</td>
<td>31,327</td>
<td>31,327</td>
</tr>
<tr>
<td>14</td>
<td>Wage Change Impacts</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>15</td>
<td>Other Price Change Impacts</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>16</td>
<td>Other Adjustments</td>
<td>-1,673</td>
<td>-1,723</td>
<td>-1,774</td>
<td>-1,828</td>
<td>(1,879)</td>
</tr>
<tr>
<td>17</td>
<td>Subtotal Expenses</td>
<td>791,009</td>
<td>805,447</td>
<td>897,551</td>
<td>907,905</td>
<td>934,861</td>
</tr>
<tr>
<td>18</td>
<td>TAXES:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>Property</td>
<td>22,681</td>
<td>22,453</td>
<td>22,083</td>
<td>19,359</td>
<td>19,060</td>
</tr>
<tr>
<td>20</td>
<td>Payroll</td>
<td>166</td>
<td>179</td>
<td>258</td>
<td>264</td>
<td>310</td>
</tr>
<tr>
<td>21</td>
<td>Federal Income</td>
<td>-15,623</td>
<td>6,764</td>
<td>29,662</td>
<td>22,859</td>
<td>22,859</td>
</tr>
<tr>
<td>22</td>
<td>State Corporation Franchise</td>
<td>24,979</td>
<td>24,955</td>
<td>36,309</td>
<td>30,659</td>
<td>33,484</td>
</tr>
<tr>
<td>23</td>
<td>Decommission</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>24</td>
<td>Nuclear Decommission</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>25</td>
<td>Total Operating Expenses</td>
<td>1,218,480</td>
<td>1,252,349</td>
<td>1,403,137</td>
<td>1,395,329</td>
<td>1,435,860</td>
</tr>
</tbody>
</table>

There are 77 identifiable language regions in this document.
Q. Please explain what is being presented in Table 7 above.
A. Table 7 presents PG&E’s estimated costs for Nuclear Fuel, Outage, Capital, and Total Nuclear Operating Costs in lines 1-4. These values were taken directly from Tables 1 and 2 of PG&E’s testimony. The other lines in the table present TURN’s estimates for costs that PG&E failed to include in its historic or forecast costs.\(^{13}\)

Q. How did you develop the above estimates for costs that PG&E did not provide to TURN?
A. It was necessary to develop forecasts for 2024-2030 for the line items in the DCPP RO model that PG&E did not provide forecasted values. To do that, I used trends of costs based on the values from 2020 (Adjusted) through 2023 from PG&E’s DCPP RO model from its GRC.\(^{14}\) For items that are partially included in PG&E’s forecasts (i.e., A&G), I developed conservative allocations.\(^{15}\) I excluded line items in Table 7 above that PG&E indicated were included in the four major categories in Tables 1 and 2 (e.g., Payroll Taxes).

Q. Please comment on the A&G line item in Table 7.
A. Total A&G for DCPP is about 18% of PG&E’s Total Operating Expenses as seen in PG&E’s DCPP RO from its GRC (see Figure 3 above). This fraction increases to about 22% by 2023. Other than Production and Depreciation, A&G is the single largest line item in the DCPP RO Model from the GRC.

\(^{13}\) Note that TURN included estimated expenses for Depreciation in 2023-2025 in Table 7. This is because the depreciation expenses for 2023-2025 will be paid by ratepayers regardless of whether DCPP continues to operate after the end of its current operating licenses or not. TURN also included forecasted costs for “Amortization” and “Other Adjustments.” It is unclear how PG&E derived these values for 2020-2023. For that reason, TURN included them in its forecast.

\(^{14}\) For income taxes, I assumed that taxes would be equal to the average of taxes for 2022 and 2023 from PG&E’s DCPP RO.

\(^{15}\) PG&E states that a portion of DCPP’s Capitalized A&G is included in Capital but fails to provide the exact amount. I conservatively estimate that the capitalized A&G is equal to 75% of PG&E’s Capital value from Tables 1 and 2 and deduct that amount from the trend of PG&E’s total DCPP-related A&G derived from the GRC.
Q. Isn’t DCPP’s A&G simply an allocation of PG&E’s total A&G?
A. For the purposes of the DCPP RO, DCPP’s A&G may be an allocation. However, TURN has previously demonstrated that if DCPP were to shut down, PG&E’s overall A&G would be reduced. PG&E has not provided sufficient detail to allow TURN to assess the amount of A&G costs identified in its current GRC that are included in (or excluded from) its extended operations cost forecast. Moreover, the lack of consistently-defined A&G costs (between the GRC and this proceeding) prevents an assessment of the company-wide amounts attributable to extended operations. Given the significance of these costs, the Commission should require PG&E to provide a comprehensive breakdown of all A&G allocated to DCPP in the GRC, identify which of these costs are included in (and excluded from) its extended operations forecast, and explain why specific A&G costs not included in the extended operations forecast were omitted.

Q. How do PG&E’s estimates of Total Operating Expenses compare with TURN’s more complete estimates?
A. PG&E’s estimates are far less than TURN’s. The following table provides a comparison:

Table 8: Comparison of PG&E and TURN Total Operating Expenses (nominal k$)

<table>
<thead>
<tr>
<th>Year</th>
<th>Nuclear Fuel</th>
<th>Outage</th>
<th>Capital</th>
<th>Production</th>
<th>Total PG&amp;E</th>
<th>TURN</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td></td>
<td>44,982</td>
<td>43,327</td>
<td></td>
<td>596,818</td>
<td></td>
<td>(621,662)</td>
</tr>
<tr>
<td>2021</td>
<td></td>
<td>41,466</td>
<td>34,360</td>
<td></td>
<td>581,342</td>
<td></td>
<td>(671,007)</td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td>63,274</td>
<td>12,995</td>
<td></td>
<td>644,111</td>
<td></td>
<td>(759,026)</td>
</tr>
<tr>
<td>2023</td>
<td></td>
<td>46,841</td>
<td>150,180</td>
<td></td>
<td>735,836</td>
<td></td>
<td>(659,493)</td>
</tr>
<tr>
<td>2024</td>
<td></td>
<td>46,841</td>
<td>150,052</td>
<td></td>
<td>744,446</td>
<td></td>
<td>(691,414)</td>
</tr>
<tr>
<td>2025</td>
<td></td>
<td>96,961</td>
<td>150,094</td>
<td></td>
<td>893,139</td>
<td></td>
<td>(715,945)</td>
</tr>
<tr>
<td>2026</td>
<td></td>
<td>50,177</td>
<td>154,312</td>
<td></td>
<td>765,143</td>
<td></td>
<td>(304,419)</td>
</tr>
<tr>
<td>2027</td>
<td></td>
<td>51,933</td>
<td>119,785</td>
<td></td>
<td>751,995</td>
<td></td>
<td>(348,335)</td>
</tr>
<tr>
<td>2028</td>
<td></td>
<td>107,502</td>
<td>123,977</td>
<td></td>
<td>885,818</td>
<td></td>
<td>(363,211)</td>
</tr>
<tr>
<td>2029</td>
<td></td>
<td>55,632</td>
<td>96,237</td>
<td></td>
<td>773,477</td>
<td></td>
<td>(402,036)</td>
</tr>
<tr>
<td>2030</td>
<td></td>
<td>23,991</td>
<td>20,751</td>
<td></td>
<td>312,811</td>
<td></td>
<td>(301,108)</td>
</tr>
</tbody>
</table>

See Exhibit TURN-2, A.16-08-006, page 8.
Q. How will PG&E recover these costs?
A. PG&E will file an application with the Commission for recovery of these operating costs through rates. It is not clear whether the costs PG&E seeks to recover in future applications will differ significantly from those presented in this proceeding.

Q. Are there other costs that PG&E excluded from the costs presented in Tables 1 and 2 in this proceeding?
A. Yes. In addition to the costs categories that TURN identified as being in the DCPP RO and that PG&E excluded from its cost estimates, it was unclear if PG&E also excluded certain other costs not specifically identified in the DCPP RO from the historic or forecast costs in its testimony. Because it was unclear if these other cost categories were included in PG&E’s costs presented in its testimony, TURN submitted data requests to PG&E. The following table summarizes whether PG&E had included in its data those categories of costs not specifically called out in the DCPP RO:

Table 9: Categories of Other Costs Excluded from PG&E May 19th Testimony

<table>
<thead>
<tr>
<th>Category</th>
<th>Excluded from Table 1</th>
<th>Basis</th>
<th>Excluded from Table 2</th>
<th>Basis</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pensions and benefits</td>
<td>N</td>
<td>TURN-2, Q2</td>
<td>N</td>
<td>TURN-2, Q3</td>
<td></td>
</tr>
<tr>
<td>Nuclear Property Insurance</td>
<td>Y</td>
<td>TURN-2, Q2</td>
<td>Y</td>
<td>TURN-2, Q3</td>
<td></td>
</tr>
<tr>
<td>Nuclear Liability Insurance</td>
<td>N</td>
<td>TURN-2, Q2</td>
<td>N</td>
<td>TURN-2, Q3</td>
<td>Included in Support Services</td>
</tr>
<tr>
<td>Materials and Supplies Inventory</td>
<td>Y</td>
<td>TURN-2, Q2</td>
<td></td>
<td>TURN-2, Q3</td>
<td></td>
</tr>
<tr>
<td>Mitigation Fees for SWCB to address entrainment</td>
<td>N</td>
<td>TURN-2, Q2</td>
<td>N</td>
<td>TURN-2, Q3</td>
<td>Included in Operations line</td>
</tr>
<tr>
<td>Refueling Outage Costs</td>
<td>N</td>
<td>TURN-2, Q2</td>
<td>N</td>
<td>TURN-2, Q3</td>
<td>Included In Outages</td>
</tr>
<tr>
<td>Employee Retention and Severance Payments</td>
<td>Y</td>
<td>TURN-2, Q4</td>
<td>Y</td>
<td>TURN-2, Q3</td>
<td>Will update in new application</td>
</tr>
<tr>
<td>Return, financing or carrying costs on nuclear fuel inventory</td>
<td>??</td>
<td>TURN-2, Q-5</td>
<td></td>
<td></td>
<td>PG&amp;E is not proposing cost recovery to include return, financing or carrying costs on fuel inventory “in this proceeding” but leaves open the possibility that such items could be requested in a future cost recovery application</td>
</tr>
<tr>
<td>Return, carrying or financing costs on capex or capital adds</td>
<td>??</td>
<td>TURN-2, Q-6</td>
<td></td>
<td></td>
<td>PG&amp;E claims that it is not proposing any return, carrying or financing costs relating to capital additions “in this proceeding” but leaves open the possibility that such costs could be requested in a future cost recovery application</td>
</tr>
</tbody>
</table>

As can be seen from the above table, PG&E excluded Nuclear Property Insurance, Materials and Supplies Inventory, and Employee Retention and Severance Payments.
from its estimated costs of DCPP. In addition, PG&E indicated that it was not proposing
cost recovery in this proceeding for two other categories\(^\text{17}\) but did not rule out left open
the possibility that PG&E might request recovery of those costs in future cost recovery
proceedings.

**Q. What is the estimated magnitude of these excluded items?**

**A.** The following table presents TURN’s estimates of these costs\(^\text{18}\):

*Table 10: TURN Estimate of Costs Not Included in DCPP RO (nominal k$)*

<table>
<thead>
<tr>
<th></th>
<th>Nuclear Property Insurance</th>
<th>Materials and Supplies Inventory</th>
<th>Employee Retention Program</th>
<th>Total Other Expenses Excluded</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>-</td>
<td>-</td>
<td>50,300</td>
<td>50,300</td>
</tr>
<tr>
<td>2021</td>
<td>-</td>
<td>-</td>
<td>50,300</td>
<td>50,300</td>
</tr>
<tr>
<td>2022</td>
<td>-</td>
<td>-</td>
<td>50,300</td>
<td>50,300</td>
</tr>
<tr>
<td>2023</td>
<td>-</td>
<td>-</td>
<td>50,300</td>
<td>50,300</td>
</tr>
<tr>
<td>2024</td>
<td>-</td>
<td>-</td>
<td>50,300</td>
<td>50,300</td>
</tr>
<tr>
<td>2025</td>
<td>6,122</td>
<td>14,265</td>
<td>50,300</td>
<td>70,687</td>
</tr>
<tr>
<td>2026</td>
<td>6,245</td>
<td>14,550</td>
<td>50,300</td>
<td>71,095</td>
</tr>
<tr>
<td>2027</td>
<td>6,370</td>
<td>14,841</td>
<td>-</td>
<td>21,211</td>
</tr>
<tr>
<td>2028</td>
<td>6,497</td>
<td>15,138</td>
<td>-</td>
<td>21,635</td>
</tr>
<tr>
<td>2029</td>
<td>6,627</td>
<td>15,441</td>
<td>-</td>
<td>22,068</td>
</tr>
<tr>
<td>2030</td>
<td>6,760</td>
<td>15,749</td>
<td>-</td>
<td>22,509</td>
</tr>
</tbody>
</table>

Source for Nuclear Property Insurance and Materials and Supplies Inventory is workpapers from Exhibit TURN-2 in A.16-08-006.

**Q. How did you develop these estimates?**

**A.** I relied on estimates that TURN had previously submitted in A.16-08-006 for Nuclear Property Insurance and Materials and Supplies Inventory.\(^\text{19}\)

For Employee Retention costs, I relied on information from D.18-11-024, which

\[^{17}\text{The two categories are “Return, financing or carrying costs on nuclear fuel inventory” and “Return, carrying or financing costs on capex or capital adds.” TURN did not include costs for these two items in its assessment of total costs for DCPP.}\]

\[^{18}\text{This table does not include Employee Retention Costs. Those costs are addressed below.}\]

\[^{19}\text{A.16-08-006, Workpapers for Exhibit TURN-2.}\]
approved PG&E’s proposed $352.1 million employee retention program (increasing employee retention from the $211.3 million approved in D.18-01-022, p. 29). D.18-11-024 approved retention payments for 7 years.\(^{20}\)

**Q.** How will PG&E recover these costs?

**A.** To the degree that these are costs that PG&E believes should be recovered, PG&E will file a request with the Commission in future applications to recover these costs in rates.

**Q.** Aside from the cost categories identified above, are there other costs associated with the continued operation of DCPP?

**A.** Yes. There are five additional significant cost items authorized under SB 846 related to the continued operation of DCPP.\(^{21}\) These should be considered additional incentive payments to keep DCPP online. The cost categories are:

- A volumetric performance-based payment of $7/MWh paid by the state general fund (via the Department of Water Resources) for all generation prior to the extension period (i.e., prior to the end of the current operating licenses for DCPP Units 1 and 2);\(^{22}\)
- A volumetric performance-based payment of $6.50/MWh (2022$) for all generation during the extension period that is paid by customers of all Load Serving Entities (LSEs) and an additional $6.50/MWh (2022$) for all generation that is paid by PG&E customers;\(^{23}\)
- A fixed management fee of $50 million per year (2022$) per unit;\(^{24}\)
- The costs to fund a Liquidated Damages account, which equals $12.5 million per month per unit until the account has a balance of $300 million; and

\(^{20}\) D.18-11-006, p. 7.

\(^{21}\) These costs are specified in SB 846.

\(^{22}\) California Public Utilities Code §712.8(f), (g), (i).

\(^{23}\) California Public Utilities Code Section §712.8(f)(5). These payments are in real 2022 dollars. Because PG&E is an LSE, its customers will pay $6.50 per MWh of generation from DCPP and an additional amount equal to PG&E’s pro rata share of an additional $6.50 per MWh of generation. Thus, the overall cost of this volumetric payment is $13/MWh for all generation from DCPP.

\(^{24}\) California Public Utilities Code §712.8(f)(6). This payment is in real 2022 dollars.

\(^{25}\) California Public Utilities Code §712.8(g).
• Employee retention costs that will be sought for recovery by PG&E in a future application.26

**Q. What is the total of these costs per year?**

A. The following table presents TURN’s estimate of these costs:

<table>
<thead>
<tr>
<th></th>
<th>Volumetric Perf-Based Pmt ($7/MWh)</th>
<th>Volumetric Perf-Based Pmt ($13/MWh)</th>
<th>Fixed Management Fee ($50MM/unit/yr)</th>
<th>Liquidated Damage Sub-Account</th>
<th>Employee Retention Program</th>
<th>Total Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2021</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2022</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2023</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2024</td>
<td>120,386</td>
<td>11,514</td>
<td>4,463</td>
<td>12,500</td>
<td>-</td>
<td>148,864</td>
</tr>
<tr>
<td>2025</td>
<td>34,312</td>
<td>162,453</td>
<td>73,915</td>
<td>200,000</td>
<td>-</td>
<td>470,679</td>
</tr>
<tr>
<td>2026</td>
<td></td>
<td>275,487</td>
<td>114,752</td>
<td>87,500</td>
<td>-</td>
<td>477,739</td>
</tr>
<tr>
<td>2027</td>
<td></td>
<td>278,462</td>
<td>118,769</td>
<td>-</td>
<td>50,300</td>
<td>447,530</td>
</tr>
<tr>
<td>2028</td>
<td></td>
<td>259,330</td>
<td>122,926</td>
<td>-</td>
<td>50,300</td>
<td>432,556</td>
</tr>
<tr>
<td>2029</td>
<td></td>
<td>292,482</td>
<td>127,228</td>
<td>-</td>
<td>50,300</td>
<td>470,010</td>
</tr>
<tr>
<td>2030</td>
<td></td>
<td>92,110</td>
<td>131,681</td>
<td>-</td>
<td>50,300</td>
<td>274,091</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>154,698</td>
<td>1,371,838</td>
<td>693,733</td>
<td>300,000</td>
<td>201,200</td>
<td><strong>2,721,469</strong></td>
</tr>
</tbody>
</table>

Note: Table assumes 3.5% per year inflation for $13/MWh volumetric payment and $50MM/unit/yr Fixed Management fee.

As can be seen from Table 11 above, these payments range from $148.9 million in 2024 to a high of $477.7 million in 2026. After 2026, these costs decline to about $274.1 million in 2030. Total additional incentive payments from 2020-2030 equal more than $2.72 billion.

**Q. How did you estimate these costs?**

A. PG&E refused to provide forecasts for these costs in response to TURN data requests.27

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26 SB 846 (adding Public Utilities Code Section 712.8.f.2)
27 PG&E responses to TURN Data Request 2, Questions 4, 10, 11, 12, and 13.
Since PG&E would not provide any such forecast, TURN estimated these costs using relatively simple methods. First, the fixed payments were straightforward (assuming that per-unit and per-year fixed payments in 2024 and 2025 were pro rata with months of operation after the end of the original operating licenses). To develop forecasts of fees based on generation, it was necessary to develop a forecast of generation for 2023-2030 since PG&E also refused to provide a forecast of expected generation by DCPP from 2023-2030. TURN developed an estimate of expected generation based on historic days of planned and unplanned outages for 2017-2021. I adjusted the days of outages from 2017-2021 to remove unplanned outages that were longer than 10 days. For purposes of forecasting generation for 2023-2030, I assumed that 2022 “normal” days of outages would be the same as the number of “normal” days of outages in 2019. For years 2023-2030, I assumed that each year would have the same number of “normal” days of outage as the average of the number of “normal” outage days for years that were 3- and 6-years prior. For example, for 2024, I assumed that outage days would be equal to the average of days of outages in 2021 and 2018.

For Employee Retention costs, I assumed that these payments would continue at the same level after the end of the original 7-year period authorized in D.18-11-024.

Q. How do these additional incentive payments compare to payments that PG&E projects to be recovered through the DWR Loan and the DOE CNC Program?

A. The total amount PG&E projects it will receive from these the DWR Loan and DOE CNC Program is $1.1 billion. The payments from these sources end in 2026. Thus, the DWR Loan and DOE CNC Program will only cover about 40.4% of the costs for 2020-2030 from Table 11 above. More importantly, the DWR Loan and DOE CNC Program funds just barely cover the costs shown in Table 11 from 2020-2026 (i.e., customers will pay $3.2 million less than the total amount of the additional incentive payments of $1.097

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28 PG&E responses to TURN Data Request 2, Questions 7, 8, 9.
29 CONFIDENTIAL Attachment to PG&E Response to TURN Data Request 3, Question 1, file “J9EKLNMZXFM6_Diablo Canyon Historic Annual Operating Conditions_Year.xlsx,” tab “Historic Operating Loss.”
30 PG&E May 19 Testimony, p. 15.
After 2026, customers will have to pay 100% of the additional incentive payments (i.e., $1.62 billion). This means that over the period from 2020-2030 customers will be asked to pay an additional $1.62 billion out of the $2.72 billion of Additional Incentive Payments shown in Table 11. The following table presents the Additional Incentive Payments paid by customers and the potential payments from DWR and DOE that might offset some of those costs:

Table 12: Cash Flows to PG&E for Extending Life of DCPP vs. Possible Outside Funding (nominal k$)

<table>
<thead>
<tr>
<th>Year</th>
<th>Starting Cumulative Balance Paid by Ratepayers for Incentive Payments [a] = [d] from prior year</th>
<th>Additional Incentives Payments to PG&amp;E [b]</th>
<th>Possible Payments from DWR/DOE Offsetting Ratepayer Costs [c]</th>
<th>Ending Cumulative Balance Paid by Ratepayers [d]=[a]+[b]+[c]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>0</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>2021</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>2022</td>
<td>-</td>
<td>-</td>
<td>(42,072)</td>
<td>(42,072)</td>
</tr>
<tr>
<td>2023</td>
<td>(42,072)</td>
<td>-</td>
<td>(381,816)</td>
<td>(423,888)</td>
</tr>
<tr>
<td>2024</td>
<td>(423,888)</td>
<td>148,864</td>
<td>(408,321)</td>
<td>(683,345)</td>
</tr>
<tr>
<td>2025</td>
<td>(683,345)</td>
<td>470,679</td>
<td>(210,256)</td>
<td>(422,922)</td>
</tr>
<tr>
<td>2026</td>
<td>(422,922)</td>
<td>477,739</td>
<td>(58,056)</td>
<td>(3,239)</td>
</tr>
<tr>
<td>2027</td>
<td>(3,239)</td>
<td>447,530</td>
<td>-</td>
<td>444,291</td>
</tr>
<tr>
<td>2028</td>
<td>444,291</td>
<td>432,556</td>
<td>-</td>
<td>876,847</td>
</tr>
<tr>
<td>2029</td>
<td>876,847</td>
<td>470,010</td>
<td>-</td>
<td>1,346,857</td>
</tr>
<tr>
<td>2030</td>
<td>1,346,857</td>
<td>274,091</td>
<td>-</td>
<td>1,620,948</td>
</tr>
<tr>
<td>Total</td>
<td>2,721,469</td>
<td>(1,100,521)</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Source for Payments to PG&E: Table 11 above. Source for Possible Payments from DWR/DOE: PG&E May 19th Testimony, p. 15.

Q. What is Table 12 above showing about the timing and amount of the revenues PG&E will receive for the various incentive payments that PG&E failed to include in its testimony relative to any potential offsetting revenue that PG&E may receive from DWR and DOE.

A. Table 12 above presents a cumulative assessment of the difference between annual amounts of the incentive payments (including payment of employee retention costs) that PG&E will receive from ratepayers relative to possible payments that PG&E might receive from DWR and DOE to offset those incentive payments. The annual values in the
third column of the table are taken from Table 11 above. The annual values in the fourth column are derived from PG&E’s May 19th testimony at page 15.31

Starting in 2022, PG&E will not have any additional incentive payments (column b) but PG&E assumes that it will receive about $42.1 million from DWR and DOE (column c). Thus, PG&E would receive about $42.1 million more than its costs in 2022 (the sum of columns b and c). Since the “starting balance” is zero in 2022, then the ending balance in 2022 is -$42.7 million ($0 + $0 million - $42.7 million). The cumulative total at the end of 2022 becomes the starting balance in 2023. In 2024, PG&E assumes it would have recovered $423.9 million from DWR and DOE but would have had no additional incentive payments. However, in 2024, customer costs are 148.9 million and PG&E assumes that there is an offsetting $408.3 million in possible payments from DWR and/or DOE, meaning that PG&E would receive $259.5 million more from DWR and DOE than the incremental incentive payments, resulting PG&E having received $683.3 million more from DWR and DOE than the additional incentive payments made by customers. This trend reverses in 2025, when the cost of the additional incentive payments exceeds the assumed payments from DWR and DOE. By the end of 2026, the offsets from DWR and DOE are only $3.2 million more than the total additional incentive costs.

Q. What is the difference in total incentive payments received by PG&E and the total possible offsets received from DWR and DOE?

A. Incentive payments exceed possible offsets by $1.621 billion (i.e., the “Ending Balance” in 2030 in Table 12).

Q. By including all of the costs that PG&E failed to include in its testimony, what is TURN’s estimate of the “gross”32 cost of power from DCPP from 2020-2030?

A. The following table summarizes TURN’s estimated costs for DCPP for 2024-2030:

31 Potential offsets from DWR and DOE are presented as negative values.
32 In this testimony, “gross” costs are costs before possible funds provided by DWR or DOE. “Net” costs are “gross” costs less possible funds provided by DWR or DOE.
As seen from Table 13 above, it appears that PG&E may have understated the annual gross costs of extending the life of DCPP by between $672 million to $1.26 billion. The following figure highlights the huge underestimation of costs by PG&E:
The bottom bar in Figure 4 above represents PG&E’s total costs as presented in its testimony; the other bars above that represent various costs that PG&E has failed to include in its cost estimate for DCPP. As seen from Figure 4, PG&E has significantly understated the total costs of DCPP (i.e., 49%-66% per year).

Q. **How does the potential offsetting revenues from DWR and DOE affect the total costs of DCPP?**

A. The following figure presents the “gross” and the “net” ratepayer costs of DCPP:
As seen from Figure 5 above, the funds from DWR and DOE only reduce the costs of DCPP from 2022-2026. Those funds essentially reduce total “net” ratepayer costs below costs in 2022 and hold them below that level until 2025.

Q. What is the total “gross” cost of power for DCPP based on TURN’s estimates of costs?

A. The following table presents the annual “gross” costs of power:

<table>
<thead>
<tr>
<th>Year</th>
<th>TURN Estimated Costs (k$)</th>
<th>TURN Estimated Generation (MWh)</th>
<th>Estimated Cost of Power ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>1,268,780</td>
<td>18,672,039</td>
<td>67.95</td>
</tr>
<tr>
<td>2021</td>
<td>1,302,649</td>
<td>18,100,948</td>
<td>71.97</td>
</tr>
<tr>
<td>2022</td>
<td>1,453,437</td>
<td>16,172,723</td>
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As seen from Table 14 above, the “gross” cost of power for DCPP in 2024 through 2030 ranges from a low of $87.0 per MWh up to a high of $169.2 per MWh. The levelized cost of power from 2023-2030 is approximately $97.9 per MWh (2024 $).

Q. How does the potential revenue from DWR and DOE affect the cost of power from DCPP?

A. The following figure presents the “gross” and the “net” cost of power for DCPP:

*Figure 6: Comparison of Gross and Net Cost of Power from DCPP (nominal $/MWh)*

As seen from Figure 6 above, the “net” cost of power dips in 2023-2024 and is less than the cost of power in 2022. After that, both the gross and net costs of power are at or
above the cost of power in 2022.\textsuperscript{33}

Q. What can you say about these results?

A. TURN has not examined the reasonableness of the costs that PG&E included in Tables 1 and 2 of its testimony other than to identify costs that PG&E had excluded from those tables.\textsuperscript{34} After a more careful analysis, the forecasted costs for Fuel, Outage, Capital, and Total Nuclear Operating Costs could well exceed PG&E’s forecasts presented in this case. In addition, the actual costs that PG&E proposes to recover associated with extending the life of DCPP will only be known when PG&E presents its cost recovery proposals in its annual applications.

Setting aside the reasonableness of PG&E’s forecasts, it is clear that PG&E has grossly understated the costs of continued operation of DCPP. The levelized “gross” cost of power for DCPP is still almost $98/MWh from 2023-2030, with the “net” cost of power being over $88/MWh over the same period. These are very high costs of power for a baseload resource and raises the question of whether there are more cost-effective GHG-free power sources available to replace DCPP.

Q. Do you have any recommendations for improving these results?

A. The results presented in this testimony are not based on PG&E’s DCPP RO model; TURN simply used the structure of the output from that model and made adjustments to certain line items. Thus, the results presented above are not based on detailed tax calculations; instead, it just uses past taxes from the 2020-2023 period. It would be appropriate for PG&E to use its own DCPP RO model and to include forecasts for costs that are not included in Tables 1 and 2 to derive a more realistic estimate of the costs of power for DCPP.

More importantly, it was necessary for TURN to develop estimates for a number of line

\textsuperscript{33} The levelized “net” cost of power for 2023-2030 is approximately $88.4/MWh (2024 $).

\textsuperscript{34} TURN reserves the right to challenge the reasonableness of proposed costs in a future proceeding where PG&E seeks recovery of additional DCPP costs from ratepayers.
items based on trends from PG&E’s GRC because PG&E refused to provide estimates for these categories of costs. TURN’s approach results in reasonable approximations but the analysis would be improved by having PG&E develop either historic levels or forecasts of costs that it excluded from Tables 1 and 2 in its testimony.

Finally, PG&E’s decision to use the EUCG cost categories in this proceeding without any sort of “crosswalk” to MWCs is unacceptable. This is especially true since PG&E claims that it will return to MWCs when it submits its applications to the Commission for cost recovery.

IV. Conclusion

Q. Does this conclude your opening testimony?
A. Yes, at this time.
APPENDIX 1

RESUME FOR WILLIAM A. MONSEN
RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE
Principal Consultant
MRW & Associates, LLC
(1989 - Present)
Specialist in electric utility generation planning, resource auctions, demand-side management policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)
Responsible for analysis of utility and non-utility investment opportunities using SDG&E's Strategic Analysis Model. Performed technical analysis supporting SDG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for SDG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION
M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.
B.S., Engineering Physics, University of California, Berkeley, 1977.
Prepared Testimony and Expert Reports

1. California Public Utilities Commission (CPUC) Applications 90-08-066, 90-08-067, 90-09-001

2. CPUC Application 90-10-003


4. CPUC Rulemaking 94-04-031 and Investigation 94-04-032

5. Massachusetts Department of Telecommunications and Energy DTE 97-120

6. CPUC Application 97-12-039

7. CPUC Application 99-09-053

8. CPUC Application 99-09-053

9. CPUC Rulemaking 99-10-025

10. CPUC Application 99-03-014
11. CPUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run

12. CPUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-

13. CPUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California
Water Company’s Application to Increase Rates for Electric Service in the Bear Valley

14. CPUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.

15. CPUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western

16. CPUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power

17. Arizona Corporation Commission Docket Numbers E-00000A-02-0051, E-01345A-01-
0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track

18. CPUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase

19. CPUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for

20. CPUC Rulemaking 01-10-024
Direct Testimony of William A. Monsen Regarding Long-Term Resource Planning Issues

21. CPUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and
22. CPUC Rulemaking 03-10-003

23. CPUC Rulemaking 03-10-003

24. CPUC Rulemaking 04-04-003

25. Sonoma County Assessment Appeals Board

26. Sonoma County Assessment Appeals Board

27. Sonoma County Assessment Appeals Board

28. CPUC Rulemaking 04-03-017

29. CPUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.

30. CPUC Application 05-02-019
31. CPUC Rulemaking 04-01-025, Phase II

32. CPUC Application 04-12-004, Phase I

33. CPUC Application 04-12-004, Phase I

34. CPUC Rulemakings 04-04-003 and 04-04-025

35. CPUC Application 05-01-016 et al.

36. CPUC Rulemakings 04-04-003 and 04-04-025

37. Public Utilities Commission of the State of Colorado Docket No. 05A-543E

38. CPUC Application 04-12-004

39. CPUC Application 04-12-004

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010

41. CPUC Application 07-01-047
42. Public Utilities Commission of the State of Colorado Docket No. 07A-447E
   Answer Testimony of William A. Monsen on Behalf of the Colorado Independent Energy

43. CPUC Application 08-02-001
   Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil
   Department Concerning the Application of San Diego Gas & Electric Company and
   Southern California Gas Company for Authority to Revise Their Rates Effective January

44. CPUC Application 08-02-001
   Rebuttal Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil
   Department Concerning the Application of San Diego Gas & Electric Company and
   Southern California Gas Company for Authority to Revise Their Rates Effective January

45. CPUC Application 08-06-001 et al.
   Prepared Testimony of William A. Monsen On Behalf of the California Demand Response
   Coalition Concerning Demand Response Cost-Effectiveness and Baseline Issues.
   November 24, 2008.

46. CPUC Application 08-02-001
   Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil
   Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas
   & Electric Company and Southern California Gas Company Biennial Cost Allocation

47. CPUC Application 08-06-034
   Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost

48. CPUC Application 08-02-001
   Rebuttal Testimony of William A. Monsen on Behalf of the City of Long Beach Gas & Oil
   Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas
   & Electric Company and Southern California Gas Company Biennial Cost Allocation

49. CPUC Application 08-11-014
   Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the
   Application of San Diego Gas & Electric Company for Authority to Update Cost
   Allocation and Electric Rate Design. April 17, 2009.

50. Public Utilities Commission of the State of Colorado Docket No. 09-AL-299E
   Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and
   Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been
   Filed Under Seal. October 2, 2009.
51. Public Utilities Commission of the State of Colorado Docket No. 09-AL-299E
   Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain,
   Inc. and Vail Summit Resorts, Inc. October 8, 2009.

52. Public Utilities Commission of the State of Colorado Docket No. 09AL-299E Surrebuttal
   Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit

53. United States District Court for the District of Montana, Billings Division, Rocky
    Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC,
    “Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007,
    of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in

54. United States District Court for the District of Montana, Billings Division, Rocky
    Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC,
    “Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption
    Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU)
    Transformer at the Hardin Generating Station, Located in Hardin, Montana,” November
    2, 2010.

55. CPUC Application 10-05-006
    Testimony of William Monsen on Behalf of the Independent Energy Producers
    Association in Track III of the Long-Term Procurement Planning Proceeding Concerning

56. Public Utilities Commission of the State of Colorado Docket No. 11A-869E
    Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy
    Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4,
    2012.

57. CPUC Application 11-10-002
    Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the
    Application of San Diego Gas & Electric Company for Authority to Update Marginal

    Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent
    Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC.
    July 16, 2012.

59. CPUC Rulemaking 12-03-014
    Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers
    Association Concerning Track One of the Long-Term Procurement Proceeding. July 23,
    2012.
60. CPUC Application 12-03-026

61. CPUC Application 12-02-013

62. CPUC Application 12-03-026

63. CPUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in Response to the Division of Ratepayer Advocates’ Opening Testimony. August 27, 2012.

64. Public Utilities Commission of the State of Colorado Docket No 11A-869E


66. Public Utilities Commission of the State Oregon Docket No UM 1182

67. Public Utilities Commission of the State Oregon Docket No UM 1182

68. CPUC Rulemaking 12-03-014

69. CPUC Rulemaking 12-03-014
70. CPUC Application 13-07-021

71. CPUC Application 13-12-012

72. Public Utilities Commission of Nevada Docket No. 14-05003

73. CPUC Application 13-12-012/I.14-06-016

74. CPUC Rulemaking 12-06-013

75. CPUC Rulemaking 13-12-010

76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.

78. CPUC Rulemaking 13-12-010

79. CPUC Application 14-06-014
80. CPUC Application 14-04-014  
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding  


82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006  
(Consolidated)  
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola  

83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042  
Prepared Direct Testimony of William A. Monsen on Behalf of the Alliance for Solar  

Rebuttal Testimony of William A. Monsen on Behalf of the Alliance for Solar Choice  
(TASC). April 7, 2016.

The Energy Freedom Coalition of America's (EFCA) Direct Testimony of William A.  
Monsen. June 1, 2016.

86. Public Utilities Commission of the State of Colorado Proceeding No. 16AL-0048-E  
Answer Testimony of William A. Monsen on Behalf of Vail Summit Resorts, Inc. June 6,  
2016.

87. CPUC Application 15-04-012  
Direct Testimony of William A. Monsen on Behalf of the City of San Diego Regarding  

The Energy Freedom Coalition of America's (EFCA) Direct Testimony of William A.  

The Energy Freedom Coalition of America's (EFCA) Rebuttal Testimony of William A.  

90. CPUC Application 15-04-012  
Rebuttal Testimony of William A. Monsen on Behalf of the City of San Diego Regarding  
Marginal Costs, Revenue Allocation, and Rate Design. October 14, 2016.

91. Public Utilities Commission of Nevada Docket No. 16-07001 and 16-08027

92. CPUC Application 15-04-012

93. CPUC Application 15-04-012

94. Public Utilities Commission of Nevada Docket No. 16-07001 and 16-08027

95. Public Utilities Commission of the State of Colorado Proceeding No. 16A-0396E

96. JAMS Arbitration Case No: 1220049998

97. CPUC Application A.16-06-013
Direct Testimony of William A. Monsen and Anna Casas on Behalf of South San Joaquin Irrigation District. March 15, 2017.

98. CPUC Application A.16-09-003

99. American Arbitration Association Case No. 01-16-0002-2121

100. American Arbitration Association Case No. 01-16-0005-1073

101. CPUC Application A.17-05-004
Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley

102. CPUC Application A.17-05-004
Rebuttal to Testimony by the Office of Ratepayer Advocates by William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case Application. October 27, 2017.

103. Superior Court of California, County of San Diego Case No. 37-2015-00014540-CU-MC-CTL

104. CPUC Application 17-06-030

105. CPUC Application 17-09-006

106. JAMS Arbitration No. 1100088728

107. JAMS Arbitration No. 1100088728

108. CPUC Application 18-03-003

109. CPUC Application 18-03-003

110. CPUC Application 19-03-002

111. CPUC Application 19-11-019
112. Rachel Kropp et al vs Southern California Edison Company Case No. BC698926

113. CPUC Application 19-11-019

114. CPUC Application 20-10-012


116. Kern County Assessment Appeals Board


118. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E

119. CPUC Application 21-06-021

120. CPUC Application 22-05-016

121. CPUC Application 22-08-010

122. CPUC Application 22-08-010
APPENDIX 2
PUBLIC ATTACHMENTS

PG&E DATA RESPONSES TO TURN
EXCERPT FROM TURN TESTIMONY IN A.16-08-006
QUESTION 001

Provide all materials (including recorded cost data and cost forecasts) shared by PG&E or its contractors with the California Energy Commission to support that agency’s preparation of a cost comparison report pursuant to Public Resources Code §25233.2.

ANSWER 001

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. Requests for information related to data used by the California Energy Commission to support that agency’s preparation of a cost comparison report should be directed to the California Energy Commission.
QUESTION 002

Identify the amounts of funding to support Diablo Canyon extended operations already provided or committed by the following entities:

a) California Department of Water Resources
b) Any other state government entity
c) US Department of Energy
d) Any other federal government entity

ANSWER 002

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. Ratepayer funds will not be used to support the transition to extended operations, and costs of extended operations are to be addressed in a future proceeding. PG&E is not seeking cost recovery in connection with the rulemaking. Notwithstanding and without waiving the foregoing objection, PG&E notes that (1) it has entered into an agreement with the California Department of Water Resources to provide up to $1.4 billion in funding to support the transition to extended operations; and (2) the U.S. Department of Energy has conditionally awarded credits valued at up to $1.1 billion to Diablo Canyon as part of its Civil Nuclear Credit program.
QUESTION 003

For any amounts of funding received from, or committed by, entities identified in Question (2), provide the following information:

a) Timing of disbursements

b) Method by which PG&E will hold funds prior to their use to cover specific expenditures

c) PG&E’s specific use of any funds received from the state or federal government to date including the projects or activities supported by these funds.

d) PG&E’s forecast of the amounts of these funds to be allocated to specific activities needed to support extended operations.

ANSWER 003

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. As noted in D.22-12-005, the assessment of whether PG&E’s costs are eligible to be included under the AB 180 and SB 846 agreements is to be determined through a process overseen by the California Department of Water Resources, and any funding amounts provided through the Civil Nuclear Credit program are to be determined by the DOE, not by the Commission. Ratepayer funds will not be used to support the transition to extended operations, and costs of extended operations are to be addressed in a future proceeding. Notwithstanding and without waiving the foregoing objection, PG&E will report the costs entered into the DCTRMA and DCEOBA within 15 days after PG&E receives the result of DWR’s semi-annual true-up review, until such time that the DCTRMA and/or DCEOBA are no longer being used.
QUESTION 004

Provide PG&E’s forecast of costs relating to the NRC relicensing process with a breakdown by cost category including a breakdown of the amounts associated with internal staffing vs. outside contractors/consultants.

ANSWER 004

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. Ratepayer funds will not be used to support the transition to extended operations, and costs of extended operations are to be addressed in a future proceeding. PG&E is not seeking cost recovery of NRC relicensing process costs in connection with the rulemaking.
QUESTION 005

What methods or processes has PG&E adopted, or does PG&E plan to adopt, to track the time devoted by its employees and contractors to activities relating to Diablo Canyon extended operations?

ANSWER 005

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. Ratepayer funds will not be used to support the transition to extended operations, and costs of extended operations are to be addressed in a future proceeding. PG&E is not seeking cost recovery in connection with the rulemaking. Notwithstanding and without waiving the foregoing objection, PG&E notes that this issue was addressed in D.22-12-005. In that decision, the Commission explains that the California Department of Water Resources “is tasked with developing the methodology and process for reviewing costs recorded under the AB 180 and SB 846 agreements (with review of SB 846-related funds performed in coordination with the Commission); therefore, the question of whether PG&E’s recorded costs will be eligible to be funded under these agreements is to be overseen and determined through a DWR, and not a Commission, process.”
QUESTION 006

Identify all recorded costs to date spent by PG&E employees or contractors on activities relating to Diablo Canyon extended operations.

ANSWER 006

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. Ratepayer funds will not be used to support the transition to extended operations, and costs of extended operations are to be addressed in a future proceeding. PG&E is not seeking cost recovery in connection with the rulemaking. Notwithstanding and without waiving the foregoing objection, PG&E will report the costs entered into the DCTRMA and DCEOBA within 15 days after PG&E receives the result of DWR’s semi-annual true-up review, until such time that the DCTRMA and/or DCEOBA are no longer being used, as required by D.22-12-005.
PG&E Data Request No.: TURN_001-Q007
PG&E File Name: DiabloCanyonPowerPlantOperationsExtensionOIR_DR_TURN_001-Q007
Request Date: March 9, 2023
Date Sent: March 24, 2023
Requester DR No.: 001
Requester: Matthew Freedman

 QUESTION 007

Is PG&E allocating the costs of work by its staff and contractors in R.23-01-007 to extended operations?

a) If yes, how does PG&E plan to recover these costs from sources outside of rates?
b) If no, how does PG&E plan to recover these costs in rates?

 ANSWER 007

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this rulemaking proceeding. Notwithstanding and without waiving the foregoing objection, PG&E notes costs associated with the transition to extended operations will be paid for using non-ratepayer funding streams (e.g., the contract between PG&E and the California Department of Water Resources). PG&E is not seeking cost recovery in connection with the rulemaking. Moreover, PG&E notes that this issue was addressed in D.22-12-005. In that decision, the Commission explains that the California Department of Water Resources “is tasked with developing the methodology and process for reviewing costs recorded under the AB 180 and SB 846 agreements (with review of SB 846-related funds performed in coordination with the Commission); therefore, the question of whether PG&E’s recorded costs will be eligible to be funded under these agreements is to be overseen and determined through a DWR, and not a Commission, process.”
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 001**

Relating to the showing of historical costs in Table 1, provide a comparison of the cost categories and values shown for historical years (2017-2022) with the itemized breakdown provided in PG&E’s Results of Operations workpapers for “Electric Generation – Diablo Canyon Power Plant” in the last three General Rate Cases.

a. For 2020-2022 data, explain any differences between Table 1 and the information provided in Ex. PG&E-10 (Results of Operations), Chapter 17 Workpapers, page WP 17-94 (A.21-06-021). Specifically explain any discrepancies between the values shown for “Total Nuclear Operating Costs” on line 9 of Table 1 and the Values for “Operating Expenses - subtotal” shown on line 18.

b. For the 2017-2019 cost data, explain any differences between Table 1 and the information provided in Ex. PG&E-10, Chapter 16 workpapers, page 16-132 (A.18-12-009). Specifically explain any discrepancies between the values shown for “Total Nuclear Operating Costs” on line 9 of Table 1 and the Values for “Operating Expenses – subtotal” shown on line 18.

**ANSWER 001**

PG&E objects to this data request on grounds that it is irrelevant, outside the scope of this proceeding, and burdensome. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows: no such analysis exists and conducting such analysis would be burdensome and unlikely to lead to admissible evidence.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 002**

Identify whether the following costs are included in Table 1. If included, identify which line item incorporates these costs and provide the specific values for each historical year. If excluded, provide the costs for each historical year:

a. Operating expenses – transmission (as shown in PG&E Results of Operations modeling in the General Rate Case)

b. Operating expenses – uncollectibles (as shown in PG&E Results of Operations modeling in the General Rate Case)

c. Administrative and General costs (as shown in PG&E Results of Operations modeling in the General Rate Case)

d. Franchise and SFGR tax requirement (as shown in PG&E Results of Operations modeling in the General Rate Case)

e. Taxes – property, payroll, business, other, start corporation franchise and federal income (as shown in PG&E Results of Operations modeling in the General Rate Case)

f. Depreciation (as shown in PG&E Results of Operations modeling in the General Rate Case)

g. Net for return (as shown in PG&E Results of Operations modeling in the General Rate Case)

h. Pensions and benefits, including the Short-Term Incentive Program, workers compensation, and vacation payoffs to departing employees.

i. Nuclear property and liability insurance

j. Materials and supplies inventory

k. Refueling outage costs
PG&E objects to the request to provide values and costs for each line item on the grounds that such itemized costs are irrelevant, outside the scope of this proceeding, and burdensome. The requested calculations are not related to the scope of this proceeding. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows:

a. Operating expenses – transmission is excluded from Table 1.
b. Operating expenses – uncollectibles is excluded from Table 1.
c. Administrative and General (A&G) costs – A portion of A&G costs are shown in the Capital line as capitalized A&G, except for contract A&G spend, which is excluded from Table 1.
d. Franchise and SFGR tax requirement is excluded from Table 1.
e. Taxes – property, payroll, business, other, start corporation franchise and federal income is excluded from Table 1, except for payroll taxes which is included in the Support Services line.
f. Depreciation is excluded from Table 1.
g. Net for return is excluded from Table 1.
h. Pensions and benefits, including the Short-Term Incentive Program, workers compensation, and vacation payoffs to departing employees is included in Table 1. See Support Services line.
i. Nuclear property insurance is excluded from Table 1. Nuclear liability insurance is included in Table 1. See Support Services line.
j. Materials and supplies inventory is excluded from Table 1.
k. Refueling outage costs is included in Table 1. See Outages line.
**PACIFIC GAS AND ELECTRIC COMPANY**
**Diablo Canyon Power Plant Operations Extension OIR**
**Rulemaking 23-01-007**
**Data Response**

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The following questions relate to PG&E's May 19, 2023, testimony:

**QUESTION 003**

For the costs included in Table 2, identify whether the following costs are included. If included, identify which line item incorporates these costs and provide the estimated values for each year. If excluded, provide the forecasted estimated costs for each future year:

- a. Operating expenses – transmission (as shown in PG&E Results of Operations modeling in the General Rate Case)
- b. Operating expenses – uncollectibles (as shown in PG&E Results of Operations modeling in the General Rate Case)
- c. Administrative and General costs (as shown in PG&E Results of Operations modeling in the General Rate Case)
- d. Franchise and SFGR tax requirement (as shown in PG&E Results of Operations modeling in the General Rate Case)
- e. Taxes – property, payroll, business, other, start corporation franchise and federal income (as shown in PG&E Results of Operations modeling in the General Rate Case)
- f. Depreciation (as shown in PG&E Results of Operations modeling in the General Rate Case)
- g. Net for return (as shown in PG&E Results of Operations modeling in the General Rate Case)
- h. Pensions and benefits, including the Short-Term Incentive Program, workers compensation, and vacation payoffs to departing employees.
- i. Nuclear property and liability insurance
- j. Materials and supplies inventory
- k. Mitigation fees for the State Water Control Board to address the entrainment impacts resulting from the continued ocean water intakes at DCPP.
- l. Refueling outage costs
ANSWER 003

PG&E objects to the request to provide values and costs for each line item on the grounds that it is irrelevant, outside the scope of this proceeding and burdensome. The requested calculations are not related to the scope of this proceeding. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows:

a. Operating expenses – transmission is excluded from Table 2.
b. Operating expenses – uncollectibles is excluded from Table 2.
c. Administrative and General (A&G) costs -- A portion of A&G costs are shown in the Capital line as capitalized A&G, except for contract A&G spend, which is excluded from Table 2.
d. Franchise and SFGR tax requirement is excluded from Table 2.
e. Taxes – property, payroll, business, other, start corporation franchise and federal income are excluded from Table 2 except for payroll taxes which is included in the Support Services line.
f. Depreciation is excluded from Table 2.
g. Net for return is excluded from Table 2.
h. Pensions and benefits, including the Short-Term Incentive Program, workers compensation, and vacation payoffs to departing employees is included in Table 2. See Support Services line.
i. Nuclear property insurance is excluded from Table 2. Nuclear liability insurance is included in Table 2. See Support Services line.
j. Materials and supplies inventory is excluded from Table 2.
k. Mitigation fees for the State Water Control Board to address the entrainment impacts resulting from the continued ocean water intakes at DCPP is included in Table 2. See Operations line.
l. Refueling outage costs are included in Table 2. See Outages line.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 004**

Have employee retention and severance payments been included in the data shown in Tables 1 or 2? If not, identify the amount of such payments by historic year and for each forecasted future year.

**ANSWER 004**

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows:

In regard to historical costs, employee retention and severance payments are not included in PG&E’s Table 1.

In regard to forecast costs, PG&E assumes this question refers to an employee retention program beyond what was already approved in D.18-11-024. As stated in PG&E’s May 19, 2023, testimony, costs associated with such an employee retention program are not included in the forecast table (Table 2) of the testimony. PG&E anticipates submitting a new application to present PG&E’s proposal of the employee retention program, pursuant to Pub. Util. Code § 712.8(f)(2) in the future. PG&E will provide an update to its forecasted costs following submission of this application in accordance with guidance by the CPUC.
The following questions relate to PG&E's May 19, 2023, testimony:

**QUESTION 005**

Identify the ratemaking treatment PG&E assumes in its forecasts shown in Table 2 for nuclear fuel.

- a. Is PG&E proposing any return, financing or carrying costs on nuclear fuel inventory? Identify the ratemaking treatment PG&E assumes in its forecasts.

- b. To the extent that PG&E is proposing any different ratemaking treatment of fuel costs than would result in different costs to ratepayers than is assumed in the forecasts provided in this testimony, explain these differences.

**ANSWER 005**

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows:

PG&E interprets this question as referring to Table 2, line 12 ("Fuel") from its May 19, 2023, testimony. As such,

- a. Assuming that the CPUC adopts new retirement dates for Diablo Canyon, PG&E expects to file an application for extended operations cost recovery in the first quarter of 2024 for rates effective beginning on January 1, 2025. At the time of such an application, PG&E will provide a cost recovery proposal specific to nuclear fuel but is not proposing cost recovery or a ratemaking proposal specific to any return, financing or carrying costs on nuclear fuel inventory in this proceeding. Pursuant to Public Utilities Code § 712.8(h)(1), Diablo Canyon costs including fuel costs "shall be recovered as an operating expense and shall not be eligible for inclusion in the operator's rate base."

    The costs presented in Table 2, line 12 ("Fuel") do not include any return, financing or carrying costs. To the extent that PG&E seeks to recover additional costs, it will do so in its future application subject to the Public Utilities Code § 712.8(h)(1) statutory requirements.

- b. Please see the response to subpart a above.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 006**

Explain the ratemaking treatment PG&E is proposing for capital additions during the period of extended operations.

a. Does PG&E intend to request recovery of any return, carrying or financing costs for capital expenditures or capital additions such as AFUDC? If so, identify and explain the ratemaking treatment PG&E intends to seek.

b. Clarify whether the response to (a) is consistent with the approach used to develop the forecasts shown in Table 2.

**ANSWER 006**

PG&E objects to this data request on grounds that it is irrelevant, not timely, and outside the scope of this proceeding. This proceeding considers the development of cost recovery mechanisms and processes, and not ratemaking proposals. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows:

PG&E is not proposing a specific cost recovery or a ratemaking proposal addressing any return, carrying or financing costs for capital expenditures or capital additions in this proceeding. As stated in PG&E’s May 19, 2023, testimony, assuming that the Commission adopts new retirement dates for Diablo Canyon, PG&E expects to file an application for extended operations cost recovery in the first quarter of 2024 for rates effective beginning on January 1, 2025. At the time of such an application, PG&E’s cost recovery request will include a cost forecast that reflects best information available at that time.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 007**

Provide actual annual generation at DCPP Unit 1 and Unit 2 (shown separately) for each year between 2010-2022.

**ANSWER 007**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E responds that historical annual electric generation of DCPP Unit 1 and Unit 2 are publicly available through PG&E’s FERC Form 1 Reports. FERC Form 1 Reports from 2018-2022 can be found at the following links with historical annual electric generation at pages 401a and 408 and can be found at the following links.


FERC Form 1 Reports from 2010 – 2017 are available in FERC’s eLibrary using the following search parameters:

- **Category**: Submittal
- **Industry Sector**: Electric
- **Document Type**: Report/Form
- **Form 1** – Annual Rpt. For Major Electric Utilities, Licensees & Others
- **Author/Affiliation**: Pacific Gas and Electric Company
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 008**

Provide a forecast of expected annual generation at DCPP Unit 1 and Unit 2 (shown separately) for each year between 2023-2030.

**ANSWER 008**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 009**

Identify expected outage schedules at DCPP Unit 1 and 2 through 2030.

**ANSWER 009**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 010**

Identify the amount of payments received, or expected to be received, from the Department of Water Resources for the monthly performance-based disbursement equal to $7/MWh generated prior to the start of extended operations (see Public Resources Code §25548.3(c)(16). Provide this information for each relevant calendar year.

a. Are these payments included in any line item shown in Table 1 or Table 2? If yes, identify the specific line items and the amounts included for each year.

**ANSWER 010**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding as such amounts are not CPUC-jurisdictional costs. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows:

Payment amounts from the Department of Water Resources related to the monthly performance-based disbursement are not included in Table 1 or Table 2.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 011**

Identify the amounts expected to be recovered in rates by PG&E in each future year tied to the $13/MWh (in 2022 dollars) volumetric payment authorized pursuant to Public Utilities Code §712.8(f)(5)

a. Are these ratepayer obligations included in any line item shown in Table 2? If yes, identify the specific line item and the amounts included for each year.

**ANSWER 011**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E clarifies that any payment amounts related to the referenced volumetric payment would be presented in a future application for extended operations cost recovery. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows. Payment amounts related to the referenced volumetric payment are not included in Table 2.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 012**

Identify the amounts expected to be recovered in rates by PG&E in each future year tied to the $50 million/unit (in 2022 dollars) fixed payment authorized pursuant to Public Utilities Code §712.8(f)(6)(A).

a. Are these ratepayer obligations included in any line item shown in Table 2? If yes, identify the specific line item and the amounts included for each year.

**ANSWER 012**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E clarifies that any payment amounts related to the referenced fixed payment would be presented in a future application for extended operations cost recovery. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows. Payment amounts related to the referenced fixed payment are not included in Table 2.
The following questions relate to PG&E’s May 19, 2023, testimony:

**QUESTION 013**

Identify the amounts expected to be recovered in rates by PG&E in each future year for the liquidated damages balancing account authorized pursuant to Public Utilities Code §712.8(g). Provide the expected collection schedule for these amounts.

a. Are these ratepayer obligations included in any line item shown in Table 1 or Table 2? If yes, identify the specific line item and the amounts included for each year.

**ANSWER 013**

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E clarifies that any payment amounts related to the referenced liquidated damages balancing account would be presented in a future application for extended operations cost recovery. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows. Payment amounts related to the referenced liquidated damages balancing account are not included in Table 1 and Table 2.
PG&E Data Request No.: TURN_004-Q001
PG&E File Name: DiabloCanyonPowerPlantOperationsExtensionOIR_DR_TURN_004-Q001
Request Date: June 9, 2023
Date Sent: June 26, 2023
Requester DR No.: 004
Requester: The Utility Reform Network
Requester: Matthew Freedman

PG&E Witness: Brian Ketelsen

QUESTION 001

Relating to the showing of historical Diablo Canyon costs in Table 1 of PG&E’s May 19, 2023 testimony, provide these same costs using the cost categories proposed in PG&E’s June 9 testimony (pages 3-3 through 3-7) as follows:

a. Operations and Maintenance Costs for each MWC (see page 3-4, Item (2))
   i. MWC AB
   ii. MWC AK
   iii. MWC BP
   iv. MWC BQ
   v. MWC BR
   vi. MWC BS
   vii. MWC BT
   viii. MWC BV
   ix. MWC OM
   x. MWC OS
   xi. MWC IG

b. Common Costs (see page 3-4, item (3))

c. Fuel and Fuel Inventory Costs (see page 3-5, item (5))

ANSWER 001

PG&E objects to this data request on the grounds that it is not timely, is premature, and not in the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E responds that the requested information does not exist. The May 19, 2023, testimony reflects PG&E’s most recent and complete set of cost information, presented in its September 2022 Department of Energy (DOE) Civil Nuclear Credit (CNC) program, and updated to reflect actual 2022 costs. However, the costs in the testimony are presented in the EUCG industry accounting format because the DOE required that the CNC applications be submitted using that methodology. The cost
categories identified in this question from the June 9, 2023, testimony are intended for a future cost recovery application proceeding.
QUESTION 002

Relating to the showing of estimated future Diablo Canyon costs in Table 2 of PG&E’s May 19, 2023, testimony, identify the amounts in the Table 2 forecast associated with each of the following cost categories proposed in PG&E’s June 9 testimony (pages 3-3 through 3-7) as follows:

a. Operations and Maintenance Costs for each MWC (see page 3-4, Item (2))
   i. MWC AB
   ii. MWC AK
   iii. MWC BP
   iv. MWC BQ
   v. MWC BR
   vi. MWC BS
   vii. MWC BT
   viii. MWC BV
   ix. MWC OM
   x. MWC OS
   xi. MWC IG

b. Common Costs (see page 3-4, item (3))

c. Expense Project Costs (see page 3-4, item (4))

d. Fuel and Fuel Inventory Costs (see page 3-5, item (5))

ANSWER 002

PG&E objects to this data request on the grounds that it is not timely, is premature, and not in the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E responds that, similar to the response to Question 1 on the historical costs, the information does not exist. The costs in the May 19, 2023, testimony reflects PG&E’s most recent and complete set of cost information, presented in its September
2022 DOE CNC program. The estimated future costs are presented in the EUCG industry accounting format because the DOE required that the CNC applications be submitted using that methodology. PG&E's proposal in the June 9, 2023, testimony is that, in its future cost recovery application, the cost categories be presented as described therein. PG&E does not plan to use the EUCG accounting format for its future cost recovery application with the CPUC.
QUESTION 003

Relating to the showing of estimated future Diablo Canyon costs in Table 2 of PG&E’s May 19, 2023, testimony, identify whether PG&E included forecasts for any of the proposed cost categories outlined in PG&E’s June 9 testimony (pages 3-3 through 3-7). If the answer is yes, identify the amounts forecasted for each of these items:

a. Employee Retention Costs (see page 3-5, item (6)(a))
b. Decommissioning Planning Costs (see page 3-6, item (6)(b)).
c. Independent Peer Review Panel Costs (see page 3-6, item (6)(c))
d. Statewide volumetric payment (see page 3-6, item (6)(d))
e. PG&E service Territory Volumetric Payment (see page 3-6, item (6)(e))
f. Fixed Payment (see page 3-7, item (6)(f))
g. Liquidated Damages Fee (see page 3-7, item (6)(g))

ANSWER 003

PG&E interprets this question as meaning whether the cost categories identified in subparts (a) through (g), as described in the June 9 testimony, are included in Table 2 from the May 19 testimony. In addition, PG&E clarifies that the EUCG accounting format as required by the DOE CNC application does not “break down” into further detail as a GRC accounting format would; rather, the EUCG format contains the costs described in Attachments A and B of the May 19 testimony (which provide the EUCG definitions). With that interpretation, PG&E responds as follows:

a. No.
b. No.
c. No. PG&E clarifies that the Diablo Canyon Independent Safety Committee and Nuclear Safety Oversight Committee are included.
d. No.
e. No.
f. No.
g. No.
QUESTION 004

For the “Common Costs – Test Year” described on page 3-4, explain how the costs to be included in this category differ from the costs classified as “Administrative and General” in PG&E’s Results of Operations workpapers for “Electric Generation – Diablo Canyon Power Plant”. (See Ex. PG&E-10 (Results of Operations), Chapter 17 Workpapers, page WP 17-94 (A.21-06-021)).

ANSWER 004

PG&E interprets the referenced Ex. PG&E-10, Chapter 17 to reference its most recent GRC in case Application 21-06-021. With this interpretation, PG&E responds based on current best available cost forecasts included in its May 19, 2023, testimony and DOE CNC application. Included in PG&E’s May 19, 2023, testimony, PG&E describes those costs not included in the cost presentation. PG&E notes that these costs, which include property taxes, income taxes, Allowance for Funds Used During Construction, depreciation, and interest expense, are not captured in the GRC for Nuclear Operations Costs. PG&E cannot describe with certainty what will be included in its first extended operations cost recovery application at this stage and as indicated in the June 9 testimony, will make a showing demonstrating that any costs PG&E seeks to recover would be incremental and therefore eligible for recovery. The Commission has not yet resolved the structure or timeline of that proceeding or responded to PG&E’s proposal. PG&E asserts that its first cost forecast application, expected to be filed sometime in Q1-2024, will be the appropriate venue to assess Common Costs.

A&G costs support and benefit all of PG&E’s functional areas, including nuclear generation, using common cost allocation factors. These common costs are generally not directly chargeable to a specific area and are allocated to all functional areas. A&G expenses include costs such as wages and salaries, office supplies, and outside services of Corporate Services departments (such as Law, Finance, Human Resources and Regulatory Affairs), Information Technology, centralized services, and the A&G portions of certain Enterprise-wide and Customer programs. A&G costs also include bank and director fees, property and liability insurances, workers’ compensation payments, third-party claims, litigation, settlements and judgments, employee benefits and the costs of maintaining common and general plant. The common A&G costs allocated to nuclear generation are recovered through PG&E’s GRC through 2025. Also, through 2024 and 2025, nuclear liability and property insurances are
included in the GRC for Units 1 and 2, respectively. Please refer to the 2023 GRC Exhibit (PG&E-10), Chapter 8, page 8-7. Equivalent common A&G costs will be included in a separately filed application for the period of extended operations. Also, PG&E clarifies that it will not double recover any costs that were recovered from its GRC or other proceedings in its future DCPP extended operations cost recovery request and application.
CPUC Docket: A.16-08-006
Exhibit Number: __________
Witness: William P. Marcus

PREPARED TESTIMONY OF THE UTILITY REFORM NETWORK

VOLUME 1 – TESTIMONY OF WILLIAM PEREA MARCUS

ADDRESSING THE PROPOSALS OF PACIFIC GAS AND ELECTRIC COMPANY RELATED TO THE COST OF CONTINUED OPERATION OF THE DIABLO CANYON POWER PLANT AND COST RECOVERY FOR LICENSE RENEWAL EXPENDITURES

(COMMON TESTIMONY OUTLINE SECTIONS I AND V)

JBS Energy, Inc.
311 D Street
West Sacramento
California, USA 95605
916.372.0534

January 27, 2017
V. PG&E Should Not Be Permitted to Recover the $53 Million Incurred on its Own Initiative to Pursue License Renewal.
List of Tables

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List of Attachments

Attachment 1 Qualifications of William Perea Marcus
Attachment 2 Data Requests Relied Upon in Diablo Canyon Cost Analysis
Attachment 3 PG&E Material Relied Upon in License Renewal Cost Analysis
Attachment 4 Booking AFUDC on Suspended Projects
closures, this report identifies lower outage costs in the Base Case with spring closures than in
the sensitivity case without them.

H. Administrative Overhead
In 2017, PG&E forecasts $587.554 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 $93.209 million.13

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.14 Given the expansion of other activities on the PG&E
system since the late 1990s, we estimate department-specific expenses related to Diablo Canyon
that would be avoidable with plant closure in the medium term as 8% of A&G expenses (roughly
half of the expenses allocated to Diablo Canyon) for purposes of this study. That figure is
$47.004 million in 2017 nominal dollars. We escalate administrative overhead expenses at
inflation even though wages at PG&E rise slightly faster than general inflation.

I. Pensions and Benefits
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
are part of the employee-related cost of Diablo Canyon even though they are not part of Diablo
Canyon’s “business unit” costs.

13 PG&E 2017 TY GRC Workpapers to Exhibit PG&E-10, O&M Labor Tab.
14 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.
APPENDIX 3
CONFIDENTIAL ATTACHMENTS
REDACTED IN PUBLIC VERSION

EXCERPT FROM PG&E APPLICATION TO
US DEPARTMENT OF ENERGY CIVIL NUCLEAR CREDIT PROGRAM