Decision **PROPOSED DECISION OF ALJs DARLING and DUDNEY**
(Mailed 11/19/2013)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Southern California Edison Company and San Diego Gas and Electric Company Associated with the San Onofre Nuclear Generating Station Units 2 and 3.	Investigation 12-10-013 (Filed October 25, 2012)
And Related Matters.	Application 13-01-016 Application 13-03-005 Application 13-03-013 Application 13-03-014

DECISION ON PHASE 1 REGARDING 2012 SONGS-RELATED EXPENSES AND EXPENDITURES

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PROPOSED DECISION ON PHASE 1 RELATED TO 2012 SONGS-RELATED EXPENSES AND EXPENDITURES

1. Summary

This decision adopts interim rate reductions for Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) ratepayers as a result of reduced operating costs in 2012 following cessation of generation at San Onofre Nuclear Generating Station (SONGS). The decision orders refunds of approximately $94.0 million for overcollection of these costs.

The Commission has undertaken a multi-phase investigation into the actions and expenses by SCE and SDG&E (collectively Utilities) after a small radiation leak in a new steam generator led to discovery of serious vibration wear that forced both SONGS reactor units offline after January 31, 2012. This decision covers the first two phases which assess the reasonableness of 2012 expenses charged to ratepayers, including those incurred as a result of the outages.

Due to the non-operation of both units during 2012, the Commission declined to give final approval to the Utilities' estimated SONGS-related 2012 expenses in their respective general rate cases. Instead, the Commission deferred final review of that portion of revenue requirement to this investigation. Meanwhile, the Utilities have already collected a range of 2012 costs in rates. The Commission's Order Instituting Investigation ordered SCE and SDG&E to record all SONGS-related expenses, including those recovered in rates and report the expenses to the Commission on a regular basis.

In the 2012 GRC decisions, the Commission preliminarily allowed rate recovery of estimated SONGS Operations and Maintenance (O&M) and capital spending, subject to refund upon later review of recorded costs within the

framework of the reasonableness of SCE's actions (as operator) as events unfolded in 2012. The Phase 1 portion of the decision provides the deferred reasonableness review of 2012 GRC expenses, and other expenses incurred in 2012 as a result of the outages.

The Commission finds that, $273.9 million (2012$, 100% share[1]) in total 2012 Base Operations and Maintenance (O&M) and associated costs, were reasonable and necessary under the circumstances. This is $115 million less than the GRC-authorized amount of $389 million. In addition, we find that $45.1 million in O&M related to the refueling outage of Unit 2 was reasonable because the work was essentially complete before SCE knew the potential for serious damage in Unit 2.

Our review of capital spending determined that $134.1 million of $167.6 million in costs recorded by SCE was reasonable SONGS-related capital spending to safely maintain the plant. Based on excess capital additions, the Commission orders a 20% reduction of net 2012 additions to rate base and corresponding decreases to recovered capital costs. The overall result is the first SONGS-related refund to ratepayers in this investigation.

For SONGS, 2012 was a transitional year. SCE took reasonable steps to investigate the steam generator problems, and to mitigate some costs, as confirmed by the U.S. Nuclear Regulatory Commission. However, we find SCE to be single-minded about its restart plan, and slow to understand the technical challenges and regulatory timeframe required to implement it. SCE's decision to apply resources to a restart plan was the result of an unsound decision-making

[1] Most SONGS-related costs are reported as total costs, or 100% of the costs. "SCE share" means $78.21% of the total costs; SDG&E share means 20% of the total costs.

process, primarily because SCE did not consider cost effectiveness or alternatives such as putting Unit 2 into preservation mode, or realistically assess the regulatory hurdles blocking a reasonably foreseeable restart. Therefore, the decision adopts interim rate reductions based on removing an approximation of resulting costs.

The Commission orders the immediate refund of the excess rates collected in anticipation of normal operations at SONGS in 2012, which are deemed not just and reasonable given the fact that no generation occurred after January 31, 2012, nor was it likely to occur in 2012. This decision provides interim rate relief to ratepayers, but $122.6 million in other O&M costs related to the steam generators are still subject to final review in Phase 3. The Commission has not yet determined how much of these costs, if reasonable, will be charged to ratepayers because SCE has made insurance and warranty claims for some of the costs, and allegations of SCE fault remain to be examined.

To reach this decision, we reviewed recorded 2012 expenses in light of the nature and effects of the damage and SCE's consequential actions and costs. The decision establishes May 7, 2012 as the date by which SCE knew, or should have known, that the new type of tube wear linked to the tube leak in Unit 3 was also present, to a lesser degree, in Unit 2. Therefore, Unit 2 and Unit 3 would not likely return to normal operations in the short-term. Despite unduly optimistic reports to SCE's Board of Directors, SCE was aware that no submission to the NRC could occur for months, and SCE's internal actions signaled an understanding that repair options were far from developed. Therefore, reductions were primarily based on removal of an approximate SGIR-related revenue requirement, tempered by SCE's regulatory requirements to maintain the plant in a safe manner.

We also order the continued tracking of incremental costs incurred due to the steam generator outages for further review in Phase 3 when the Commission examines the Steam Generator replacement project as a whole. The Utilities shall cease collection of these incremental costs, and these funds shall be separately accounted for, including interest paid as of June 1, 2012 on recorded SGIR-related O&M and capital costs, if already collected in rates.

The Phase 1A portion of today's decision adopts a method for calculating the cost of replacement power in 2012, and orders the utilities to serve exhibits detailing their calculations according to the adopted method. Recovery of the calculated replacement power costs will be decided in Phase 3 of this proceeding.

2. Background

The San Onofre Nuclear Generating Station (SONGS), located adjacent to Camp Pendleton near San Clemente California, is jointly owned by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and the City of Riverside (with shares of 78%, 20% and 2% respectively).[2] SCE is the plant operator and bills co-owners for their share of costs.

Pursuant to SCE's 2004 application,[3] the Commission authorized the replacement of the four steam generators at SONGS Unit 2 (U2) and Unit 3 (U3),[4] to be followed by utility applications for reasonableness review of the project costs after completion.[5] Mitsubishi Heavy Industries (MHI) designed and

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[2] The City of Riverside is a municipal utility not under the California Public Utilities Commission's (Commission's) jurisdiction.

[3] Application (A.) 04-02-026.

[4] SONGS Unit 1 has been decommissioned.

[5] Decision (D.) 05-12-040 at Ordering Paragraph (OP) 11, as modified by D.11-05-035.

manufactured the replacement steam generators. The steam generators in U2 were replaced and put online in January 2010; U3 steam generators were replaced and put online in January 2011. In reliance on the Commission's decision approving the Steam Generator Replacement Project (SGRP), both Utilities began to recover a portion of the originally approved costs in 2011.

On January 10, 2012, U2 was taken out of service for a scheduled Refueling Outage (RFO) and expected to return to service on March 5, 2012. U3 was taken offline on January 31, 2012, after station operators detected a radiation leak in a steam generator tube. U2 and U3 were offline throughout the rest of 2012. On June 7, 2013, SCE announced it would not seek to restart either SONGS unit.

In February 2012, the first of many inspections and tests identified different types of tube wear in the U2 and U3 steam generators. SCE engaged with the U.S. Nuclear Regulatory Commission (NRC) following the discovery in U3, and NRC conducted an audit of the problem. SCE also undertook its own investigations and inspections. An unknown phenomena, known as tube-to-tube wear was observed in both U2 and U3 by April 27, 2012.

SCE rescheduled the date for completion of the U2 RFO from March 4, 2012 to March 20, 2012, the first of many delays. SCE identified all compromised, or potentially compromised, tubes and plugged or stabilized them. However, the NRC did not allow SCE to restart the units, even at reduced power, during 2012, or thereafter.

As part of their 2012 General Rate Case (GRC), SCE initially sought approval of its total forecast 2012 SONGS-related expenses based on ordinary

operating conditions.[6] SCE estimated $389 million ($2012) for 2012 Operations & Maintenance (O&M) (100%), and $189 million for capital expenditures, as well as $45.0 million for each of two scheduled refueling outages. SDG&E requested rate recovery of its 20% pro rata share through its 2012 GRC, in addition to capital costs and other internal SONGS-related expenses.

Both SCE's and SDG&E's GRCs were pending during 2012. However, the evidentiary records closed well before the year ended and all facts were known. During 2012, SCE incurred O&M costs and capital spending even as it became clear that the units would not be restored to service in 2012, a critical change in circumstance. The Commission decided to review all actual 2012 expenses associated with the non-productive plant after they became known, including SCE's operational response to the extended outages.

Pursuant to Public Utilities Code Section 455.5, on November, 1, 2012, the Commission issued an Order Instituting Investigation (OII)[7]:

> This investigation will consider the causes of the outages, the utilities' responses, the future of the SONGS units, and the resulting effects on the provision of safe and reliable electric service at just and reasonable rates.[8]

The OII ordered SCE and SDG&E to each establish a SONGS Outage Memorandum Account (SONGSMA) to track by category all SONGS-related costs and expenditures incurred on or after January 1, 2012, and revenues collected in recovery of those costs. The Utilities were required to categorize

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[6] A.10-11-015.

[7] Unless otherwise indicated, all future statutory references refer to the Public Utilities Code.

[8] Order Instituting Investigation (I.) 12-10-013 at 2.

recorded expenses by certain subaccounts to identify, inter alia, fixed costs, variable costs, SGRP costs, investigation costs, safety-related program costs, replacement generation, repair costs, regulatory costs, etc.[9] A copy of SCE's year-end 2012 report on the SONGSMA (SCE share) is attached hereto as Appendix A; a copy of SDG&E's year-end reports is attached as Appendix B.

In the GRC decisions for both Utilities, the Commission concluded it was in the best interests of ratepayers to preliminarily allow SONGS-related 2012 O&M and capital expenditures that would have been authorized under normal operating conditions. We anticipated that SCE would need to maintain some systems (e.g., cooling) and divisions (e.g., security, environmental safety) in 2012, regardless of operating conditions, as well as apply resources to understand and address the effects and conditions it faced for the future.

We deferred the final reasonable reviews to the OII and ordered these 2012 costs subject to refund. In Decision (D.) 12-11-051, the Commission confirmed its order to SCE and SDG&E to establish memorandum accounts to be harmonized with the OII, for the purpose of tracking all post-2011 SONGS-related costs for subsequent review. Consistent with the OII, the Commission imposed similar orders in the SDG&E GRC decision.[10]

Following the U3 outage, SCE incurred inspection and repair costs for U2 and U3, while it claimed to be developing a short-term restart plan for U2 and exploring long-term plans for both units. These costs are distinct from Base

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[9] The Utilities developed a common format but SCE claims it cannot segregate "safety-related" costs on the basis that safety activities cross several budgets and cannot be reasonably identified.

[10] D.13-05-010.

(routine) O&M. In 2012, both SCE and SDG&E also had to purchase power to replace power lost due to the SONGS outages. The methodology to calculate the amount of replacement power purchased is established below.

3. Procedural History

On November 1, 2012, the Commission opened this OII to consolidate and consider issues raised by the extended outages of SONGS U2 and U3.

The OII identified rate recovery issues including: (1) review of all post-2011 O&M costs and capital spending; (2) costs of scheduled RF) and emergent activities; (3) removal of non-useful generation assets from rate base; and (4) various questions around the costs, viability, and prudency of the SGRP approved in D.05-12-040.

Within the OII, the Commission stated its intention to consolidate other proceedings, to be initiated in the future, which would encompass review of the full range of post-outage costs and activities.[11] Subsequently, SCE and SDG&E have each filed applications for reasonableness review of 2012 recorded O&M and capital spending,[12] for approval of the totality of the SGRP costs,[13] and for power purchased during 2012, including replacement of power lost due to the outages.[14] The Utilities seek rate recovery from ratepayers for all of these expenses.

A prehearing conference (PHC) was held on January 12, 2013. The assigned Commissioner and Administrative Law Judge (ALJ) determined that to

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[11] OII at 8.

[12] A.13-01-016 (SCE), A.13-03-013 (SDG&E).

[13] A.13-03-005 (SCE), A.13-03-014 (SDG&E).

[14] A.13-04-001 (SCE).

promote the efficient administration of the OII, it would be divided into several phases, each with its own PHC and Scoping Memo. Among the benefits of this approach are: (i) the building of a chronological record, (ii) pacing for certain information not yet known, and (iii) consistent decisions in future phases.

On January 28, 2013 assigned Commissioner Michel Peter Florio and ALJ Melanie M. Darling[15] issued a scoping memo for Phase 1, set dates for parties to serve testimony, and established dates for evidentiary hearings in Phase 1. The Phase 1 scope is as follows:

1. Nature and effects of the steam generator failures in order to assess the reasonableness of SCE's consequential actions and expenditures;
2. Whether 2012 SONGS-related O&M expenses and capital expenditures recorded in the SONGSMA are reasonable and necessary, including:
   - 100% of cost-savings from personnel reductions and other avoided costs; and
   - 100% of refueling outage expenses;
3. A review of the reasonableness and effectiveness of SCE's 2012 actions and expenditures for community outreach and emergency preparedness related to the SONGS outages; and
4. Other issues as necessary to determine whether SCE should refund any rates preliminarily authorized in the 2012 GRC, in light of the changed facts and circumstances of the unit outages; if so, when should the refunds occur.

SCE's and SDG&E's applications for review of 2012 O&M costs and capital expenditures recorded in the SONGS Memorandum Accounts, consolidated with

[15] On May 1, 2013, ALJ Kevin Dudney was co-assigned to the OII.

the OII, are the primary focus of review in Phase 1. These proceedings were consolidated with the OII in April, 2013.[16]

In response to the OII, SCE and SDG&E both argued the Commission lacked authority to (1) review and refund 2012 estimates of O&M and capital spending, as deferred by the GRC decision; and (2) remove any SONGS assets and associated O&M from rate base pursuant to § 455.5, prior to SCE's 2015 GRC. The Scoping Memo directed parties to brief these legal issues.

An April 30, 2013 Assigned Commissioner and Administrative Law Judge Ruling resolved these questions. As it relates to Phase 1, the Commission ruled that it has legal authority to conduct the deferred final reasonableness review of SONGS-related expenses (100%) sought in SCE's 2012 GRC and immediately order refunds, if warranted.[17]

Therefore, Phase 1 identifies what SONGS-related costs SCE and SDG&E incurred in 2012, and how should they be categorized, e.g., base (GRC) O&M, base capital expenditures, RFO base costs and emergent work, incremental and consequential steam generator inspection and repair costs. In addition, Phase 1 considers the reasonableness of the various identified 2012 costs given the facts and circumstances SCE knew, or should have known, at the time the costs were incurred. Finally, Phase 1 determines whether refunds should be issued to ratepayers for overcollections in 2012.

By e-mail ruling on May 3, 2013, the assigned ALJs created a sub-phase, called Phase 1A, to develop a method for calculating 2012 costs of replacement

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[16] Ruling dated April 19, 2013.

[17] Assigned Commissioner's and Administrative Law Judge's Ruling on Legal Questions (April 30, 2012) at 17.

power. Although the ALJs announced that they intended to resolve Phase 1A issues by a ruling, we have decided to resolve both Phase 1 and Phase 1A issues in today's decision.

Several parties participated in Phase 1 and Phase 1A by serving testimony, conducting cross-examination of witnesses, and/or filing post-hearing briefs. In addition to SCE and SDG&E, these parties are Division of Ratepayer Advocates (DRA),[18] The Utility Reform Network (TURN), Alliance for Nuclear Responsibility (A4NR), World Business Academy (WBA), Women's Energy Matters (WEM), Joint Parties (comprised of National Asian American Coalition, Ecumenical Center for Black Church Studies, Latino Business Chamber of Greater Los Angeles and Chinese American Institute for Empowerment), and the Coalition to Decommission San Onofre (CDSO).

Motions to alter the Scoping Memo, to immediately order refunds, strike testimony, etc. have been filed and ruled upon, none of which altered the course of the OII set forth in the Scoping Memo, except to clarify that ordinary review of power purchases by both Utilities would continue to occur in their respective Energy Resource Recovery Account (ERRA) proceedings.

Evidentiary hearings in Phase 1 were held from May 13 to 17, 2013. During examination of SCE witnesses, it was disclosed that SCE had identified "Base" O&M costs by timing each month, rather than by actual purpose of the expense. At the end of the hearings, SCE and SDG&E each agreed to provide an exhibit with a revised breakdown of 2012 costs by month, segregated as to Base O&M and costs incurred as a result of the outages. As a result, on July 22, 2013,

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[18] Now known as the Office of Ratepayer Advocates.

SCE served SCE-35 and SDG&E served SDGE-11. These exhibits are accepted into the proceeding record.

Phase 1 Opening Briefs and Reply Briefs were filed by SCE, SDG&E, DRA, TURN, A4NR, WBA, CDSO, Joint Parties and WEM on June 28, 2013 and July 9, 2013, respectively.

Evidentiary hearings in Phase 1A were held on August 5 and 6, 2013. SDG&E served late-filed exhibit SDGE-17 on August 9, 2013, which is an errata to SDG&E's 2012 SONGS Outage Memorandum Account (SONGSMA). This exhibit is admitted into the proceeding record.

Phase 1A Opening Briefs were filed on August 29, 2013 by SCE, SDG&E, DRA, and A4NR. Phase 1A Reply Briefs were filed by SCE, SDG&E, TURN, A4NR, DRA, and WEM.

The matter, including both Phase 1 and Phase 1A, is submitted as of September 12, 2013.

4. Standard of Review

Phase 1 is in essence a ratesetting action and the standard of review for rate recovery is the preponderance of evidence.[19] Despite A4NR's reference to dated Commission decisions which used the term "clear and convincing," this legal standard has been explicitly rejected by the Commission.[20] We are not persuaded by A4NR's argument that SCE's conduct has been found to be so imprudent in its response to the outages that the higher burden of proof should apply. The Commission has not made any finding of imprudence in the Phases

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[19] D.12-11-051.

[20] D.11-05-018 at 34.

resolved in this decision. Instead, the test is whether SCE's 2012 actions as the SONGS operator, were reasonable and prudent.

A4NR and SDG&E both emphasized past Commission findings which evaluated the reasonableness of operational decisions. As affirmed by SDG&E, SCE must show that its decision-making process was sound, its managers considered a range of options in light of information that SCE knew or should have known, and decided on an action within the bounds of reasonableness.[21]

A4NR recalls the Commission's prior finding that "a 'reasonable and prudent' act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction."[22]

This standard of reasonableness does not derive from the consequences of managerial action, but the soundness of the utility's decision-making process that led to the decision and the consequences.[23]

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[21] SDG&E Opening Brief (OB) at 3.

[22] A4NR OB at 7 (citing D.05-08-037 at 4-5).

[23] D.05-08-037 at 4-5 (citing D. 89-02-074) ("a decision may be found to be reasonable and prudent if the utility shows that its decision making process was sound, that its managers considered a range of possible options in light of information that was or should have been available to them, and that its managers decided on a course of action that fell within the bounds of reasonableness, even if it turns out not to have led to the best possible outcome").

5. Parties' General Positions

5.1. Utilities

SCE and SDG&E seek a finding that all of the 2012 SONGS-related recorded expenses are reasonable under the circumstances, and request Commission approval to recover 100% of the expenses in rates.

In addition to testimony provided in these proceedings, each utility has regularly provided the Commission with reports of recorded SONGS-related costs, pursuant to the OII.[24] As a result of accounting anomalies revealed, each utility provided a further breakdown of recorded "Routine" O&M between "Base-Routine" and "Base-SGIR" costs after the evidentiary hearings concluded.[25]

In 2012, SCE recorded its share of total "routine" O&M and capital costs of $520.2 million ($2012), plus an additional $139.8 million for the U2 RFO, seismic study costs, and SG Base and Inspection and Repair (SGIR) costs.[26] SCE recorded total (100% share) capital expenditures of $167.6 million, of which the SCE share is $131.08 million.[27] SGIR-related capital expenditures by SCE total $13.9 million.

SDG&E claims its total share of comparable 2012 costs is $133.47 million,[28] plus an additional $36.288 million for the U2 RFO, seismic study costs, and SGIR

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[24] SCE provides monthly reports, SDG&E provides quarterly reports.

[25] SCE-35; SDG&E-11.

[26] Appendix A, SCE Monthly Report filed in compliance with I.12-10-013 (February 1, 2013).

[27] SCE-04 at 87-88 (SCE recorded $133.606 million which includes $2.5 million for SCE's share of license renewal-related expenditures not claimed for recovery).

[28] Includes an adjustment of $694,000 based on difference between Routine O&M in 1Q2013 SDG&E Quarterly Report filed in compliance with I.12-10-013 (April 2, 2013) and SDG&E-11 ($73.559 - $72.865 million = <0.694 million>).

costs.[29] SDG&E recorded capital expenditures of $39.3 million invoiced by SCE, and an additional $10 million for its own overheads.[30] The capital expenditures for SGIR are not quantified.[31]

SCE contends that, in light of the nature of the steam generator failures, its consequential actions and expenditures during 2012 were reasonable, including completion of U2 refueling activities and all costs related to inspection and repair of the steam generators (SGIR). Although both SONGS units were in extended outages as a result of the tube problems in both units, SCE argues that SONGS was an operating facility in 2012.[32]

As operating agent, SCE states it was required to ensure that all plant systems remained functional to protect the nuclear fuel and to ensure the radiological health and safety of the public and workers. Systems were maintained, rather than be allowed to deteriorate, to prepare for resumed operations.

In addition, SCE claims it postponed or canceled some capital projects and O&M activity when it was possible "without compromising regulatory and safety-related objectives."[33] Furthermore, SCE asserts it would have been imprudent not to undertake actions to investigate the causes of the damage to the units, and to develop plans to return the units to service in the long-term.[34]

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[29] SDG&E-3 at 12; SDG&E-11 at 3.

[30] *Id.,* Work papers at 3.

[31] SDG&E-3 at 9; SDG&E 3-Workpapers at 3.

[32] SCE OB at 1.

[33] *Ibid.*

[34] *Ibid.*

Therefore, SCE asks the Commission to find that it acted reasonably in 2012 in taking actions to maintain systems, structures, components, and other processes and procedures as required by its operating licenses, and to restore the units safely to service. SCE also asks the Commission find that 100% of 2012 expenses recorded in the SONGSMA were reasonably incurred, and to allow full rate recovery.

SDG&E agrees with SCE, primarily because it relies on SCE to undertake decision-making and activities consistent with the terms of the Operating Agreement[35] and the NRC license.[36] SCE states that it "is unaware of any material facts or representation made by SCE during Phase 1 that would contradict SCE's written testimony or data responses pertaining to its consequential actions, the timing thereof, and the resulting expenditures in 2012 in light of the steam generator failures."[37]

SDG&E requests similar treatment for its share of total SONGS-related expenses recorded by SCE, and approval of approximately $60.5 million in other 2012 GRC costs for which the Commission deferred reasonableness review to this proceeding.[38] Although the extra SDG&E expenditures occur regardless of whether SONGS generates electricity, SDG&E claims they are required as a result of its ownership of SONGS. Therefore, SDG&E requests that these 2012

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[35] SCE and the other co-owners have executed an Operating Agreement covering the terms and conditions for operations and pro rata recovery of costs.

[36] SDG&E OB at 3.

[37] *Ibid.*

[38] D.13-05-010 (A.10-12-006).

incurred expenses associated with these activities be found reasonable, prudently incurred and recoverable from ratepayers

5.2. Division of Ratepayer Advocates (now known as Office of Ratepayer Advocates)

DRA disagrees that SCE has established any 2012 SONGS costs were reasonably incurred in 2012. Instead, DRA argues the Commission cannot conduct a reasonableness review of SCE's SONGS-related 2012 expenses, should not allow rate recovery at this time, and should promptly order refunds of "unnecessary" charges associated with SONGS.[39] DRA explains that "unnecessary" charges include revenue requirement collected in excess of actual expenses, but does not quantify what it considers "necessary" or "unnecessary."

DRA has "no objection" to eventual recovery of "verifiable" safety and security-related 2012 costs, but argues that SCE did not establish those actual expenses, e.g., no segregated safety expenses, no workpapers to support security expenses.[40] Moreover, DRA concludes there is insufficient evidence to support a Commission finding that SCE's 2012 actions and expenditures in connection with the steam generator failures were reasonable.[41] As to these costs, DRA recommends that the Commission defer any such finding until completion of the NRC's investigations into SONGS Units 2 and 3 and key facts about third party cost recovery are known.[42] One of DRA's witnesses went further and stated that no recovery should be allowed at all, because SCE can obtain recovery from MHI

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[39] DRA OB at 12.

[40] *Id.* at 11.

[41] *Id.* at 6.

[42] *Id.* at 7.

or through insurance and it would prompt more shareholder oversight of management. [43]

5.3. The Utility Reform Network

TURN, similar to other non-utility parties, argued that "incremental" costs resulting from the steam generator failures should be removed from the SONGSMA and denied rate recovery here.[44] TURN asserts the incremental costs lack any presumption of reasonableness since they are "the direct result of imprudence by SCE and/or its vendors…."[45] Instead, TURN would remove all SGIR-related expenses from the SONGSMA and require a separate application for review.

TURN identified certain cost categories it agreed should be tracked in the SONGSMA (e.g., pre-core fuel inventory, materials and supplies inventory, cash working capital attributable to SONGS, third party payments), but found SCE's testimony "murky" and seeks further clarification for particular cost categories. TURN would limit utility rate recovery here to "unavoidable expenditures required to maintain the plant and meet minimum federal license requirements."[46] For example, "Base-Routine" O&M costs in the SONGSMA should be subject to reasonableness review, and TURN would cap recovery at the final levels identified by the utilities in Phase 1.[47]

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[43] TR at 992-993.

[44] TURN OB at 5.

[45] *Id.* at 7.

[46] *Id.* at 5.

[47] *Ibid.*

In addition, TURN recommends the Commission adopt a presumption that all Construction Work In Progress (CWIP) as of December 31, 2012 is abandoned plant, ineligible for accrued Allowance for Funds Used During Construction (AFUDC).[48] However, TURN suggests an exception for capital projects which SCE can show are necessary to maintain safety at the facility under permanent shutdown.

TURN also posits that the SONSGMA does not accurately capture all SONGS-related costs. TURN points to SCE's failure to provide a SONGS-only cash working capital (CWC) calculation, separate from its overall utility-wide CWC, including separate SONGS-only lead lag calculations, leading to an unacceptable omission of costs.[49]

TURN also asks the Commission to suspend SCE's authority to collect any future revenues for seismic studies related to the relicensing of the plant and eliminate any seismic O&M expenditures already incurred in Edison balancing accounts in current rates

5.4. Alliance for Nuclear Responsibility

A4NR rejects rate recovery for any 2012 SONGS-related expenses. As soon as SCE became aware of the extent of vibratory damage to the steam generator tubes in both units, A4NR argues that SCE should have decided to shut down permanently. A4NR concludes that SCE should have known the costs to repair or replace the steam generators, in light of about $1 billion of plant still in rate

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[48] *Id.* at 10.

[49] *Id.* at 14.

base, rendered any action other than immediate shutdown to be economically unreasonable.[50]

Based on SCE's proffered evidence of what it knew, or should have known, about the condition of the U2 and U3 steam generators in the immediate aftermath of the January 31, 2012 tube leak, A4NR asserts it is impossible to characterize the managerial decision making as sound, logical, reasonable, or prudent. A4NR also questions SCE's characterization of the most extensive types of wear in U2 as "manageable," an assumption that led to the U2 restart plan.

Furthermore, asserts A4NR, SCE's witnesses provided no evidence its managers considered a range of possible options in light of the information that was or should have been available to them. Because SCE failed to show why the decision to permanently shut down could not, and should not, have been made early in 2012, A4NR concludes that all subsequent facility-related rates are over-collections and should be refunded.[51]

5.5. World Business Academy

WBA assumes that sometime in 2012, SCE knew or should have known the SONGS facility would never restart or produce electricity again. Because SONGS is now permanently out of service, and has provided no power since January 2012, WBA urges the Commission to immediately refund 100% of 2012 SONGS costs retroactively to that date.[52] WBA contends SCE did not show that

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[50] A4NR OB at 2.

[51] *Ibid.*

[52] WBA-1 at 3.

its 2012 SONGS- related costs were just and reasonable, and delaying the return of revenues unjustly collected will continue to harm ratepayers.[53]

WBA claims SCE failed to meet its burden of proof because its testimony was largely conclusory, "offering broad narratives unsupported by the requisite degree of specificity and detailed explanation" (except for emergency preparedness).[54] Although WBA signals openness to rate recovery for costs and capital expenditures specifically related to ensuring safety of the plant, it found SCE's testimony "contradictory" and lacking in any uniform definition of "safety-related."

WBA focuses on SCE's claimed inability to segregate "safety-related" costs, and surmises SCE preferred to characterize all costs as safety-related in order to maximize recovery. As an alternative, WBA recommends the Commission order a third-party financial audit to identify all 2012 safety-related expenses for a final reasonableness determination.

Additionally, WBA contends that SCE and MHI are objectively at fault for the SONGS shut-down and third-party payments should cover consequential costs instead of ratepayers.[55] Finally, SCE did not demonstrate the reasonableness of its 2012 incremental costs to investigate the causes of the tube wear, develop a plan to return U2 to service at 70% power, and place U3 in an extended shutdown condition.[56]

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[53] WBA OB at 1.

[54] *Id.* at 3.

[55] WBA-1 at 5, 16.

[56] WBA OB at 10.

5.6. Women's Energy Matters

WEM opposes rate recovery for all 2012 SONGS-related costs, including the U2 RFO. WEM 's position is premised on the view that SCE knew the steam generators were "experimental" and knew or should have known they were irreparably damaged at the first inspection during the U2 RFO.[57] Instead of going to permanent shutdown, states WEM, SCE engaged in a futile and expensive set of activities to try to support the restart of U2. SCE's failure to undertake a cost-effectiveness analysis of the restart plan is further evidence of its unreasonable course of action, claims WEM.[58]

WEM argues that the only 2012 SONGS-related costs that might be reasonable to recover from ratepayers are those incurred in January, subject to refund if SCE is later found to have been imprudent or "committed fraud" regarding the SGRP.[59] Similar to TURN, WEM also contends some costs are missing from the SONGSMA because they are "buried" in other company budgets.

For example, WEM specifically identifies Community Outreach and Emergency Planning, Education, and Philanthropy[60] as one such area, along with Regulatory Affairs, and Information Technology support. WEM opposes all funding for Community Outreach activities which it views as functionally corporate public relations and designed to mislead, rather than educate, the

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[57] WEM OB at 6.

[58] *Id.* at 11.

[59] *Id.* at 3.

[60] Utility philanthropy is not funded by ratepayers.

public.[61] WEM states it would only support cost recovery, if SCE expands emergency planning and public education beyond the minimum requirements of the NRC and Federal Emergency Management Agency.

5.7. Coalition to Decommission San Onofre

CDSO also favors immediate refunds of SONGS expenses collected in rates, and opposes ratepayer funding of any 2012 SONGS-related costs, except costs required to maintain safety-related components of the plant, as defined by the NRC.[62] Consequently, CDSO opposes rate recovery for any RFO and SGIR expenses.

CDSO asks the Commission to order SCE to identify the NRC-defined "systems, structures and components, and procedures and processes that are absolutely necessary in emergency, non-routine conditions to safely shutdown the plant and maintain it in a safe shutdown condition," and associated costs.[63] A public workshop run by the Energy Division is CDSO's suggested form of SONGSMA cost review.

Underlying CDSO's position is its allegation that SCE "deliberately misrepresented the SGRP to the NRC, the Commission, and the public, and knew the moment it discovered tube wear during the U2 RFO, that repairs were imprudent.[64] Furthermore, CDSO criticizes SCE for a failure to consider the

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[61] WEM-8 at 9.

[62] CDSO OB at 4.

[63] *Ibid.*

[64] CDSO OB at 5.

safety or costs of alternative solutions to the U2 restart. Instead, asserts CDSO, SCE should have moved both units to preservation mode in June.

Based on the Augmented Inspection Team (AIT) Report which identifies several "more than minor" procedure violations, CDSO claims ratepayers should not pay for (unspecified) non-compliant operations. The group also argues SCE's Community Outreach and Education costs are not reasonable because SCE does not comply with state law requiring a 35-mile radius for its public education zone.

5.8. Joint Parties

Joint Parties focused on Community Outreach and Education activities (in company-wide O&M), and criticize SCE for not taking "appropriate steps" to educate and inform a diverse population in the service territory surrounding SONGS.[65] One particular area of concern is that SCE does not specifically track the costs related to "SONGS outreach" which, according to Joint Parties, prevents the Commission and parties from fully evaluating SCE's actions and expenditures.[66]

Joint Parties specifically criticize some outreach activities, such as those conducted on weekdays when people with "regular jobs" cannot attend, or a Rotary Club presentation because it does not reach "the underserved.[67]" On a broader point, the group views many of SCE's outreach activities as primarily

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[65] Joint Parties OB at 8.

[66] *Id.* at 4.

[67] *Id.* at 4-5.

about improving SCE's corporate image, instead of providing public education about SONGS.

Joint Parties asks the Commission to order SCE to provide an accounting for these costs and, that an employee be designated to coordinate all of the public education and community outreach efforts for SONGS.[68] The Commission should then defer its reasonableness review of these costs until the accounting is provided, and costs that benefit corporate image should be disallowed.

Other recommendations from Joint Parties are that SCE should be ordered to:

- expand the reach of its public education effort to be a 20-50 mile radius from SONGS;
- ensure that all community outreach, education, marketing, and external relations related to SONGS are, from this point forward, universally provided in Vietnamese, Korean, Khmer/Cambodian, Chinese, Tagalog, and Spanish; and
- conduct a comprehensive survey of communities within 20 miles of SONGS to ascertain residents' attitudes and knowledge regarding nuclear power and SONGS.[69]

6. What SCE Knew or Should Have Known

As a starting point for determining whether SCE's decision-making process was sound, the Commission examined the NRC's Confirmatory Action Letter (CAL)[70] and the NRC's AIT Report for the sequence of events and known facts, and an independent assessment of SCE's actions from NRC's on-site inspectors.

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[68] *Id.* at 5.

[69] *Id.* at 9-10.

[70] Appendix 2 to SCE-02 and SCE-03, Tabs 2, 25.

SCE provided a chronology of key operational facts and significant dates in 2012 related to the outages.[71] Based on the record, other dates and some information has been added to the timeline, which is attached as Appendix C. This chronology also assisted the Commission in its review of the reasonableness of SCE's actions and recorded expenses during 2012.

Both U2 and U3 were in their first cycle of operation with new replacement steam generators. Each replacement steam generator (SG) has 9,727 tubes, two SGs per Unit. In the straight-leg portion of the tubes, the tubes are supported by a series of tube support plates (TSP) through which the tubes penetrate. The U-bend region is located at the top of the tube bundle and is supported by an anti-vibration bar (AVB).[72]

According to SCE, and elsewhere in the record, SG tubes have historically experienced tube degradation related to various phenomena. These degradation mechanisms can impair tube integrity if they are not managed effectively. SCE states that when the degradation of the tube wall reaches a prescribed repair criterion, the tube is considered defective and corrective action must be taken.[73]

Based on the CAL, AIT Report, and SCE's testimony, we are persuaded by a preponderance of evidence that SCE knew or should have known the following:

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[71] SCE-10 at Q4.

[72] SCE-04 at 77-78.

[73] *Id*. at 79.

- On January 31, 2012 when the U3 leak was discovered, U2 was about half-way through its scheduled refueling outage where significant inspections, testing, and repairs take place.[74]
- AIT found that SCE plant operators responded to the January 31, 2012, SG tube leak in accordance with procedures and in a manner that protected public health and safety. Plant safety systems also worked as expected during the event.[75]
- In early February, SCE's routine eddy current testing[76] of U2 tubes identified 2,411 tubes with indications (most less than 20%) of tube wear attributable to retainer bar wear, support plate wear, or AVB. SCE plugged six damaged tubes and another 182 tubes were plugged as a precaution.[77]
- AIT considered the U2 wear indications found similar to those found at other replacement steam generators after one cycle of operation.[78]
- On February 12, 2012, SCE inspection confirms leak in U3 SG tube; eddy current testing identifies unexpected retainer bar wear, similar to U2, and significant Tube-to-Tube wear (TTW) in the U-tube region of the SG.[79]

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[74] SONGS--NRC Augmented Inspection Team Report 05000361/20122007 and 05000362/20122007 (June 18, 2012) (AIT Report), § 1.1.

[75] *Id.* at Executive Summary.

[76] Eddy current testing involves inserting a probe into each tube and measuring the tube wall thickness throughout the full length of the tube through the use of electromagnetic signals.

[77] AIT Report at § 1.4.

[78] *Id.* at § 1.4 (A total of 2411 tubes were found with indications at the tube support plates and anti-vibration bar supports, the vast majority of which had a measured depth of less than 20 percent of the tube wall thickness).

[79] *Id.* at § 1.1

- On March 13, 2012, eight U3 tubes failed additional in-situ pressure testing by SCE's consultant (AREVA), of 129 tubes that showed the most wear.[80]
- AIT stated failure of U3 in-situ pressure test is an indication that, for certain design basis events, such as main steam line break, these SG tubes may not be able to maintain structural integrity.[81]
- On March 19-29, 2012, AIT was on-site conducting its inspections. MHI and SCE were onsite conducting cause evaluations for the tube failures and unexpected wear in U3.[82]
- On March 23, 2012, SCE submitted SG Return-to-Service (RTS) Action Plan to NRC outlining its commitments to corrective actions before restarting either unit.[83]
- On March 27, 2012, NRC sent SCE a CAL that notified SCE it may not restart either unit until SCE completes a list of actions and NRC completes its review of the actions, including:
  - ✓ Determine causes of TTW; plug all tubes with significant wear.
  - ✓ Submit written results of SG assessments for both units, proposed inspection protocols, schedule for a mid-cycle shutdown, and basis for SCE's conclusion thatU2 will safely operate as required by NRC regulations.
  - ✓ The CAL will remain in effect until the NRC has (1) reviewed SCE's response, including responses to staff questions and the results of SCE's evaluations, and (2) NRC has written its

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[80] U.S. Nuclear Regulatory Commission Confirmatory Action Letter to SCE (March 27, 2012) (CAL) at 1.

[81] *Ibid*.

[82] *Id.* at § 2.0.

[83] SCE-10 at Q4.

conclusion that the units can operate safely without undue risk to public health and safety, and the environment.[84]

- In March 2012, SCE developed a plan to postpone, cancel, and re-schedule capital projects; SCE also began work on short-term and long-term repair options.[85]
- On April 10, 2012, SCE identified two tubes with TTW in the U3 free-span U-bend region, where U2 TTW was found.[86]
- Regarding SCE's extensive U3 eddy current testing completed April 15, 2012, more than half of the TTW indications in each SG had maximum measured depths exceeding the 35% plugging limit in the technical specifications, and ranged to as much as 99%.[87]
  - ✓ Over 460 tubes in each SG had wear indications at the tube support plates; about 170 tubes in each SG exhibited indications at the tube support plates that exceeded the 35% plugging limit.[88]
  - ✓ Approximately 800 tubes in U3 SGs exhibited wear indications at the AVB supports; most measured less than 20%, only two exceeded the 35% plugging limit.[89]
  - ✓ Four tubes with retainer bar wear indications were plugged and stabilized; the remaining 184 tubes that intersect the retainer bars were plugged as a preventative measure.[90]

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[84] CAL at 2-3.

[85] TR at 714.

[86] AIT Report at § 1.4.

[87] AIT Report at § 1.5.

[88] *Ibid.*

[89] *Ibid.*

[90] *Ibid.*

- On April 23, 2012, SCE issued U2 tube wear Root Cause Analysis (RCA) which identified the cause of TTW as Fluid Elastic Instability (FEI).[91]
- On April 26, 2012, SCE Board of Directors was told that U2 RTS was scheduled for 6/1, and U3 on 6/30, after SCE responded to the CAL.[92]
- On May 7, 2012, SCE issued U3 RCA which included identification of TTW in U2 and U3.[93]
- In March/April and May/June, SCE was able to fully characterize the conditions at U2 and U3, respectively, and focus on responding to TTW.[94]
- On June 18, 2012, the NRC held a public meeting and presented the AIT Report to SCE executives who acknowledged the findings, including:
  - ✓ NRC team identified ten "unresolved" items requiring additional review for regulatory action.
  - ✓ SCE was adequately pursuing the causes of the unexpected TTW degradation; SCE retained a significant number of outside industry experts, consultants, and SG manufacturers to perform modeling and analysis.
  - ✓ SCE was adequately pursuing the causes of the unexpected steam generator tube-to-tube degradation. SCE retained a significant number of outside industry experts, consultants, and steam generator manufacturers, including Westinghouse

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[91] SCE-04 at 82.

[92] A4NR-5 at 2.

[93] SCE-10 at Q4.

[94] TR at 772.

and AREVA to perform thermal -hydraulic and flow induced vibration modeling and analysis.[95]

- In June 2012, SCE began planning to put U3 into Preservation Mode.[96]
- On June 12, 2012 MHI issued its technical RCA.
- On June 18, 2012, NRC presented AIT Report Exit at public meeting.
- In July 2012, SCE created a long term repair team for both units to develop options with MHI.
- On October 3, 2012, SCE submitted Response to CAL; NRC identifies 6 -7 month window for review, inspections, response to staff information requests, public meetings, etc.
- On November 11. 2012, NRC issued draft Report of vendor inspection at MHI: two notices of non-conformance re Quality Assurance issues.
- On December 5, 2012, the Atomic Safety Licensing Safety Board held hearing to determine whether SCE will need a license amendment to try U2 restart plan.
- On December 14, 2012, MHI sends two progress letters to SCE regarding development of long-term repair options.[97]
- December 20, 2012, MHI provides long-term repair options and recommendations.[98]

6.1. Discussion

This discussion draws inferences as to what SCE knew in 2012 based on the facts as they unfolded and became known to SCE. The non-utility parties

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[95] AIT Report at § 14.

[96] SCE-10 at Q4.

[97] SCE-16, SCE-17.

[98] SCE-15.

argue from the assumption that SCE entered 2012 with pre-existing knowledge about risks and problems with the design and/or operations of the replacement steam generators arising from the inception of the project in 2004. However, the SGRP was approved by the Commission in 2005, rate recovery authorized upon completion, and a presumption of reasonableness applied if costs remained below forecasts.

Therefore, in this phase, we confine our review to knowledge gained by SCE in 2012 which informed, or should have informed, SCE's decisions in how to respond to the SG problems. In Phase 3, we will examine the SGRP as a whole and, if it is established that SCE had pre-existing knowledge about risks at the SGs, then it is possible that some or all SGIR-related expenses in 2012 may be found unreasonable.

During January and February, the Commission finds that SCE acted as a prudent operator of a generation facility to detect the U3 leak, identify the source of the leak, inspect all of the U2 and U3 tubes for damage, investigate the causes of excessive and unexpected wear, and to assess whether repair is a reasonable option. SCE first knew about both excessive wear in both units and the unique phenomena of TTW in U3 in mid-March. This raised the question of whether there was a design, installation, or operation problem, and whether it was fixable, and if SCE bore any fault. SCE considered TTW as the most significant and complex phenomena, and a key barrier to restart of U2.[99]

SCE understood that the units were likely to be offline for some time, because SCE developed a plan in March to postpone, cancel, and re-schedule

[99] TR at 735.

capital projects and began work on short-term and long-term repair options. SCE also notified the NRC in March of its decision to restart U2, before understanding the causes of TTW, whether it existed in U2, or what repair options were viable. The NRC responded by prohibiting either unit from restart until SCE received written permission from the NRC.

By April, SCE was able to fully characterize the conditions at U2 and focus on responding to TTW, as the other wear was "manageable."[100] SCE understood from its own RCA issued in April, that the cause of the unprecedented TTW wear was a previously unknown condition: Fluid Elastic Instability (FEI). However, at least by May 7, when SCE confirmed by its own analysis that both units had TTW, SCE knew the fix for FEI was not going to be quick. The U2 RTS date continued to slip.

Nonetheless, SCE states it had high confidence U2 would restart in 2012, and decided to maintain readiness to operate, despite costs that amounted to about $1 million per day.[101] The assumption was "an important assumption in terms of how we prioritize work for the plant staff, the operators, and others".[102] At an April 26 meeting of the Board of Directors, SCE managers unrealistically advised the Board that U2 could return to service by June 1, and U3 by June 30.[103] These projections were unrealistic for several reasons.

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[100] TR at 772.

[101] TR at 947; A4NR OB at 23-24.

[102] TR at 947.

[103] A4NR-5

TTW was new and unique, and SCE had retained several expert consultants to assist SCE and MHI with analyzing the problem and providing possible restart options. Any repair options would take time to develop and implement. Moreover, the NRC had prohibited SCE from any restart until NRC certified SCE had complied with the many conditions of the March CAL. SCE implies that compliance with the CAL is pro forma and immediate. This is incorrect and SCE, an experienced operator, should have known better. As evidenced by how the NRC responded to SCE's eventual CAL response, submitted in October, there would likely be a six to eight month process lag until the NRC could issue written permission to start—assuming no license amendment was required (by no means assured).

During the first few months of 2012, SCE worked closely with the NRC, MHI, and its contracted experts Westinghouse, AREVA, and Intertek to investigate the damage and to develop operational assessments to support a limited restart of U2 for the purpose of testing impact on the SG tubes. SCE had near daily meetings with them and knew, or should have known, the general thinking and direction of the forthcoming AIT report and MHI RCA.

On May 7, SCE knew, or should have known, by its own analysis that U2 was susceptible to the same TTW, and could no longer be run at 100% power which provided the damaging steam flow. After months working with SCE on-site, MHI issued its RCA and AIT issued its Report in June, both of which reached conclusions about the presence and source of TTW consistent with SCE's own prior analysis. The AIT Report found that both the U2 and U3 SGs were susceptible to the design-induced TTW:

> "…the NRC team concluded that both units' steam generators were of similar design with similar thermal hydraulic conditions and

> configurations. **Therefore, SONGS Unit 2 steam generators are also susceptible to this phenomenon (emphasis added).”**

Notwithstanding the potential for TTW, SCE teams worked with MHI and expert consultants to develop both a U2 restart plan, and long-term repair options for both units. SCE’s restart plan was to operate U2 at 70% for five months then go offline to gather data about tube wear.

SCE contends the decision to restart U2 was part of normal operations for an operating generation facility--simply a delayed restart from a scheduled outage. It was more than that. SCE was prohibited under its license from restart of either unit, until it had completed a months-long response to the CAL, and the NRC had several more months to process the response. Yet, SCE did not consider other options, or consider that it had failed to accurately estimate the time necessary to obtain NRC approval. Instead, it was singularly focused on the restart option on the grounds that it “obviously” was the best option. As a consequence, SCE decided to retain the staff required for a fully operational facility, resulting in large O&M expenses even as some employees voluntarily left in September and later.

A decision-making process which does not consider alternative actions, cost effectiveness, or the ratepayer’s perspective is not reasonable or prudent.

It is undisputed that the tube wear in U3 was more extensive than in U2 but the units have similar tube designs. In June, SCE began planning to put U3 into preservation mode, and the SCE Budget Review Committee met to defer capital projects. At that time, SCE knew U3 would not restart in the foreseeable future, and should have known that U2 was similarly situated.

U2 would not restart in 2012, in part because SCE was months away from submitting its CAL response, and six or more months away from NRC approval,

assuming no license amendment would be required for the 70% test. This pushed the U2 restart date into at least 2Q 2013, but was not acted upon in contrast to SCE's actions regarding U3. For example, during a September Board of Directors meeting, SCE managers justified its move of U3 into preservation mode based on SCE's revised 4Q2013 estimate for U3 RTS.

The Commission finds the primary purpose of SCE's U2 restart plan was not for electric generation; it was a theoretical test for five months at 70% power, to gather data for long-term repair options. Therefore, it does not qualify as "normal operations" but as a strategic step towards long-term RTS in late 2013.

SCE did not establish that its decision to keep all systems operating instead of putting Unit 2 into preservation mode was reasonable. SCE acknowledged it would take just two months to move U3 from preservation mode to service-ready. Given the built-in time delays facing development and approval of SCE's restart plan, it is not reasonable to assume that U2 would restart in 2012, which might have justified retention of the employees. Instead, it was possible to decide that U2 could be handled similarly, even though SCE admitted it did not consider it. It may be that SCE's decision was reasonable when viewed in light of the lay-up and RTS costs, a consideration we will make during the entire SGRP review in Phase 3. However, we cannot find it reasonable in 2012 because it was ill-considered, based on the Phase 1 record.

Therefore, based on confirmation that U3 had tube-to-tube wear, the Commission finds that SCE knew or should have known by March 15 that a potential design defect was present in both units and thus fault could become an issue to rate recovery. Therefore, incremental SGIR costs would likely be disputed, and not suitable for immediate rate recovery until the Commission could develop a record about them.

The Commission also finds, based on confirmation that both units had tube-to-tube wear in the same area, that SCE knew or should have known by May 7, 2012 that pursuit of a restart plan for U2 was not in the interests of immediately restoring power generation for the benefit of ratepayers. Instead it was a brief theoretical exercise to further the development of long-term repair options with MHI.

The Commission concludes the record does not establish that costs associated with the restart and long-term repair options (SGIR) are routine O&M for which it would be just and reasonable to collect immediate recovery from ratepayers.

7. 2012 Recorded Expenses in SONGS Outage Memorandum Accounts

For 2012, SCE and SDG&E reported year-end recorded expenses to the Commission for their respective SONGSMA accounts, as follows (excluding power replacement and U2 RFO costs (discussed elsewhere in the decision):

2012 YE Recorded SONGS-related Non-capital Expenses ($000s)

Subaccount	SCE	SDG&E
Base -Routine O&M	300,489	72,685
Seismic Safety	3,261	832
Investigation	67,059	17,155
Repairs – After Outage	27,302	6,004
Regulatory – After Outage	3,421	903
Defueling	932	167
Litigation	6,145	--
Payroll Taxes	13,442	3,744
Other (Pensions, PBOP, Insurance)	23,059	31,624
Unit 2 Refueling Outage (RFO)	**35,255**	**9,116**
Total	**443,536**	**133,294**

8. Base O&M and Other Non-Capital Costs

In each utility's GRC, the O&M/overhead forecasts were based on normal operations at SONGS in 2012. However, SCE incurred routine operating expenses, as well as incremental other costs resulting from the outages of both U2 and U3 (SGIR). SCE and SDG&E also recorded other non-capital costs related to the U2 RFO and Commission-ordered seismic studies. (Capital expenditures are discussed below.)

8.1. Operations and Maintenance (O&M) Costs

In today's decision, we segregate recorded O&M costs into two categories: Base O&M and Steam Generator Inspection and Repair (SGIR) O&M. In the context of a GRC, Base O&M costs are primarily for labor and associated overhead costs. SCE submitted testimony which addressed SONGS total (100%) O&M by SONGS Functional Group.[104] SCE's testimony provided a description of the type of activities undertaken by each functional group, including some systems or activities SCE states are required by its operating license and associated technical specifications, to remain safely operable and capable of performing their design. Over the course of the proceeding, SCE eventually divided O&M into three categories: Base-Routine, Base-SGIR, and SGIR.

A summary of the type of activities and systems by functional group, preliminarily allowed (GRC) Base O&M costs, recorded costs, and an estimate of the percentage of costs necessary to comply with regulatory requirements as put forth by SCE is attached as Appendix D.

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[104] SCE-04.

SCE also provided a final 2012 O&M Summary by functional group which separates slightly revised costs by Base-Routine and SGIR-related costs.[105] Of the total $488,702 million recorded (100% $2012) for O&M costs, $347.747 million is recorded as Base-Routine, $140.955 million as SGIR-related (including Base-SGIR). This total amount is approximately $100 million more than the $389 million preliminarily allowed for all O&M in the GRC decision. In addition to Base and SGIR O&M, SCE also reports O&M costs related to information technology (IT), employee severance, and an artificial functional group for accounting purposes called Corporate Support. These costs are $9.054, $17.600, -$20.463 million, respectively. The negative value for Corporate Support reflects its use as a credit.

SDG&E 's O&M costs are not wholly derivative from its 20% ownership interest, because it applies separate overheads and calculates its own capital costs. For 2012, SDG&E reported total O&M as follows: $106.122 million for Base-Routine (+ overhead) and $26.34 million for SGIR-related.

8.2. Discussion of Base O&M and SGIR O&M

Typically, the Commission reviews forecasted costs in a GRC based on previous spending history and proposed new activities. The utility re-allocates the total revenue requirement adopted by the Commission based on emerging priorities. SCE contends that it did just that in 2012 with preliminarily allowed revenue --which SCE re-directed to inspections, testing, developing the U2 restart plan and long-term repair plans, and putting U3 into preservation mode.

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[105] SCE-35 at 6.

In this review, based on recorded costs, the Utilities' position is that all non-capital costs recorded in 2012 should be considered reasonable because as a prudent operator, SCE had a duty to identify the problems in the units, protect the assets for potential return-to-service, develop repair and return-to-service (RTS) plans, and to maintain safe operations and conditions at SONGS in compliance with regulatory requirements and SCE's NRC license and associated technical specifications.[106] Therefore, SCE and SDG&E assert the Commission should not order any refunds.

The Utilities rely on cost-of-service ratemaking principles where ratepayers are expected to pay for the reasonable costs of the generated electricity received, and utilities have an opportunity to earn a regulated rate of return over the estimated life of an asset. The Utilities reject the positions of WEM, CDSO, and WBA which advocate disallowance of all costs during these outages as a result of no electricity being generated. SCE argues it fundamentally undermines the risk sharing principles implicit in cost-of-service ratemaking, and further observes that ratepayers benefit when assets outlive expected service lives (e.g., hydroelectric plants).

The Commission agrees that cost-of-service ratemaking is applicable to regulated electric utilities, and automatic disallowance of all costs whenever there is an unplanned outage is erroneous. We expect that generation facilities like SONGS will have some planned and unplanned outages during ordinary operations. However, not all outages are the same, and indeed these extended outages resulting in premature, permanent shutdown are unique, particularly

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[106] SCE-2 at 27.

after nearly a billion dollar investment, with generators in their first cycles of operation. The Commission has oversight responsibility to carefully examine an electric utility's actions to ensure that amounts charged to ratepayers are just and reasonable.[107]

All of the non-utility parties view SCE's testimony and other evidence as insufficient to establish what O&M costs SCE incurred and whether the costs were reasonable. There is some agreement that it may be reasonable for ratepayers to pay for "safety-related" costs, but no party accepted SCE's expressions of judgment as to the percentage of functional group expenses. DRA points out the offered percentages lack work papers or other supporting documentation.[108]

We have reviewed SCE's testimony and found the narrative descriptions similar to what is provided in a GRC, and consistent with the type of activities known to occur at SONGS. Although this review is based on actual costs, we agree with SCE that a sufficient showing does not require an itemized list of all O&M costs. Based on the Commission's knowledge gained through decades of regulatory oversight, we are able to find that SCE generally provided adequate explanations of what O&M activities it undertook and why, albeit without specific detail for Base O&M. (For the much more limited SGIR costs, SCE provided an itemized breakdown of costs.) In response to any residual concerns, we observe that SCE's books and records will be examined by ORA as part of its upcoming GRC, and the Commission always retains jurisdiction to audit.

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[107] Pub. Util. Code § 451.

[108] DRA-02 at 2.

For most Functional Groups, the recorded Base-Routine O&M is less than the GRC amounts, due in part to re-allocations of expenses to SGIR. One substantial example is the Engineering Group where SCE recorded more than $110 million to Engineering SGIR (discussed below).[109] Security costs also rose, but only about 5%., or $2.2 million, and are not unexpected.

Excluding Severance costs (discussed below), 49% of Base O&M costs are recorded in either the Maintenance or Nuclear Support Groups. SCE recorded $88.154 as Maintenance Base-Routine O&M, about $20 million less than the GRC amount.[110] SCE claims this is because it took steps to limit overtime and reduce contractor work force from about 200 to 65 full time equivalents, enhanced work processes, and rescheduled some non-critical maintenance activities.[111]

According to SCE, the Maintenance Group supports the actual plant electrical systems by "performing preventive and corrective maintenance and regular surveillance testing of mechanical and electrical equipment, instrumentation and controls, and protective devices" in compliance with various regulatory requirements, industry standards, and internal controls.[112]

The group reportedly processed 15,795 work orders during 2012, fewer than 4,000 were for U3. This low number is understandable given that (1) during April-May, SCE evaluated all scheduled preventive maintenance and surveillance testing resulting in suspension of 700 U3 work orders and re-

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[109] SCE-35 at 6.

[110] *Ibid*.

[111] SCE-33.

[112] SCE-04 at 27.

scheduling 300 surveillance tests; and (2) in June SCE began planning to put U3 into preservation mode.[113]

The Nuclear Support Functional Group provides administrative support to SONGS O&M, including Business and Financial Services, Site Support Services, Nuclear Business Administration, and General Expenses. Activities include financial planning, budgeting, and accounting policies, preparation for ratemaking proceedings, record management, employee timekeeping, payroll, regulatory compliance programs, environmental protection programs, and payment of required fees.[114]

For the Nuclear Support Group, SCE recorded $82.5 million in Base-Routine O&M, about $7 million (8%) less than the GRC amount. SCE argues that regardless of whether SONGS is producing electricity, many of the identified functions of this group had to be carried out, particularly as it relates to the presence of employees, financial planning, and compliance with document-related regulatory compliance.

We observe that the activities described for both groups are generally of the type necessary to provide routine administrative services and to keep all systems operating, including critical systems necessary to keep the plant in a safe condition compliant with its operating license. That is to say—Base O&M. Similarly, we find that the activities described for the other Functional Groups are appropriate and predictable activities at an operating nuclear facility.

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[113] *Id*. at 28

[114] SCE-04 at 61-63.

Based on the historic O&M costs provided,[115] we find that the total recorded Base-Routine O&M is similar in proportion by Functional Group, and about 10.5% less in total amounts recorded, to what we would expect of an operating facility—the status the Utilities impute to SONGS.

However, we disagree that SONGS should be considered an "operating facility" for all of 2012. First, neither unit produced electricity for ratepayers after January 31, 2012. Second, by mid-March when it confirmed U3 TTW, SCE knew that there was a probability that issues of design fault would arise and SGIR expenses should be segregated for separate review. By May7, 2012, after confirming TTW and other types of tube wear in U2, SCE knew or should have known that it was not reasonably foreseeable that Unit 2 would return to producing electricity in 2012 or even that a short-term restart was viable.

Therefore, the Commission concludes it is reasonable for SCE to recover total recorded O&M, including Base-Routine and all SGIR (discussed in more detail below) for January, February, and half of March when all activities involved the reasonable response of a prudent operator to an unexplained outage. Beginning in the second half of March, all SGIR expenses, including Base-SGIR, are not yet eligible for rate recovery and shall be segregated for further review in Phase 3, subject to refund, where issues of outage-related fault or imprudence by SCE will be raised.

Additionally, SCE's Base-Routine O&M is reasonable through May. However, we find that SCE's request to recover all Base-Routine O&M recorded in 2012 is unreasonable. The record is not sufficiently detailed for the

[115] SCE-29 at Tab 8.

Commission to try to reconstruct what portion of post-May Base O&M is not reasonably associated with the minimum activities which would have been incurred if SCE had not pursued its decision to restart U2, and both units moved into preservation mode. We do know that SCE recorded normal time costs for SCE employees for SGIR activities as normal time funded via the base budgeting process. Therefore, commission finds recorded Base-Routine O&M is excessive after May.

Several parties criticize SCE's showing, and it is true that the Commission is not in a position to find that every O&M cost was properly recorded as "Base-Routine" O&M instead of SGIR. Nonetheless, such granular review is atypical for a GRC, and we note that in Phase 3 we will be examining SGIR activities more closely. Therefore, the Commission finds that ratepayers will be best served by proceeding with the record at hand to adjust rates with reasonable approximation.

In order to account for Base-Routine O&M costs incurred as a result of SCE's not well-considered decisions to maintain all, or nearly all, operating staff through the end of 2012, we conclude a gradually increasing reduction to Base-Routine O&M should occur, beginning in June. The Commission finds it reasonable and in the public interest to adopt a sliding path of decreasing Base-Routine O&M between June and December of 2012 to reflect both the unreasonable decision to devote all resources to a U2 restart in 2012, unrecorded credits, and various uncertainties about what was recorded in Base O&M.

Beginning in June, 10% of Base-Routine O&M shall be disallowed, followed by 20% in July and so on until November and December 2012 when

40% of Base-Routine O&M will remain in rates.[116] This amount approximately conforms with SCE's unsupported estimate that about one-third of SCE's Base-Routine O&M is necessary to maintain safe conditions and full regulatory compliance in a permanent shutdown mode. The result is reasonable because shutdown is a viable possibility for SCE after December 20, when MHI presents two repair options: SCE questions the viability of one strategy on a technical basis, and the other is full or partial replacement of the SGs, over a multi-year period.

The Commission finds reasonable and adopts the following 2012 Base-Routine O&M for SONGS-related costs, as follows (in 000s of 2012$, 100% share):

	Base - Routine	SGIR (includes both "Base" and "Total" SGIR)	Total
Recorded	347,746	140,956	488,702
Authorized	273,867	18,353	292,220
To Review in Phase 3	---	122,603	122,603

A worksheet for these calculations is attached as Appendix E.

8.3. Steam Generator Inspection and Repair (SGIR) Costs

SCE recorded $140.956 million (2012$, 100%) for 2012 incremental SGIR expenses, including $8.555 million re-allocated post-hearing from Base O&M.[117] Above, we found that $8.555 million recorded as SGIR through March 15, 2012

[116] In Phase 2 of these proceedings, the Commission is considering whether to remove plant from rate base, along with associated O&M, as of November 1, 2012.

[117] SCE-35 at 6.

was reasonable for ordinary operations during an unplanned outage. SDG&E's post-hearing adjustments identified $26.34 million recorded for incremental SGIR.[118] In support of these claimed amounts, SCE submitted testimony by Functional Group, as described above, including some descriptions of SGIR activities. SCE also provided an itemized breakdown by unit, work order, and Functional Group.[119]

SCE recorded about $113 million of SGIR costs in the Engineering Functional Group, more than 80% of total SGIR costs recorded in 2012. A majority of the costs ($94.6 million) was for outside consultants, experts, and contractors for testing, analysis, and tube plugging in both units.[120]

According to SCE, the Engineering group works in conjunction with Maintenance to perform day-to-day repairs of SONGS systems that remain in service. SCE also points to several regulatory-driven safety-related programs which SCE asserts must continue even during shutdown conditions.[121]

More specifically, the Engineering group consists of five functions: (1) Design Engineering; (2) Plant Engineering; (3) Nuclear Fuel Management; (4) Nuclear Safety Concerns; and (5) Nuclear Oversight and Assessment.[122] SGIR-Engineering costs are significant, states SCE, because the staff was fully engaged in plant restart activities (e.g., analyzing cause of tube wear in the SGs, defining and managing lay-up activities, determining repair options, supporting

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[118] SDGE-11 at 2.

[119] SCE-10 at 13 – 21.

[120] SCE-04 at 85-86.

[121] *Id*.at 35.

[122] *Id*. at 30.

regulatory review and requests for information, and maintaining the units available for restart).[123] This evidence is undisputed and, as described, corresponds to known emergent work otherwise documented in the record.

Some Engineering Expense was labor, "necessary to maintain qualified staff to perform functions required by the SONGS operating licenses and technical specifications."[124] No one challenged SCE's testimony that hiring and retaining qualified engineers is difficult, which made short-term staffing adjustments of engineers "cost-prohibitive and not the industry standard."[125]

The next largest recorded amount for SGIR was $7.4 million for the RadChemical Control Function (RadChem) Group, including $4 million for contractor health physics technicians and laundry services for radiologically controlled areas.[126] According to SCE, the Health Physics division establishes, implements, and manages the radiation protection and radioactive material control programs for SONGS, as well as interfaces with state and federal agencies responsible for radiological health and safety.[127] Its Chemistry division manages various chemistry control programs, manages the radioactive effluent monitoring program, and provides technical support.

During 2012, the Utilities argue that all of these activities are necessary to maintain SONGS in a safe and secure condition during extended outages, and to restore the units safely to service. The Chemistry division was particularly active

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[123] *Id.* at 36.

[124] *Ibid.*

[125] *Ibid.*

[126] SCE-04 at 86.

[127] *Id.* at 41.

in ensuring that U2's systems could be returned to service safely, and U3's systems were adequately protected for longer-term shut-down. Notably, SCE admits the total O&M (Base and SGIR) for this group would have declined overall if it had decided in 2012 to move for permanent shutdown.[128]

None of the non-utility parties support the Utilities' request for rate recovery of SGIR expenses in 2012. Instead, the parties outright reject all recovery because the facility was in extended shutdown, should have been permanently closed in 2012, costs should be paid by insurance and MHI, or SCE was at fault and its shareholders should cover the costs.

We give these arguments for automatic disallowance for all SGIR-related costs no weight because the record does not support them. We have made no finding that SCE was at fault or imprudently managed the steam generator replacement project, or unreasonably incurred the incremental SGIR costs in 2012. However, the prudence of SCE's management of the project, and whether costs associated with the replacement steam generators were reasonable and necessary, will form the basis for the third phase of these consolidated proceedings.

As we discussed in relation to Base O&M, an unplanned outage does not necessarily mean that a utility was at fault or that it should be assumed to be a permanent condition for purposes of rates. Moreover, SCE has agreed to apply any warranty or damage amounts from MHI, and insurance recovery, to offset SGIR costs for the benefit of ratepayers. SCE acknowledged it received a payment from MHI for $45.5 million (100%) and it should be applied towards

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[128] *Id.* at 44.

SGIR costs as determined in Phase 3. However, we decline to speculate as to future third party recovery and prematurely apply credits before funds are in hand.

Our review of the (100%) costs allocated to SGIR is incomplete. Based on the itemized SGIR costs initially provided by SCE, the Commission makes an initial finding that the items and activities referenced appear to be of the sort that could be undertaken to investigate, inspect, and repair steam generators, develop and implement a restart plan, and move a reactor unit into preservation mode.

However, we have not yet determined whether these costs are reasonable under the circumstances and, therefore, whether ratepayers should pay for any of them. In Phase 3, we will examine the 2012 incremental costs in context of the overall SGRP and SCE's management of the project, and apply third party payments received from MHI or insurance.

Above we concluded SCE was reasonably pursuing normal operations, or a return thereto, through May 2012. During June through December, we made reductions to recorded Base O&M given SCE's decision to restart and maintain full operations at SONGS throughout 2012. The result is that the removed Base O&M is re-allocated to SGIR for final review in Phase 3.

Therefore, the total 2012 SGIR expenses, subject to further review in Phase 3 is $122,603 million.

8.4. Severance Pay

In its 2012 GRC, SCE forecast preliminary workforce reductions of 500 SONGS personnel, and 100 contractors, to align the workforce with those of

the other nuclear generating sites over time.[129] The Commission found the proposed reductions had been delayed since 2009, resulting in ratepayers funding excess positions for two years to rectify management problems at SONGS which required a resetting of the safety culture through various activities. We determined that SCE should allocate to ratepayers 100% of savings from reductions of SONGS personnel.[130]

Based on the changed conditions and 2012 staffing needs, SCE revised planned reductions to 730 over 2012-2013, reducing staff by almost one-third, from 2,250 to 1,500.[131] SCE reports voluntary severance of 258 employees and involuntary severance of 15 managers, in November and December of 2012. The actual severance costs were $17.6 million, with savings of $3.96 million.[132]

The GRC O&M amounts included all estimated severance costs within Functional Groups.[133] In SCE's report on recorded O&M, severance costs are a presented as a separate item, and not available by Functional Group. SCE stated the delayed reductions were a result of re-allocation of staffing to meet new inspection and repair activities, the need to retain highly skilled employees for anticipated outage and restart-related tasks, and the lengthy process to layoff represented employees, e.g. collective bargaining, bumping rights.[134]

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[129] SCE-1 at 2.

[130] D.12-11-051 at 33; (TR at 1211 SCE witness Mr. Worden stated that the GRC model had not made that adjustment, but SCE would abide by it if adopted here).

[131] SCE-04 at 36.

[132] *Ibid.*

[133] TR at 369.

[134] TR at 1089-90.

Although employee severance costs are routine costs, the Commission finds it was not reasonable for SCE to retain full staffing through November of 2012. The Commission also finds that SCE has not credited the $3.96 million in 2012 savings from staff reductions to the overall calculation of costs. In order for rates to be just and reasonable, we conclude that this credit must be made to the overall costs subject to rate recovery for 2012 Base O&M. We address both issues as a part of the gradual O&M reductions adopted above.

8.5. Seismic Studies

In D.12-05-004, we approved SCE's and SDG&E's applications to record and recover their actual costs of up to $64 million (nominal $, 100% share) in O&M costs associated with seismic studies at SONGS. These studies are responsive to Public Resources Code Section 25303 and recommendations of the California Energy Commission.[135] In testimony, TURN suggests that these seismic study costs are related to relicensing and should be disallowed,[136] but does not advance this argument in briefs. In testimony and briefs, SCE suggests that TURN misunderstands the purpose of the seismic studies and asserts that the studies are a regulatory obligation, not related to license renewal.[137]

SCE's recorded costs for seismic studies in 2012 are $3.261 million; SDG&E's are $815.5 thousand.[138]

We find that these studies were authorized by this Commission and are not directly related to the operational status or relicensing of SONGS.

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[135] D.12-05-004 at 1-2.

[136] TURN-1 at 9.

[137] SCE OB at 24-25, citing SCE-8 at 9.

[138] SCE February 1, 2013 Monthly Report in Compliance with I.12-10-013; SDGE-11 at 2.

D.12-05-004 describes certain ratemaking treatment for these studies. Based on the record in this proceeding, we do not make any changes to the previously approved ratemaking treatment of these studies.

9. 2012 Capital Expenditures

SCE initially planned to undertake substantial capital projects at SONGS during this rate cycle. In the 2012 GRC decision, the Commission preliminarily authorized SCE to expend $189.2 million ($2012, 100%) for anticipated operational needs.[139] SCE actually recorded $167.6 million (100%) in total capital expenditures. Unlike O&M expenses, SCE's testimony combines U2 RFO capital expenditures and SGIR expenditures with all other SONGS-related capital expenditures.

9.1. Utility Applications

SCE asks the Commission to find that its 2012 SONGS-related capital expenditures of $131.08 million (SCE share) are reasonable, along with other capital costs recorded in SONGSMA. SDG&E requested approval for $49.3 million in capital expenses, comprised of $39.25 million identified as its 20% share of SONGS capital expenditures billed by SCE, adjusted for overheads ($1.19 million), plus $8.82 million for AFUDC.[140] (It is unexplained whether the AFUDC is actually attached to plant into rate base during 2012.) SDG&E's testimony also addresses its capital-related revenue requirement—a different calculation and rate component.

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[139] SCE-04 at 88.

[140] SDG&E-3 at 9; See Appendix B (SDG&E's reports capital expenditures of $38.475 million in its SONGSMA).

According to SCE, Units 2 and 3 required on-going capital investment in 2012 to maintain the plant's condition at a level supporting long-term safe, regulatory-compliant, and reliable operation – both in the near-term during shut-down conditions and in the long-term when and if either or both return to service. SCE provided cost and descriptive information about the capital projects (most presented earlier in the 2012 GRC), and took steps to postpone, suspend, or cancel some projects during 2012 based on the extended outages, including projects related to the suspended U3 refueling outage.

SCE contends that recorded capital expenditures are $21.6 million less than preliminarily allowed, largely due to the outages. Implementation of SCE's plan to postpone, cancel or re-schedule capital projects during 2012, claims SCE, also led to savings. Therefore, SCE asserts that all expenditures should be found reasonable.

SCE points out that 47% of the capital expenditures were incurred prior to April 2012 (with the majority of that amount incurred during the Unit 2 Cycle 17 RFO), before the full extent of the wear conditions of the Unit 2 & 3 steam generators was known. SDG&E supports SCE's position that over 80% of the 2012 capital expenditures were necessary to maintain the units in a safe and secure condition, or to meet federal and state regulatory requirements.

SDG&E provided a table of adjustments to SCE invoices for its pro rata share of capital expenditures. SCE provided a narrative description of capital projects SCE states it was unable to defer, such as the U2 RFO, as well as those it could postpone or suspend without compromising safety. SCE classifies the capital projects under the following sub-categories:

Capital Expenditures By Category[141]
($2012, $millions)

Category	Projects	100%	SCE	SDG&E
Common Required includes capital projects for site, not unit specific, but necessary;	more than $23 million is required for storage of spent fuel	38.389	30.024	7.678
Work In Progress Projects in progress in 2011, mostly completed, required to sustain plant infrastructure	Completion prudent given mostly complete; includes back-up generators; almost 90% is related to U2 RFO;	84.533	66.113	16.907
Emergent-Regulatory Required not forecast, due to new regulatory requirements	74% for various security projects; $2.6 million for	17.937	14.029	3.587
Rescheduled Projects begun in 2012 & suspended due to outages	Small U2 and U3 projects	1.434	1.122	0.287
On-going Completion Rescheduled Projects started before 2012 suspended due to outages	Primarily for U3 RFO, $9 million for high pressure turbine	19.754	15.450	3.951
Marine Mitigation Requirement of Coastal Commission permit	$4.2 million for corrective construction to wetlands project; monitoring of artificial reef	5.559	4.350	1.112
Total (includes RFO)		$167.61	$131.088	$33.522

DRA and WBA argue that the Commission should not find any SONGS-related capital expenditures to be reasonable. DRA contends the Utilities did not provide sufficient information to establish reasonable capital

[141] *Id.* at 89-113; Appendices A and B to this Decision (Year End 2012 SONGSMA report).

expenditures in 2012. Both DRA and WBA ask the Commission to further defer review of these expenditures.[142] However, we find deferral unnecessary because there is sufficient evidence to make an approximate determination of reasonable capital expenditures during 2012.

We agree with the Utilities that some capital expenditures were necessary during 2012, even though the reactor units were not operating, because the NRC operating license requires SCE to maintain many systems in order to protect the safety of the plant, its workers and the public

Our review of the pattern of expenditures confirms that more than $89 million (53.5%) of total capital expenditures were booked between January and April 2012, primarily for the U2 RFO. We conclude below that the RFO was essentially completed before SCE had knowledge of the extent and nature of tube wear in U2, and allow O&M associated with the RFO as reasonable. Similarly, we find that SCE's capital expenditures for the U2 RFO were reasonable when made, although we do not concur that SCE established the U2 RFO expenditures are necessary for maintaining a safe plant during the outage.

On the other hand, we found elsewhere in this decision that SCE knew or should have known by May 7, 2012 that it was not reasonable to expect either unit to return to service for up to a year. Therefore, we find that SCE 's effort to suspend, cancel, and re-schedule some projects, while commendable, was inadequate to reflect the overall reduction of capital projects that should have occurred at SONGS.

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[142] DRA OB at 12.

It is appropriate to reduce the amount of 2012 SONGS capital expenditures the Commission finds reasonable by 20% to reflect what the Utilities' internal experts determined were not necessary to safely maintain SONGS during the 2012 outage, in compliance with applicable federal and state regulations.

Therefore, the Commission finds that only $134.08 million (80%) of 2012 total recorded capital expenditures ($167.6 million) are reasonable. Capital expenditures will be subject to further review in Phase 3 if the expenditures were made as a result of the tube damage in the U2 and U3 SGs.

9.2. Capital-related Expenses Derived From Rate Base

When capital projects are completed, the capital expenditures are recorded into rate base as in-service and capital-related expenses (e.g., depreciation, taxes, return) are charged to ratepayers. According to SCE's SONGSMA report, the capital related-expenses increased substantially beginning in March and more than half of the total revenue requirement for these expenses was added between March and May 2012.

Although SCE provided assumed closing dates for its 2012 capital expenditures, SCE did not identify which capital expenditures and projects were actually moved into rate base during 2012. In the SONGSMA, SCE reported its net rate base (additions and removals) grew by $78.66 million from January 30, 2012 through December 31, 2012.

Additionally, 2012 combined capital-related revenue requirements exceed preliminary allowed amounts for both utilities. For example, SCE recorded depreciation expenses of $80.3 million, or $20.3 million more than the GRC

amount.143 Tax expense also exceeds the GRC amount by $18.4 million. SDG&E similarly asks that its capital –related revenue requirement be found reasonable, but did not support its request for recovery of $27.3 million, $3.1 million more than its GRC estimate.

TURN and DRA are the only parties to directly address capital-related expense. DRA argues that utility recovery of SONGS Units 2 and 3 rate base related revenue requirements, along with SGRP revenue requirements, should be terminated effective January 31, 2012, the date of the Unit 3 forced outage. The SGRP revenue requirement is not at issue in this phase. However, we agree that not all capital investment moved into rate base was reasonable, as evidenced by excess capital-related expenses charged to ratepayers, and the net increase to rate base over the year.

However, DRA's recommendation to remove all SONGS assets from rate base is too blunt because it does not consider that capital work at U2 was part of a scheduled outage, that SCE did not know as of January 31, 2012 that U2 and U3 were not likely to return to service in 2012, or thereafter what capital was reasonable and necessary to maintain safe and secure conditions at SONGS in compliance with federal and state regulations.

TURN's position is that, as of November 1, 2012, the capital-related costs of U3 should be removed from rates based on the principle that fixed costs should be removed from base rates if there is no near-term timetable for a unit to come back. The single largest capital cost is the return, taxes, depreciation, and property tax for U3 (excluding common plant), which has about $110 million of

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143 SCE SONGSMA Report (February 1, 2013 at 3).

rate base (return plus income taxes) plus property taxes in the range of $14.5 million annually, and depreciation expense of approximately $25 million. TURN's position is based on § 455.5 which will be addressed by the Commission in Phase 2.

The Commission finds that SCE's recorded rate base is excessive and should be reduced to reflect the changed conditions at the plant as the year progressed. The reduction should reflect removal of capital projects added to rate base in 2012 that do not compromise the safe operation of the plant in compliance with all regulatory requirements during the year. Therefore, it is reasonable to apply the 20% reduction adopted for capital expenditures to serve as a reasonable proxy for excess capital projects moved to rate base in 2012. This amount shall be removed from the rate base and any associated revenue requirement found to be unreasonable for 2012.[144]

There is no need for SCE to attempt, post-decision, to try to parse its capital projects in a different way. This decision only affects 2012 revenue requirement. Evidentiary hearings in Phase 2 have already been held where the Commission will address all SONGS plant in rate base and associated O&M pursuant to § 455.5. Furthermore, all costs related to the SGRP and subsequent outages remain under review in Phase 3 where issues of fault could lead to further rate reductions.

TURN also proposed that 50% of the Materials & Supplies (M&S) inventory be removed from rate base. However, SCE opposes the adjustment on

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[144] Due to tax consequences, the reduction in rate base actually results in an increase to revenue requirement of $0.5 million; larger reductions to rate base would result in a higher revenue requirement.

two grounds: (1) it was reasonable to maintain M&S inventory in 2012; and (2) TURN assumes an erroneous premise that M&S is apportioned 50/50 by unit. TURN's assumption is incorrect, and fails to recognize that some M&S is for common plant.

TURN's position is predicated on a finding that U3 should be removed from rate base in Phase 1 because it is abandoned plant. The Commission has not made that finding and the Phase 1 record does not support that result. We also observe that it would result in nominal increase to revenue requirement.

No other specific testimony or argument was made by a party about these elements of revenue requirement. As described above, the Commission previously authorized rate recovery of SGRP costs until the post-completion reasonableness review occurs. We view TURN's requests to reduce rate base as relevant to the Commission review of rate base pursuant to § 455.5 in Phase 2.

9.3. Construction Work in Progress

During 2012 a number of capital projects at SONGS were delayed or suspended. By the end of the year, SCE recorded $216.7 million (SCE share) for Construction Work in Progress (CWIP).[145] CWIP costs are not in rate base. This amount reflects projects where money has been spent but the project was not yet in-service at the end of 2012. Allowance for Funds Used During Construction (AFUDC) represents the cost of financing capital projects before they enter service. It is accumulated while the projects are under construction, and then included with the capital cost of the project when added to rate base.

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[145] Appendix A.

The associated AFUDC accrued by SCE for these capital projects totaled $14.5 million.[146] SDG&E reports that, at as of December 31, 2012, it had recorded $110.855 million in CWIP, but did not identify accrued AFUDC.[147]

TURN initially recommended the Commission order SCE to stop accruing AFUDC on suspended capital projects, retroactive to the date of suspension.[148] As a result of SCE's 2013 decision to permanently shut down the entire facility, TURN urged the Commission to presume all recorded CWIP represents abandoned plant as of December 31, 2012, ineligible for the accrual of AFUDC. The requested result would be that the Utilities zero out all accrued AFUDC.[149]

TURN primarily relied on accounting standards to support its view. TURN cites Statement of Financial Accounting Standards (SFAS) No. 34 which requires the capitalization of interest to cease when a construction project is suspended voluntarily by the company. Federal Energy Regulatory Commission (FERC) requirements are apparently similar as applied to suspended construction of gas pipelines.

SCE and SDG&E adamantly opposed TURN's recommendations. They object that, if adopted, the Commission would be improperly preventing the utilities from recovering the 2012 cost of financing SONGS capital projects, regardless of future events.[150] During 2012, it was not clear whether U2 or U3

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[146] TURN OB at 9-10.

[147] Appendix B.

[148] TURN-1 at 10.

[149] TURN OB at 3-4.

[150] SCE-8 at 10.

would return to service, but the capital expenditures had received preliminary approval.

SCE also argues that the referenced accounting standards are neither determinative, nor applicable. We agree with SCE that the Commission's judgment on whether costs are reasonable is not controlled by accounting standards. The utilities distinguished the accounting rules cited by TURN. TURN did not refute SCE's claim that SFAS-71, not SFAS-34, is the applicable accounting rule for public utilities, and provides for accrual of financing costs with capitalized costs.[151]

We also disagree with TURN's premise that since the June 2013 announcement that SONGS will not restart, it is reasonable to assume the plant will be removed from rate base, the CWIP will never be placed into rate base, and there is" no possibility that these capital projects will be deemed used and useful."

This phase is primarily an extension of the 2012 GRC, converted from a forecasting exercise to review of what was reasonable given what SCE knew at the time it incurred the expenses. The Utilities state that, in 2012, SCE did not suspend substantially all activities at SONGS, and some necessary capital work continues.

We agree it is not reasonable to impute knowledge of a June 2013 decision to shut down SONGS permanently, to SCE during 2012. Furthermore, TURN jumps to the conclusion that no 2012 capital projects could be reasonable, an assumption that seems imprudent given that some critical systems may be

[151] SCE-8 at 10; SDG&E-5 at2.

impacted and capital investment required to meet regulatory obligations regardless of the operating status of the plant in 2012. Thus, some projects recorded in CWIP may have entered service in 2012, or will enter service in the future.

TURN suggested an exception to its blanket disallowance of all CWIP for capital projects which SCE can show are necessary to maintain safety at the facility under permanent shutdown.[152] However, this neither addresses the fact there is no evidence to show that SCE knew in 2012 that it would permanently shut down SONGS in 2013, nor that projects to maintain safety adequately describes the universe of reasonable capital projects left at SONGS.

Therefore, the Commission does not find it reasonable to prevent the Utilities from accruing AFUDC in 2012 for SONGS-related CWIP. However, the issue is relevant in phase 2 where the Commission may remove some SONGS plant from rate base, and associated projects may become permanently abandoned.

9.4. Cash Working Capital

SCE did not calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012. CWC is a component of rate base which represents the shareholder cost of funding day-to-day operational requirements when there is a gap between the time expenses must be paid and corresponding revenues must be collected. The Operational Cash requirement is the average balance of funds SCE's investors provide the utility to meet its daily operational needs.

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[152] TURN OB at 3.

In SCE's 2012 GRC, SCE provided a "lead lag" study to determine the required funds, based on estimated timing differences between when certain operating expenses are paid and revenues are received.[153] The Commission adopted SCE's Revenue Lead lag study, but made several adjustments advocated by DRA and TURN to SCE's proposed Expense Lag Study.[154] To the extent the Commission decides to make changes to revenue requirements in this proceeding, there will be some minor consequential effects to CWC.

TURN initially called for a SONG-specific lead lag study to support a SONGS-only CWC calculation, claiming that some SONGS costs would otherwise be omitted from review. At the evidentiary hearings, TURN's witness acknowledged that such a study could require significant extra work, and agreed that use of the company-wide lead lag study to SONGS expenditures would still be useful.[155]

In its post-hearing brief, TURN clarified that it wanted the Commission to order SCE to calculate a SONGS-only cash working capital (CWC) calculation, separate from its overall utility-wide CWC, using the parameters adopted in the 2012 GRC.[156] SCE disputes this approach, because the total company-wide Expense lag does not necessarily reflect the Expense Lag associated with SONGS.[157]

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[153] D.12-11-051 at 633-34.

[154] D.12-11-051 at 640-645.

[155] TR 795-896.

[156] TURN OB at 4.

[157] SCE OB at 45; SCE-8 at 3.

We agree with TURN's intent to capture all 2012 SONGS-related costs for review in this Phase. SCE stated in its post-hearing brief that if it were directed to perform the calculation, it could develop an approximate estimate using the lead-lag days adopted in the GRC. Although not a perfect measure, the Commission finds it reasonable to direct SCE to perform the calculation, as it proposed, which may result in a minor, but reasonably appropriate, adjustment to SONGS rate base. SCE shall provide the Commission with this calculation as part of the revised modeling of the revenue requirement which SCE shall undertake as a result of this decision.

10. SDG&E Other SONGS-Related Costs

SDG&E incurred $60.492 million of SONGS-related costs not included in the SONGS portion of SCE's 2012 GRC or in SCE's OII testimony.[158] These cost categories and forecast amounts were addressed in SDG&E's 2012 GRC and include capital-related expenses arising from the SGRP.

SDG&E's SONGS-Related Costs Deferred from GRC
($YOE 000s)

Category	Amount
SONGS Unit 1 Spent Fuel Storage	994
SONGS Site Easement	20
SONGS Insurance	2,364
SONGS Operations and Billing Oversight	642
SONGS Depreciation	23,273
SONGS Taxes	13,270
SONGS Return on Rate Base	19,929
Total	$60,492

[158] SDG&E-3 at 2.

SDG&E provided testimony which described the nature of these expenses, although somehow omitted any reference to the SGRP. The categories Depreciation, Taxes, and Return on rate base include a total of $29.1 million related to the SGRP. We expect this omission was an oversight and not intended to shield this component from review SDG&E argues that all of these costs are required regardless of whether SONGS is operating and have been deemed reasonable in prior rate cases. SDG&E requests the Commission find the expenses reasonable and prudent.

We recognize that, under a prior decision, the Utilities currently have authority to recover these costs. However, SDG&E is aware the decision also provided for a final reasonableness review of the SGRP costs, which will occur in Phase 3 of these proceedings. Therefore, our interim finding that these costs are reasonable does not exempt these SGRP costs from the final review to come.

With that caveat, the Commission finds these 2012 costs to be reasonable and authorizes rate recovery.

11. Community Outreach and Education

At the request of Joint Parties and others, the Commission included in Phase 1, a review of SCE's 2012 actions and expenditures for community outreach and emergency preparedness related to the SONGS outages. The costs of SCE's Customer Outreach and Emergency preparedness programs are part of the company-wide GRC review, primarily through budgets for Local Public Affairs and Corporate Communications. SCE 's community outreach program is implemented in three public zones: a 10-mile radius from SONGS is the

Emergency Planning Zone, a 20-mile radius is the public education zone, and 30-50 miles is the "ingestion pathway" zone.[159]

SCE points out that the requirements for emergency preparedness followed by SCE, and other operators of commercial nuclear plants in the United States, are established by the NRC, Federal Emergency Management Agency (FEMA), and certain state agencies. SCE described its emergency preparedness activities on an on-going basis, and illustrated what it called "a significant community presence in the region surrounding SONGS."

For example, SCE performs regular drills and exercises site-wide and in coordination with the Interjurisdictional Planning Committee (IPC). In 2012, SCE reports it also provided radiological training for area Emergency Responders and updated service agreements with several area hospitals and transportation services.

After the outages, SCE states it also stepped up its public education program within the 20-mile plant radius, including numerous outreach presentations to local communities and school districts, sent Emergency preparedness brochures to 60,000 ratepayers within the federally-established 10-mile Emergency preparedness Zone, and expanded availability of Spanish language materials within the 20-mile public education zone.

Both Joint Parties and WEM ask the Commission to order SCE to segregate SONGS-related public education activities from SCE's company-wide program and subject these costs to future review. Both parties contend that SCE's efforts are insufficient, and include significant corporate image activities of questionable

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[159] "Ingestion pathway" refers to the potential for radiation to contaminate food sources.

value to the ratepayers. WEM criticizes the content of SCE's materials as "pro-nuclear public relations." WEM suggests a broad range of potential consequences of radiological leaks and emergency instructions should be required, and more extensive outreach beyond regulatory requirements. Joint Parties want the Commission to order SCE to appoint a single person to coordinate SONGS-related outreach and emergency preparedness and to translate all materials into numerous languages.

SCE observes that WEM does not dispute that SCE remains in full compliance with state and federal regulatory requirements, nor does WEM argue that SCE has failed to comply with any federal, state, or county regulations regarding emergency preparedness. No party contradicted SCE's assertion that, to the extent WEM objected to certain statements in its materials, the statements are accurate and consistent with similar information disseminated by federal and state authorities responsible for emergency preparedness in the event of a nuclear power plant accident.

SCE also provided evidence that, in 2011, the NRC reaffirmed its commitment to the 10-mile radius requirement for Emergency Planning Zones (EPZ) around U.S. nuclear power plants. The NRC said, "The current EPZ size has been in use since the 1970s and was the result of extensive emergency planning studies performed by a federal task force. That task force concluded a 10-mile-radius EPZ would assure that 'prompt and effective actions can be taken to protect the public in the event of an accident' at a plant."

SDG&E adds that the Commission has already rejected Joint Parties' proposal in the SDG&E 2012 GRC. In D.13-05-010, the Commission said, "to impose a SONGS-related community outreach program on SDG&E would be

duplicative of what SCE already does, and would result in unnecessary programs whose costs would be borne by ratepayers."

We are not persuaded that SCE's SONGS-related outreach fails to meet regulatory requirements or misleads the public. The Emergency Planning zones are established by the federal government, and there is insufficient evidence in the record for the Commission to intervene in the multi-jurisidictional emergency planning in place. Although some community outreach activities listed by SCE may have a self-serving component in terms of corporate image, we have previously supported an IOU's involvement with communities within its service territory.

On the other hand, we agree with the thrust of parties' concerns that, going forward, communities surrounding SONGS will begin to learn more about the coming decommissioning and have new questions and concerns. Therefore, the Commission finds it is in the public interest for SCE to expand its public education about SONGS and the future decommissioning beyond the 20-mile designated public education zone to 50 miles for the immediate future. SCE shall be particularly sensitive to pockets of alternative language users and coordinate with community based organizations to ensure wide distribution of public information and availability of emergency planning information.

Therefore, within 90 days of the effective date of the decision, SCE shall make an Information-only Filing, as defined in Section 3.9 of the General Rules of General Order 96-B, to the Commission which identifies SCE's strategy for expanding its public outreach activities as described.

12. Refueling Outage (RFO)

In SCE's 2012 GRC A.10-11-015, the company requested approval for two refueling outages (RFO) in 2012, one for SONGS Unit 2 during January –March

2012 and one for Unit 3 during October – December 2012, at a cost of $46 million (100%) each, or $36 million (SCE share). SCE submitted that it began the first RFO in January 2012 on U2. However, in the decision for SCE's 2012 GRC D.12-11-051, the Commission noted that U2 was not restarted and directed SCE to track the RFO expenses in the SONGSMA for future reasonableness review.[160] Based on the operational uncertainty of the SONGS units, the Commission continued the flexible outage schedule mechanism for the GRC cycle, but did not allow preliminary recovery of SCE's estimate of $72 million (SCE share) for the two forecast RFOs in 2012.[161]

12.1. Parties' Positions

SCE notes that based on its 2011 expectations, "the company included expenses for two RFOs – totaling $102.606 million – in rates." However, since D.12-11-051 did not authorize any 2012 revenue requirement for RFOs, SCE has "overcollected" by that amount. SCE explains that, "through the routine operation of SCE's Base Revenue Requirement Balancing Account (BRRBA)" the difference will be refunded to ratepayers, through SCE's 2013 ERRA forecast proceeding.[162]

During January – March 2012, SCE conducted one RFO, the U2 Cycle 17 RFO, at a cost of $45.1 million; the U3 Cycle 17 RFO was not conducted.[163] SCE's testimony describes the activities of the U2 Cycle 17 RFO.[164] SCE asserts that

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[160] D.12-11-051 at 34.

[161] *Ibid.*

[162] SCE Phase 1 OB at 46-47, citing SCE0-7 at.6.

[163] SCE Phase 1 OB at 46, citing SCE-4 at 76.

[164] See SCE-4 at 69-76.

these activities were "incurred before SCE was aware of the extent of the tube wear in either unit" and that the Commission should, in this proceeding, find the costs reasonable and authorize SCE to recover them in rates.[165] SCE summarizes this ratemaking in its testimony:

> In other words, SCE will refund the previously-collected forecasted costs of the Unit 2 and Unit 3 Cycle 17 RFOs when the recorded 2012 BRRBA balance is included in rates, and is seeking to recover the recorded costs for that Unit 2 Cycle 17 RFO costs in future rates.[166]

SDG&E notes that its 20% share of RFO costs were invoiced by SCE and paid by SDG&E. SDG&E asserts that these costs are reasonable and should be recovered in rates.[167] SDG&E further explains that it included $28.7 million in 2012 rates for two RFOs (via Advice Letter 2302-E), and that it has already (via Advice Letter 2416-E) refunded, in 2013 rates, the amount not spent on the 2012 RFO.[168] SDG&E does not clarify in testimony the amount it recorded for the U2 Cycle 17 RFO. In combination SDG&E's Quarterly Reports on its SONGS Outage Memorandum Account dated June 10, 2013 and July 1, 2013[169] show a recorded cost of $9.1 million for the 2012 RFO.

DRA "recommends that the Commission direct SCE to refund any RFO revenues recovered in rates that are in excess of the RFO expenses incurred in 2012 and incorporate the adjustment in rates immediately."[170]. DRA's calculation

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165 SCE OB at 47.

166 SCE-7 at 7.

167 SDG&E Phase 1 OB at 4.

168 SDGE-6 at 1-3.

169 Line 29: "Refueling {1 in 2012}."

170 DRA Phase 1 OB at 15.

of the over-collection is that $102.6 million was authorized for two RFOs in 2012,[171] and the actual costs of the U2 Cycle 17 RFO were $45.1 million,[172] yielding a difference of $57.5 million to be refunded.[173]

TURN suggests that SCE made an unreasonable decision to place new fuel in the U2 core during the RFO and the consequence "was an unnecessary destruction in value that could have been recouped through a resale of the unused fuel."[174] TURN asserts that SCE-4[175] demonstrates that by "early February of 2012" SCE had "substantial evidence of problems" at U2 prior to moving the fuel to the core, completed on March 1.[176] TURN-1 shows that SCE transferred $121 million to the in-core inventory in June 2012.[177] TURN suggests that the Commission can calculate lost value "either by relying on an independent assessment or by using pricing data when SCE ultimately sells its existing unused pre-core fuel inventory."[178] CDSO also argues that moving fuel to the U2 core was unreasonable.[179] CDSO observes that SCE witness Palmisano estimates a typical timeframe for moving fuel to the core is seven days.[180] SCE

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[171] DRA-1 at 10.

[172] SCE-4 at 76.

[173] DRA Phase 1 OB at 15.

[174] TURN Phase 1 OB at 10.

[175] At 77.

[176] TURN Phase 1 OB at 10, citing timeline in SCE-10, Question 4 at 1.

[177] TURN-1 at 3.

[178] TURN Phase 1 OB at 11.

[179] CDSO Phase 1 OB at 4.

[180] *Id.* at 5, citing RT 764:16-18.

concurs with this observation, and places the start date at approximately February 25.[181]

SCE contends that TURN and CDSO's claims "assume perfect foresight regarding the nature and extent of the Unit 3 steam generator failure, which was not understood until a later point in time."[182] SCE's Palmisano interpreted the U2 testing, as of February, 2012, to show "overall satisfactory results."[183] Because contractors were already on site, SCE further argues, delaying insertion of the fuel as scheduled would have imprudently resulted in additional costs.[184]

WEM, A4NR, and Joint Parties do not directly comment on the subject of RFO costs.

12.2. Discussion

No party contests that exactly one RFO occurred in 2012, and no party has challenged the amount recorded by the utilities for the U2 Cycle 17 RFO. We agree with DRA's recommendation that any over-collection for a second 2012 RFO originally forecast for U3 should be refunded, to the extent that that refund has not already occurred. We find that SCE's cost of $45.1 million (100% share) for the 2012 U2 Cycle 17 RFO were reasonably incurred and authorize each utility to recover their share of these costs in rates. Any amount previously collected beyond this amount, including any collection for the U3 Cycle 17 RFO that did not occur, shall be refunded to ratepayers, to the extent that such a refund has not previously occurred.

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[181] SCE Phase 1 Reply Brief (RB) at 3.

[182] SCE Phase 1 RB at 3.

[183] RT 850:11-14.

[184] SCE Phase 1 Reply Brief at 3, citing RT 766:13-24.

Despite arguments by TURN and CDSO we find that SCE's decision to place new fuel in the U2 core was reasonable. Before SCE initiated the fuel insertion on February 25, 2012, SCE did not have sufficient evidence to delay placing fuel in the reactor of U2. Although SCE knew of the U3 steam generator leak and of unexpected levels of tube-retainer bar wear in both U2 RSGs, it did not yet know of TTW in one of the U2 RSGs. SCE testimony, cited by TURN, [185] does reference TTW, but TURN mistakenly attributes this conclusion to the U2 "expanded" eddy current testing completed on February 14, 2012. The correct date of this finding is April 10, 2012,[186] which apparently corresponds to the "special interest" eddy current testing started on April 5, 2012.[187]

13. 2012 Replacement Power Cost Calculation (Phase 1A)

The purpose of Phase 1A of this proceeding is to adopt a method for calculating the approximate[188] cost of replacement energy and capacity, foregone sales, and other market related costs (collectively "replacement power costs") of the outage of SONGS. If, in a later phase (tentatively Phase 3) of this proceeding the Commission determines a certain range of dates that SCE and SDG&E should not be allowed to recover the replacement power costs, this method will be

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[185] SCE-4 at 77 and SCE-10, Question 4 at 1.

[186] RT 852:21-25.

[187] SCE-10, Question 4 at 1.

[188] We cannot calculate the precise replacement power costs because market participants, including the utilities, would have made different bidding, procurement, and operational decisions if the outage had not occurred. Consequently, it is impossible to know with certainty the outcome of those decisions or the market prices that would have resulted. See SCE-2 at 19. No party suggests that it is possible to calculate replacement power costs exactly.

applied to calculate replacement power costs for those dates. As scoped, Phase 1A is limited to calendar year 2012. However, if circumstances require, we will investigate what, if any, differences in the method should be used for other time periods. We reiterate that the costs referenced here are only for meeting the needs of bundled customers; this discussion is separate from ongoing discussions in the long term procurement plan proceeding, Rulemaking 12-03-014, about system reliability in light of the SONGS outage and retirement. Here we focus exclusively on the cost of what has been done to meet the needs of bundled customers in 2012, not what may (or should) be done in the future on behalf of system customers.

13.1. Definition of Replacement Power

Some of the parties have devoted considerable energy to the debate of what categories of costs should actually be encompassed by the method to be established here. SCE suggests that replacement power costs should be "limited to the costs SCE incurred to replace lost SONGS generation for hours in which SCE had a net-short energy position."[189] SDG&E concurs.[190]

TURN instead suggests that the definition include "*all* the economic harm – in the form of higher revenue requirements and rates – that the SONGS outages would otherwise impose on bundled customers."[191] A4NR supports the TURN recommendation. DRA argues that several different capacity-related and

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[189] SCE Phase 1A OB at 5.

[190] SDGE Phase 1A Reply Brief at 3.

[191] TURN Phase 1A OB at 1.

market-related costs should be included because they are "financial consequences" of the outages.[192]

SCE observes that, since California's electric industry restructuring in 1998, utility-owned generation exists in a market-based framework and suggests that our Phase 3 discussion of replacement power cost recovery should be informed by this reality.[193] We agree that the replacement power cost calculations should be based on the realities of the market at the time of the outage.

Our intended, high-level, definition of replacement power costs is the net increase in costs to the utility of meeting its energy and capacity obligations to bundled customers. More specifically, this definition:

- Includes the cost to replace lost, potential generation as well as lost revenues from potential sales. SCE's argument that foregone sales should not be considered has no merit. As proposed by the utilities in this proceeding, the only distinction between a MWh of energy to be replaced and a MWh whose sale is foregone is the utility's position at the relevant hour. The change in net cost to meet customer energy needs due to the lost MWh is only impacted by price at that hour. We do not see a reason to draw any distinction on cost responsibility (as opposed to cost calculation) based on the utility's position.
- Includes capacity and demand response costs allocated to bundled customers for maintaining system reliability in Southern California, to the extent these costs are clearly linked to the SONGS outage. SCE argues that capacity-related charges should not be considered replacement power because they do not "replace the energy output of SONGS."[194] SCE does not provide an affirmative rationale for why non-energy replacement costs

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[192] DRA Phase 1A Reply Brief at 3.

[193] SCE-37 at 1-2, SCE Phase 1A OB at 3-4.

[194] SCE Phase 1A OB at 12.

should be treated differently than replacement energy costs. DRA observes that SCE's own testimony contradicts SCE's brief, quoting SCE-8 "These 2012 CAISO charges can be considered replacement costs because they were incurred as a result of power charges assessed to SCE to replace generation from SONGS."[195]

- Includes onsite SONGS loads. SCE argues that replacing onsite loads is not replacement power because SONGS is not a "bundled customer."[196] TURN points out that this "is a distinction without a difference."[197] We find that load from the SONGS facility is not qualitatively different than load from bundled customers, it is simply load that would have been met by SONGS generation had SONGS been generating energy. The cost of meeting this load with non-SONGS energy is a replacement power cost.
- Does not include changes in the value of pre-existing utility hedges, including Congestion Revenue Rights (CRRs), but does include the net cost (e.g. cost net of revenues received) of CRRs purchased in response to the outages. We have a history of encouraging and requiring the utilities to hedge their risks against adverse outcomes. The SONGS outage is one example of the type of adverse outcomes that the utilities should hedge against. In order to avoid creating a perverse incentive against hedging, we will not consider changes in the value of the utilities' portfolio of hedges as replacement power costs. This does not preclude our evaluation of any new hedges in later phases of this or other proceedings.
- Does not include Energy Efficiency (EE) programs. WEM suggests that "surplus" achievements of EE programs saved more energy in 2012 than forecast and that this should be

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[195] DRA Phase 1A Reply Brief at 2-3, quoting SCE 8 at 15-16. Note that DRA's reply brief incorrectly attributes the quote to an earlier portion of SCE-8.

[196] SCE Phase 1A OB at 13.

[197] TURN Phase 1A Reply Brief at 11.

> considered in calculating replacement power costs.[198] As SCE observes, "there is no evidence that SCE incurred additional EE costs in 2012 in connection with the outages."[199] We agree. To the extent that EE programs led to loads being lower than forecasted, this may have changed the utilities' net positions (i.e. they were less short or longer than they would have been). Potentially, this could have shifted costs from replacement energy to foregone sales, resulting in a change to net costs. However, the record before us presents no viable means of quantifying this inaccuracy or correcting for it.

For clarity, we divide our discussion of the replacement power method into three categories. Each of these categories would be calculated individually, and then summed together to reach a total replacement power cost for the identified range of dates. The categories are:

1. Replacement energy costs and foregone energy sales,
2. Capacity-related costs, and
3. Other market related costs.

To prepare for using this method in a future phase, we direct each utility to serve exhibits detailing their calculation of replacement power costs according to the method here.

13.2. Replacement Energy Costs and Foregone Energy Sales

The replacement energy and foregone energy sales category represents the net cost to the utility of meeting its bundled energy needs that would have, but for the outage, been provided by SONGS.

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[198] WEM Phase 1A OB at 7-8.

[199] SCE Phase 1A Reply Brief at 14.

13.2.1. Positions of the Parties

SCE suggests the following formula for each[200] hour in this category:

Q*P = Hourly Replacement Energy Cost or Foregone Sales

Where, Q is the quantity, the portion of the hourly net short (long) position attributed to the outage (in MWh) and P is the price for that hour ($/MWh).[201] Other parties agree with this basic formula.[202] SDG&E adds an additional term "O" that represents:

- "CAISO Allocated costs," in the context of replacement energy costs,[203] which are separable and which we address in the other market costs category below, and
- "lost revenue from RA sales" in the context of foregone sales,[204] which are also separable and which we address in the capacity-related costs section below.

This is a very simple and familiar formula: cost (or lost sales revenue) equals quantity multiplied by price. The calculation of the terms Q and P provokes more controversy.

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[200] Note that SCE proposes a price elasticity adjustment to the term P in some hours. We address this adjustment below.

[201] SCE-37 at 7.

[202] In TURN-14 and in cross-examination, TURN witness Woodruff argues for changes about the calculation of the terms P and Q, implying acceptance of the basic formula. Similarly, in DRA-2, DRA makes a variety of recommendations about the terms P and Q, implying acceptance of the basic formula. Note that earlier versions of the utility testimony, to which DRA-2 responds, show the formula as Q*(P-F), where F represented avoided nuclear fuel costs. DRA-2 suggests that F should be zero. The utilities have agreed, in SCE-37 and SDGE-9B, to set F equal to zero, thus simplifying the formula to Q*P.

[203] SDGE-9B at 5.

[204] SDGE-9B at 7.

13.2.1.1. Q, Quantity

Q represents the amount of energy that must be bought, or could not be sold, for the hour due to the outage. SCE suggests that Q be limited to the amount of energy "that SONGS could have generated had it been available to operate that would have reduced [the utility's] net short position."[205] This limit encompasses two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic operating expectations, and 2) limiting the amount of energy attributed to each utility based on that utility's ownership share of SONGS. No party opposes this limit in concept. Q represents the approximate result of subtracting the utility's actual day ahead energy position from what the position would have been, had SONGS been available to operate. In some hours, the utility would be shorter due to the SONGS outage and have replacement energy costs; in others it would be less long and have foregone energy sales. In still other hours, when the utility was short by less than its share of the SONGS output, the utility had both replacement energy costs and foregone sales. This last possibility is not explicitly referenced in plain language by any party. However, the parties' various arguments about which costs do (or do not) constitute replacement power costs are related. For example, TURN's comments about assuming that "SONGS is always the marginal generation unit" appear to address this possibility.[206] TURN observes that D.05-12-040, which approved the replacement steam generators at

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[205] SCE-2 at 18.

[206] TURN Phase 1A Reply Brief at 3, and 7-8

SONGS, relied on an SCE analysis that assumed the entire generation of SONGS, not limited by the utility's net open position.[207]

How to measure the utility's position is one key question. SCE proposes using the utility's actual position in the day-ahead time frame, specifically, "its final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity".[208] SDG&E agrees.[209] TURN, by contrast, suggests that use of the actual day ahead position creates "downward bias" in the estimate of Q. In response, SCE "contends that there are too many factors to consider to reliably assume a downward bias."[210]

SCE and SDG&E suggest that Q should be calculated using a 2.15% forced outage rate, based on a recent ten year average. SCE also notes this is consistent with the industry average 2% rate reported by the Nuclear Regulatory Commission.[211] SCE suggests that the forced outage rate should be applied equally in all hours (e.g. the assumed lost generation of SONGS would be reduced by 2.15% in each and every hour of the outage).[212] DRA, in contrast suggests a 1.21% forced outage rate, based on a five year average.[213] DRA alternatively suggests using the industry average 2% rate.[214]

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[207] TURN Phase 1A Reply Brief at 5, citing D.05-12-040 at 21-22

[208] SCE-2 at 21.

[209] SDGE-9B at 3

[210] SCE 37 at 19.

[211] SCE-37 at 7; SDGE-9B at 5.

[212] RT 1415:1-3.

[213] DRA-2 at 14.

[214] DRA Phase 1A OB at 6.

SCE suggests that Q should be limited by scheduled refueling and maintenance outages so that only the unit that would not have been on a scheduled outage is counted for replacement power cost calculations. SCE suggests the following scheduled outage dates:[215]

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

No party disputes the dates or the use of these scheduled outages to limit Q during those time periods.

Both utilities suggest that the Q applied to each of them individually should be limited to their respective ownership share of SONGS.[216] No party disputes this.

13.2.1.2. P, Price

P represents the price or the value to the utility of the energy that must be purchased or cannot be sold. SCE suggests using the "SP-15 day-ahead index prices" as reported by Platt's MegaWatt Daily.[217] SCE notes that it procures energy for bundled customers in many different timescales ranging from multi-year to hourly and that there is no single price point that accurately reflects its

[215] SCE-38 at 12.

[216] SDGE-9B at 3, SCE-38 at 2-3.

[217] SCE-38 at 3. Note that SP-15 refers to the region of the California electric grid to the South of Path 15. SP-15 includes the service territories of both SCE and SDGE, as well as the SONGS facility.

incremental costs.[218] SCE supports its position by asserting that the SP-15 day-ahead index represents costs for the utilities both as buyers and as sellers:

> SP-15 is an appropriate pricing point because the SONGS energy that would have otherwise been produced would have generally served SP-15 load. Additionally, bilateral transactions that SCE would make to cover bundled demand would generally be purchased with an SP-15 delivery or settlement price. Specifically, SP-15 day-ahead index prices are commonly used to settle financial transactions for energy transacted for delivery in southern California.[219]

SDG&E proposes the "SP-15 Trading Hub day-ahead prices" as published by the California Independent System Operator (CAISO), noting that this is the price SDG&E would receive from CAISO for its share of the SONGS output when SONGS was operating.[220] The CAISO trading hub price is calculated for each hour in the day, in contrast to the Platts SP-15 Index proposed by SCE, which is calculated for the on-peak and off-peak periods of each day.[221] SDG&E notes that it is "agreeable" to using the Platts SP-15 Index.[222]

DRA expresses a slight preference for the Platts SP-15 Index proposed by SCE and recommends that the same measure of P be used for both utilities. DRA notes that, although the difference between the two measures proposed by the Utilities is large in some hours, there is very little difference on average. DRA's

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[218] SCE-37 at 16.

[219] SCE-38 at 3.

[220] SDGE-2 at 18.

[221] RT 1442:14-1443:7.

[222] SDGE Phase 1A Reply Brief at 6.

reasoning for this preference is based on the index's use to settle financial and physical transactions in SP-15.[223]

TURN and A4NR suggest that the utilities' respective Default Load Aggregation Point (DLAP) prices should be used for replacement energy costs and the SP-15 Existing Zone Generation Hub (SP-15 EZ-Gen) for foregone sales. The DLAP price represents prices paid by load in the CAISO markets and SP-15 EZ Gen represents prices paid to generators.[224] A4NR's rationale is that ex-post prices are preferable to ex-ante (e.g. the day-ahead Platts) for the purpose of calculating damages and that this approach would be using a load-based price (DLAP) for replacement energy and a generation-based price (SP-15 EZ-Gen) for foregone sales. TURN focuses on the "gap" between the two prices and argues that the simplicity of using a single price does not justify the decrease in accuracy. In support, TURN provides an SCE data response suggesting a 2.5% difference.[225] SCE notes that it is "not opposed" to this proposal "as a matter of principle," but raises the practical objection that the DLAP and SP-15 EZ-GEN prices are not detailed in the record.[226]

For hours with foregone energy sales, SCE proposes that P be modified as (P-E) where E is the "estimated price elasticity impact of SONGS not being available to operate (expressed in $/MWh)."[227] SCE calculated E for on-peak and

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[223] DRA-2 at 7-8.

[224] A4NR Phase 1A OB at 4-6; TURN Phase 1A OB at 7-9.

[225] TURN Phase 1A OB at 8, citing TURN-9, Question 13b.

[226] SCE Phase 1A Reply Brief at 19.

[227] SCE-37 at 8-9.

off-peak periods for each month based on a regression analysis.[228] SDG&E and TURN each conceptually agree with SCE's approach on this elasticity analysis, but are not able to offer detailed quantitative comment on SCE's estimates. TURN did note that "the results seemed reasonable."[229] No other parties have commented on the subject.

13.2.2. Discussion

We will adopt the formula proposed by SCE and supported by SDGE, TURN, and DRA, including the price elasticity adjustment for foregone sales. Basic economic reasoning suggests this formula: cost (or foregone sales) is equal to the quantity purchased (or not sold) multiplied by the unit price. We apply this formula as summarized in this table:

Hours when the net open position is	**Formula**	**Replacement Energy Cost or Foregone Energy Sales?**
Short	Q_{short} *P =	Replacement Energy Cost
Long	Q_{long} *(P-E) =	Foregone Energy Sales
Short by less than ownership share of SONGS energy	Q_{short}*P =	Replacement Energy Cost
	Q_{long}*(P-E) =	Foregone Energy Sales

13.2.2.1. Q, Quantity

Q is the net open position, in MWh, of the utility, up to its ownership share of SONGS energy. We agree with SCE that Q should be limited by two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic operating expectations, and 2) limiting the amount of

[228] RT 1415:7-24.

[229] RT 1454:17-24; RT 1574: 7-23.

energy attributed to each utility based on that utility's ownership share of SONGS. For hours when the utility's net open position is short (long), it buys (sells) energy to meet the needs of its customers; the amount of this short (long) position up to each utility's ownership share of the lost SONGS energy is the "replacement" energy ("foregone" sales). Amounts beyond the ownership share are ordinary purchases or sales that would have happened regardless of the outage. For hours when the utility's net open position is short by less than its ownership share of SONGS energy, the short position is shown as Q_{short}; the remaining portion of its ownership share is indicated as Q_{long} (i.e. $Q_{short} + Q_{long} = Q$ = the utility's ownership share of SONGS energy). This mathematical treatment of Q recognizes that the total amount of energy replaced (or sales foregone) is independent of the utility's net open position. Stated differently, the sum of energy replaced and sales foregone in each hour is equal to the utility's ownership share of SONGS energy that would have been produced (given operating assumptions discussed below) in that hour.

In all hours, Q should be limited based on realistic operating parameters of SONGS. We agree with parties that these limits are based on both forced and planned outages. We find that each SONGS unit had one planned outage during 2012 and that only the generation of the unit not on outage should be included in Q during the scheduled outage. The planned outages are:

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

We recognize that there is no single "correct" historical timeframe to consider in selecting an appropriate forced outage rate to assume for this analysis. The range presented to us is small (1.21% to 2.15%), changing the

calculated costs in this category by less than one percent, and total replacement costs by an even smaller fraction. Further, we note that the replacement steam generators would represent a significant change in the SONGS facility, which calls into question the basic assumption that past experience at SONGS should be the guide. Therefore, we find that it is appropriate to use the industry average 2% forced outage rate reported by the Nuclear Regulatory Commission.

Finally, we agree with SCE and SDG&E that measuring each utility's net open position based on its "final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity" is appropriate. We agree with TURN that this likely does introduce a downward bias because, as SCE admits, the utilities procure energy on many different timescales including products that could have been purchased during the outage for later parts of the outage more than one day forward. However, we see no viable, analytically rigorous alternative based on the record before us.

13.2.2.2. P, Price

P represents the price or the value to the utility of the energy that must be purchased or cannot be sold. We agree with TURN and A4NR that it is worthwhile to use the DLAP price for replacement energy costs and the SP-15 EZ-Gen price for foregone sales. This avoids any "downward bias" associated with using a price that does not match the transaction (i.e. generation based price for a purchase for load, or vice versa). We recognize that this choice imposes a small additional analytic burden on the parties, but believe this work is justified by the increased accuracy in the calculation.

We agree that a price elasticity adjustment, as suggested by SCE, is appropriate for foregone sales, in the form of P-E. The adjustment originally calculated by SCE was intended to modify the Platts SP-15 Index, and will need

to be recalculated for the SP-15 EZ-Gen price. However, we see no reason for the basic mechanics of the calculation to change. The Utilities shall calculate a new adjustment, E, for the SP-15 EZ-Gen price, using a regression analysis as presented in work papers and testimony in Phase 1A. The analysis should calculate E for on-peak and off-peak periods of each month

13.3. Capacity-Related Costs

SCE describes three types of capacity costs related to the SONGS outages:[230]

- CAISO Capacity Procurement Mechanism (CPM) charges. CPM charges are allocated to bundled customers based on their load ratio share in certain Transmission Access Charge Areas.
- CAISO Standard Capacity Product (SCP) penalty charges for forced outages. Other Resource Adequacy (RA) resources that qualified for an availability bonus under the SCP during 2012 received bonus payments funded by the SONGS SCP penalty. SCE netted the bonuses it received against its penalty charges.
- Replacement RA capacity. In order to reduce SCP penalty charges, SCE purchased some replacement RA capacity.

CPM costs were incurred related to the outages of both units. The Unit 2 outage, because it was classified as planned, did not result in SCP penalty charges or replacement RA capacity purchases.[231]

SDG&E describes the same three capacity cost categories.[232] However, we must also address the foregone RA sales that SDG&E notes in its testimony.[233]

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[230] SCE-38 at 8-9

[231] SCE-38 at 9

[232] SDGE-9B at 7-8

[233] SDGE-9B at 7

Lost RA value is a broader issue than presented in the SDG&E testimony. Based on the RA rules that were adopted in D.06-07-031 (see table below), the extension of the Unit 2 scheduled outage would prevent that unit from being used to satisfy RA requirements for any month in 2012, after the outage became known. By this rule, both SCE and SDG&E may have lost the value of Unit 2's RA capacity for each month of 2012, excluding January and February for which the RFO was originally scheduled. However, the record before us does not describe which months the Unit 2 RA value was actually lost. It is reasonable to assume that RA value was lost for July to September, when RA requirements are highest. Unit 3's outage, classified as forced rather than scheduled, did not diminish that unit's RA value by this rule. D.06-07-031 summarizes the scheduled outage counting rule as follows:[234]

Time Period	Description of How Resource Would Count at Time of the Showing
Summer May through September	Any month where days of scheduled outages exceed 25% of days in the month, the resource does not count for RAR. If scheduled outages are less than or equal to 25% of the days in the month the resource does count for RAR.
Non-Summer Months October through April	For scheduled outages less than 1 week, the resource counts towards RA obligations. For scheduled outages 1 week to 2 weeks, the amount counted for RAR is prorated using the formula: [1 - (days of scheduled outage/days in month) - 0.25] * NQC in MW = NQC that can count towards an LSE's RA obligation The formula will allow resources to count between 50% and 25% of NQC. For scheduled outages over 2 weeks, the resource does not count for RAR.

Providing RA capacity to meet requirements is a direct cost of serving bundled customers' capacity needs and to the extent that the net cost of meeting RA requirements increased due to the SONGS outage, the increase is a replacement power cost. We find that each utility's ownership share of Unit 2's RA value (Net Qualifying Capacity, or NQC) multiplied by the monthly system

[234] D.06-07-031 at 10.

RA price is the appropriate measure of this lost RA value, for July through September in 2012.[235] This measure assumes that in each month either replacement RA was procured or RA sales were foregone, or both. The record before us does not clearly show RA prices for each month. In calculating lost RA value, each utility shall use the average price of its RA-only[236] transactions during calendar year 2012 for July through September of 2012.

DRA notes that both utilities describe the same cost categories.[237]

We find that all three of the capacity-related costs identified by SCE, as well as any foregone RA sales, are replacement power costs. No party disputes that each of these categories represents a capacity cost incurred on behalf of bundled customers as a result of the outage. As discussed above, SCE argues that capacity costs should not be counted as replacement power, but does not provide a persuasive rationale.[238] SCE cites two prior Commission decisions (post-restructuring) that use replacement power costs as a penalty for unreasonable forced outages and uses them to support its assertion that replacement power costs should be limited to replacement energy.[239] SCE neglects to mention that the outages contemplated in these decisions are of a

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[235] Even though SONGS is a "local" RA resource, the local premium is only valuable in year-ahead RA contracts and prices. The month-ahead RA program does not explicitly measure local RA.

[236] By RA-only, we intend to isolate the price paid for RA, exclusive of other attributes. Therefore, to perform this calculation, the utilities should exclude contracts that include other values, such as: tolling, combined heat and power, renewables, and qualifying facilities.

[237] DRA-2 at 16.

[238] See: **Error! Reference source not found.**.

[239] SCE Phase 1A OB at 4, citing D.10-07-049 and D.11-10-002.

much shorter duration than in the instant case. This is an important distinction due to the incentive for grid operators to take action, for example via CPM, to replace the capacity on outage when that outage may have a long duration. Further, in the market, as it existed in 2012, outages of any duration have a different impact on capacity-related costs than outages during the time periods discussed in the previous decisions. The SCP, and by extension SCP penalties and the need for replacement RA, was created in the CAISO markets in January, 2010 after the outages in the decisions cited by SCE.[240] SDG&E cites one similar decision, but its subject is also a short duration outage prior to the SCP.[241]

TURN suggests adding an additional capacity-related line item from the outage memorandum accounts: the Demand Response (DR) subaccount (line 40).[242] SCE argues that the DR at issue was "exclusively designed as a grid reliability measure" and should not be considered as replacement power because it was not "to meet bundled customer demand."[243] As TURN observes, this distinction is "artificial" – the program was designed to alleviate reliability concerns that were at least in part caused by the SONGS outage.[244] Indeed, this OII directed that the only DR tracked in the subaccount is the DR "specifically

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[240] *California Independent System Operator Corporation* (June 26, 2009) 127 FERC ¶ 61,298 (Order Accepting in Part and Rejecting in Part Tariff Revisions Subject to Modification) at 1.

[241] SDGE Phase 1A Reply Brief at 2, citing D.12-03-014.

[242] TURN-14 at 8.

[243] SCE Phase 1A OB at 14, partly referring to RT 1361: 9-10.

[244] TURN Phase 1A OB at 9-10, referencing TURN-4 at 15.

implemented to address the loss of SONGS Units 2 and 3 capacity."[245] We find that the DR subaccount is an element of replacement power costs.

13.4. Other Market Costs

In this section, we address other market costs individually.

As discussed above, we view CRRs as a valid component of the Utilities' risk hedging activities. We will not treat net changes in values of previously held CRRs as a replacement power cost. SDG&E notes that it procured CRRs in the monthly CAISO auctions after the outages to manage outage-related congestion costs and that it treats these CRRs as a component of 2012 replacement power costs.[246] We agree -- the net cost of CRRs purchased during 2012 in response to the outages is a replacement power cost.

Real Time Imbalance Charges were charged for the early hours of the outage (in January 31 and February 1 of 2012), when the actual output of SONGS deviated from its schedule in the CAISO markets. Auxiliary Load charges were incurred for load at the facility for the hours when SONGS was not generating during 2012. When SONGS operated, these auxiliary loads were met by SONGS generation. Auxiliary Load is billed by the CAISO through the Real Time Imbalance Charges. Although the Utilities report these two categories differently, they should be proportional to the ownership share of the facility.[247]

The CAISO's Participating Intermittent Resources Program (PIRP) allocates certain charges to all uninstructed negative deviations in the market.

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[245] OII.12-10-013 at 12-13.

[246] SDGE-9B at 5.

[247] RT 1422:25 – 1423:16.

Auxiliary load is treated as such a deviation, and therefore triggers PIRP charges.[248]

The Real Time Imbalance, Auxiliary Load, and PIRP costs would not have been incurred, except for the SONGS outage, in any hour that one or both units would have been scheduled to generate. Therefore we find that these are replacement power costs.

13.5. TURN Proposal for Supplemental Modeling

In its Opening Brief, TURN "offers an alternative approach to the calculation of replacement power costs." The approach is "that each utility be required to perform the specified modeling . . . and make an additional filing subject to comment by the parties." The modeling would calculate energy costs, generation revenues, and CRR costs and revenues by comparing "SONGS OUT" and "SONGS IN" scenarios, based on recorded quantities and actual or estimated prices.[249] TURN argues that this approach avoids "downward biases" found in the approaches suggested by the Utilities.

The Utilities argue against this approach on both procedural (e.g. timing) and practical (e.g. large number of required assumptions) grounds.[250] We agree with the Utilities' practical arguments. Simply stated, we do not have convincing evidence before us that any likely improvement in the accuracy of replacement power cost estimates justifies the considerable extra effort to pursue this modeling approach.

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[248] RT 1424:16 - 1425:8.

[249] TURN Phase 1A OB at 13-15.

[250] See SDGE Phase 1A Reply Brief at 4-6, SCE Phase 1A Reply Brief at 19-23.

13.6. Other Miscellaneous Proposals

WEM alleges that any expenses related to Huntington Beach Units 3 and 4 are illegal, and therefore are not replacement power and should be disallowed.[251] This is outside the scope of this Investigation. Further, SCE explains that it was not directly involved in the Huntington Beach transactions and that CAISO was the purchasing entity.[252]

WEM argues that the Utilities have failed to comply with the Loading Order.[253] This is out of scope.

13.7. Supplemental Exhibit Calculating Replacement Power Costs

In order to implement the replacement power calculations as adopted herein, the Utilities must each recalculate their replacement power costs. As stated above, we intend to have the estimate available for use in future phase of this proceeding (tentatively Phase 3). Therefore, we direct the Utilities to each serve a preliminary Phase 3 exhibit, including summary tables of these calculations within 45 days of today's decision. The summary tables shall contain at least the following details for each month of 2012 and other specified periods, all in 2012 dollars:

- Replacement Energy Cost,
- Foregone Energy Sales,
- Price elasticity adjustment, E, to SP-15 EZ-Gen price for on-peak and off peak periods for each month,

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[251] WEM Phase 1A OB at 4 and 24.

[252] SCE Phase 1A Reply Brief, RT 1391-1393.

[253] WEM Phase 1A OB at 24-25, citing e.g. D.12-01-033.

- CPM Charges,
- SCP Penalty Charges,
- Replacement RA,
- Foregone RA Sales,
- DR Costs,
- PIRP, Real Time Imbalance, and Auxiliary Load Charges, and
- Net Cost of SONGS-Related CRR Purchases.

In addition to the monthly periods, these items shall be calculated for each of the following periods:

- Calendar year 2012,
- Beginning of the SONGS Outage (1/31/2012) through 12/31/2012, and
- Beginning of the SONGS Outage (1/31/2012) through 10/31/2012.

Following the Utilities' submission of these exhibits, parties may serve reply testimony, if, and only if, they allege that the Utilities' calculations do not comply with today's decision or contain calculation errors. Such reply testimony will be due 45 days after the Utility testimony. If any reply testimony is served, rebuttal testimony may be served 20 days later. The assigned ALJs may modify this schedule. Neither the original Utility exhibits nor any reply or rebuttal testimony may be used as an attempt to relitigate any Phase 1A issue. The focus of the exhibits shall be exclusively on recalculating replacement power costs in compliance with today's decision.

14. Revenue Requirements and Refunds

Today's decision segregates 2012 SONGS related costs into three groups: adopted as reasonable costs for recovery, unreasonable costs that shall be

refunded in 2014 rates, and costs for which the final reasonableness review shall occur in Phase 3. These adjustments and the resulting 2012 revenue requirement reduction are summarized below:

Summary of Adopted Ratemaking			
100% share, 000s of 2012$			
Cost Category	Adopted	Refund in 2014 Rates	Review in Phase 3
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300)	

The Utilities shall refund the excess revenue requirement identified by the Commission herein, collected in rates for 2012 expenses, through each utilities' established base rate balancing mechanism, to become effective on January 1, 2014. In addition, for rates collected applicable to SGIR incremental expenses, these funds shall be separately accounted for and interest accrued at the one-year Treasury rate for the benefit of ratepayers should the Commission find in a later phase these funds should also be refunded.

15. Comments on the Proposed Decision

The proposed decision of the ALJs in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____ and reply comments were filed on _____ by _____.

16. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and ALJ Kevin Dudney and ALJ Melanie M. Darling are the assigned ALJs in this proceeding.

Findings of Fact

1. On January 31, 2012 when the Unit 3 (U3) leak was discovered, Unit 2 (U2) was about half-way through its scheduled refueling outage where significant inspections, testing, and repairs take place.

2. On February 12, 2012, SCE confirmed a leak in U3 Steam Generator (SG) tube; additional testing identified several types of tube wear, including significant Tube-to-Tube wear (TTW) in the U-tube region of the SG.

3. On March 13, 2012, SCE was aware that eight U3 tubes failed in-situ pressure testing due to TTW.

4. On March 23, 2012, SCE submitted a SG Return-to-Service (RTS) Action Plan to NRC outlining its commitments to corrective actions before restarting either unit; at the time SCE did not know the cause or extent of tube wear in the steam generator tubes.

5. On March 27, 2012, U.S. Nuclear Regulatory Commission (NRC) sent SCE a Confirmatory Action Letter (CAL) that notified SCE it could not restart either unit until SCE completed a list of actions and NRC completed its review of the actions, including determining causes of TTW.

6. SCE knew the CAL would remain in effect until the NRC had (1) reviewed SCE's response, including responses to staff questions and the results of SCE's evaluations, and (2) NRC had written its conclusion that the units could operate safely without undue risk to public health and safety, and the environment.

7. In early 2012, TTW was unknown; SCE considered TTW as the most significant and complex phenomena, and a key barrier to restart of U2.

8. SCE completed all, or nearly all, of the work related to the U2 refueling outage before SCE knew the potential for serious damage in that unit.

9. In March 2012, SCE developed a plan to postpone, cancel, and re-schedule capital projects; SCE also began work on short-term and long-term repair options.

10. SCE knew or should have known by March 15, when it confirmed tube-to-tube wear in Unit 3, that a potential design defect was present in both units and thus fault could become an issue to rate recovery.

11. SCE's extensive U3 testing completed April 15, 2012, found more than half of the TTW indications in each SG had maximum measured depths exceeding the 35% plugging limit in the technical specifications.

12. On April 23, 2012, SCE issued a U2 tube wear Root Cause Analysis (RCA) which identified the cause of TTW as Fluid Elastic Instability (FEI).

13. On April 26, 2012, SCE Board of Directors was told by SCE managers that U2 return-to-service (RTS) RTS was scheduled for June 1, 2012, and U3 on June 30, 2012.

14. SCE's assumption that U2 could restart in 2012 served as a basis to prioritize work for the plant staff, the operators, and others.

15. SCE did not consider alternative courses of action for U2, other than the restart plan.

16. Cost considerations were not a dominant factor in SCE's analysis of its intended actions for U2.

17. On May 7, 2012, SCE issued U3 RCA which included identification of TTW in U2 and U3.

18. SCE knew or should have known by May 7, 2012, when it confirmed tube-to-tube and three other types of tube wear in Unit 2, that pursuit of a restart plan for U2 was not in the interests of immediately restoring power generation for the benefit of ratepayers

19. In June 2012, SCE began planning to put U3 into Preservation Mode, which maintains the unit in a condition that would allow future refueling and restart, assuming a long-term repair was completed.

20. During the first few months of 2012, SCE worked closely with the NRC, MHI, and its contracted experts to investigate the damage and to develop operational assessments to support a limited restart of U2 for the purpose of testing impact on the SG tubes.

21. SCE's decision to restart U2 was not part of normal operations for an operating generation facility because it was not reasonably foreseeable that the unit would return to full generation in 2012.

22. In July 2012, SCE created a long term repair team for both units.

23. On October 3, 2012, SCE submitted its response to CAL; NRC identifies 6 -7 month window for review, inspections, response to staff information requests, public meetings, etc.

24. On December 5, 2012, the Atomic Safety Licensing Safety Board held hearing to determine whether SCE will need a license amendment to try U2 restart plan

25. On December 14, 2012, Mitsubishi Heavy Industries (MHI), which designed & manufactured the replacement steam generators, sent two progress letters to SCE regarding development of long-term repair options.

26. On December 20, 2012, MHI provides SCE with long-term repair options and recommendations.

27. The primary purpose of SCE's U2 restart plan was a limited theoretical test to gather data for long-term repair options, not for electric generation.

28. SCE bills SDG&E for its pro rata share of SONGS-related expenses; SG&E also has internal-only expenses related to its ownership interest in SONGS.

29. SCE has not credited the $3.96 million in 2012 savings from staff reductions to the overall calculation of O&M.

30. Of the total $488,702 million recorded (100% $2012) for O&M costs, $347.747 million is recorded as Base-Routine, $140.955 million as SGIR-related.

31. By early May 2012, SCE knew or should have known that it was not reasonably foreseeable that Unit 2 would return to producing electricity in 2012 or even that a short-term restart was viable.

32. In order to reasonably account for O&M costs incurred as a result of SCE's not well-considered decision to maintain all, or nearly all, operating staff through the end of 2012, O&M costs recoverable in rates should gradually decrease beginning in June 2012.

33. SCE recorded $140.855 million (100%) for 2012 incremental SGIR expenses, including $8.555 million re-allocated post-hearing from Base O&M.

34. SCE collected some SGIR-related expenses in rates because it viewed them as normal O&M or capital costs.

35. The seismic studies approved by D.12-05-004 are not directly related to relicensing; they are related to regulatory requirements.

36. The Commission preliminarily authorized SCE to make $189.2 million ($2012, 100%) in SONGS-related capital expenditures; SCE actually recorded a total of $167.6 million for all types of projects, including the RFO and SGIR expenses.

37. More than $89 million (53.5%) of total capital expenditures occurred between January and April, 2012.

38. Some capital expenditures were necessary during 2012, even though the reactor units were not operating, because the NRC operating license requires SCE to maintain many systems in order to protect the safety of the plant, its workers and the public.

39. SCE's effort to suspend, cancel, and re-schedule some projects was inadequate to reflect the overall reduction of capital projects that should have occurred at SONGS.

40. Rate-based 2012 capital revenue requirements exceed preliminary allowed amounts for both SCE and SDG&E by a combined total of $41.8 million.

41. SCE's evidence is incomplete as to the extent that SGIR-related and U2 RFO capital projects are recorded as in-service and added to rate base in 2012.

42. The evidence does not establish that SCE knew in 2012 that it would decide in 2013 to permanently shut down the SONGS facility.

43. SCE did not calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012, but said it could develop an approximate estimate using the lead-lag days adopted in the GRC.

44. SDG&E recorded $60.492 million of SONGS-related costs not included in the SONGS portion of SCE's 2012 GRC or in SCE's OII testimony.

45. The costs of SCE's Customer Outreach and Emergency preparedness programs are part of the company-wide GRC review, primarily through budgets for Local Public Affairs and Corporate Communications.

46. The requirements for emergency preparedness followed by SCE, and other operators of commercial nuclear plants in the United States, are established by the NRC, Federal Emergency Management Agency (FEMA), and certain state agencies.

47. It is in the public interest for SCE to expand its public education about SONGS and the future decommissioning beyond the 20-mile zone, to 50 miles, for the immediate future.

48. In 2011, SCE expected two RFOs to occur in 2012 and included $102.606 million in 2012 rates for these RFOs (100% share).

49. SDG&E included $28.7 million in rates for its share of two RFOs in 2012.

50. Only one RFO, the U2 Cycle 17 RFO, occurred during 2012 at a cost of $45.1 million, resulting in an effective over-collection of $57.5 million (100% share).

51. SDG&E recorded $9.1 million for the 2012 RFO, $19.6 million less than collected.

52. The utilities' costs of $45.1 million (100% share) for the U2 Cycle 17 RFO during 2012 were reasonably incurred.

53. Any amount collected beyond the $45.1 million for 2012 RFOs is an over-collection.

54. SCE seeks to refund its over-collection via its 2013 ERRA forecast proceeding.

55. SDG&E has refunded its over-collection via Advice Letter 2416-E.

56. SCE's decision to place new fuel in the U2 core during U2 Cycle 17 RFO was reasonable.

57. For purposes of calculating 2012 replacement power costs in Phase 1A of this proceeding, the definition of replacement power is the net increase in costs to the utility of meeting its energy and capacity obligations to bundled customers. This definition includes: the cost of replacing potential generation and lost revenues from potential sales; capacity and demand response costs allocated to bundled customers, to the extent these costs are clearly linked to the SONGS outage; the net cost of Congestion Revenue Rights (CRRs) purchased in response to the outages; and onsite SONGS loads. This definition excludes energy efficiency programs and the changes in the value of pre-existing utility hedges including CRRs.

58. The formula detailed in the following table is appropriate for calculating replacement energy cost and foregone sales, where: Q represents the SONGS outage-related portion of the hourly net open position in megawatt-hours, P represents the energy price in dollars per megawatt-hour, and E represents a price elasticity adjustment in dollars per megawatt-hour.

Hours when the net open position is	**Formula**	**Replacement Energy Cost or Foregone Energy Sales?**
Short	Q_{short} *P =	Replacement Energy Cost
Long	Q_{long} *(P-E) =	Foregone Energy Sales
Short by less than ownership share of SONGS energy	Q_{short}*P =	Replacement Energy Cost
	Q_{long}*(P-E) =	Foregone Energy Sales

59. Q is appropriately limited by two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic

operating expectations, and 2) limiting the amount of energy attributed to each utility based on that utility's ownership share of SONGS.

60. Each SONGS unit had one planned outage during 2012, for the dates below.

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

61. It is reasonable that only generation for the unit not on outage be included in Q during each of the scheduled outages.

62. It is appropriate to use the industry average 2% forced outage rate reported by the Nuclear Regulatory Commission for calculating Q.

63. Measuring each utility's net open position (Q) based on its final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity is appropriate.

64. It is reasonable to use the Default Load Aggregation Point (DLAP) price for replacement energy costs and the South of Path 15 Existing Zone Generation Hub (SP-15 EZ-Gen) price for foregone sales.

65. A price elasticity adjustment is appropriate for foregone sales.

66. There are five types of capacity-related costs that are replacement power costs: California Independent System Operator (CAISO) Capacity Procurement Mechanism (CPM) charges, CAISO Standard Capacity Product (SCP) penalty charges, replacement Resource Adequacy (RA) capacity, foregone RA sales, and Demand Response (DR) specifically implemented to address the loss of SONGS.

67. It is reasonable to assume that RA value was lost for July to September of 2012, when RA requirements are highest.

68. Each utility's ownership share of Unit 2's RA capacity value (Net Qualifying Capacity) multiplied by the monthly system RA price is the appropriate measure of this lost RA value, for July through September in 2012.

69. It is reasonable for each of the Utilities to use the average price of its RA-only transactions concluded during calendar year 2012 for July through September of 2012, or any month therein, as the RA price for July through September 2012.

70. The Real Time Imbalance, Auxiliary Load, and PIRP costs would not have been incurred, except for the SONGS outage, in any hour that one or both units would have been scheduled to generate, and therefore these costs are replacement power costs.

Conclusions of Law

1. During January and February, SCE acted as a prudent operator of SONGS to detect the U3 leak, identify the source of the leak, inspect all of the U2 and U3 tubes for damage, investigate the causes of excessive and unexpected wear, and to assess whether repair is a reasonable option.

2. SCE's decision-making process was not reasonable or sound when the utility decided after May 7, 2012 to pursue RTS for U2 as soon as possible.

3. SCE's decision in May 2012 to retain the staff required for a fully operational facility, resulting in large O&M expenses, was unreasonable.

4. The record does not establish that costs associated with the restart and long-term repair options (SGIR) are routine O&M for which it would be just and reasonable to collect immediate recovery from ratepayers.

5. It is reasonable for savings realized from employee layoffs to be credited to ratepayers as part of the overall costs subject to rate recovery for 2012 O&M.

6. Beginning in June 2012, 10% of O&M shall be re-allocated to SGIR for further review as SGIR-related expenses in Phase 3, followed by 20% in July and so on until November and December 2012 when 40% of recorded O&M will remain in rates.

7. The total amount of reasonable 2012 SONGS-related O&M is $292.030 million, $96.97 million less than the amount preliminarily authorized in the GRC ($389.0 million).

8. It is reasonable to defer the final reasonableness review of 2012 incremental costs related to the outages of the steam generators to Phase 3 in the context of the overall SGRP and SCE's management of the project.

9. It is reasonable to apply a 20% reduction to recorded capital expenditures to establish the necessary and reasonable amount to maintain the units in a safe and secure condition, or to meet federal and state regulatory requirements.

10. It is reasonable for ratepayers to receive interest on previously collected SGIR expenses which have not yet been found by the Commission to be reasonable, nor were they preliminarily authorized by the Commission.

11. Approximately $134.08 million (80%) of 2012 total recorded capital expenditures are reasonable, including expenditures related to the U2 RFO.

12. It is reasonable to apply the 20% reduction in approved capital expenditures as a proxy for excess capital projects moved to rate base in 2012, to remove this amount from the rate base, and the associated revenue requirement is determined to be unreasonable for 2012.

13. It is not reasonable to impute knowledge of SCE's June 2013 decision to shut down SONGS permanently, to SCE during 2012.

14. It is not reasonable to prevent the Utilities from accruing AFUDC in 2012 for SONGS-related Construction Work In Progress.

15. In order to capture additional SONGS-related costs, it is reasonable for SCE to calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012.

16. The Commission's interim finding that SDG&E's internal SONGS-related costs of $60.5 million are reasonable does not preclude the Commission's subsequent review of SGRP and SGIR costs from the final review to come.

17. There is no evidence that that SCE has failed to comply with any federal, state, or county regulations regarding emergency preparedness.

18. It is reasonable for SCE to expand its public outreach activities into the 50-mile radius surrounding SONGS during the transition to decommissioning activities.

19. The ratemaking treatment approved by D.12-05-004 for the SONGS seismic studies should not be changed by today's decision.

20. The utilities should be authorized to recover their actual, reasonably incurred costs for the U2 Cycle 17 RFO of $45.1 million (100% share).

21. The utilities should be required to refund to ratepayers any amount previously collected for 2012 RFOs beyond the actually incurred $45.1 million.

22. To prepare for using the replacement power cost calculation method adopted here, the utilities should be required to serve Phase 3 exhibits detailing their calculation of their replacement power cost using the adopted method. The exhibits should also include other detailed information as specified in the body of today's decision.

23. Reply and rebuttal testimony in response to the Utilities' Phase 3 replacement power exhibits should be permitted if, and only if, any party alleges that the Utilities' exhibits do not comply with today's decision or contain calculation errors.

24. No party should be allowed to use the Phase 3 replacement power exhibits to relitigate any Phase 1A issue.

25. The assigned ALJs should be permitted to modify the schedule for the Phase 3 replacement power testimony.

O R D E R

IT IS ORDERED that:

1. Application 13-01-016 is granted to the extent set forth in this Decision. Southern California Edison Company's preliminarily allowed 2012 revenue requirement derived from expenses related to the San Onofre Nuclear Generation Stations is reduced by approximately $74 million. Southern California Edison Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the revised company revenue requirement of $5.671 billion as set forth in Appendix G, effective January 1, 2012.

    a. As part of the revenue requirement calculation ordered in paragraph 3, Southern California Edison Company shall calculate a separate estimate of Cash Working Capital requirements attributable to San Onofre Nuclear Generation Stations in 2012 using the lead lag and other relevant inputs adopted for the company in its 2012 General Rate Case.

2. Application 13-03-013 is granted to the extent set forth in this Decision. San Diego Gas & Electric Company's preliminarily allowed 2012 revenue requirement derived from expenses related to the San Onofre Nuclear Generation Stations is reduced by approximately $19 million. San Diego Gas & Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the revised revenue requirement effective

January 1, 2012.

a. San Diego Gas & Electric Company is also authorized to recover in rates $60.4 million in additional expenses incurred solely as a result of San Diego Gas & Electric Company's ownership interest and oversight responsibilities, and which are not included in Southern California Edison Company's invoiced pro rata share of San Onofre Nuclear Generation Stations operational expenses.

3. Within 10 days of the effective date of this decision, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the Utilities), in consultation with the Commission's Energy Division, shall each prepare a revised 2012 revenue requirement based on input of the reduced expenses and reduced rate base authorized herein, into each utility's 2012 General Rate Case model. The Utilities shall each submit the revenue requirement to the Commission as a Tier 1 Advice Letter, and serve the Advice Letter on the service list for these consolidated proceedings.

4. Within 20 days of the effective date of this decision, Southern California Edison Company and San Diego Gas & Electric Company shall submit revised tariff sheets to implement the revised 2012 revenue requirement. The revised tariff sheets shall become effective on filing, subject to a finding of compliance by the Commission's Energy Division, and shall comply with General Order 96-B.

5. Southern California Edison Company and San Diego Gas & Electric Company shall re-calculate the amount of 2012 operations and maintenance expenses directly related to steam generator inspection and repair, as set forth in this Decision, and identify the portion which was previously collected in rates. The Utilities shall separately account for the steam generator inspection and repair expenses previously collected, and those not yet collected in rates, in the San Onofre Nuclear Generation Station (Outage) Memorandum Accounts.

6. The Utilities shall accrue interest on collected steam generator inspection and repair funds at the one-year Treasury rate for the benefit of ratepayers to protect the value of the funds until the Commission completes its Phase 3 review of all expenses related to the replacement steam generators. All steam generator inspection and repair expenses, including those not recovered by the Utilities in rates, shall continue to be tracked in the San Onofre Nuclear Generation Station (Outage) Memorandum Accounts.

7. Within 90 days of the effective date of this decision, Southern California Edison Company shall develop a strategy for expanding public education activities about San Onofre Nuclear Generation Station and the future decommissioning to the public within a 50-mile radius of San Onofre Nuclear Generation Stations through 2016. Southern California Edison Company shall be particularly sensitive to pockets of alternative language users and coordinate with community-based organizations to ensure wide distribution of information to the public about the status of San Onofre Nuclear Generation Stations and its planned decommissioning. Southern California Edison Company shall submit the proposed strategy and implementation schedule to the Commission as an Information-Only Filing, as defined in Section 3.9 of the General Rules of General Order 96-B and serve it on the service list for these consolidated proceedings.

8. The ratemaking treatment approved by Decision 12-05-004 for the seismic studies shall remain unchanged by today's decision.

9. Southern California Edison Company and San Diego Gas & Electric Company are authorized to recover their respective shares of $45.1 million (100% share) for the Unit 2 Cycle 17 Refueling Outage that occurred in 2012.

10. Southern California Edison Company and San Diego Gas & Electric Company shall refund to ratepayers any amount previously collected for 2012

Refueling Outages beyond this $45.1 million.

a. Southern California Edison Company shall refund any remaining over-collection in its 2014 rates to the extent that the refund has not previously occurred in 2013 rates based on its 2013 Energy Resource Recovery Account filings.

b. San Diego Gas & Electric Company shall refund any remaining over-collection in its 2014 rates to the extent that the refund has not previously occurred in 2013 rates based on its Advice Letter 2416-E.

11. Within 45 days of the effective date of this decision Southern California Edison Company and San Diego Gas & Electric Company shall each serve a preliminary Phase 3 exhibit, including summary tables of their 2012 replacement power cost calculations according to the method adopted in today's decision. The summary tables shall include at least the details specified below:

a. Replacement Energy Cost;

b. Foregone Energy Sales;

c. Price elasticity adjustment, E, for on-peak and off peak periods for each month;

d. Capacity Procurement Mechanism Charges;

e. Standard Capacity Product Penalty Charges;

f. Replacement Resource Adequacy;

g. Foregone Resource Adequacy Sales;

h. Demand Response Costs;

i. Participating Intermittent Resource Program, Real Time Imbalance, and Auxiliary Load Charges; and

j. Net Cost of Related Congestion Revenue Rights Purchases.

12. Following the Utilities' submission of these preliminary Phase 3 exhibits, parties may serve reply testimony, if, and only if, they allege that the Utilities' calculations do not comply with today's decision or contain calculation errors.

Such reply testimony will be due 45 days after the Utility testimony. If any reply testimony is served, rebuttal testimony may be served 20 days later. The assigned ALJs may modify this schedule. Neither the original Utility exhibits nor any reply or rebuttal testimony may be used as an attempt to relitigate any Phase 1A issue.

13. All rulings made by the assigned Commissioner and/or Administrative Law Judge(s) to date are affirmed, all motions applicable to Phase 1 and Phase 1A and not yet ruled upon are deemed denied.

14. Investigation 12-10-013, Application 13-01-016, Application 13-03-005, Application 13-03-013, and Application 13-03-014 remain open.

This order is effective today.

Dated _____, at San Francisco, California.

Appendix A

Southern California Edison Company's Year End 2012 SONGSMA Report

(End of Appendix A)

Appendix B

San Diego Gas & Electric Company's Year End 2012 SONGSMA Report

(End of Appendix B)

Appendix C

Timeline

Appendix C - Timeline

1/9/2012	U2 Cycle 17 (C17) refueling outage (RFO) started 60-day schedule
1/272012	U2 Fuel moved to fuel pool complete
1/31/2012	U3 leak identified
2/5/2012	U2 steam generator retainer bar problem identified
2/8/2012	SCE begins Root Cause Analysis (U3)
2/11/2012	U2 initial Eddy Current Testing (ECT) completed
2/12/2012	U3 ECT inspection locates leaking tube
2/14/2012	U2 Expanded ECT (based on U3 findings)completed
2/14/2012	U2 replace Emergency Core Cooling System mini flow piping project completed
3/1/2012	U2 fuel move from fuel pool to core completed
3/1/2012	SCE Board of Directors (BoD) meeting; Dietrich reports delay restart U2 until source of U3 tube leak known
3/2/2012	U2 High pressure Turbine retrofit project completed
3/4/2012	U2 Replacement Reactor Vessel head project completed
3/4/2012	U2 C17 RFO originally scheduled to end (Return to Service -RTS)
3/13/2012	U2 C17 RTS restart schedule change from 3/20 to 4/15 due to additional ECT
3/13/2012	U3 In-situ pressure test of 129 tubes; 8 tubes fail
3/14/2012	U2 C17 RFO restart schedule changed from 4/15 to 5/16
3/16/2012	U2 equipment hatch closed
3/19/2012	NRC onsite Augmented Inspection Team (AIT) begins ten days of inspections
3/23/2012	SCE submits Steam Generator Return-to-Service Action Plan to NRC
3/27//2012	Confirmatory Action Letter issued by NRC
3/27//2012	U2 C17 RFO restart schedule changed from 5/16 to 6/1
3/2012	SCE developed plan to postpone, cancel, and re-schedule capital projects
4/1/2012	U2 FAC project completed
4/2/2012	U2 RTS scheduled
4/3/2012	U2 equipment hatch opened
4/6/2012	U2 special interest ECT
4/10/2012	U2 Tube-to-Tube wear (TTW) discovered
4/15/2012	U3 initial ECT completed
4/20/2012	U2 TTW inspection letter to NRC
4/23/2012	U2 first tube wear Root Cause Analysis (RCA) issued by SCE
4/23/2012	U2 Emergency Diesel generator replacement project completed
4/24/2012	U2 tube plugging and stabilizing list issued
4/26/2012	SCE BoD meeting with update on SONGS: Fluid Elastic Instability cause of TTW; reports U2 restart on 6/1/12; U3 by 6/30/12
5/7/2012	U3 first tube wear RCA issued by SCE, finds TTW in U2
5/72012	U2 C17 RFO restart schedule changed from 6/1 to 7/1

5/7/2012	NRC Restart statement issued
5/16/2012	NRC issued AIT Charter rev.1
6/2012	U3 planning begins to place U3 into preservation mode
6/7/2012	U2 C17 RFO restart schedule changed from 7/1 to 8/17
6/18/2012	NRC public meeting in San Juan Capistrano (AIT Exit)
6/25/2012	Budget Review Committee meeting to defer capital projects (part 1 of 2)
7/2012	Efforts to place U3 into preservation mode begin
7/1/2012	U2 Vibration and Loose Parts Monitoring System replacement project completed
7/11/2012	Budget Review Committee meeting to defer capital projects (part 2 of 2)
7/18/2012	NRC issues initial AIT report
7/19/2012	U2 C17 RFO restart schedule changed from 8/17 to 11/18
7/27/2012	SCE separates outage response team into U2 Restart and U2/U3 long-term repair teams; SCE tells MHI of expectations of warranty conditions for long-term repair
8/23/2012	U2 C17 RFO restart schedule changed from 11/18 to 12/2
8/22/2012	NRC performs follow-up steam generator AIT inspection
8/25/2012	SCE BoD meeting with SONGS update:
9/4/2012	NRC adopted modified inspection plans for U2/U3 based on “extended Outage Shutdown Condition”
9/6/2012	SCE BoD meeting with SONGS update: status of SONGS as of 8/27 target U2 restart 12/12, U3 4Q2013
9/11/2012	U3 major systems engineering recommendations completed re long-term lay-up plan, reviews on-going; SCE-25
9/24/2012	NRC meets with Mitsubishi Heavy Industries (MHI) in Kobe, Japan
9/28/2012	NRC follow-up inspection of unresolved issues from AIT report
10/2012	SONGS-wide meeting re more inspections(TR 1056)
10/1/2012	U3 reactor defueling begins
10/3/2012	U2 CAL response submitted to the NRC re U2 restart plan
10/5/2012	U3 reactor defueling ends
10/9/2012	NRC public meeting at Dana Point
10/11/2012	MHI reps meet with Avella and Dietrich and proposed repair/replacement options; assessment expected by 2Q13 or 3Q13
10/17/2012	U2 equipment hatch closed
10/20/2012	U2 achieves Mode 4 to test systems
10/23/2012	U2 achieves Mode 3 (raised reactor coolant system to normal operating pressure and temperature to test return-to-service readiness)
10/25/2012	U2 Reactor Coolant System test at normal operating conditions (reactor not critical)
10/25/2012	SCE BoD meeting SONGS status: U2 response to CAL filed with NRC, restart discussions underway; U3 long-term repair plans in development
10/26/2012	U2 entered Mode 4
10/27/2012	U2 returned to Mode 5
11/8/2012	U2 C17 RFO restart schedule changed from 12/2 to 2/3/13

11/8/2012	E. Avella (SCE) Letter to Dr. A. Kaguchi: provides MHI with SCE's acceptable warranty conditions for long-term repair of the SGs; given in meetings since 7/27/2012; SCE-24
11/9/2012	AIT Follow-up Report : two unresolved issues from CAL; advised no reply to SCE's CAL response until inspections, technical review, public meetings, + 45 days of process time before earliest U2 restart
11/13/2012	Letter from Edward Avella to MHI Regarding Screening Criteria for Acceptance of Steam Generator Permanent Repair (SCE-20)
11/20/2012	SCE submits 1st Proof of Loss to NEAL under outage accident insurance policy (replacement power)
11/28/2012	Letter from P. Dietrich to K. Yamauchi at MHI: MHI hasn't complied with contract to provide repairs or replacements with due diligence; wants repair options for U2 and U3 by 12/28; (SCE-21)
11/30/2012	NRC public Meeting in Laguna Hills
12/3/2012	NRC conducts follow-up inspections to SCE's CAL response
12/5/2012	NRC's Atomic Safety Licensing Board held hearings to determine whether SCE needs a license amendment to restart U2 at 70%
12/13/2012	U2 C17 restart schedule changed from 2/2/13 to 3/3/2013
12/14/2012	MHI progress letters (2) to SCE on long-term repair options (Exhibits SCE-14, SCE-17)
12/14/2012	SCE submits 2nd Proof of Loss to NEAL
12/14/2012	MHI/SCE meeting for status on repair options; SCE-22
12/18/2012	NRC public meeting on requests for Additional Information (RAIs) in Washington D.C.
12/19/2012	Letter from P. Dietrich to K. Yamauchi at MHI: contract requires actual repair or replacement to occur with due diligence and dispatch; SCE-23
12/19/2012	Letter from E. Avella (SCE) to Dr. H. Kaguchi at SONGS SG Repair Site Team: follow-up to 12/14 meeting, MHI should provide 3 options, following SCE review criteria—MHI missed two prior dates for final recs
12/20/2012	MHI provided long-term repair options and recommendations (SCE-15)
12/20/2012	SCE submits 3rd Proof of Loss to NEAL; total of claims is $234 million (100%), $183 million (SCE share)
12/26/2012	NRC request for additional information in response to CAL
12/29/2012	MHI Letter to SCE
2013	
1/30/2013	U3 Long term preservation Plan Rev. 8; SCE-25

(End of Appendix C)

Appendix D

O&M by Functional Group

Appendix D – O&M by Functional Group

Functional Group		Preliminarily Allowed	Total Base Recorded	Recorded Base-Routine	Difference between Preliminarily Allowed and Recorded Base-Routine	SCE Claimed Exempt[1] ($ / %)	Comments
		All values in 1000s of 2012$, 100% Share					
Operations	Labor	$31,654	$39,437	$34,373	$(2,719)	$10,657 / 30%	Responsible for operation of SONGS, including safety systems, in normal or shutdown conditions.
	Non-Labor	$3,704	$1,385	$1,385	$2,319		
	Total	$35,358	$40,822	$35,758	$(400)		
Maintenance	Labor	$64,401	$52,518	$51,409	$12,992	$33,025 / 30%	Performs preventive and corrective maintenance and testing of mechanical, electrical, control, and protective systems.
	Non-Labor	$45,584	$36,745	$36,745	$8,839		
	Total	$109,985	$89,263	$88,154	$21,831		
Engineering	Labor	$41,984	$40,049	$37,758	$4,226	$7,923 / 15%	Of the five divisions within this group, SCE asserts that three divisions (Plant Engineering, Nuclear Safety, and Nuclear Oversight/Assessment) are essential during shutdown.
	Non-Labor	$10,653	$(1,257)	$(1,257)	$11,910		
	Total	$52,637	$38,792	$36,502	$16,136		
Site Projects	Labor	$852	$657	$657	$196	$0 / 0%	Performs cyclical or reactive projects. SCE does not contend that expenses in this group would be necessary under extended shutdown conditions.
	Non-Labor	$14,876	$16,896	$16,896	$(2,020)		
	Total	$15,728	$17,553	$17,553	$(1,825)		
Rad Chemical	Labor	$15,770	$12,835	$11,828	$3,942	$7,238 /	Responsible for chemistry control of

[1] Converted from 2009$ as shown in Table V-4 of SCE-1 by multiplying by 1.095

Functional Group		Preliminarily Allowed	Total Base Recorded	Recorded Base-Routine	Difference between Preliminarily Allowed and Recorded Base-Routine	SCE Claimed Exempt[1] ($ / %)	Comments
Control	Non-Labor	$8,314	$7,624	$7,624	$690	30%	fuel pools and effluent as well as radioactive material control.
	Total	$24,084	$20,459	$19,452	$4,632		
Regulatory Affairs	Labor	$8,917	$9,316	$9,112	$(195)	$9,591 / 75%	Includes emergency preparedness and occupational safety and health.
	Non-Labor	$3,843	$1,714	$1,714	$2,129		
	Total	$12,760	$11,030	$10,825	$1,935		
Security	Labor	$39,870	$41,601	$41,326	$(1,456)	$37,357 / 90%	Protection against radiological sabotage per NRC regulations.
	Non-Labor	$1,410	$2,112	$2,112	$(702)		
	Total	$41,280	$43,713	$43,438	$(2,158)		
Training	Labor	$10,670	$10,963	$10,942	$(272)	$4,427 / 30%	Trains operations, maintenance, and other staff.
	Non-Labor	$4,049	$2,619	$2,619	$1,430		
	Total	$4,719	$13,582	$13,561	$1,158		
Nuclear Support	Labor	$31,239	$30,646	$29,762	$1,477	$17,879 / 20%	Implements financial planning, budgeting, accounting, and compliance programs.
	Non-Labor	$58,328	$52,743	$52,743	$5,585		
	Total	$89,567	$83,389	$82,506	$7,061		
Corporate Support	Labor	$(10,688)	$0	$0	$(10,688)	n/a	
	Non-Labor	$(7,032)	$(20,463)	$(20,463)	$13,431		
	Total	$(17,720)	$(20,463)	$(20,463)	$2,743		
Total	Labor	$234,669	$238,021	$227,165	$7,504	$128,096 / 32%	
	Non-Labor	$143,729	$100,118	$100,118	$43,611		
	Total	$378,398	$338,139	$327,284	$51,114		

(End of Appendix D)

Appendix E

SONGS 2012 Base O&M Costs Excluding Corporate Support, Severance, and IT (100% share, 000's of 2012$

Appendix E – SONGS 2012 Base O&M Costs, excluding Corporate Support, Severance, and IT (100% share, 000's of 2012$)

Month	Base - Routine				SGIR (includes both "Base" and "Total" SGIR)				Total Adopted Base O&M
	Recorded[1]	Adjustment Factor	Adopted	Disallowed	Recorded[2]	Adjustment Factor	Adopted as Base O&M	To Review in Phase 3[3]	
January	35,354	1.0	35,354	0	0	1.0	0	0	35,354
February	33,788	1.0	33,788	0	9,246	1.0	9,246	0	43,034
March	29,112	1.0	29,112	0	18,214	0.5	9,107	9,107	38,219
April	29,556	1.0	29,556	0	20,970	0.0	0	20,970	29,556
May	29,135	1.0	29,135	0	7,832	0.0	0	7,832	29,135
June	25,770	0.9	23,193	2,577	10,092	0.0	0	10,092	23,193
July	28,294	0.8	22,635	5,659	13,603	0.0	0	13,603	22,635
August	27,222	0.7	19,055	8,167	30,171	0.0	0	30,171	19,055
September	23,483	0.6	14,090	9,393	20,471	0.0	0	20,471	14,090
October	35,353	0.5	17,677	17,677	2,007	0.0	0	2,007	17,677
November	25,515	0.4	10,206	15,309	3,794	0.0	0	3,794	10,206
December	25,164	0.4	10,066	15,098	4,556	0.0	0	4,556	10,066
Total	347,746	n/a	273,867	73,880	140,956	n/a	18,353	122,603	292,220

(End of Appendix E)

[1] SCE-35 at 6.

[2] Ibid. Sum of lines: "Total Base – SGIR Recorded" and "Total SG Insp & Repair Recorded."

[3] If, in Phase 3, SCE is found to have been imprudent or otherwise at fault, these SGIR costs may be subject to refund.

Appendix F

Capital Expenditures

Appendix F – Capital Expenditures

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
Common - Required	Total	$38,389	Includes projects that are not unique to a single reactor unit.
	Spare Parts Blanket	$4,182	Includes long lead time items needed for continuity of service that are not typically used more than once a year.
	Outage Replacements - overhauls to SONGS 2C17 Allowance	$5,377	Replacements of in-kind capital equipment during the U2 Refueling Outage (RFO)
	U2/3 ISFSI AHSMs	$4,819	New Advanced Horizontal Storage Modules (AHSMs) are added to the Independent Spent Fuel Storage Installation (ISFSI) for each refueling. The AHSMs protect the fuel canisters and provide radiation protection.
	SCR 32PTH System - Canister	$5,223	This project is an upgrade of the dry storage fuel canisters to hold more fuel per canister. The project also includes purchase of related equipment.
	U2/3 Dry Cask Spent Fuel Storage - Canisters	$11,281	Transfer of fuel from the ISFSI to dry storage for the U2 RFO and U3 defueling.
	Other (furniture, computers, tools, transfer of fuel to ISFSI)	$7,507	
Work in Progress	Total	$84,533	Includes projects that were in process during 2011.
	Control Room Upgrade	$3,545	Changes to the Control Room to meet industry standards and NRC expectations.
	Eddy Current Testing U2C17	$3,851	The NRC requires a full length examination of each steam generator tube after the first cycle of operation.
	CCW Heat Exchangers SONGS 2	$5,017	The Component Cooling Water (CCW) heat exchangers for U2 were replaced during the RFO.

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
	U2 High Pressure Turbine (HPT) Retrofit	$7,075	The U2 HPT was replaced during the RFO. This project was approved by the CPUC in SCE's 2009 GRC, D.09-03-025.
	Replace 400' of U2 ECCS Schedule 10 Mini Flow Piping	$7,629	During the U2 Cycle 16 RFO, evidence of damage to the Emergency Core Cooling Schedule (ECCS) 10 piping was discovered. During the U2 Cycle 17 RFO in 2012, the highest risk sections of piping were replaced.
	FAC - Capital R2C17	$7,658	This is part of a long-term project to replace piping components subject to Flow Accelerated Corrosion (FAC). The costs shown here were incurred during the U2 Cycle 17 RFO. Replacements for U3 were rescheduled.
	U2 Rapid Refueling	$10,840	Completed during the U2 Cycle 17 RFO, this project was designed to allow faster assembly and disassembly of the Reactor Vessel Heads (RVH).
	U2 Procure & Install RRVH Heads	$29,069	Replacement of the RVH during the U2 Cycle 17 RFO.
	Other (Tech Specs, various capital replacements)	$9,849	
Emergent - Regulatory Required	Total	$17,937	Projects that emerged after SCE's 2012 GRC forecast due to regulatory requirements.
	Cyber Security Phase 2	$3,576	Phase 2 (of 3) of an NRC-required project to implement a cyber security defense strategy.
	NFPA-805 Fire	$4,494	An ongoing project to meet NRC fire protection requirements that apply regardless of the operational status of the plant.
	Other (upgrades related to Once Through Cooling environmental, Fukushima	$9,867	

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
	responses, and security)		
Rescheduled	Total	$1,434	Projects that were started in 2012, but rescheduled or suspended after the outage began.
Ongoing - Completion Rescheduled	Total	$19,754	Projects started before 2012, but rescheduled or suspended due to the outages. Includes some projects for U3 that are analogous to U2 projects described in the "Works in Progress" category.
	U3 HPT Retrofit Project	$8,963	Analogous to the U2 project above, but not completed.
	Other (CCW Heat Exchangers, Rapid Refueling and RVHs, U2 water purification)	$10,791	
Marine Mitigation	Total	$5,559	Ongoing projects to comply with SONGS's permit from the California Coastal Commission.
	Reef	$1,388	Costs associated with Coastal Commission monitoring of the completed reef.
	Wetlands	$4,171	Monitoring of the restored wetlands and corrective construction.
Grand Total		**$167,606**	

(End of Appendix F)

Appendix G

Results of Operations Model Output From SCE's GRC

Appendix G – Results of Operations Model Output, from SCE's 2012 GRC

Line	Item	Adopted (1000s of dollars)	
1.	**TOTAL OPERATING REVENUES**	5,596,526	
2.	**OPERATING EXPENSES:**		
3.	Production		
4.	Steam	14,478	
5.	Nuclear	298,447	
6.	Hydro	56,000	
7.	Other	126,328	
8.	Subtotal Production	495,253	
9.	Transmission	87,740	
10.	Distribution	465,850	
11.	Customer Accounts	209,595	
12.	Uncollectibles	11,062	
13.	Customer Service & Information	45,521	
14.	Administrative & General	818,289	
15.	Franchise Requirements	49,381	
16.	Revenue Credits	(149,965)	
17.	Subtotal	2,032,725	
17.	Escalation	168,852	
18.	Depreciation	1,221,584	
19.	Taxes Other Than On Income	245,929	
20.	Taxes Based On Income	463,520	
21.	Total Taxes	709,449	
22.	**TOTAL OPERATING EXPENSES**	4,132,609	
23.	**NET OPERATING REVENUE**	1,316,581	
24.	**RATE BASE**	15,063,859	
25.	**RATE OF RETURN**		8.74%
26.	Four Corners	88,388	
27.	Mohave	(5,552)	
28.	Legacy Meters	64,500	
29.	**REVENUES AT PRESENT RATES**	5,398,840	
30.	**NET INCREASE OVER PRESENT RATES**		197,686

(End of Appendix G)