SCE's Decision to Retire San Onofre Units 2 & 3: Economic Considerations

This paper summarizes the economic considerations relevant to the decision by Southern California Edison (SCE) to retire San Onofre Nuclear Generating Station Units 2 and 3, announced on June 7, 2013. The objective of this paper is to provide context for a more complete public understanding of SCE's decision.

Method of Estimating Costs and Benefits of San Onofre Operation

An economic analysis compares the total cost of retiring San Onofre to the cost of various operating scenarios. In other words, all costs that would be incurred or avoided based on the operating conditions of San Onofre should be considered. Those costs include the amount required to operate San Onofre; the costs of purchasing energy, capacity and greenhouse gas allowances in the market if San Onofre is not operating; the costs of maintaining San Onofre personnel and systems in a condition that would permit the plant to return to service, as well as the costs of maintaining San Onofre in a shutdown state; the amortization of the cost of nuclear fuel; and the impact of higher market prices resulting from San Onofre being out of operation on other contracts and resources under SCE's control. In addition, the risks surrounding the level and timing of these costs, and the uncertainty surrounding restart and repair options, should be weighed. Not relevant to this analysis, however, are costs already incurred and hence unavoidable regardless of whether San Onofre returned to service.

In determining the total cost of various San Onofre operating scenarios, this analysis makes no assumptions as to who would pay those costs: Mitsubishi (the designer and fabricator of the defective replacement steam generators), Nuclear Electric Insurance Limited (SCE's insurer), ratepayers or shareholders. The allocation of costs among those stakeholders will be determined in the future.[1]

Operating Scenarios and Assumptions

While many operating scenarios could be considered, three are most relevant given the operational limitations of the replacement steam generators (RSGs): (1) retire both units, (2) operate Unit 2 at 70-percent power and retire Unit 3, and (3) operate Unit 2 at 70-percent power and operate Unit 3 at 60-percent power.[2] The costs of each scenario are considered through 2022, which is the year in which each of the San Onofre Unit 2 and 3 operating licenses issued by the Nuclear Regulatory Commission (NRC) expire. To operate San Onofre beyond the 2022 license dates, SCE would need to apply to the NRC for a license renewal, and the defects in the RSGs introduced considerable uncertainty regarding any license renewal. Accordingly, it is

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[1] In presenting this economic analysis, SCE reserves all rights, including rights against Mitsubishi and Nuclear Electric Insurance Limited.

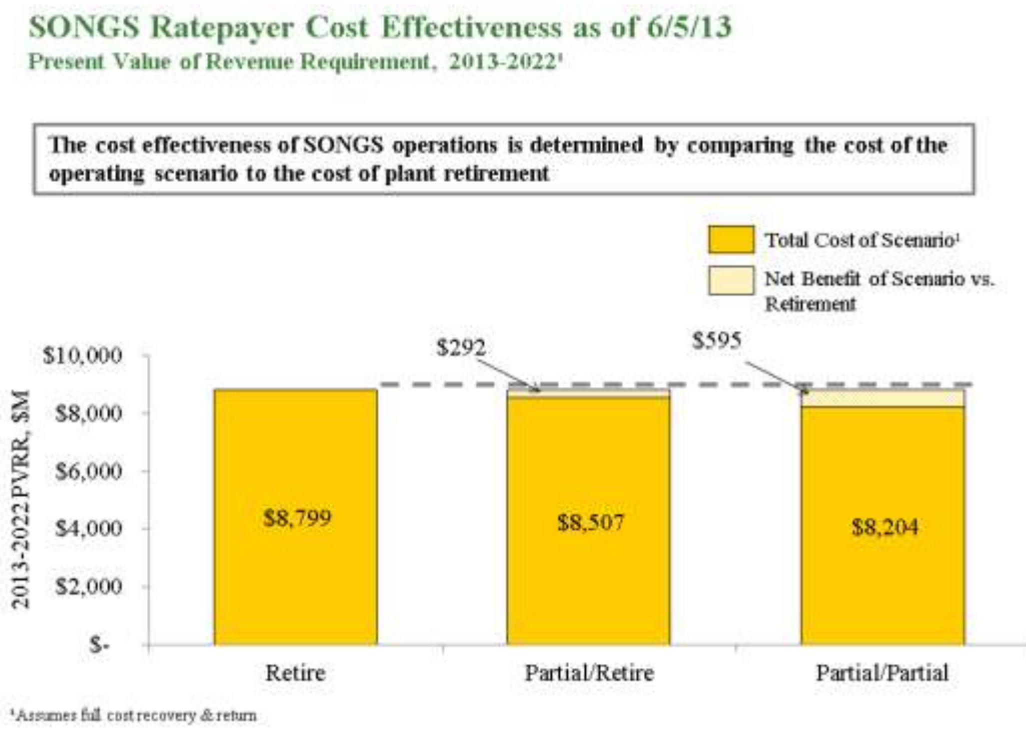
[2] The 60-percent power for Unit 3 is used for the purposes of economic analysis given the more extensive tube wear in that unit compared to Unit 2. However, there was significant uncertainty whether Unit 3 could have been operated even at that lower power level.

reasonable to consider cost scenarios through 2022. The San Onofre operating scenarios can then be compared to one another by computing the present value of the costs projected for each scenario.

Any analysis of future costs is necessarily based on projections, such as projected market prices for energy, capacity and greenhouse gas allowances, and the projected costs of operating San Onofre. In addition, as explained below, the projected dates that the units restart are critical variables that significantly affect the analysis of all scenarios. To make the analysis clear, this paper assumes the best-case scenario: that Unit 2 could have restarted in September 2013 and Unit 3 could have restarted 15 months later (*i.e.*, January 2015) at partial power levels. As of June 2013, there was no realistic possibility that the units could have been restarted any earlier than those dates. The importance of these assumptions, and their impact on the conclusion, are discussed below.

Costs and Benefits of San Onofre Operations

A summary of the costs of the various operating scenarios, based on these assumptions and projections, is shown below:

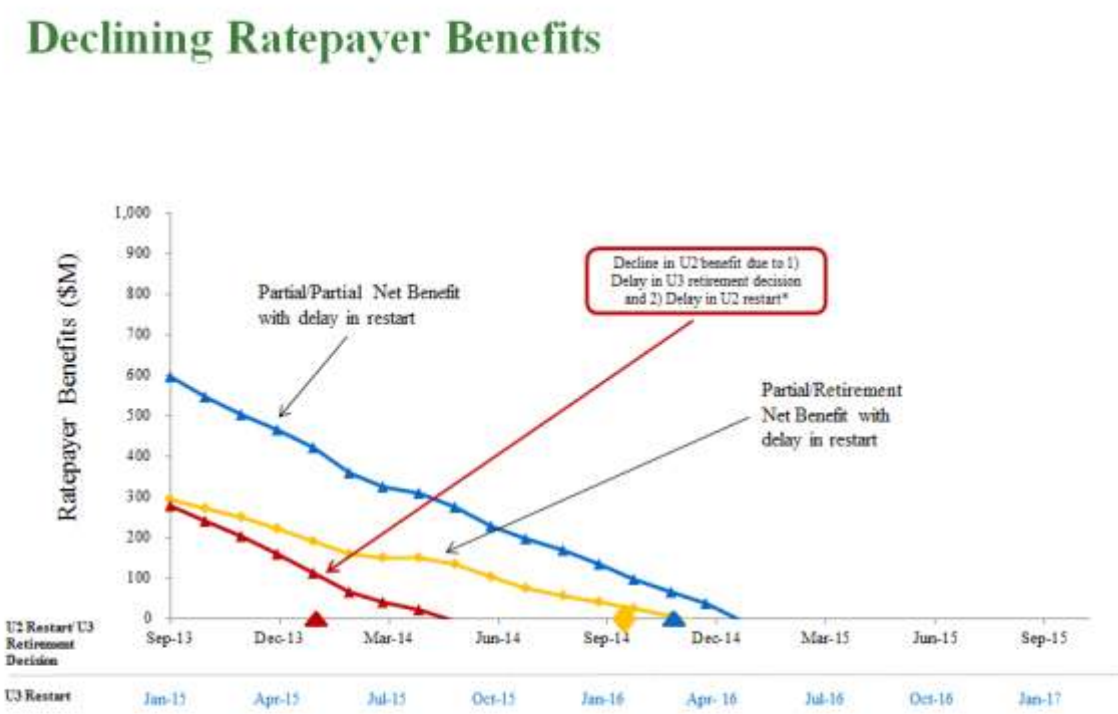


This graphic illustrates the costs (1) of operating Unit 2 at 70 percent starting in September 2013 and retiring Unit 3 in June 2013 (partial/retire) and (2) of operating Unit 2 at 70 percent starting in September 2013 and Unit 3 at 60 percent starting in January 2015 (partial/partial). The graphic shows that the partial/retire scenario is projected to cost $292 million less than retirement, whereas the partial/partial scenario is projected to cost $595 million less than retirement. These cost savings are also referred to in this paper as the “benefits” of the specified operating scenarios.

As this graphic demonstrates, the projected benefits of both operating scenarios are relatively small (3-7 percent) compared to the overall costs of each scenario. Given the uncertainty inherent in the assumptions on which the projections are based, even a small variance in those projections could result in future costs greater than the savings under the above assumed conditions, thereby eliminating the benefits.

<u>Impact of Delay in Restart</u>

The timing of restart has a dramatic impact on the costs of the scenarios. As noted, the benefits shown above assume that Unit 2 restarts in September 2013 and Unit 3 restarts 15 months later at partial power. As those restart dates slip, the benefits decline quickly. In order to enable San Onofre to be restarted, SCE had to spend large amounts to keep San Onofre personnel and systems in a state of readiness. As restart is delayed, those costs continue to increase, while the corresponding benefits decrease (because less time is available for San Onofre to operate before the end of the current NRC operating license period). The impact of delay in restart is illustrated by the following graphic:



The red line shows that the benefits of restarting Unit 2 decline to zero if restart of Unit 2 is delayed from September 2013 to March 2014 while the option to restart Unit 3 is kept open. The yellow line shows that this timeline could be extended by about six months if Unit 3 were retired immediately. In that partial/retire scenario, SCE could save some of the costs associated with Unit 3. The yellow line shows that the benefits of restarting decline to zero if Unit 3 is retired immediately and restart of Unit 2 is delayed from September 2013 to November 2014.

The blue line shows that, if both units are kept in readiness and ultimately restart, the benefits of restarting decline to zero if restart of Unit 2 is delayed from September 2013 to January 2015. As noted above, however, there was substantial technical uncertainty as to whether Unit 3 could be restarted even at a 60 percent power level.

While the additional costs of maintaining San Onofre personnel and systems in a state of readiness for restart are certain, the economic benefits of restart are uncertain because it cannot be known whether or when the NRC would have allowed SCE to restart Units 2 and/or 3. As restart is delayed, the total amounts that SCE would have to expend increases, and the associated benefit decreases because San Onofre would have less time to operate before the end of its current operating license.

Unit 2 Option Value & Cost
(100% SONGS Share, 2013-2022 Ratepayer NPV)

Unit 2 Startup / Operational Slippage	Cost of Unit 2 Option ($M)[1]	Net Benefit of Unit 2 @ 70% ($M)
9/1/13	0	292
6 months	114	148
1 year	177	39

[1]Unit 2 option cost is the difference in O&M and repair costs between the retire and partial/retire scenarios

The above graphic illustrates this tradeoff, showing that as restart of Unit 2 is delayed, costs increase while benefits decrease. The graphic quantifies the cost of maintaining the "option" to restart Unit 2. It shows the amount that SCE would have to spend to keep personnel and systems in place past Sept. 1, 2013 in order to enable Unit 2 to be restarted. If restart is delayed by one year past Sept. 1, 2013, SCE would have to spend $177 million. If, at the end of that year, Unit 2 restarts at 70-percent power, the benefit is projected at $39 million through 2022. Of course, if restart were pursued but not permitted, the additional $177 million investment would produce no benefit.

Impact of NRC Process on Timing of Restart

Because a delay in restart increases the total costs of non-operation and decreases the time to accumulate the benefits that result from an operating unit, it is important to evaluate whether and when the NRC could permit restart. In evaluating that question, the May 13, 2013 decision of the Atomic Safety Licensing Board (ASLB) is significant. That ASLB decision, in effect, required SCE to obtain a license amendment before restart because of the fluid-elastic instability the RSGs experienced, and to do it on grounds broader than those encompassed within the license amendment request SCE had previously filed with the NRC on April 5, 2013. As a result, SCE could not realistically have restarted without either filing a new license amendment request or persuading the NRC to stay or overturn the ASLB's decision. Both of these actions would have required substantial time.

The ASLB's decision and SCE's previously-filed license amendment request of April 5, 2013 raise the critical question of whether an adjudicatory hearing would be required before the NRC would grant the license amendment and permit SCE to restart San Onofre. The process for this type of hearing, which is called a "pre-issuance hearing," typically takes at least a year from the date that the hearing request is made. Thus, if a pre-issuance hearing were held, the earliest a license amendment could be expected would be mid to late 2014.

A pre-issuance hearing could be ordered at any of a number of points in the process. In order to grant a license amendment permitting restart without a pre-issuance hearing, the NRC staff would have to make a finding that the license amendments would present "no significant hazards consideration" (NSHC). The NSHC determination could be challenged in the U.S. Court of Appeals. A pre-issuance hearing could result (1) if the NRC staff determined that the license amendment would involve a significant hazards consideration, (2) as a result of a request by Friends of the Earth for the Commission to use its inherent supervisory authority to find that the NRC staff's NSHC determination in connection with the license amendments was not appropriate, or (3) a reversal of the NRC staff's NSHC determination by the U.S. Court of Appeals.

An adverse determination at any one of these steps would result in a pre-startup hearing and concomitant delay in restart.

Beyond the issues surrounding the April 5, 2013 license amendment request and the ASLB decision, there were several other NRC actions that could have negatively impacted restart of San Onofre Unit 2. Those include the following: (1) the NRC staff could have delayed a decision on or denied SCE's request to restart Unit 2 at 70-percent power; (2) in response to Friends of the Earth's petition under 10 CFR 2.206, the NRC staff could have decided that a license amendment was needed for installation of the replacement steam generators in 2010-2011; (3) in response to a likely request for a stay of restart by Friends of the Earth, the commission could have agreed to issue a stay; and (4) the NRC staff could have delayed in making its decision on SCE's license amendment request of April 5, 2013 or a license amendment request submitted in response to the ASLB decision.

To evaluate whether restart of Unit 2 would occur and the timing of a restart decision, one must consider the compound probability of all of the events discussed above. Considering each of these steps in light of the political environment following the tube leak, the likelihood that SCE would have been allowed to restart in 2013 appears small. Therefore, as a matter of probability, it should be assumed that Unit 2 could not restart until sometime in 2014 (possibly not until the second half of 2014). Under the economic assumptions noted above, a delay in the restart of Unit 2 to the fall of 2014 erases all of the benefits of restart, even if Unit 3 were retired immediately. Furthermore, if SCE were to have kept open the option of operating Unit 3, all benefits of restart of Unit 2 at 70-percent power would be erased if restart would not occur by March 2014.

Impact of Other Uncertainties

In addition to the uncertainty regarding the timing of restart, the projected benefits of restart are subject to other significant uncertainties. While the benefits of restart could have been greater than projected (for example, if natural gas prices were higher than assumed), they could also have been smaller (for example, if the costs of operating and maintaining San Onofre were higher than assumed).

Impact of Repair or Replacement Options

Up to this point, we have examined the benefits of restarting Units 2 and 3 at reduced power without making any further repairs. Mitsubishi advocated two possible options for addressing the defects in the steam generators. The first was to repair them by inserting additional anti-vibration bars. Mitsubishi did not demonstrate that this repair option was viable. Mitsubishi's concept was so preliminary and subject to so many uncertainties that it would not have been prudent to continue spending money to maintain San Onofre personnel and systems in readiness for over a year — and potentially to spend an estimated $125 million per generating unit — to pursue that option.

A fundamental problem with Mitsubishi's repair option is that it did not meaningfully address the extreme thermal-hydraulic conditions that led to the tube failures. The fluid-elastic instability that caused the tube failures resulted from the combination of high-steam velocity, high-void fraction and the absence of sufficient contact force between the tubes and the support structures. SCE's proposed restart was based on addressing the first two conditions: reducing power unquestionably reduces steam velocity and void fraction. Mitsubishi's repair proposal chose the opposite route of attempting to increase contact force by adding anti-vibration bars. Because Mitsubishi's original anti-vibration bar design did not adequately control fluid-elastic instability, and because Mitsubishi's new concept was a first-of-a-kind project, the success of Mitsubishi's repair proposal was at best speculative.

Mitsubishi's concept of inserting additional anti-vibration bars also had the potential to introduce new problems, including new modes of tube bundle damage, increased vibration of the existing AVBs, deformation of tubes, ballooning of tubes and additional tube-to-tube wear. Mitsubishi did not demonstrate that these risks could be avoided.

Furthermore, Mitsubishi did not show that the NRC would approve the repair option in light of these and other concerns. Eight months after SCE submitted its restart proposal for Unit 2, the NRC had not approved it, even though there was no question that lower power would reduce steam velocity and void fraction and even though Unit 2 evinced less wear than Unit 3. Mitsubishi's proposal reflected that it had not confirmed the licensability of its repair, and Mitsubishi provided no basis for believing that the NRC would approve a restart at 100-percent power with its repair option, given the tremendous uncertainty about whether that option would prevent fluid-elastic instability.

The second option Mitsubishi offered — and the one it recommended in December 2012 — was to replace the tube assembly in the defective steam generators with a brand new set of tubes. This option potentially could have been economic if, but only if, the units were restarted at reduced power in a timely manner. As noted, whether and when the NRC would permit restart was uncertain. The replacement option also suffered from a number of uncertainties. For example, Mitsubishi had not yet offered a proposed design for the new tube bundle, much less demonstrated that such a design would prevent the serious problems experienced with its prior design. Installation also posed significant risks, as it was not clear that new tube bundles could be installed through existing containment access pathways, and no other plant had successfully opened its containment domes on multiple occasions. Moreover, the replacement of the tube assembly would have cost hundreds of millions of dollars, in addition to the hundreds of millions of dollars SCE would have had to spend to keep San Onofre personnel and systems in place for the four years (or longer) that it would have taken to complete the replacement. Mitsubishi, however, did not offer to pay for any of these costs. Furthermore, given the long lead-time for designing and fabricating new tubes, SCE would have had to commit to this replacement quickly in order for a replacement tube bundle to be installed in time to produce benefits before the expiration of the NRC licenses.

To be clear, in order for SCE to have adopted Mitsubishi's second repair option, SCE would have been required to:

1. Commit to spend nearly a billion dollars (or even more) on a repair that Mitsubishi had not yet designed, had not established would be successful and had not offered to pay for;

2. Wait at least five years for the replacement tube bundle to be installed, even if everything went perfectly;

3. Commit to pursuing the replacement option before knowing whether or not the NRC would permit restart at reduced power, or when that permission might be granted, or if the other uncertainties noted above were resolved

Given these unreasonable and unacceptable conditions, it was not prudent to pursue a replacement option.[3]

[3] While some of the inputs to the analysis upon which SCE relied in making the decision to retire San Onofre are protected by the attorney-client privilege, this paper does not reveal privileged information. SCE does not intend to, and does not, waive any applicable privilege.